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DTE Energy

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January 31, 2018

Kavita M. Kale
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: In the matter of the application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for accounting authority
Case No. U-18014

Dear Ms. Kale:

Pursuant to the Commission's final order in the above referenced case, please find attached DTE Electric Company's Distribution Operations Five-Year (2018-2022) Investment and Maintenance Plan Final Report. If you have any questions, please feel free to contact me.

Very truly yours,

Andrea Hayden

Digitally signed by Andrea Hayden
DN: cn=Andrea Hayden, o=General Counsel - Regulatory, ou=General Counsel - Regulatory, email=andrea.hayden@dteenergy.com, c=US
Date: 2018.01.31 15:29:18 -05'00'

Andrea Hayden

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DTE Electric Company

Distribution Operations Five-Year (2018-2022)

Investment and Maintenance Plan

Final Report

January 31, 2018

MPSC Case No. U-18014

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1 Introduction

1.1 Regulatory Context

In the Final Commission Order for Case No. U-18014, the Michigan Public Service Commission (MPSC) directed DTE Electric (DTEE) to develop and submit a five-year distribution investment and maintenance plan. Specifically, the order indicated that the plan should comprise: (1) a detailed description, with supporting data, on distribution system conditions, including age of equipment, useful life, ratings, loadings, and other characteristics; (2) system goals and related reliability metrics; (3) local system load forecasts; (4) maintenance and upgrade plans for projects and project categories including drivers, timing, cost estimates, work scope, prioritization and sequencing with other upgrades, analysis of alternatives (including Advanced Metering Infrastructure, also known as AMI, and other emerging technologies), and an explanation of how they will address goals and metrics; and (5) benefit-cost analysis considering both capital and O&M costs and benefits. The Commission further directed DTEE to submit a draft plan to Staff by July 1, 2017, and to meet with the Staff to complete a final five-year distribution investment and maintenance plan to be submitted by December 31, 2017.

On October 11, 2017, the Commission issued a supplemental order in Case No. U-18014, providing clarification that this first iteration of the five-year distribution plan should primarily focus on the following priorities: (1) defining the scope of work, capital and O&M investments needed to address aging infrastructure and the risk assessments that drive the prioritization of these investments; (2) identifying known safety concerns on the system and work necessary to address these concerns; (3) system maintenance and investment strategies that improve resiliency and mitigate the financial effects and safety issues associated with inclement weather; and (4) company objectives and associated performance metrics relevant to the utility near-term investment and maintenance plan. In particular, the Commission requested a timeline and investment strategy for meeting the Governor's 2013 reliability goals addressing the frequency and duration of electric outages: (1) operate in the first quartile among peers for system average interruption frequency index (SAIFI) and (2) in the top half among peers for system average interruption duration index (SAIDI). The order also extended the final report submission timeline for DTEE from December 31, 2017 to January 31, 2018.

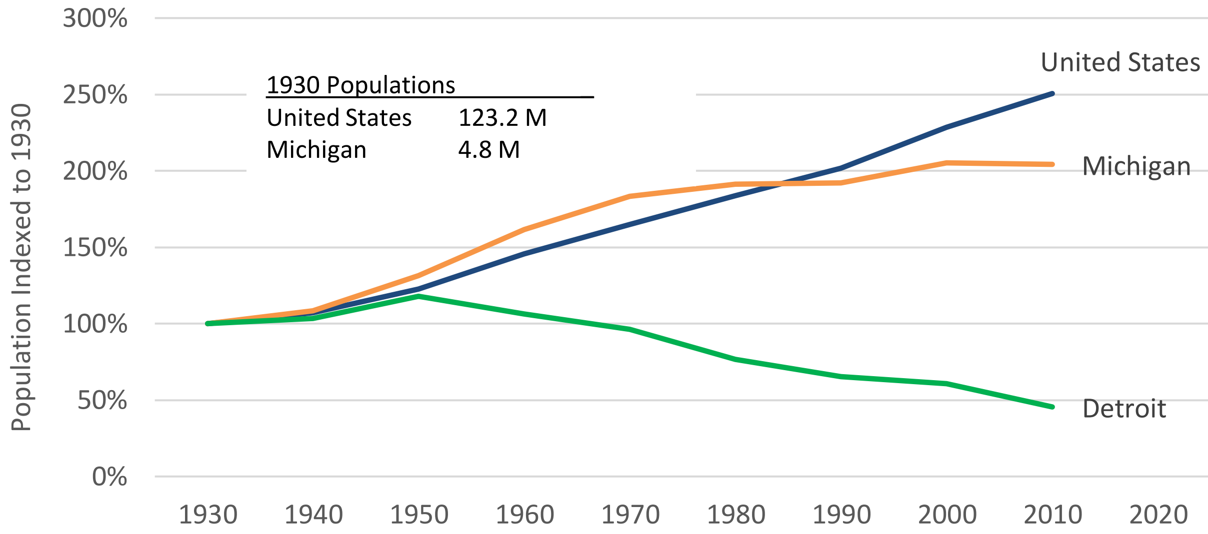
1.2 Aging Infrastructure Challenges

DTEE is facing the same aging infrastructure challenges that many others are experiencing. As the American Society of Civil Engineering pointed out in its 2017 Infrastructure Report Card, America's infrastructure – including more than 16 areas, such as bridges, roads, schools and energy – gets a cumulative rating of D+, reflecting *"the significant backlog of needs facing our nation's infrastructure … underperforming, aging infrastructure remains a drag on the national economy."* The energy sector infrastructure is rated at D+ as well. The Report stated:

> "*The U.S. energy sector faces significant challenges as a result of aging infrastructure, including supply, security and reliability, and resiliency issues in the face of severe weather events, all posing a threat to public safety and the national economy. Between 2003 and 2012, weather-related outages, coupled with aging infrastructure, are estimated to have cost the U.S. economy an inflation-adjusted annual average of $18 billion to $33 billion*."

Michigan is among the states most in need of infrastructure investments. This situation has been driven mostly by demographic trends. As shown in Exhibit 1.1.1, Michigan experienced rapid population growth from 1940 to 1970 and, consequently, much of its infrastructure was built during that time. Flat to declining population for the state and its major cities over the past 30 years made it financially challenging for government entities and utilities to replace infrastructure, so the focus became extending the life of these assets. Particularly, the decline in Detroit's population was unparalleled at a national level, as illustrated in Exhibit 1.1.1.

Exhibit 1.1 U.S., Michigan and Detroit Population Change (Indexed to 1930 Population)



In November 2016, the 21st Century Infrastructure Commission, which was created by Governor Snyder's Executive Order 2016-5, concluded that:

> *"Michigan's infrastructure is aging, and maintenance has been deferred for decades, leaving us in a state of disrepair. Failing infrastructure interrupts daily life, slows commerce, jeopardizes public health, pollutes the environment, and damages quality of life."*

The 21st Century Infrastructure Commission identified a number of priority areas for infrastructure improvement, such as safe and clean water, safer roads, structurally sound bridges, a modernized and dependable electric grid, and alternative energy sources. The report further concluded that a key priority related to electric reliability is to "*reduce the frequency and duration of electric outages to ensure that customers do not experience significant disruption in their service*".

DTEE has focused on maintaining its existing distribution assets in a cost-effective manner for decades, expanding the distribution system when needed to meet demand. However, many of these assets are reaching an age and condition that require they be replaced in the coming years. The rebound in the Southeast Michigan's economy and the revitalization of many of its business and population centers require that the electrical infrastructure be upgraded to continue to serve customers in a safe and reliable manner. In addition, as new technology comes to the energy sector (e.g., distributed resources, energy storage, demand response), the grid must be upgraded in a way that will enable evolving customer and public policy needs to be met. This report lays out DTEE's strategy for investing in a grid that will serve Michigan's residents and businesses for many decades to come.

1.3 Report Outline

This report provides a comprehensive description of DTEE's distribution investment and maintenance programs for the five-year period of 2018-2022. It provides details regarding asset and electrical system issues that drive the investment and maintenance programs and the projected benefits associated with the plan.

This report is organized to help readers understand DTEE's five-year distribution investment and maintenance plan, which is summarized in Section 2, with supporting details provided in Sections 3 - 7. The organization of the report is as follows:

- **Section 2** starts with a discussion of the five-year plan's objectives and development process. A plan framework illustrates how various programs are categorized into the four pillars of the investment plan. This is followed by a summary of the five-year investment and maintenance plan, description of the methodology, results, and key considerations of programs and projects' benefit-cost analysis and prioritization methodology. The section ends with system impact projections on risk, reliability and costs, responding to the Commission's request for a timeline to meet the Governor's 2013 reliability goals addressing the frequency and duration of electric outages.
- **Section 3** provides key statistics and an overview of DTEE's distribution system.
- **Section 4** provides detailed information of the key asset classes in DTEE's distribution system including age, expected useful life, and equipment in need of replacement. For

each asset class, preventive maintenance and/or proactive replacement programs are discussed and summarized.

- **Section 5** provides detailed information regarding electrical system issues and capital programs identified to eliminate or mitigate these issues.
- **Section 6** provides detailed information regarding two critical maintenance programs: preventive maintenance and tree trimming.
- **Section 7** provides detailed information on DTEE's approach for key enablers, including industry benchmarking, workforce planning, capital project approval and planning process, distribution design standards, and replacement unit and spare parts management.

This report focuses on key strategic components of DTEE's investment plan. Discussion of O&M costs is limited to tree trimming and preventive maintenance. The report also does not include in-depth discussion of capital expenditures for emergent replacements, customer connections, or customer relocations, as defined below. However, the estimated capital spend for these three categories is included in the summary table in Section 2.4 to provide a complete picture of DTEE's projected capital expenditures.

1. Emergent Replacements capital is used to perform capital replacements during trouble and storm events. These capital expenditures are reactive in nature and necessary to restore customers' service during outages or abnormal system conditions.
2. Customer Connections capital is used to provide service for individual customers. New customer requests include simple service connections, line extensions for a commercial business or housing development, and industrial substations for manufacturing facilities.
3. Customer Relocations capital is used to accommodate requests to relocate existing facilities. Examples include the Gordie Howe bridge project, road widening requests from the Michigan Department of Transportation, or customer property expansions.

2 Distribution Investment and Maintenance Plan

2.1 Plan Objectives

DTEE strives to provide safe, reliable, and affordable electricity to our customers. As such, DTEE's distribution investment and maintenance plan is designed to reduce risk, improve reliability, and manage costs.

Exhibit 2.1.1 DTEE Distribution Operations Objectives

DTEE is committed to implementing an investment and maintenance plan that will maximize customer benefits and provide a modern electric distribution system to meet the needs of the 21st century economy.

2.2 Plan Development

DTEE's Distribution Investment and Maintenance Plan was first developed over a 12-month period that started in late 2014. More than 50 subject matter experts (SMEs), including industry experts, were involved from the initial detailed assessments of assets and systems to the final development of the plan.

During the initial phase of plan development, individual asset classes were assessed based on their age, loading, known manufacturing issues, failure rate curves and/or any past performance issues. System level issues such as reliability performance, capacity limitations, operational constraints, and/or the risk of major outage events were also analyzed to understand the drivers of the issues and opportunities to mitigate them.

For each identified asset and system issue, remediation options were developed based on engineering analysis and input from field operations personnel. These options were then evaluated and compared through a series of engineering reviews that ultimately resulted in the recommended capital investment and maintenance programs. The recommended programs take many different forms. Some are of relatively short duration, completed in three to five years. Others are of long duration, taking 15 years or longer to complete due to the volume of work (e.g., breaker replacements, system cable replacements). Some programs will continue indefinitely, such as routine and scheduled preventive maintenance. Regardless of the type of program, each has a defined scope and targets specific issues. For instance, the breaker replacement program replaces end-of-life oil breakers with more reliable vacuum breakers to improve operability and reduce the operations and maintenance costs associated with them.

Individual programs are then compared to assess their relative ranking and importance based on their projected impact on risk reduction, reliability improvement and cost reduction. Finally, annual plans are developed based on the program rankings, with significant consideration given to the resources needed to ensure successful execution of the work scope and to the cost and affordability implications of the expenditures.

It is important to understand that the DTEE Distribution Investment and Maintenance Plan is continuously refined as more data are obtained from: industry benchmarks and best practices, increased understanding of asset and system conditions, and ongoing evaluations of program effectiveness. DTEE will update its long-term plan on an annual basis to ensure that maximum customer benefits are achieved through the different capital and maintenance programs.

2.3 DTEE Distribution Investment and Maintenance Plan Framework

The DTEE Distribution Investment and Maintenance Plan addresses risk, reliability and cost. It is built on four pillars: Tree Trimming, Infrastructure Resilience & Hardening, Infrastructure Redesign, and Technology & Automation. Exhibit 2.3.1 shows the DTEE Distribution Investment and Maintenance Plan Framework.

Exhibit 2.3.1 DTEE Distribution Investment and Maintenance Framework

Tree Trimming

- Enhance the tree trimming plan – with a particular focus on specifications and quality of work – to improve reliability and lower trouble costs

Infrastructure Resilience & Hardening

- Harden the 4.8 kV system to address customer outages and increase storm resiliency
- Install sectionalizing devices to reduce outage size and restoration time
- Replace aging infrastructure to reduce major failure events

Infrastructure Redesign

- Eliminate substation loading constraints to serve area load growth and enhance operational flexibility
- Convert the existing 4.8 kV and 8.3 kV electric circuits to a modern 13.2kV distribution system

Technology & Automation

- Invest in remote monitoring and control devices, an Advanced Distribution Management System (ADMS), and System Operations Center modernization
- Upgrade the smart meter network, enhance cybersecurity, and improve distributed energy resource integration

Objectives

Reduce Risk

Improve Reliability

Manage Costs

In addition, DTEE is actively engaged in five key enablers to ensure the plan can be executed in the most effective and sustainable manner. The key enablers, listed below, will be discussed in detail in Section 7 of this report.

- Industry benchmarking
- Workforce planning
- Capital project approval and planning process
- Distribution design standards
- Replacement unit and spare parts management

2.4 Investment and Maintenance Plan Summary

DTEE plans to invest approximately $4.2 billion of capital, a minimum of $440 million of maintenance tree trimming, and over $60 million of preventive maintenance on the electric distribution infrastructure over the next five years. Within the projected capital spend, approximately $2.3 billion is dedicated to strategic investments, with the remainder for "base capital" programs including emergent replacements, customer connections and customer relocations. The planned DTEE Distribution Investment and Maintenance spend is summarized in Exhibit 2.4.1. This report focuses on the strategic capital programs and the two key maintenance programs (tree trimming and preventive maintenance). The strategic capital programs are itemized in Exhibit 2.4.2.

It is important to note that the projected spend in Exhibits 2.4.1 and 2.4.2 is based on the best knowledge and information available as of year-end 2017. The actual spend may deviate from the projected spend due to various unforeseen factors, new system information or field learnings.

Exhibit 2.4.1 Projected DTEE Five-Year Distribution Investment and Maintenance Spend (Excluding PLD)

Category		$ Millions 2018	2019	2020	2021	2022	5-Year Total
Capital Investments ($ Millions)							
Base Capital	Emergent Replacements (Reactive Trouble and Storm Capital)[1]	$197	$199	$196	$194	$192	$978
Base Capital	Customer Connections & Relocations	$176	$173	$172	$176	$181	$878
Strategic Capital Programs (details in Exhibit 2.4.2)		$393	$412	$422	$490	$595	$2,312
Total Capital Investments		**$766**	**$784**	**$790**	**$860**	**$968**	**$4,168**
O&M Investments ($ Millions)							
Tree Trimming		$84	$86	$88	$91	$93	$442
Preventive Maintenance		$12	$12	$12	$13	$13	$62

[1] In the absence of the strategic investment and maintenance plan, emergent replacements capital or reactive trouble and storm capital would increase a minimum of $20 million by 2022.

Exhibit 2.4.2 Projected DTEE Five-Year Distribution Strategic Capital Program Spend (Sorted by Reference Section Number)

Programs	$ Millions						Reference Section #
	2018	2019	2020	2021	2022	5-Year Total	
Infrastructure Resilience & Hardening							
Circuit Breakers	$14	$12	$12	$12	$17	**$67**	Section 4.3
Subtransmission Disconnect Switches	$1	$1	$1	$2	$2	**$7**	Section 4.4
Relay Replacement	$5	$2	-	-	-	**$7**	Section 4.5
Pole / Pole Top Hardware	$33	$39	$39	$39	$39	**$189**	Section 4.7
Fuse Cutouts	$5	$5	$5	$5	-	**$20**	Section 4.9
System Cable Replacement	$15	$19	$19	$25	$36	**$114**	Section 4.15
Underground Residential Distribution (URD) Cable	$9	$9	$10	$10	$10	**$48**	Section 4.16
Vaults	$9	$8	-	-	-	**$17**	Section 4.18
Substation Outage Risk	$17	$11	$17	$21	$15	**$81**	Section 5.2
System Resiliency	$7	$7	$6	$6	$6	**$32**	Section 5.3
Frequent Outage (CEMI) including Circuit Renewal	$27	$24	$23	$22	$22	**$118**	Section 5.3
4.8 kV System Hardening	$53	$59	$64	$70	$77	**$323**	Section 5.5
Ground Detection Program (4.8 kV Relay Improvement)	$3	$3	$4	$4	$4	**$18**	Section 5.5

Programs	$ Millions 2018	2019	2020	2021	2022	5-Year Total	Reference Section #
Infrastructure Redesign							
System Loading	$53	$50	$38	$50	$69	**$260**	Section 5.1
Demonstration: Non-Wire Alternatives	$3	$2	$2	-	-	**$7**	Section 5.1
Targeted Secondary Network Cable	$2	$2	$2	$2	-	**$8**	Section 5.5
4.8 kV Conversion and Consolidation	$54	$55	$85	$152	$225	**$571**	Section 5.5
8.3 kV Conversion and Consolidation	$1	$5	$12	$19	$11	**$48**	Section 5.5
Technology & Automation							
Advanced Metering Infrastructure (AMI) 3G to 4G Upgrades	$16	$10	$22	-	-	**$48**	Section 4.19 Section 5.4
Line Sensors	$7	$7	-	-	-	**$14**	Section 5.4
Energy Management System (EMS) / Generation Management System (GMS)	$22	$8	-	-	-	**$30**	Section 5.4
Advanced Distribution Management System (ADMS)[2]	$7	$25	$19	$7	-	**$58**	Section 5.4
System Operations Center (SOC) Modernization	$25	$40	$30	$1	-	**$96**	Section 5.4
13.2 kV Telecommunications	$1	$3	$5	$5	-	**$14**	Section 5.4
Substation Automation	-	-	-	$12	$24	**$36**	Section 5.4
Circuit Automation	-	-	-	$12	$24	**$36**	Section 5.4
Pilot: Technology (including capital programs post pilot)	$3	$5	$7	$14	$14	**$43**	Section 5.4
Other Miscellaneous Projects[3]	$1	$1	-	-	-	**$2**	-

[2] In addition, the ADMS project requires $24 million of regulatory asset spend

[3] Other miscellaneous projects include Analog Line Elimination and Filmore Substation Access

2.5 Benefit-Cost Analysis and Program / Project Prioritization

DTEE assesses the impacts of strategic investment programs and projects on each of its three objectives: risk mitigation, reliability improvement and cost management. The expected benefits of each program and project are used to develop an initial ranking so that capital investments can be evaluated against each other. The cost of each program and project is used to refine the prioritization. Finally, execution factors such as resource availability and system operational constraints are considered to develop a detailed execution plan.

2.5.1 Investment Programs Evaluation Methodology

Strategic investment programs are evaluated against seven impact dimensions, as described in Exhibit 2.5.1, in DTEE's Global Prioritization Model (GPM). Quantitative assessments are developed for all the impact dimensions to score and rank programs.

Exhibit 2.5.1 Program Impact Dimensions

Index	Impact Dimension	Major Drivers
1	Safety	• Reduction in wire down events • Reduction in secondary network cable manhole events • Reduction in major substation events
2	Load Relief	• System capability to meet area load growth and system operability needs • Elimination of system overload or over firm
3	Regulatory Compliance	• MPSC staff's recommendation (March 30, 2010 report) on utilities' pole inspection program • 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 less than 5 within a 12-month period
4	Substation Outage Risk	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours (as detailed in Section 5.2)
5	Reliability	• Reduction in number of outage events experienced by customers • Reduction in restoration duration for outage events
6	O&M Cost	• Trouble event reduction and truck roll reduction • Preventive maintenance spend reduction • Maintenance tree trimming spend reduction
7	Reactive Capital Spend	• Trouble event reduction and truck roll reduction • Reduction in capital replacement during equipment failures

Strategic programs are assessed, scored and ranked in a quantitative manner on each impact dimension. Exhibit 2.5.2 shows the benefit mapping of the programs to each of the impact dimensions.

Exhibit 2.5.2 Selected Programs and Projects' Benefit Mapping

Program	Safety	Load Relief	Regulatory Compliance	Substation Outage Risk	Reliability	O&M Cost	Reactive Capital
Tree Trimming to the Enhanced Specification	X		X		X	X	X
4.8/8.3 kV Conversion and Consolidation	X	X		X	X	X	X
Substation Outage Risk Reduction	X	X		X	X		X
Load Relief		X		X			
System Cable Replacement	X			X	X		X
Breaker Replacement	X			X	X	X	X
Ground Detection (4.8 kV Relay Improvement)	X						
Line Sensors					X	X	
ADMS	X	X		X	X	X	X
System Automation	X			X	X	X	X
Subtransmission Hardening	X	X			X	X	X
4.8 kV System Hardening	X				X	X	X
System Resiliency					X		
Frequent Outage (CEMI)	X		X		X	X	X
URD Cable Replacement					X	X	X
Pole Replacement	X		X		X		X
Pole Top Hardware Replacement	X				X	X	X

Some strategic projects are excluded from the prioritization model due to their unique benefits and situations addressed. For instance, subtransmission disconnect switches (Section 4.4) and the Pontiac vault projects (Section 4.18) are necessary to meet operational safety needs. AMI 3G to 4G upgrades (Section 4.19) are necessary to address the phase-out of 3G technology by telecommunication companies by the end of 2020. The Ann Arbor System Improvement project (Section 5.1) is necessary to address subtransmission system integrity and power quality concerns in the City of Ann Arbor and University of Michigan. Projects that are excluded from the Global Prioritization Model are subject to close examination of their criticality before being deemed as "must fund" in the capital plan.

Detailed analyses based on historical data, engineering assessments and field feedback were performed to quantify programs' benefits within each impact dimension. The quantified benefits are then compared to the programs' costs to derive their benefit-cost ratios.

Unit measurements used for benefit-cost analysis are different for each impact dimension. Reliability benefits are captured in customer minutes of interruption reduction. O&M and reactive capital benefits are captured in dollar savings. Safety, load relief, regulatory compliance and major substation outage benefits are rated in indexed scores.

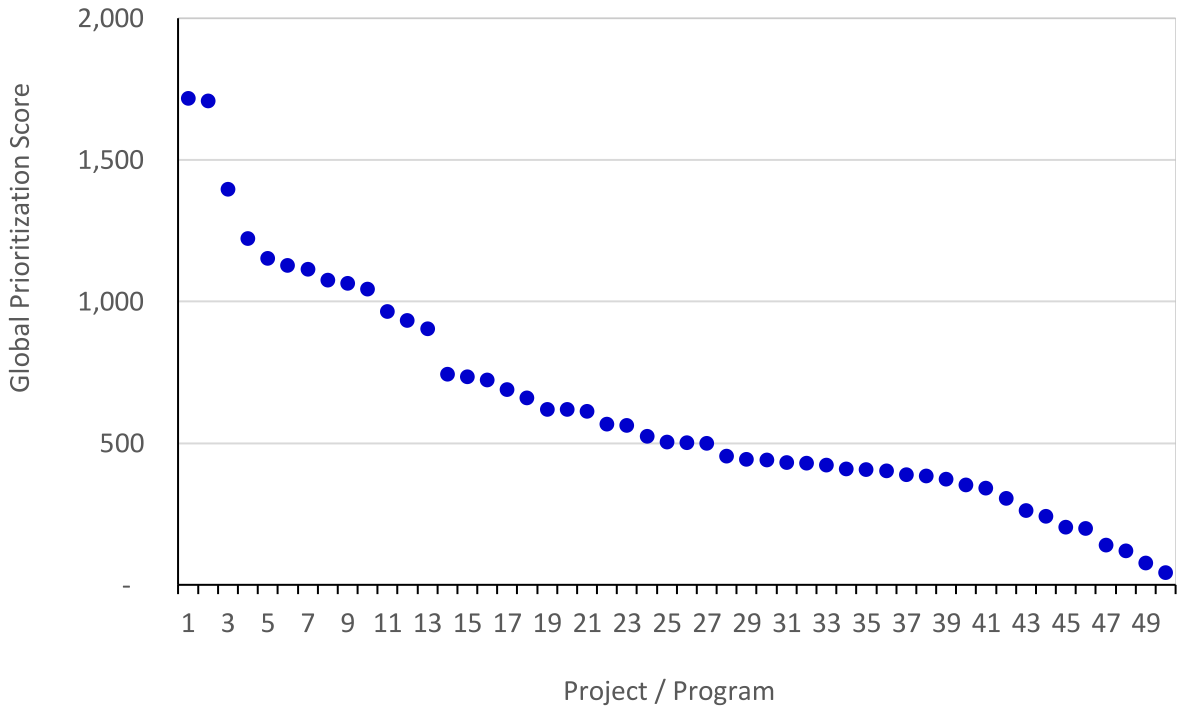
To aggregate a program's benefit-cost ratios across all the impact dimensions, reliability, O&M and reactive capital, benefit-cost ratios are indexed to benefit-cost scores of 0-100. However, a score of 100 in one dimension is not considered equal to a score of 100 in another dimension. A program's overall benefit-cost score is calculated as the weighted summation of the program's benefit-cost scores across all the impact dimensions. Exhibit 2.5.3 lists the different weights given to different impact dimensions that reflect our customer priorities.

Exhibit 2.5.3 Impact Dimension Weights

Impact Dimension	Safety	Load Relief	Regulatory Compliance	Substation Outage Risk	Reliability	O&M Cost	Reactive Capital
Weight	10	4	4	4	3	3	3

The benefit-cost scores for strategic capital programs, ranked from highest to lowest, are illustrated in Exhibits 2.5.4 and 2.5.5. Tree trimming to the enhanced specification, although excluded from the Exhibits, continues to provide the highest customer benefits of any program in the five-year investment portfolio. [4]

Exhibit 2.5.4 Overall Benefit-Cost Scores for Strategic Capital Programs and Projects



[4] Tree trimming, as an O&M program, is excluded from the Exhibits. Nonetheless, tree trimming to the enhanced specification has a benefit-cost score of 2,964, the highest among all the programs.

Exhibit 2.5.5 Top 50 Strategic Capital Programs and Projects Based on Benefit-Cost Prioritization Ranking

Rank	Capital Program / Project
1	CODI[5] – Charlotte Network
2	4.8 kV System Hardening
3	Frequent Outage (CEMI) Program
4	Pole Top Hardware Replacement
5	Ground Detection Program
6	Line Sensors
7	CODI – Madison Conversion
8	CODI – Garfield Network
9	CODI – Targeted Secondary
10	ADMS
11	I-94 Substation and Circuit Conversion
12	Herman Kiefer Substation and Circuit Conversion
13	Malta Substation Risk
14	CODI – Howard Conversion
15	Argo/Buckler Load Transfer
16	CODI – Amsterdam Conversion
17	CODI – CATO/Orchard Conversion
18	Pole Replacement
19	Apache Substation Risk Reduction
20	8.3 kV Conv/Cons – 3rd Phase Catalina
21	System Cable Replacement
22	Pontiac 8.3 kV Overhead Conversion
23	Calla Circuit Conversion
24	Almont Relief and Circuit Conversion
25	Bloomfield Substation Risk Reduction
26	White Lake Decommission and Circuit Conversion
27	Belle Isle Substation and Circuit Conversion
28	Spruce (SCIO) Substation Risk Reduction
29	System Resiliency
30	Subtransmission Hardening
31	Savage Substation Risk Reduction
32	Chestnut Substation Risk Reduction
33	Wixom Load Relief
34	Grayling Load Relief
35	Sheldon/Gilbert/Zachary Load Relief
36	Circuit Breaker Replacement
37	Reno Decommission and Circuit Conversion
38	Birmingham Decommission and Circuit Conversion
39	Lapeer-Elba Expansion and Circuit Conversion
40	CODI – Kent/Gibson Network
41	Hancock/Quaker Load Relief
42	URD Cable Replacement
43	Jupiter Substation Risk Reduction
44	System Automation
45	Diamond Load Relief
46	Berlin Load Relief
47	Trinity Load Relief
48	Oasis Load Relief
49	South Lyon Decommission and Circuit Conversion
50	Cypress/Mohican Load Relief

[5] CODI: City of Detroit (Downtown) Infrastructure

2.5.2 Other Considerations

The benefit-cost scores of programs and projects and their prioritization ranking provide a solid foundation for DTEE's strategic investment decisions. However, there are other key considerations that impact capital funding decisions:

- Capital spend profiles for new projects are subject to key development milestones, especially in the conceptual and early development stage, including land availability and property purchases, municipal approvals and construction permits, right-of-way and easements and major equipment long-lead items from manufacturing companies. While DTEE takes proactive measures, such as advanced planning and project monitoring, to mitigate some of these execution risks, many of these early stage milestones are out of the Company's control and can introduce schedule delays or cost increases. Therefore, DTEE's investment and maintenance plan is designed to be flexible to accommodate these unpredictable variations in timing and cost.
- Funding decisions for programs and projects need to consider the implication on resources and workforce planning. Resources required from engineering, design, project management, and scheduling and construction need to be evaluated not only by project type (substation, overhead or underground) but also by region and service center. Resource gaps need to be understood and addressed before funding decisions are made. Funding decisions on programs and projects also need to consider the Company's capability to effectively manage the work as DTEE partners with industry vendors in project execution. DTEE bears the responsibility to oversee the project scope, schedule, cost, and to ensure adherence to DTEE standards.
- As DTEE continues to make investments in distribution infrastructure, the effectiveness of the capital spend is examined on a continuous basis. The benefit-cost scores of the programs and projects may change over time as new performance data and field experience become available. The prioritization ranking of the programs and projects may change accordingly.

- Some capital replacement programs are funded annually despite having lower benefit-cost scores. This is done to avoid an acceleration of asset failures and a large number of assets reaching end-of-life concurrently, thus exceeding available resources to replace them (e.g., underground residential distribution cable program).
- Last but not least, some programs and projects may not receive immediate funding due to their lower benefit-cost scores. This does not mean these programs or projects are not important. Rather, all the programs and projects identified in this report provide system improvements and are good candidates for funding over the next five years. While the strategic capital investment is primarily driven by the Global Prioritization Model, DTEE may adjust the annual plans based on changing circumstances.

2.6 Projected System Impact

Executing the investment and maintenance plan as presented in Section 2.4 will significantly improve the reliability of DTEE's distribution system. DTEE's system SAIDI (excluding MEDs) measures system performance excluding the most pronounced weather events and will be on a strong trajectory toward Governor Snyder's reliability goal for utilities to be operating in the top half among peers for SAIDI. DTEE's system SAIFI (excluding MEDs) is projected to remain in the 1st quartile and meet Governor Snyder's reliability goal. Significant improvement in all-weather SAIDI and SAIFI will also be achieved.

Exhibits 2.6.1-2.6.4 each show the SAIDI or SAIFI impacts resulting from two investment scenarios. The "Five-Year Investment scenario" illustrates the reliability improvements resulting from the investment plan set forth in Exhibit 2.4.1. The "Constrained Investment scenario" illustrates the changes if no strategic investments were made on distribution infrastructure beyond the "base capital" program defined in Exhibit 2.4.1. The SAIDI and SAIFI baselines shown in the Exhibits are the five-year average values between 2012 and 2016. DTEE believes that the projections for "Constrained Investment scenario" could prove to be optimistic, as assets may be approaching a condition, in which they could experience accelerations in the rates of equipment failures.

Exhibit 2.6.1 System SAIDI excluding Major Event Days (MED)

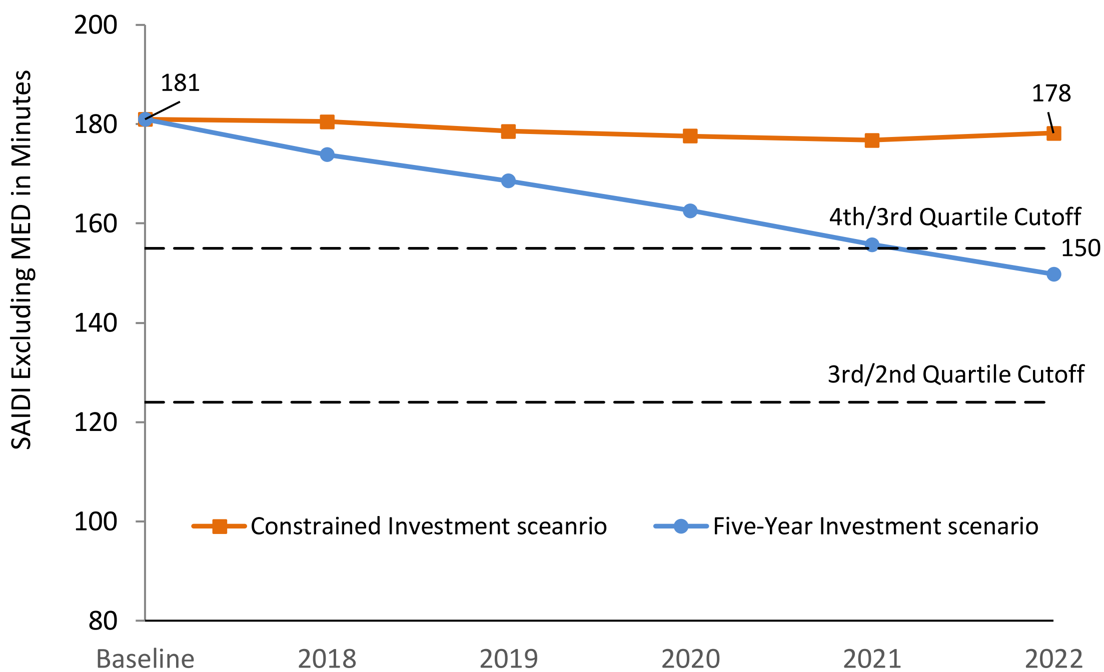


Exhibit 2.6.2 System SAIFI excluding Major Event Days (MED)

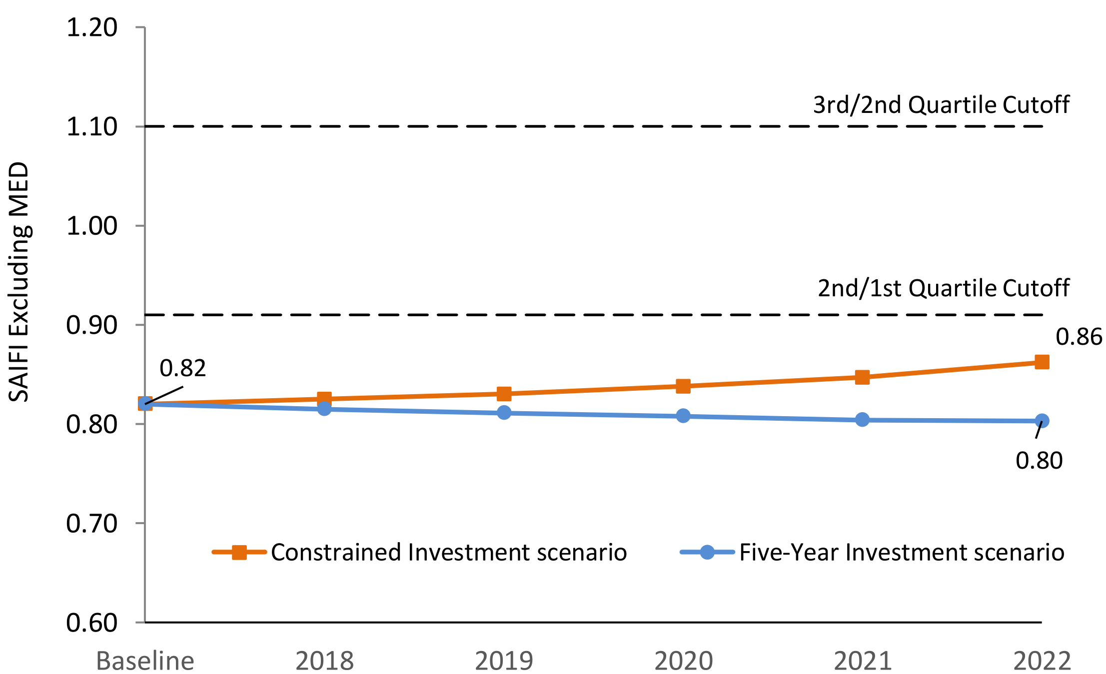


Exhibit 2.6.3 All Weather System SAIDI

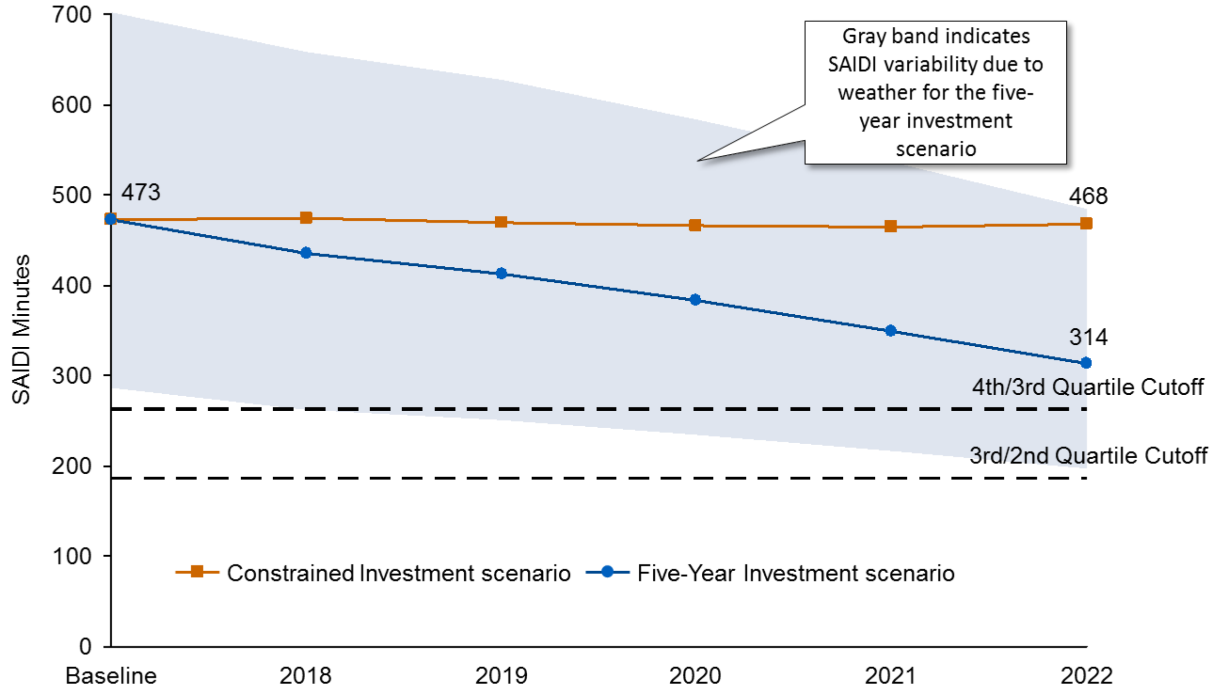
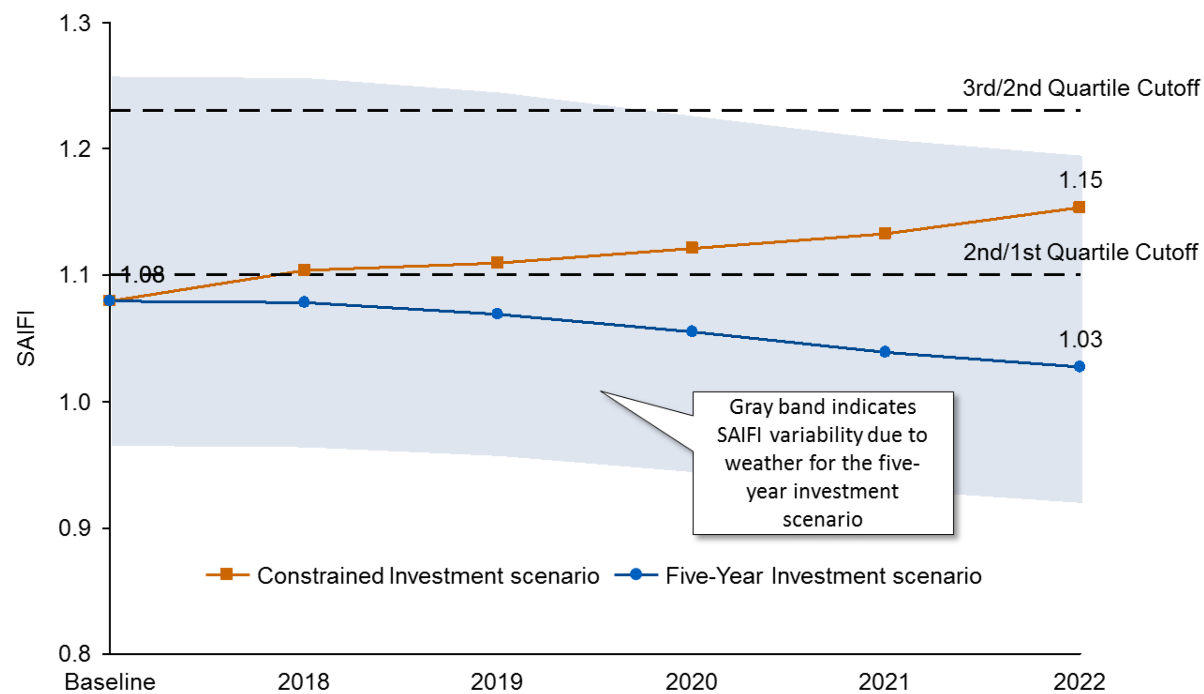
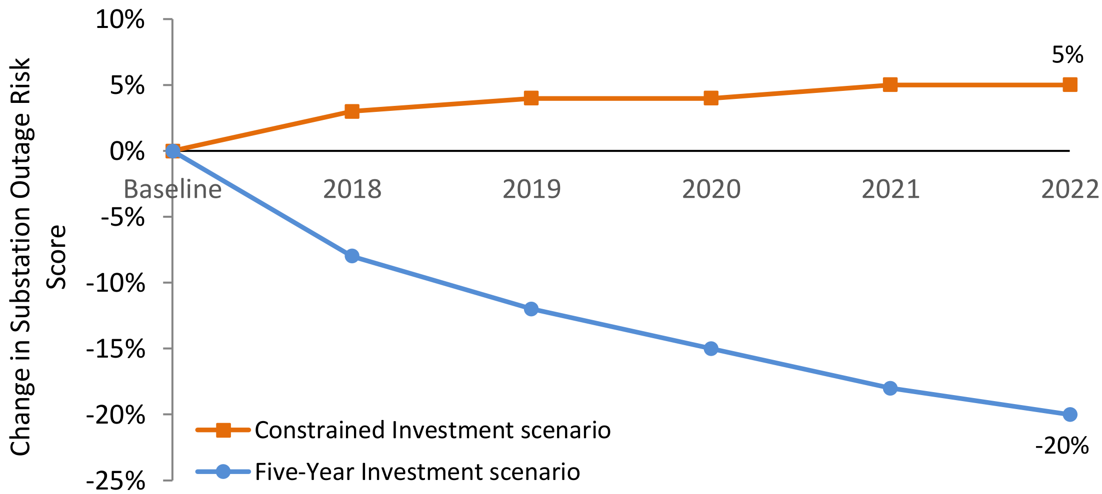


Exhibit 2.6.4 All Weather System SAIFI



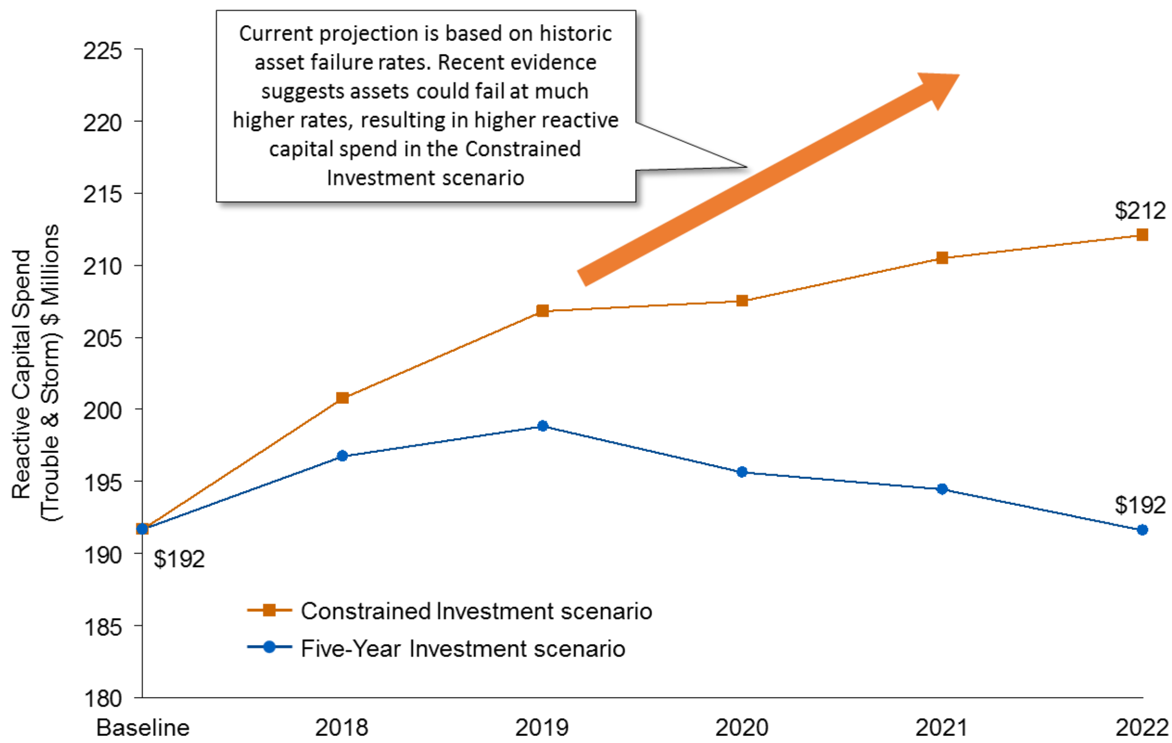
The strategic investment and maintenance plan will also greatly improve the risk profile of the system. The “Five-Year Investment scenario” in Exhibit 2.6.5 illustrates that substation outage risk will be reduced by 20% over the next five years with the strategic investment and maintenance plan laid out in Section 2.4. Substation outage risk, detailed in Section 5.2, is the risk of a significant substation outage event resulting in thousands of customers experiencing loss of power for more than eight hours or even for multiple days. In the “Constrained Investment scenario”, substation outage risk would continue to increase from today’s level.

Exhibit 2.6.5 Substation Outage Risk Reduction



The “Five-Year Investment scenario” in Exhibit 2.6.6 shows reactive trouble and storm capital spend projections for the next five years based on an average level of storm / trouble activity. As discussed in Section 2.4, reactive trouble and storm capital spend would increase by a minimum of $20 million by 2022 in the “Constrained Investment scenario”.

Exhibit 2.6.6 Reactive Capital (Trouble / Storm) Spend Projection



The strategic investment and maintenance plan will lead to avoided annual O&M cost. However, the avoided O&M cost will be more than offset by O&M increases from inflation and continued system degradation.

More importantly, the system improvements driven by DTEE's strategic investment and maintenance plan are expected to bring $6-9 billion of economic benefit to our customers in the next five years. The economic benefits are calculated based on the Interruption Cost Estimation Calculator developed by Nexant and Lawrence Berkeley National Lab with further details in Appendix I.

3 DTEE Distribution System Overview

DTEE owns and operates approximately 31,000 miles of overhead distribution lines and 16,000 miles of underground distribution lines. Our service territory encompasses 7,600 square miles and includes approximately 2.2 million residential, commercial, and industrial customers. DTEE's distribution system consists of six voltage levels: 120 kV, 40 kV, 24 kV, 13.2 kV, 8.3 kV and 4.8 kV with the key statistics listed in Exhibits 3.1-3.5.

Exhibit 3.1 DTEE Substations

Substation Type	Total Number of Substations	Number of Substations by Low Side kV							
		4.8	8.3	13.2	4.8 13.2	24	40	24 40	Other
General Purpose	550	254	4	238	35	3	10	1	5
Single Customer	138	49	0	79	1	0	0	0	9
Customer Owned	95	NA	NA	NA	NA	NA	NA	NA	NA
Total	783	303	4	317	36	3	10	1	14

NA: Not Applicable

Exhibit 3.2 DTEE Transformers

Voltage Level	Number of Transformers	kVA Capacity
Substation - Subtransmission	174	12,350,000
Substation - Distribution	1,449	23,176,200
Distribution - Overhead and Padmount	437,845	31,392,104
Total	439,468	66,918,304

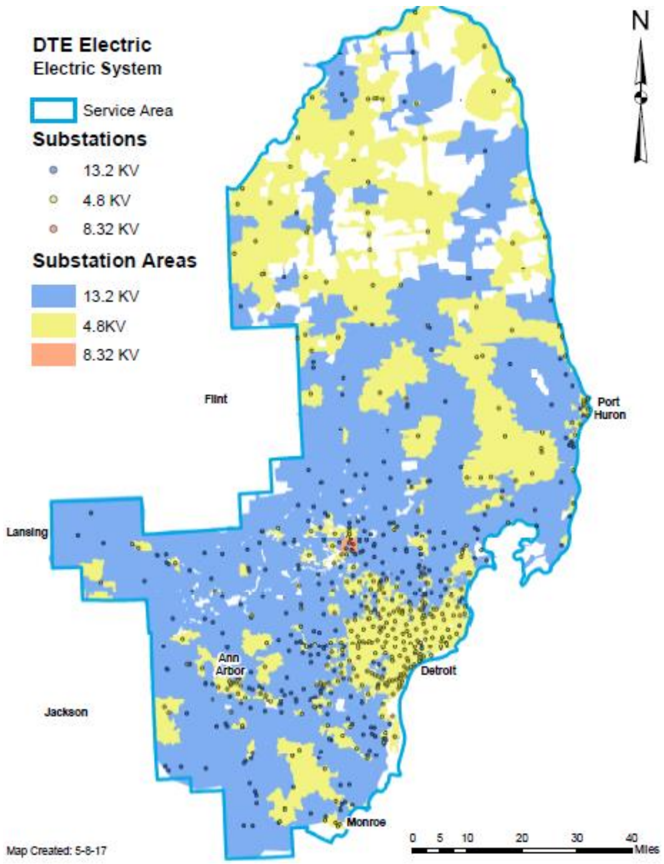
Exhibit 3.3 DTEE Subtransmission Circuits

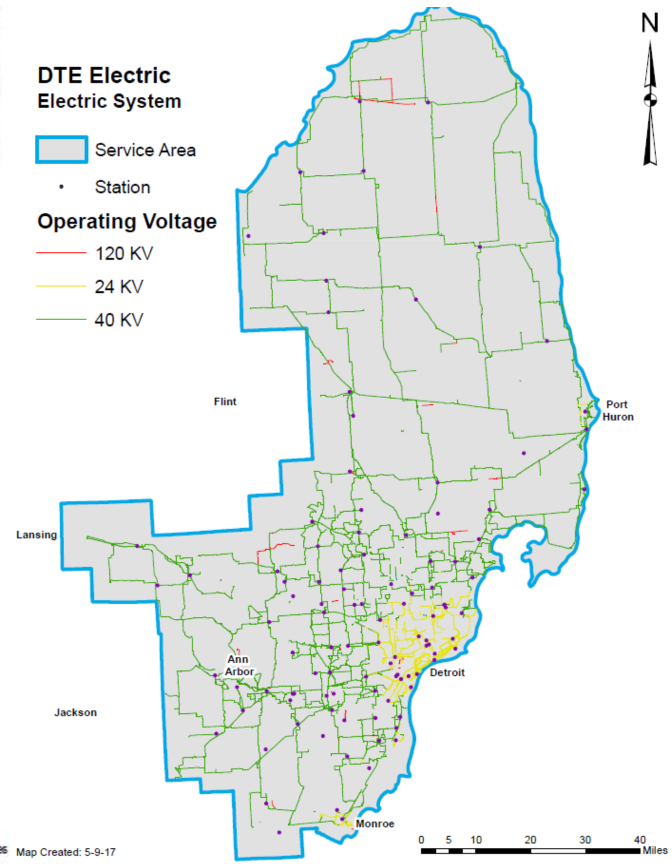
Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
120 kV	67	60	8	68
40 kV	318	2,297	376	2,673
24 kV	255	182	689	871
Total	640	2,539	1,073	3,612

Exhibit 3.4 DTEE Distribution Circuits

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
13.2 kV	1,222	11,623	11,613	23,236
8.3 kV	13	52	14	66
4.8 kV	2,082	16,784	3,332	20,116
Total	3,317	28,459	14,959	43,418

Exhibit 3.5 DTEE Distribution System





4 Asset Condition Assessment

DTEE engineers regularly conduct asset condition assessments on 19 asset classes and use the results to generate investment and maintenance programs to proactively address identified issues.

These 19 asset classes represent the most important assets in DTEE's distribution system, both from the economic value of the assets and the impacts of potential failures for our customers. They represent approximately 80 percent of the distribution plant asset base.

The average age, range of ages and industry life expectancy for the 19 asset classes are summarized in Exhibit 4.1. The industry standard life expectancy is based on a combination of manufacturer recommendations, industry benchmarks, EPRI (Electric Power Research Institute) Industry Database, NEETRAC (National Electric Energy Testing, Research & Applications Center) Asset Survival Plots, and DTEE's own experience. DTEE is using condition-based assessments to evaluate its assets. However, age can become a significant factor when replacement parts become unavailable or if asset condition deteriorates sharply with age. The remainder of this section provides a detailed description of individual asset assessments.

The preventive maintenance and proactive replacement programs for the 19 asset classes are summarized in Exhibit 4.2. A proactive replacement program for an asset class means a program established to specifically replace a type of asset on a proactive basis based on recommendations from asset condition assessments, not as a result of inspection or failure events. It is important to understand that the asset condition assessments provided in the report are the assessments over a long-term view (i.e., 15 years). Some assets are targeted for a more near-term replacement than others based on their unique conditions. Some assets can be addressed by predictive and preventive maintenance, and are consequently not targeted for proactive replacement. The remainder of this section along with Section 6.2 provides a detailed description of individual asset preventive maintenance and proactive replacement programs.

Exhibit 4.1 Asset Age Summary

Section	Asset	DTEE Average Age (Years)	DTEE Age Range (Years)	Industry Life Expectancy (Years)
4.1	Substation Power Transformers	41	0 – 93	40 – 45
4.2	Network Banks	62 (structures) 46 (transformers)	0 – 85+	40 – 45 (transformers)
4.3	Circuit Breakers	48	0 – 87	30 – 40
4.4	Subtransmission Disconnect Switches	51	0 – 75+	NA
4.5	Relays	46	0 – 60+	15 – 50
4.6	Switchgear	34	0 – 64	35 – 45
4.7	Poles and Pole Top Hardware	44	0 – 90+	40 – 50
4.8	Small Wire (i.e., #6 Copper, #4 ACSR, and #4 Copper)	70+	Not available	Vary based on field conditions
4.9	Fuse Cutouts	19	0 – 50+	30
4.10	Three-Phase Reclosers	11	0 – 25	20
4.11	SCADA Pole Top Switches	15	0 – 25	15
4.12	40 kV Automatic Pole Top Switches	32	0 – 50+	30
4.13	Overhead Capacitors	Not available	Oldest: 25+	20
4.14	Overhead Regulators	Not available	Oldest: 25+	20
4.15	System Cable	40	0 – 100+	25 – 40
4.16	Underground Residential Distribution (URD) Cable	23	0 – 50+	25 – 35
4.17	Manholes	75	0 – 90+	Vary based on construction quality and field conditions
4.18	Vaults	Not available	Not available	Vary based on construction quality and field conditions
4.19	Advanced Metering Infrastructure	4.5	0 – 11	20

Exhibit 4.2 Asset Program Summary

		Preventative Maintenance Programs	------ Proactive Replacement Program -------			
Section	Asset	(Yes/No)	Yes/No	2018-2022 Spend ($M)	2018-2022 Number of Units	Entire Program Spend ($M)
4.1	Substation Power Transformers	Yes	No	Not Applicable		
4.2	Network Banks	Yes	Yes	Included in Downtown City of Detroit (CODI) Project		
4.3	Circuit Breakers	Yes	Yes	$67	394	$550 - $800 through 2045
4.4	Subtransmission Disconnect Switches	Yes	Yes	$7	250	$9 through 2024
4.5	Relays	Yes	Yes	$7	328	Not Applicable
4.6	Switchgear	Yes	Yes	Included in Substation Risk Reduction Program		
4.7	Poles and Pole Top Hardware	Yes	Yes	$189	30,000	$403 through 2027
4.8	Small Wire (i.e., #6 Copper, #4 ACSR, and #4 Copper)	Yes	No	Not Applicable		
4.9	Fuse Cutouts	No	Yes	$20	23,500	$20
4.10	Three-Phase Reclosers	Yes	No	Not Applicable		
4.11	SCADA Pole Top Switches	Yes	No	Not Applicable		
4.12	40 kV Automatic Pole Top Switches	Yes	Yes - Pilot	Depending on results of the pilot		
4.13	Overhead Capacitors	Yes	Yes - Pilot	Depending on results of the pilot		
4.14	Overhead Regulators	Yes	Yes - Pilot	Depending on results of the pilot		
4.15	System Cable	No	Yes	$114	93 Miles	$890 - $2,000 through 2035
4.16	Underground Residential Distribution (URD) Cable	No	Yes	$48	260 Miles	$400 - $600 through 2035
4.17	Manholes	Yes	No	Not Applicable		
4.18	Vaults	No	Yes	$17 - $34	14	$17 - $34
4.19	Advanced Metering Infrastructure	No	Yes	$48 - $54	9,300	$48 - $54

Replacement costs within each asset class vary significantly depending on the voltage, location, capacity, size, model, configuration, etc. Exhibit 4.3 shows the range of replacement costs by asset class for proactive replacements. The assets listed in Exhibit 4.3 are the assets for which DTEE tracks individual replacement costs. Costs could be higher or lower than the ranges driven by factors such as unique equipment configurations, changes in material costs, changes in wages, or the need to bring construction resources from out-of-state. Reactive replacements performed during storm or on trouble will generally have a significantly higher replacement cost than listed in Exhibit 4.3.

Exhibit 4.3 Estimated Unit Replacement Costs

Asset	$ / unit or $ / mile
Substation Power Transformers	$800,000 - $1,700,000
Circuit Breakers	$150,000 - $350,000
Subtransmission Disconnect Switches	$11,000 - $47,000
Relays	$30,000 - $50,000
Pole Replacements	$5,800 - $11,200
Fuse Cutouts	$850 - $2,000
40 kV Automatic Pole Top Switches	$125,000 - $175,000
System Cable (per mile)[6]	$1,100,000 - $3,000,000
Underground Residential Distribution Cable (per mile)[7]	$130,000 - $200,000

[6] Installation of underground cable for subtransmission and distribution feeders, excluding installation of conduit and manholes

[7] Installation of direct-buried underground cable for residential areas only

4.1 Substation Power Transformers

DTEE has approximately 1,600 substation power transformers, which connect to the transmission system (120 kV) to the subtransmission system (40 kV and 24 kV) and to the distribution system (4.8 kV, 8.3 kV, and 13.2 kV). Approximately 30 percent of the transformers have a high side voltage of 120 kV. Exhibit 4.1.1 shows a substation power transformer. Exhibit 4.1.2 shows the age distribution of substation power transformers connected to the DTEE system. The average age of substation power transformers is approximately 41 years. Exhibit 4.1.3 shows the historical substation power transformer failures.

Exhibit 4.1.1 Substation Power Transformer

Exhibit 4.1.2 Substation Power Transformer Age Distribution

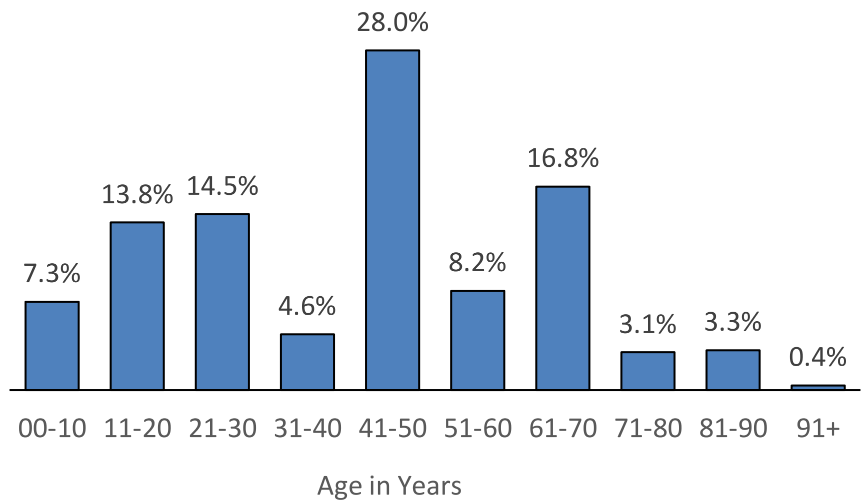


Exhibit 4.1.3 Substation Power Transformer Failures

	2012	2013	2014	2015	2016	2017
# Substation Power Transformer Failures	21	11	17	11	16	19

The average number of substation power transformer failures is 16 per year – this includes units that were identified and replaced prior to actual failure based on dissolved gas analysis (DGA) results. Bushings, load tap changers, and winding insulation breakdown account for approximately 56 percent of the failures. The transformer average age at time of failure is around 47 years. The failure rate for substation transformer units past their life expectancy is more than double that of units within their life expectancy (7.2 percent vs. 3.4 percent).

A power transformer is classified as a candidate for replacement if it has abnormal dissolved gases in its oil, is water cooled, has experienced a high number of through faults, or is beyond 70 years old (Exhibit 4.1.4). Failures of substation power transformers can cause outages on multiple circuits simultaneously and can reduce system redundancy for extended periods of time, negatively impacting thousands of customers. Approximately 11 percent of power transformers are candidates for replacement.

Exhibit 4.1.4 Substation Power Transformers Replacement Factors

Factors	Impact
DGA results indicating gassing in the main tank	• Indicates a transformer is in early stages of failure
Water cooled transformers and regulators	• High costs to maintain water cooling • Greater chance of failures
High number of through faults	• High mechanical and electrical stress on the transformer core and winding insulation
70+ years old	• Increasing deterioration of winding insulation

DTEE conducts regular inspections and DGA testing on all substation power transformers once per year. DGA testing is an industry-proven Substation Predictive Maintenance Inspection (SPdM) methodology to identify internal transformer degradation and to predict incipient transformer failures. Based on results from routine inspection and DGA testing, DTEE determines when to either proactively replace or repair substation power transformers that do not pass the inspection. Substation power transformers can also be replaced reactively when they fail during service and are deemed uneconomical to repair.

DTEE also conducts preventative and reactive maintenance on ancillary parts of power transformers such as load tap changers or bushings.

Exhibit 4.1.5 Substation Power Transformer Program Summary

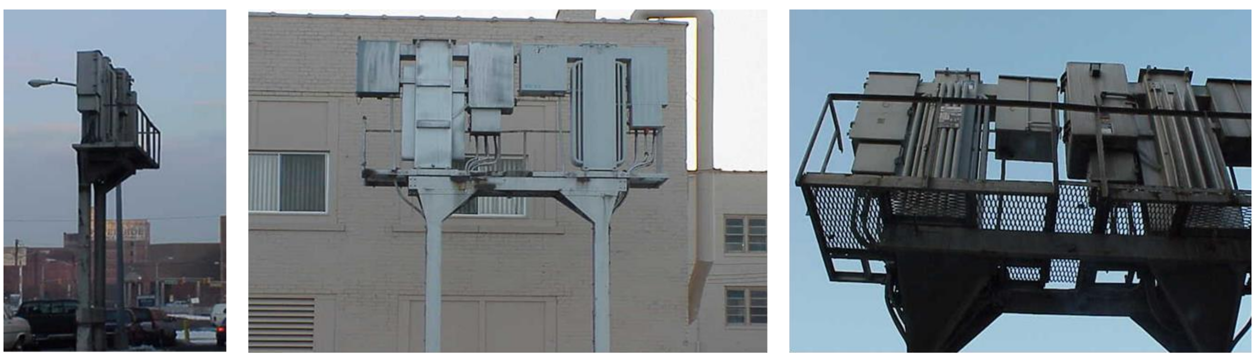
Program Summary	
Equipment	Substation Power Transformers
Preventive Maintenance Program	Yes: DGA Testing, Routine Inspection
Proactive Replacement Program	Not Applicable

4.2 Network Banks (Netbanks)

Netbanks are used to describe an installation consisting of transformers, network protectors, and primary disconnect switches. A netbank system is recognized as the industry standard for the highest degree of continuity of service in heavy load-density city areas.

DTEE has netbank systems in the core downtown areas of Detroit and Ann Arbor as well as Mount Clemens and Port Huron. There are a total of 505 netbank transformers operating on the distribution system - the majority (90 percent) are located in Detroit. Netbank transformers are mounted on steel skids, steel columns, wood poles, and a few are located in underground vaults. On columns and poles, netbank transformers are typically mounted approximately 15 feet above ground. The netbank transformers have an average age of 46 years. The netbank supporting structures have an average age of 62 years with the average age of steel structures at 80 years.

Exhibit 4.2.1 Netbank System Mounted on Steel Columns



DTEE conducts Electrical Integrity Inspections (EII) on a five-year cycle on netbank systems as part of the preventive maintenance program. It includes inspection of the primary disconnect and protector, visual (inside / outside) inspection of transformer tanks for corrosion, signs of water and oil sludge, PCB (Poly Chlorinated Biphenyl) and DGA oil analysis, and high voltage testing on the primary and secondary windings of the transformer.

The structural inspection of steel columns that support the netbanks is conducted to determine the replacement and repair needs based on the steel condition. In 2015 and 2016, a total of 115 structures were inspected. Of those, eight (7 percent) required replacement and 25 (22 percent) required repair. The primary cause of failure is due to steel corrosion at the foundation base. Based on these results, DTEE is expanding these inspection efforts and plans to complete the inspection of all remaining 300 structures between 2017 and 2019.

The wood pole inspection is conducted as part of the pole inspection and replacement program (Section 4.7).

Netbank systems will be replaced as part of the 4.8 kV conversion program, as discussed in Section 5.5.

Exhibit 4.2.2 Netbank Program Summary

Program Summary	
Equipment	Netbanks
Preventive Maintenance Program	Yes: Electrical Integrity Inspection; Pole Inspection; Steel Structure Inspection
Proactive Replacement Program	As part of the Downtown City of Detroit Infrastructure (CODI) project (Section 5.5)

4.3 Circuit Breakers

A circuit breaker is an electrical switch designed to isolate faults that occur on substation equipment, buses, or circuit positions. Its basic function is to interrupt current flow after a fault is detected to minimize equipment damage due to high fault currents and to isolate the faulted asset from the electrical system. Exhibit 4.3.1 illustrates an oil breaker installed in the 1940s versus a recently installed vacuum breaker.

Exhibit 4.3.1 Circuit Breakers

Traditional 4.8 kV Oil Breakers

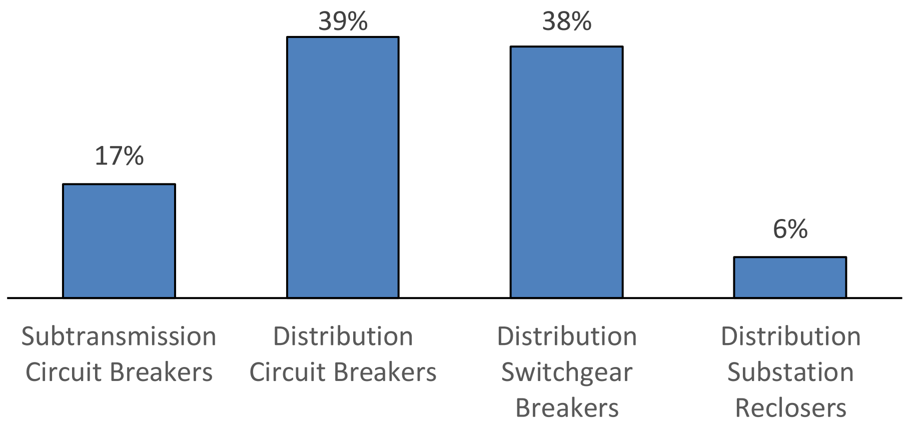
Modern Distribution Vacuum Breakers

Traditional 120 kV Oil Breakers

Modern 120 kV Gas Breakers

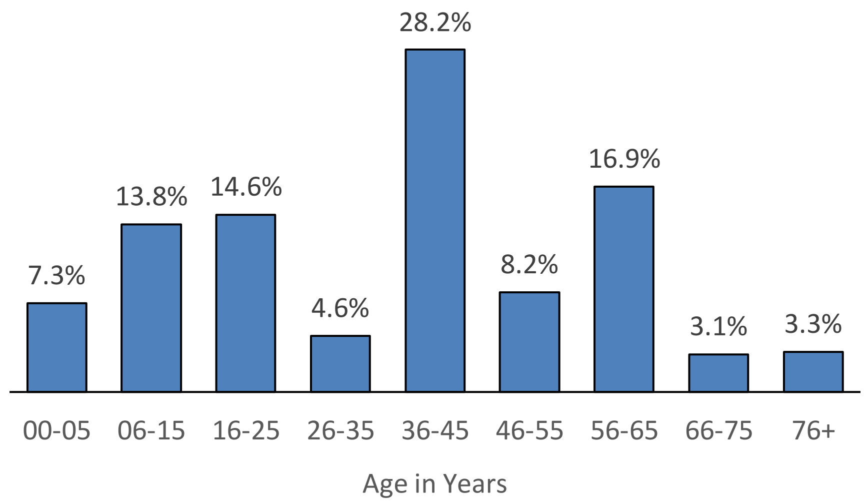
DTEE has approximately 6,000 circuit breakers on its system, which include subtransmision circuit breakers, distribution circuit breakers, distribution switchgear breakers, and distribution substation reclosers (Exhibit 4.3.2).

Exhibit 4.3.2 Circuit Breakers by Application



The industry life expectancy of a circuit breaker is approximately 40 years for early to middle 20th century equipment, while modern equipment has a life expectancy of 30 years and is designed for ease of maintenance and replacement. Exhibit 4.3.3 shows that approximately 60 percent of DTEE's circuit breakers are beyond industry life expectancy.

Exhibit 4.3.3 Circuit Breaker Age Distribution



Of the approximately 6,000 circuit breakers, about 63 percent are candidates for replacement based on the latest assessment. Replacement factors are detailed in Exhibit 4.3.4.

Exhibit 4.3.4 Circuit Breaker Replacement Factors

Factors	Impact
Safety Risk	• Possibility of major failures
Unavailable parts	• Little or no vendor support and expensive to replace parts
High O&M Cost	• High O&M costs due to short maintenance cycles
Environmental Concerns	• Oil spill and contamination to the environment
SCADA Control	• Not compatible with SCADA control technology

Circuit breakers that are candidates for replacement could degrade the reliability and operability of the subtransmission and distribution systems. A failure of a circuit breaker can cause outages on multiple circuits and could reduce system redundancy for an extended period during repairs. Depending on the extent of the failure and possible adjacent collateral damage, thousands of customers could be impacted for an extended duration. Exhibit 4.3.5 shows the number of breaker failures to operate (i.e., trip or close) that result in repairs, and the number of unrepairable breaker failures that result in reactive capital replacements in the past three years. Although failures to operate lead to repairs instead of reactive capital replacements, these types of failures often lead to customer outages or longer outage durations. The unrepairable breaker failures are major failures that require reactive capital replacements and often lead to extensive outage events for our customers or extended periods that the system operates in abnormal conditions.

Exhibit 4.3.5 Circuit Breaker Failures

Failure Type	2015	2016	2017
Failures to Operate (Trip)	10	9	30
Failures to Operate (Close)	28	41	68
Failures in Service (Reactive Replacements)	2	8	6
Total # of Failures	**40**	**58**	**104**

DTEE performs regular periodic inspections of circuit breakers based either on a time interval or the number of breaker operations recommended by manufacturers. Circuit breakers that do not pass inspection are either repaired (if economical to do so) or replaced. Over the last three years, an average of approximately 30 breakers fail inspection annually.

In addition, DTEE has a proactive breaker replacement program to eliminate targeted breakers from the system. Exhibit 4.3.6 lists the types and quantities of the breaker replacements planned for the next five years. Subtransmission H breakers, FK breakers and substation PR reclosers are prioritized for near-term replacements as allowed by field execution.

Exhibit 4.3.6 Projected Proactive Breaker Replacement 5-Year Plan

Breaker Type	Target Quantity
Subtransmission H Breaker	32
Subtransmission FK Breaker	14
Substation PR Recloser	4
Subtransmission Other	39
Distribution Breaker (Oil and 1st/2nd Generation Air Magnetic)	305
Total Number of Breakers	**394**

To the extent possible, breaker replacements are coordinated with other capital or maintenance work to reduce costs and minimize the overall time the equipment is out of service. In most cases, breaker replacements include relay replacements to make the breaker SCADA controllable and to increase the penetration rate of substation remote monitoring and control capability. This is expected to bring significant customer benefits that come from improved substation operability (see Section 5.4 for detailed discussion on remote control capability).

Exhibit 4.3.7 Circuit Breaker Program Summary

Program Summary	
Equipment	Circuit Breakers
Preventive Maintenance Program	Yes
Proactive Replacement Program	
Spend Projection 2018-2022	$67 million
Unit Projection 2018-2022	394
Entire Program Spend Projection (until 2045)	$550 - $800 million

4.4 Subtransmission Disconnect Switches

Subtransmission disconnect switches are used to sectionalize and provide isolation points on the electrical system for operational reasons or for service / maintenance. DTEE has approximately 3,900 disconnect switches that operate at 24 kV, 40 kV, and 120 kV.

Failures of disconnect switches during service are infrequent and do not usually lead to customer outages. However, failures of disconnect switches during operation, when operators attempt to open or close a disconnect manually, can lead to safety concerns, reduce system operability, and force additional equipment to be taken out of service to allow critical work to continue. Approximately 258 Cap & Pin style (Exhibit 4.4.1) and 76 PM-40 model (Exhibit 4.4.2) disconnect switches are candidates for replacement, with replacement factors detailed in Exhibit 4.4.3.

Exhibit 4.4.1 Cap & Pin Disconnect Switch

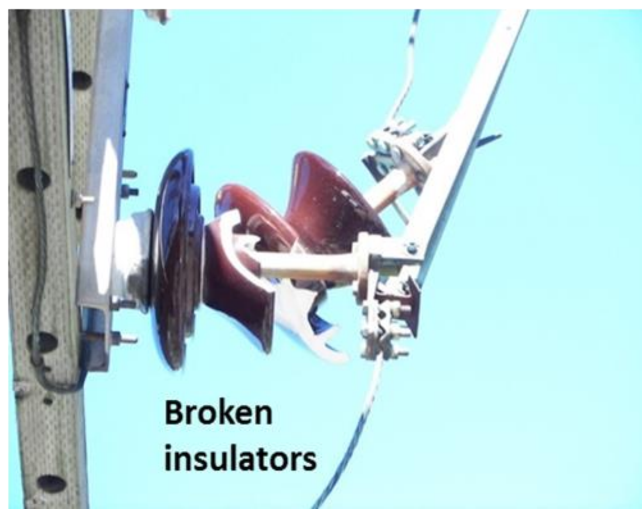


Exhibit 4.4.2 PM-40 Disconnect Switch

Exhibit 4.4.3 Subtransmission Disconnect Switch Replacement Factors

Factors	Impact
Cap & Pin Disconnects	• Insulators are problematic and could fail during operation • Employee safety concern upon failure during manual operation
Known Manufacturer Issues on PM-40 (120 kV)	• Equipment could fail during operation due to bearing problems • Employee safety hazard

DTEE has a preventive maintenance program for subtransmission disconnect switches. In addition, DTEE has a proactive capital replacement program to replace the Cap & Pin and PM-40 disconnects.

The plan is to replace 250 Cap & Pin disconnects in the next five years, with the remaining eight Cap & Pin and 76 PM-40 disconnects to be replaced in the following years.

Exhibit 4.4.4 Subtransmission Disconnect Switch Program Summary

Program Summary	
Equipment	Subtransmission Disconnect Switches
Preventive Maintenance Program	Yes
Proactive Replacement Program	
Spend Projection 2018-2022	$7 million
Unit Projection 2018-2022	250
Entire Program Spend Projection (2018-2024)	$9 million

4.5 Relays

The function of relays is to monitor system current and voltage, detect abnormal conditions (primarily fault current) and initiate breaker operations to isolate abnormalities.

DTEE relays operate on the transmission, subtransmission and distribution systems. There are three types of relays: electro-mechanical, solid state, and micro-processor. The majority (85 percent) of the approximately 28,000 relays are electro-mechanical relays as shown in Exhibit 4.5.1 and described in Exhibit 4.5.2.

Exhibit 4.5.1 Relays Design Types

Electro Mechanical

Solid State

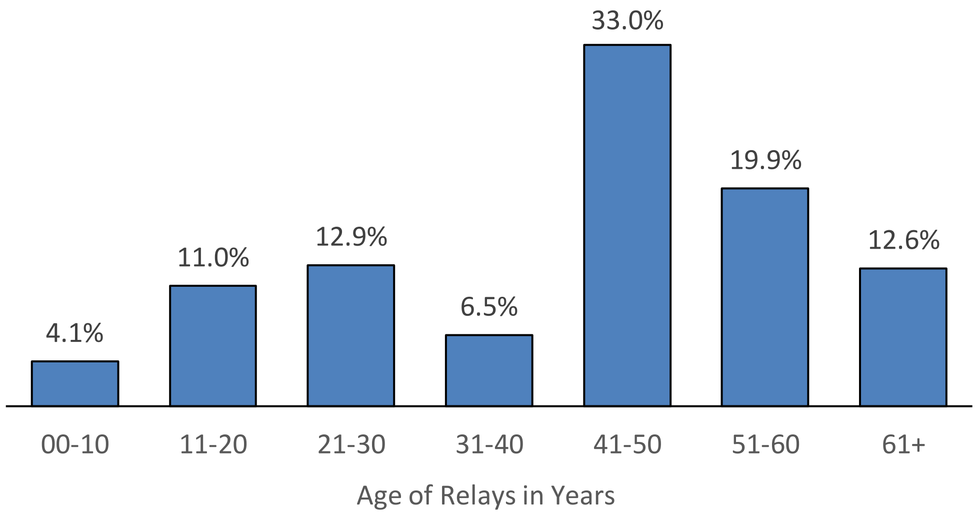
Micro-Processor

Exhibit 4.5.2 Relay Design Type Benefits and Drawbacks

Relay Type	Life span	Benefits	Drawback
Electro-mechanical (85% of Total)	50 years	• Contain no electronics • Long life span • Low maintenance • Settings can be easily adjusted	• Obsolete technology • No SCADA or Communication • No fault location detection • No metering or power flow monitoring • Unavailable parts
Solid state (5% of Total)	40 years	• Settings can be easily adjusted • No moving parts – mechanism does not wear out	• Obsolete technology • No SCADA or Communication • No fault detection • No metering or power flow monitoring • Unavailable parts
Micro-processor (10% of Total)	15 – 20 years	• Provide SCADA, fault detection and metering functions • Replace 5+ electro-mechanical relay functions • Require limited preventive maintenance due to self-checking capability • Provide condition-based information for breakers and transformers • Relay settings can be applied remotely	• Relatively short life span • Early models have power supply issues and have limited capabilities as compared to newer models

The average age of DTEE relays is 46 years, with the age distribution illustrated in Exhibit 4.5.3. A relay failure can lead to loss of ability to return equipment to service. It may also result in a larger outage (e.g., a substation bus gets de-energized due to a distribution circuit relay failing to operate) or possibly result in damage to other control or power equipment.

Exhibit 4.5.3 Relay Age Distribution



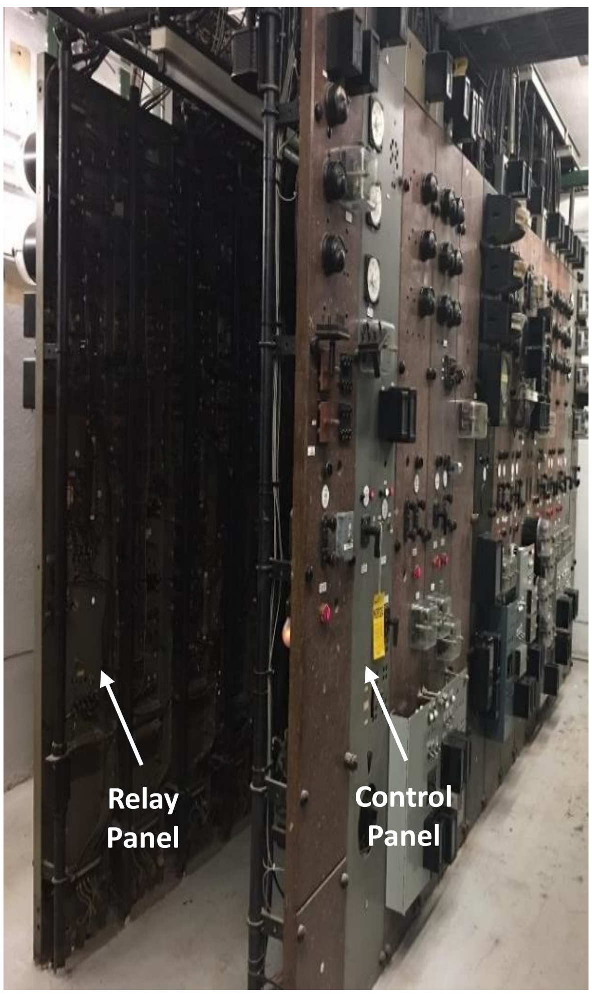
Approximately 46% of the relays are classified as candidates for replacement based on factors listed in Exhibit 4.5.4.

Exhibit 4.5.4 Relay Replacement Factors

Factors	Impact
Known high impact failure modes	• Poor operational performance that has led to customer outages • Significant amount of time erroneously troubleshooting power equipment to find cause of fault indicated by the relay
Known high failure rate reclosing relays	• Unnecessary sustained customer interruptions due to the inability of breakers to close automatically
Microprocessor relay 15+ Years (Distribution) and 20+ Years (Subtransmission)	• Modern relays have a shorter life span and start failing after 15 years
Solid State 40+ Years	• Solid state electronic components begin to fail with age • Repetitive DC surges cause failures over time
Electromechanical Relays 50+ Years	• Mechanical stress wears relay triggers (springs) out over time • Electrolytic capacitors internal to relay dry out over time – causing non-correctable calibration issues • Unavailable or expensive replacement parts

DTEE has a preventive maintenance program for relays. Relays found non-operational during maintenance or in service are replaced or repaired. Relay replacements are generally coordinated and included as part of the breaker or transformer replacements. In addition, DTEE plans to replace end-of-the-life marble relay panels (as shown in Exhibit 4.5.5) in Warren and Northeast subtransmission stations over the next two years to improve safety, operability, and SCADA capability.

Exhibit 4.5.5 Relay Panels



Old Marble Relay Panel
(Separate panels for relay and control functions)

Modern Relay Panel
(Single panel for relay and control functions)

Exhibit 4.5.6 Relay Program Summary

Program Summary	
Equipment	Relays
Preventive Maintenance Program	Yes
Proactive Replacement Program	• As part of breaker and transformer replacements (Sections 4.1 and 4.3) • Identified as individual projects (i.e., Warren and Northeast Relay Panel Replacements)
Warren and Northeast Spend Projection (2018-2019)	$7 million
Warren and Northeast Unit Projection (2018-2019)	82 panels and 328 units

4.6 Switchgear

Switchgear is used to house a combination of multiple equipment types including circuit breakers, power bus, relays, metering, SCADA control and communication support, housed in metalclad compartments / positions. Switchgear is used to de-energize equipment to allow work to be done and to isolate faults. Exhibits 4.6.1 and 4.6.2 provide exterior and interior views of switchgear.

Exhibit 4.6.1 Switchgear Design Types

Outdoor Single Row

Across-the-Aisle

Two-Tier Switchgear

A failure in a single switchgear position, for some switchgear models, can cause damage to multiple adjacent switchgear positions, potentially resulting in the loss of power for an entire bus or substation and affecting thousands of customers. This could also result in the system being in an abnormal state for an extended period of time until all the positions are repaired or replaced.

Exhibit 4.6.2 Switchgear Interior View

DTEE has 256 sets of switchgear on its system. As illustrated in Exhibit 4.6.3, the majority (75 percent) of the switchgear are operating at 13.2 kV. As illustrated in Exhibit 4.6.4, the average age of switchgear in DTEE's system is approximately 34 years old, with more than 53 percent of the switchgear more than 40 years old.

Exhibit 4.6.3 Switchgear by Voltage

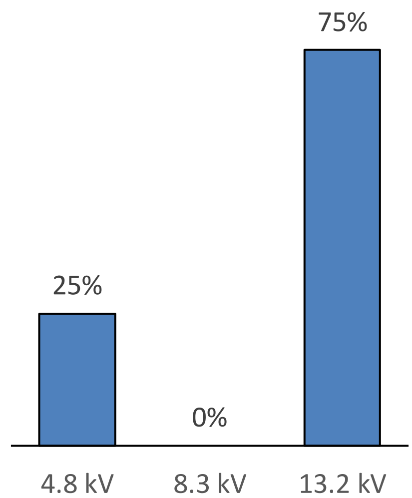
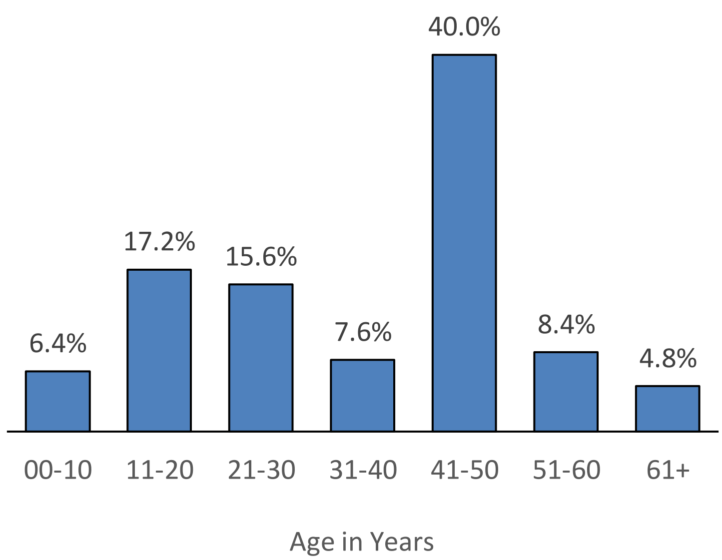


Exhibit 4.6.4 Switchgear Age Distribution



Approximately 25 percent of the switchgear sets are candidates for replacement. Factors driving the need for replacement include design type, age, number of Calvert buses (Exhibit 4.6.6), spare parts availability, racking type, and previous performance issues.

Exhibit 4.6.5 Switchgear Replacement Factors

Factors	Impact
Age	• Bus insulation begins to degrade, which requires replacement to prevent bus failures. Replacing old insulation is a very expensive task and requires a lengthy shutdown of associated equipment
Calvert Bus	• Prone to failure due to exposure to the elements – See Exhibit 4.6.6
Design type	• Some switchgear designs (outdoor single row, indoor across-the-aisle) are more likely to fail than others (two-tiered switchgear) – See Exhibit 4.6.1
Racking type	• Some switchgear utilizes open door breaker racking which potentially increases arc flash hazards
Spare parts	• Vendors/manufacturers no longer supply parts for some older vintage switchgear

Exhibit 4.6.6 Calvert Bus

DTEE does not have a stand-alone preventive maintenance program for switchgear; however, the different equipment types within the switchgear such as circuit breakers, power bus, or relays have their own preventive maintenance programs.

Replacing switchgear involves an extensive substation re-build. It includes pouring new concrete pads and executing a significant amount of underground work to install cable from the transformers, capacitors and circuit exits. Equipment control wiring and testing can take several weeks to complete. While the work is in progress, a significant amount of load must be transferred to adjacent substations or circuits, and/or fed by portable substations or distributed generation. The additional loading on adjacent circuits creates operational constraints on the system. Due to the complexity and cost requirements, switchgear replacement is executed as part of the broader Substation Risk Reduction Program discussed in Section 5.2.

Exhibit 4.6.7 Switchgear Program Summary

Program Summary	
Equipment	Switchgear
Preventive Maintenance Program	Conducted on different equipment types within the switchgear
Proactive Replacement Program	As part of substation Outage Risk Reduction Program (See Section 5.2)

4.7 Poles and Pole Top Hardware

DTEE owns more than 1 million poles and attaches to nearly 200,000 poles owned by other utilities (e.g., AT&T). The average pole age in the DTEE system is approximately 44 years. The age distribution is illustrated in Exhibit 4.7.1. The industry standard life expectancy of a pole is 40 years for wood pine poles and 50 years for wood cedar poles, though the actual useful life expectancy can vary based on field conditions.

Exhibit 4.7.1 DTEE Owned Wood Pole Age Distribution

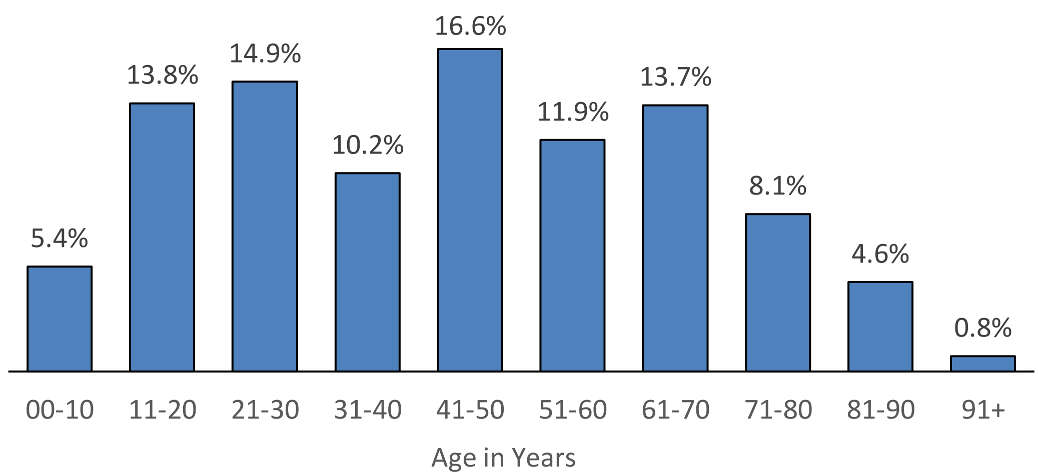


Exhibit 4.7.2 Non-DTEE Owned Wood Pole Age Distribution

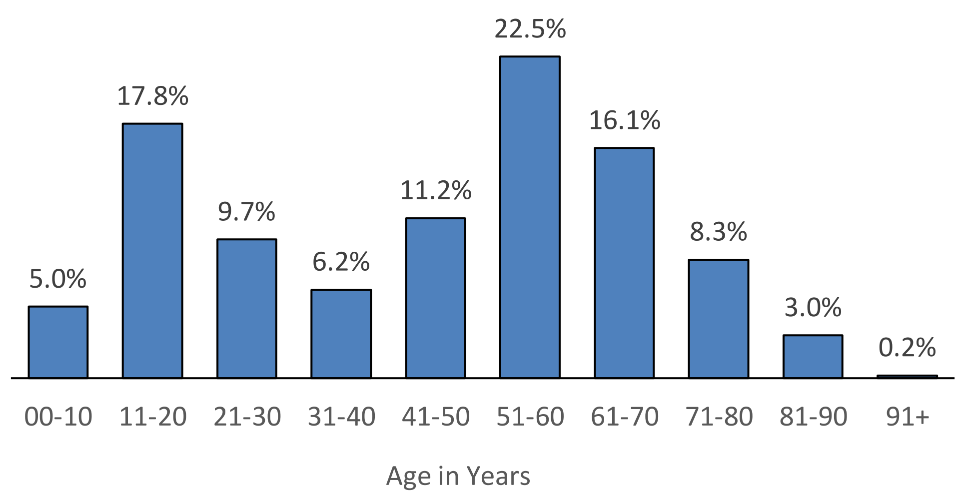
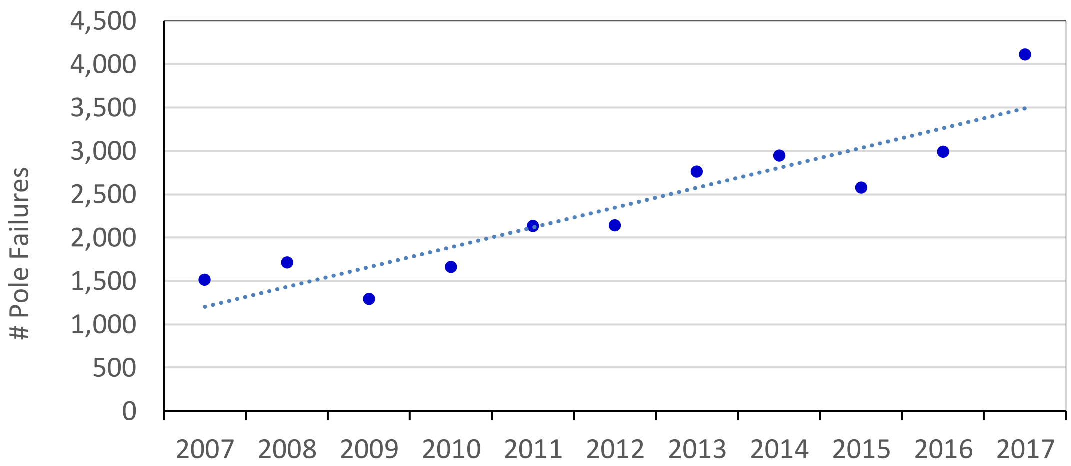


Exhibit 4.7.3 shows the increasing trend of broken poles. A broken pole does not always result in customer outages – the pole may be fractured or damaged but the integrity of the conductors is maintained.

Exhibit 4.7.3 Annual Broken Pole Events (Failures during Service)



Not all broken poles are the result of aging. A portion of them are due to vehicle strikes, trees, icing or wind loads above the design standard, etc. To identify and remediate poles with deteriorating strength, DTEE has the Pole and Pole Top Hardware Program. It is a proactive program to test poles for mechanical strength and integrity and to inspect pole top hardware to identify and repair or replace weakened poles or defective pole top hardware before they fail during service. The replacements of poles and pole top hardware are based on the latest Distribution Design Orders (Section 7.4) to provide greater strength and storm resiliency than in the past.

Annually, foot patrols are done on a portion of the system to inspect poles and pole top hardware. Data from these patrols show that approximately 5-7 percent of the total poles inspected have reduced strength and need to be remediated. These poles are either replaced or reinforced based on specific criteria. Reinforcing a pole extends its life up to 20 years and costs approximately 10-12% of the replacement cost. Pole reinforcement is widely considered as a cost-effective way to extend the life of a pole as compared to pole replacement in the industry. Reinforcing a pole consists of driving a steel channel alongside the pole and banding the pole to the steel channel. The pole may also be treated to prevent further decay and/or insect infestation.

Exhibit 4.7.4 Pole and Pole Top Maintenance Program Summary

Program Summary	
Equipment	Poles and Pole Top Hardware
Preventive Maintenance Program	Yes
Proactive Replacement Program	
Spend Projection 2018-2022	$189 million
Unit Projection 2018-2022	30,000 poles replaced or reinforced
Entire Program Spend Projection (2018 -2027)	$403 million

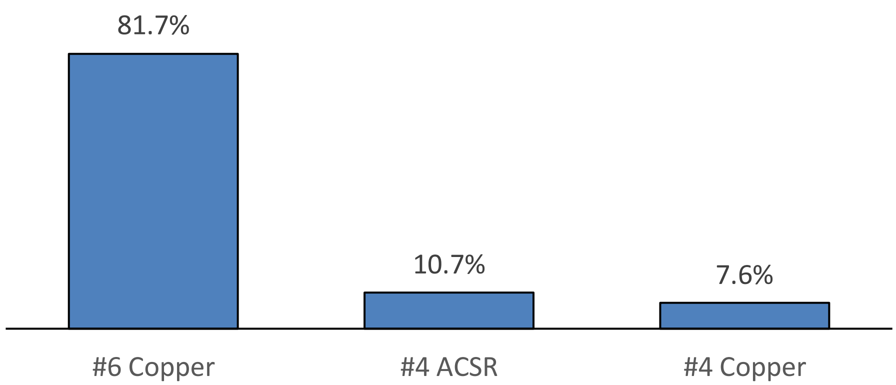
4.8 Small Wire

The overhead distribution primary system has approximately 13,000 miles of small wire (i.e., #6 Copper, #4 ACSR, #4 Copper), representing 15 percent of the total overhead primary wire miles. These wire sizes are no longer used for installation. Small wire is of concern because of its vintage (primarily installed pre-1950) and its mechanical strength.

To improve reliability, DTEE has upgraded standard sizes of conductors that are installed on all planned work. The new wire specifications provide strengths that are 2-3 times stronger than small wire sizes.

There is no stand-alone proactive replacement program for small wire presently. However, small wire replacement is performed during other capital work to support load growth, system hardening, or reliability improvements.

Exhibit 4.8.1 Small Wire by Size



Note: Small wire presents 15% of DTEE wire miles

Exhibit 4.8.2 Small Wire Program Summary

Program Summary	
Equipment	Small Wire
Preventive Maintenance Program	No
Proactive Replacement Program	As part of other capital projects/programs

4.9 Fuse Cutouts

A fuse cutout is a combination of a fuse and a fuse carrier. This equipment provides overcurrent protection for the primary distribution system. The fuse opens (blows) when excessive current is produced by abnormal conditions such as line faults caused by trees, overloads, or equipment failures.

DTEE has approximately 644,000 fuse cutouts on its system. The fuse cutout replacement criteria are shown in Exhibit 4.9.1. Exhibit 4.9.2 illustrates the S&C R10/R11 Porcelain Cutouts.

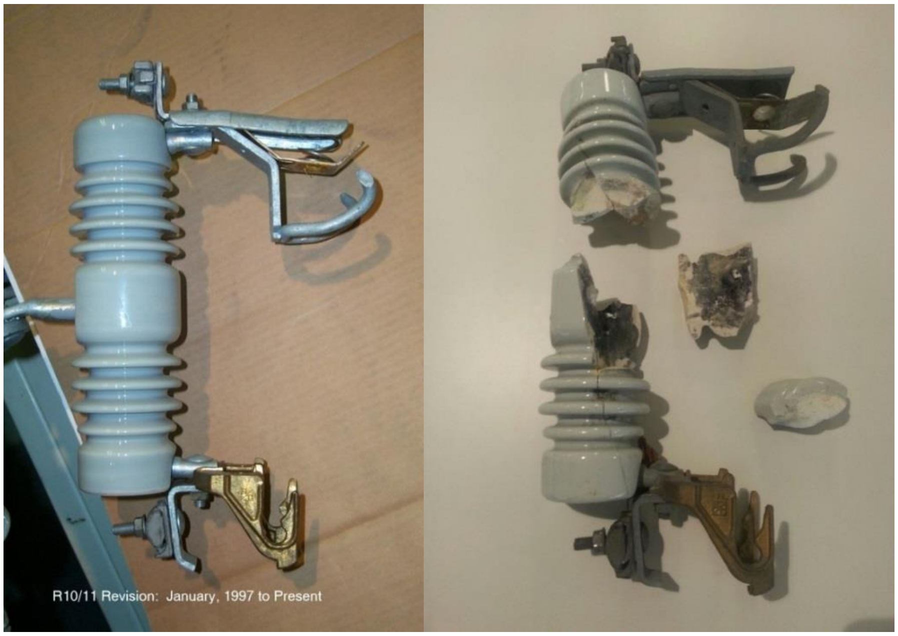
Other defective cutouts include certain vintages of AB Chance Porcelain and Durabute Polymer. Past programs replaced most of these devices; those that remain on the system are being identified and replaced during the Pole Top Maintenance program (Section 4.7).

Defective cutouts are estimated to fail at a rate of approximately 6.8 percent annually, representing approximately 75 percent of the cutout failures.

Exhibit 4.9.1 Fuse Cutout Replacement Criteria

Type	Approximate Population	Reason for replacement
S&C Porcelain R10/R11 (2005 – 2007)	59,000	Premature failure due to latent defect
AB Chance Porcelain	28,000	Premature failure due to latent defect
Durabute Polymer	1,500	Improper operation
Total Defective Cutouts	89,000	

Exhibit 4.9.2 S&C R10/R11 Porcelain Cutout



DTEE has a proactive replacement program to address defective fuse cutouts, particularly the S&C porcelain R10/R11. Approximately 40 percent of the defective S&C porcelain R10/R11 cutout locations can be readily identified and therefore included in the proactive capital replacement program. The remaining defective cutouts will be identified and addressed through the PTM program.

Exhibit 4.9.3 Fuse Cutout Program Summary

Program Summary	
Equipment	Fuse cutouts
Preventive Maintenance Program	No
Proactive Replacement Program	
Spend Projection 2018-2022	$20 million
Unit Projection 2018-2022	23,500
Entire Program Spend Projection (2018-2022)	$20 million

4.10 Three-Phase Reclosers

An overhead three-phase recloser is a sectionalizing device that is located at key points on overhead circuits. It acts like a circuit breaker by opening under detection of high current due to a downstream fault, such as a tree branch across two phases. Reclosers localize the fault to the circuit section beyond the recloser (downstream of the recloser), leaving customers intact on the remainder of the circuit (upstream of the recloser). Unlike a fuse that will open and stay open, a recloser is designed to automatically attempt to reclose several times. The open and reclose cycle allows a temporary fault, such as a small falling tree limb, to clear from the circuit and restores power to customers with only a momentary interruption. In the case of a sustained fault, the recloser will eventually remain open and isolate the fault from the rest of the circuit.

Reclosers with SCADA control capability can be used for automatic restoration in distribution system loop schemes. A typical loop scheme involves at least two separate but adjacent circuits: each of the circuits has a normally closed recloser installed near the midpoint; a normally open recloser is installed at the tie point of the two circuits. The scheme automatically operates to isolate a fault that occurs between a circuit breaker and the midpoint recloser. After the breaker locks open, the midpoint recloser opens and the tie recloser closes between the two circuits. This automatically restores half of the circuit by transferring it to the adjacent circuit, reducing the number of customers experiencing an extended outage.

DTEE operates approximately 1,066 overhead three-phase reclosers on its distribution system. Of the total, 93.6 percent are installed on the 13.2 kV system and 6.4 percent on the 4.8 kV system. Approximately 83 percent of the reclosers have SCADA monitoring and control capability.

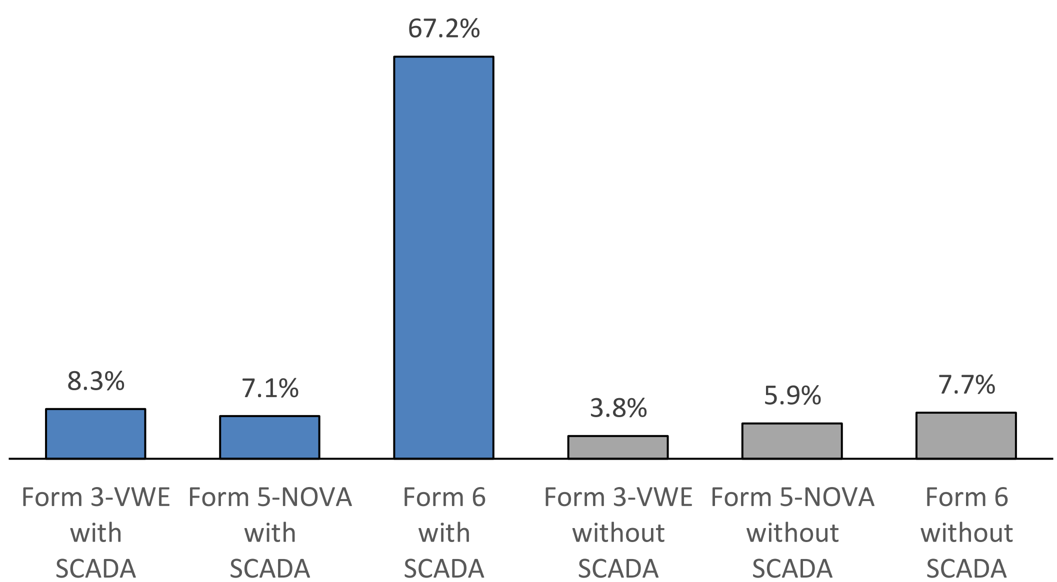
Exhibit 4.10.1 Three-Phase Recloser Design Types

VWE Recloser

NOVA Recloser

Triple Single Recloser & Form 6 Control

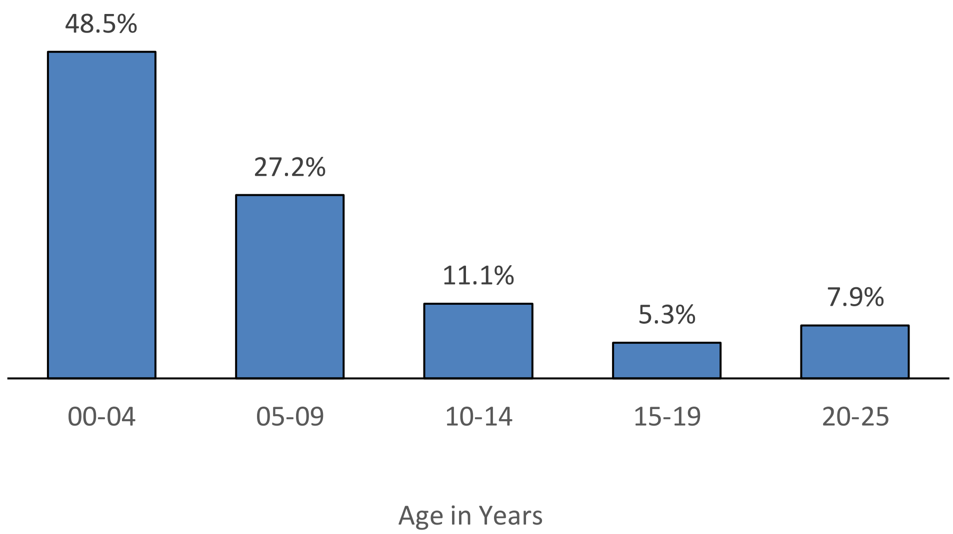
Exhibit 4.10.2 Three-Phase Recloser Type Distribution



DTEE installs Eaton Cooper three-phase reclosers with different types of controls. Form 3-VWE and Form 5–NOVA reclosers operate all three phases simultaneously. The Form 6 (Triple Single) reclosers can operate in single phase mode as well as three phase mode (Exhibit 4.10.1). The ability to operate single phase reduces the number of customers interrupted during an outage event. However, the single-phase mode can only be utilized in locations where no three-phase customers are being served.

The average age of the three phase reclosers is approximately 11 years. Exhibit 4.10.3 shows the age distribution.

Exhibit 4.10.3 Three-Phase Recloser Age Distribution



Form 3-VWE and Form 5-NOVA reclosers (25 percent of the total population) are candidates for potential replacement due to multiple replacement factors including unavailable parts, higher failure rates (average 3.9 percent compared to less than 2 percent for Form 6), environmental issues, and SCADA compatibility (Exhibit 4.10.4). Depending on the failure mode (failed to close or open), the number of customers impacted can range between 300 and 1,500.

DTEE has a preventive maintenance (PM) program for overhead three-phase reclosers. Reclosers not passing PM inspection or failing in service are replaced or repaired.

Exhibit 4.10.4 Three-Phase Recloser Replacement Factors

Factors	Impacts
Unavailable Parts	Many replacement parts for Form 3-VWE and Form 5-NOVA are unavailable; others are becoming increasingly unavailable
Known high failure rate	Form 3-VWE reclosers have seen high failures of batteries, controls and mechanical parts Form 5-NOVA reclosers have seen high failures of mechanical parts
Environmental issues	Form 3-VWE reclosers contain oil and can leak during service
SCADA capability	Form 3-VWE does not have diagnostic capability. It is expensive to retrofit SCADA on Form 3 controls

Exhibit 4.10.5 Three-Phase Recloser Program Summary

Program Summary	
Equipment	Three-Phase Reclosers
Preventive Maintenance Program	Yes
Proactive Replacement Program	Not Applicable

4.11 SCADA Pole Top Switches

A complete SCADA pole top switch (PTS) includes a switch and a SCADA control box that provides an interface between the switch and the Energy Management System (EMS) master-station computer.

A SCADA PTS allows the System Operations Center (SOC) to quickly isolate faults and restore customers remotely. Additional switches permit the circuit to be divided remotely, so load can be transferred to other circuits in the event of an outage.

DTEE operates 290 SCADA PTS's. There are two types of SCADA PTS's: S&C SCADA Mate switches and Bridges Auto Topper switches (Exhibit 4.11.1).

Exhibit 4.11.1 SCADA Pole Top Switch Types

S&C SCADA Mate switches

Bridges Auto Topper switches

Exhibit 4.11.2 SCADA Pole Top Switch Type Distribution

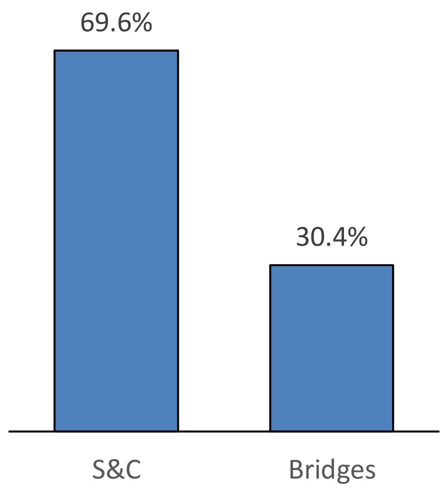
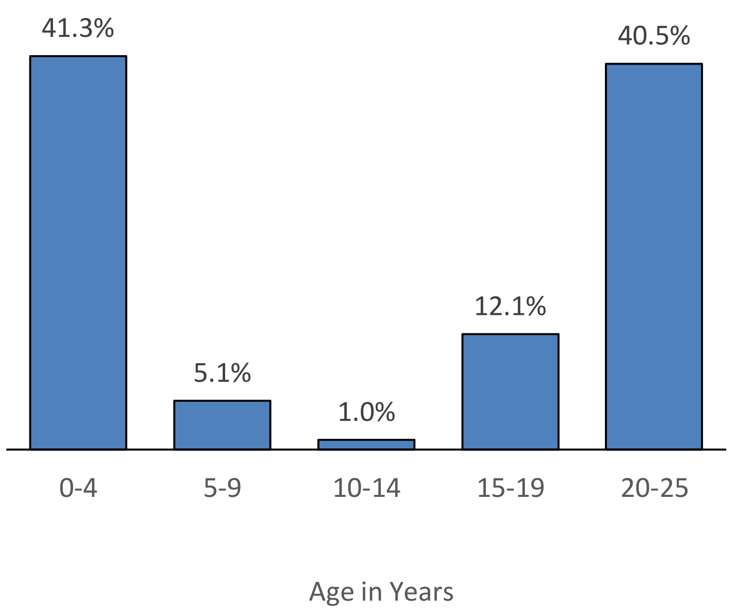


Exhibit 4.11.3 SCADA Pole Top Switch Age Distribution



The average age of all SCADA pole top switches is approximately 15 years. The Bridges switches average age is more than 20 years. Historically, Bridges switches have had a significantly higher failure rate (4.3 percent compared to 1 percent for the S&C SCADA Mate). The factors driving higher failure rates for Bridges switches include an open-air switch design vulnerable to adverse weather conditions, motor–timer failures, control board failures and Lindsey sensor failures. Additionally, many Bridges switches have RTU control boxes with carbon steel cabinets, which are prone to rusting. Because of these factors, all Bridges SCADA PTS's (30 percent of the SCADA PTS population) are candidates for potential replacement.

When SCADA pole top switches fail to open or fail to close, remote restoration is unavailable and the switch must be opened manually by field personnel, resulting in longer restoration times. DTEE has a preventive maintenance program on SCADA pole top switches. S&C SCADA units that do not pass preventive maintenance inspections or fail in service are either repaired or replaced, while failed Bridges SCADA units are generally replaced.

Exhibit 4.11.4 SCADA Pole Top Switch Program Summary

Program Summary	
Equipment	SCADA Pole Top Switches
Preventive Maintenance Program	Yes
Proactive Replacement Program	Not Applicable

4.12 40 kV Automatic Pole Top Switches (40 kV APTS)

DTEE has approximately 144 automatic pole top switches (APTS) with control boxes on the 40 kV subtransmission system. In recent years, the failure rate of these switches has been increasing, ranging from 15 percent to 20 percent annually. A failure of one of these switches has the potential to interrupt thousands of customers or result in significant operational constraints. The entire 40 kV APTS population is considered for replacement to address high failure rates and unavailable spare parts for early vintages.

DTEE has a preventive maintenance program for 40 kV APTSs. DTEE is also conducting a pilot study for 40 kV APTS replacement to verify the latest technology and optimize installation. Based on the learnings from this pilot, DTEE will ramp up a proactive replacement program to replace the entire population of the 40 kV automatic pole top switches.

The exact age of each 40 kV APTS is difficult to determine as parts and controllers have been replaced throughout their lives; however, Exhibits 4.12.1 and 4.12.2 show the switch types and vintages. Recent failure modes of the 40 kV APTSs are shown in Exhibit 4.12.3.

Exhibit 4.12.1 40 kV Automatic Pole Top Switches

Elpeco

R&IE

S&C R9

S&C R10

Exhibit 4.12.2 40 kV Automatic Pole Top Switches by Vintage

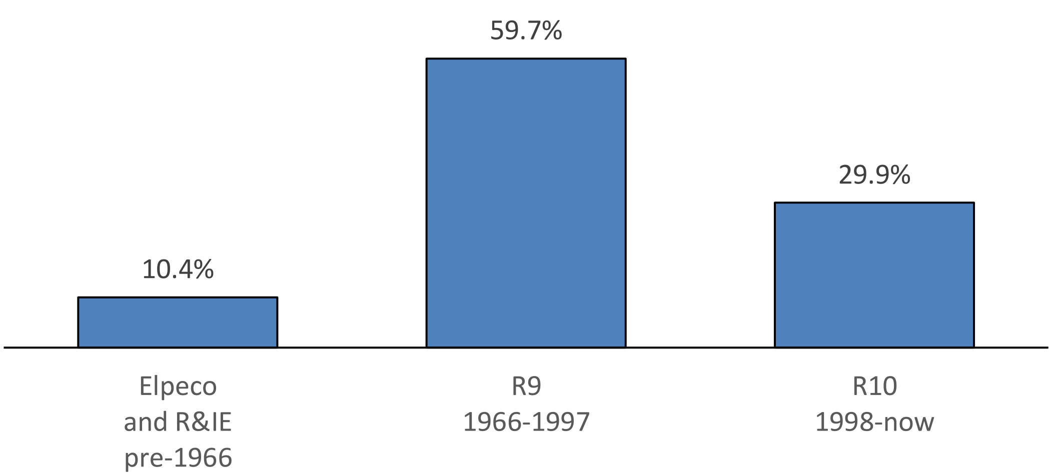


Exhibit 4.12.3 40 kV Automatic Pole Top Switch Failure Modes

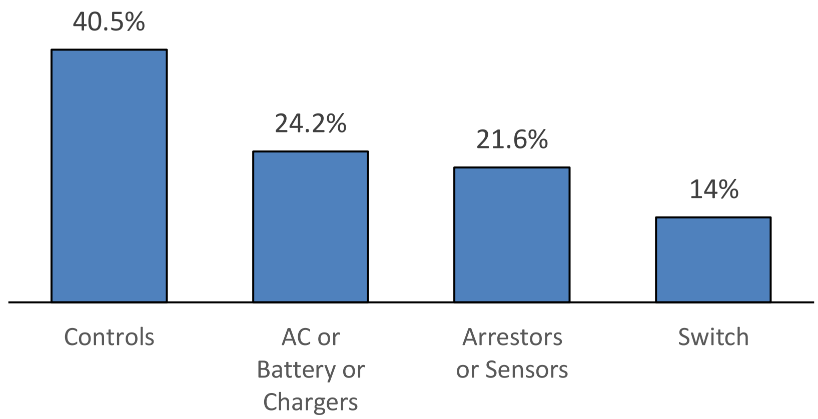


Exhibit 4.12.4 40 kV Automatic Pole Top Switch Program Summary

Program Summary	
Equipment	40 kV Automatic Pole Top Switches
Preventive Maintenance Program	Yes
Proactive Replacement Program	• In pilot phase • Will ramp up based on learnings from the pilot program

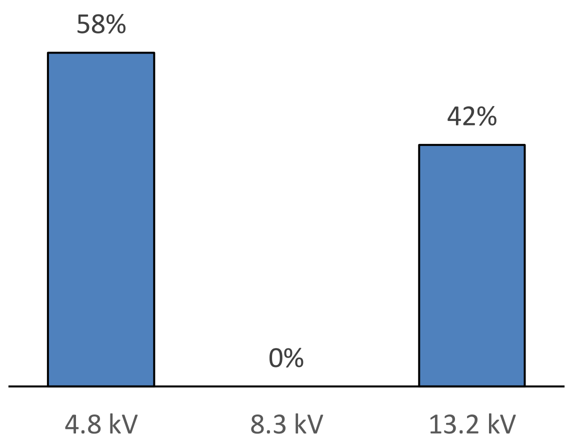
4.13 Overhead Capacitors

Overhead capacitors are passive electronic components that provide a static source of reactive power to the distribution system. They are used to manage the reactive power and consequently voltage and losses on a distribution circuit.

DTEE has approximately 3,300 overhead capacitor banks installed on 1,788 overhead circuits. They provide approximately 2,000 MVAR of reactive power. Not all circuits have or need capacitors. Engineering analyses are done to determine which circuits would benefit from the addition of capacitors and where those capacitors should be located on the circuit. Most capacitors were installed in the early 1990s.

Exhibit 4.13.1 Overhead Capacitor Bank

Exhibit 4.13.2 Overhead Capacitor Bank Voltage Distribution



Overhead capacitor failures typically do not lead to customer interruptions, but may impact power quality and line losses.

DTEE has a preventive maintenance program (PM) for overhead capacitors. Reactive replacements are made for units that do not pass PM inspection or fail in service. DTEE is planning a pilot study in 2018 to test retrofitting of remote monitoring, control and condition based monitoring for overhead capacitors. If the pilot proves cost effective, a program to retrofit the overhead capacitors with smart monitoring and control may be established. New devices or those that are replaced due to failure or obsolescence will be built with the remote monitoring and control capability as standard.

Exhibit 4.13.3 Overhead Capacitor Bank Program Summary

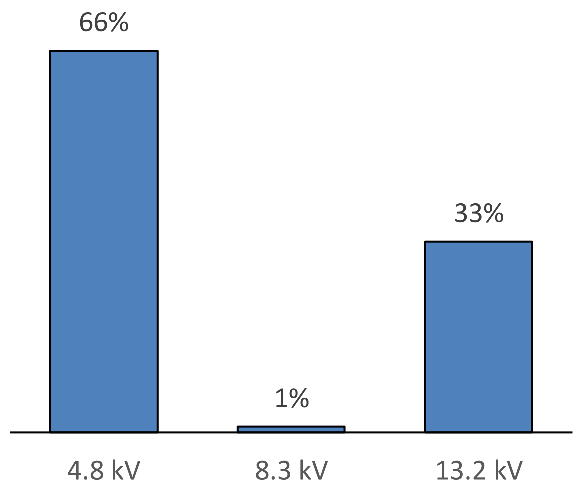
Program Summary	
Equipment	Overhead Capacitors
Preventive Maintenance Program	Yes
Proactive Replacement Program	In pilot phase

4.14 Overhead Regulators

Overhead regulators are used to maintain circuit voltage, particularly in situations where the load is distant from the substation. DTEE regulators adjust automatically based on the changing load to maintain circuit voltage level. Not all circuits have or need regulators. Engineering analyses are done to determine which circuits would benefit from the addition of regulators and where those regulators should be located on the circuit. DTEE has approximately 2,400 regulators on its overhead circuits.

Exhibit 4.14.1 Overhead Regulator

Exhibit 4.14.2 Overhead Regulator Voltage Distribution



Overhead voltage regulator failures typically do not lead to customer interruptions, but may result in low voltage situations.

DTEE has a preventive maintenance program for overhead voltage regulators. Reactive replacements are made for units that do not pass PM inspection or fail in service. DTEE is planning a pilot study in 2018 to test retrofitting remote monitoring, control and condition based monitoring for overhead regulators. If the pilot proves cost effective, a program to retrofit the overhead regulators with smart monitoring and control may be established. New devices or those that are replaced due to failure or obsolescence will be built with the remote monitoring and control capability as standard.

Exhibit 4.14.3 Overhead Regulator Program Summary

Program Summary	
Equipment	Overhead Regulators
Preventive Maintenance Program	Yes
Proactive Replacement Program	In pilot phase

4.15 System Cable

DTEE's distribution and subtransmission system has over 16 million feet or 3,100 miles of underground system cable. System cable is installed in conduit and requires manholes or switch-cabinets approximately every 100 to 800 feet depending on the cable type and path. Manholes and switch-cabinets provide locations where sections of cable can be pulled through the conduit and spliced together. System cable provides higher storm resiliency than overhead lines; however, the cost and time to install, repair or replace are much greater. System cable is especially useful to route multiple circuits through a small congested area (e.g., entrances and exits of a substation).

Exhibit 4.15.1 Underground System Cable Types

PILC VCL Nitrogen Gas XLPE EPR

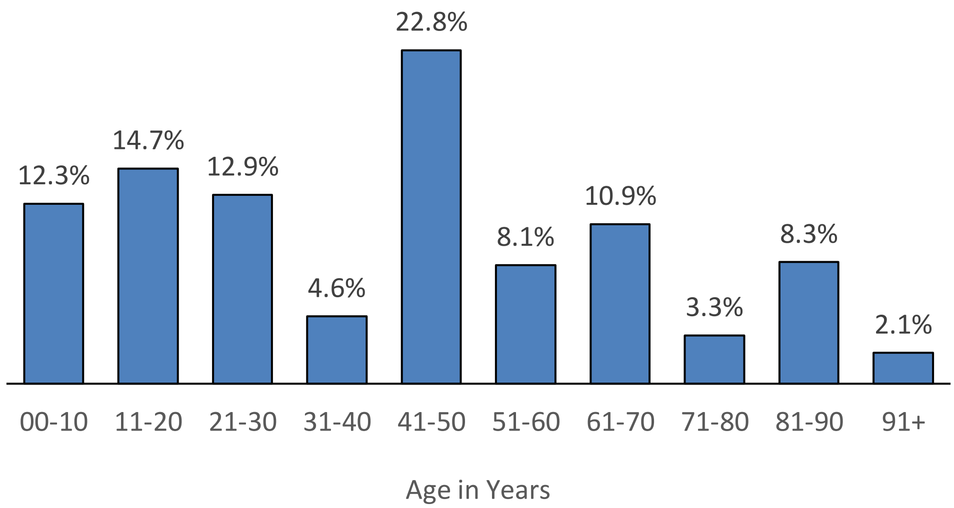
Exhibit 4.15.1 illustrates the five major types of underground system cable installed in DTEE's distribution system. Exhibit 4.15.2 shows the types, quantities, average age, and life expectancy of system cable in the DTEE system. The average life expectancy of system cables is 40 years or less, although actual useful life varies depending on field conditions.

Exhibit 4.15.2 Underground System Cable Ages and Life Expectancy

Cable Type	PILC	EPR	VCL	Gas	XLPE Post 1985 (Tree retardant)	XLPE Pre 1985 (Non-tree retardant)
Miles	2,312	526	115	65	95	22
% of Total Population	73.7%	16.8%	3.7%	2.1%	3.0%	0.7%
Average Age	49	15	57	52	25	38
Life Expectancy	40	35	40	40	40	25

As shown in Exhibit 4.15.3, more than 55 percent of DTEE system cable is beyond its typical life expectancy.

Exhibit 4.15.3 Underground System Cable Age Distribution



System cable is a critical component for both the subtransmission and distribution systems. A failure typically interrupts a large number of customers for an extended period of time. Approximately 34 percent of the system cable is identified as candidate for replacement. This includes XLPE cable installed before 1985 (non-tree retardant XLPE cable), nitrogen gas cable, VCL (Varnished Cambric Lead), and any cable beyond 60 years old.

- XLPE (cross-linked polyethylene) cable manufactured before 1985 has a design defect that leads to premature insulation breakdown and dielectric failures (also called “Treeing”). The XLPE cable failure rate is approximately 0.14 failures per mile per year. Approximately 22 miles of XLPE cable remain in the DTEE system that will be replaced.

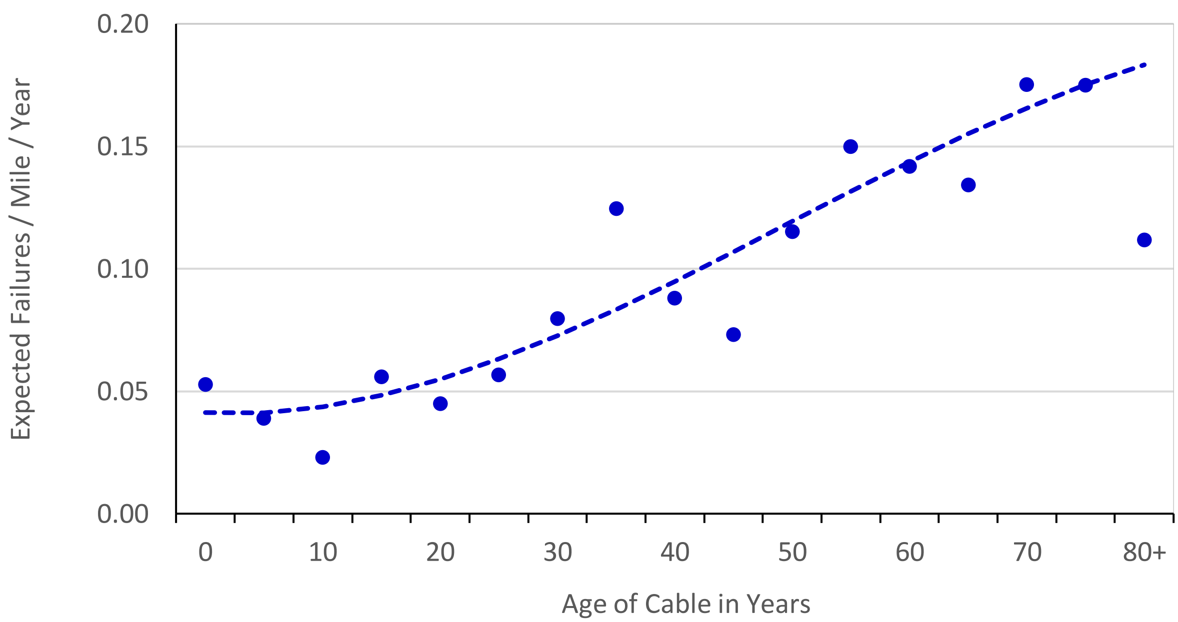
- Gas (gas filled paper lead) cable has cavities within the insulating layer that are filled with gas (usually nitrogen gas) under pressure. This type of cable is prone to mechanical damage that leads to gas leaks and dielectric failures. Re-gassing this type of cable is very expensive.

The Nitrogen Gas cable failure rate is approximately 0.10 failures per mile per year. There are 65 miles of nitrogen gas cable remaining in the DTEE system that will be replaced.

- VCL (varnished cambric lead) cable is prone to failure under heavy loading and high temperature environment. The heavy loading or high temperature causes the insulation to degrade and lose its dielectric integrity. The VCL cable failure rate is approximately 0.18 failures per mile per year. Approximately 115 miles of VCL remain in the DTEE system and will be replaced.

- Age: based on DTEE's cable failure data, cable failure rates increase with age. System cable at 60 years old experiences 0.15 failures per mile per year.

Exhibit 4.15.4 DTEE Underground System Cable Failure Rates



DTEE has a proactive replacement program to replace targeted system cable. The replacement of system cable is prioritized based on multiple factors including cable type, vintage, previous failure history, impacts to the system, cable loading and O&M costs. Exhibit 4.15.5 lists the types and quantities of the system cable replacements planned for the next five years.

Exhibit 4.15.5 Projected Proactive Underground System Cable Replacement 5-Year Plan

System Cable Type	Target Quantity	Timeline
Pre-1985 XLPE	116 thousand feet (22 miles)	2018-2019
Gas (gas filled paper lead)	343 thousand feet (65 miles)	2019-2021
VCL or PILC > 60 years (paper in lead)	32 thousand feet (6 miles)	2022 (Rest of VCL and PILC>60 years will be replaced beyond 2022)

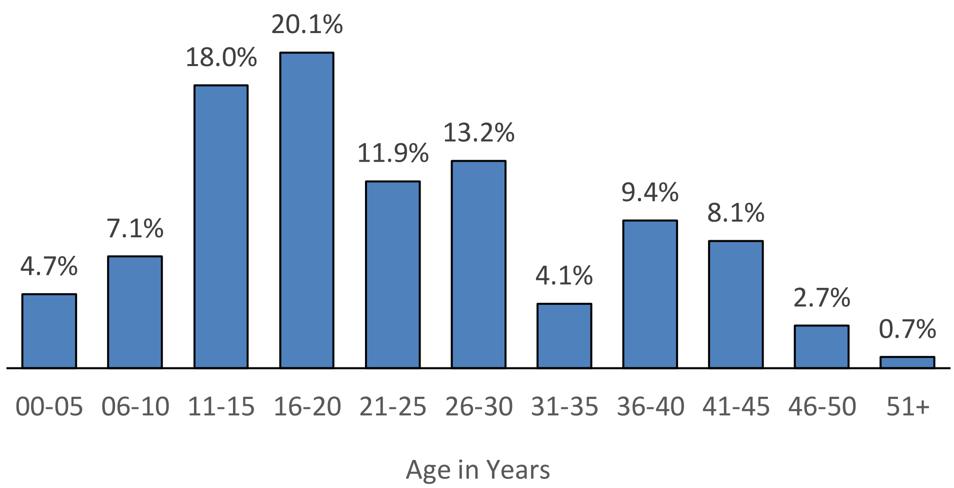
Exhibit 4.15.6 Underground_System Cable Program Summary

Program Summary	
Equipment	System cable
Preventive Maintenance Program	No
Proactive Replacement Program	
Spend Projection 2018-2022	$114 million
Unit Projection 2018-2022	491 thousand feet (93 miles)
Entire Program Spend Projection (until 2035)	$890 million - $2 billion

4.16 Underground Residential Distribution (URD) Cable

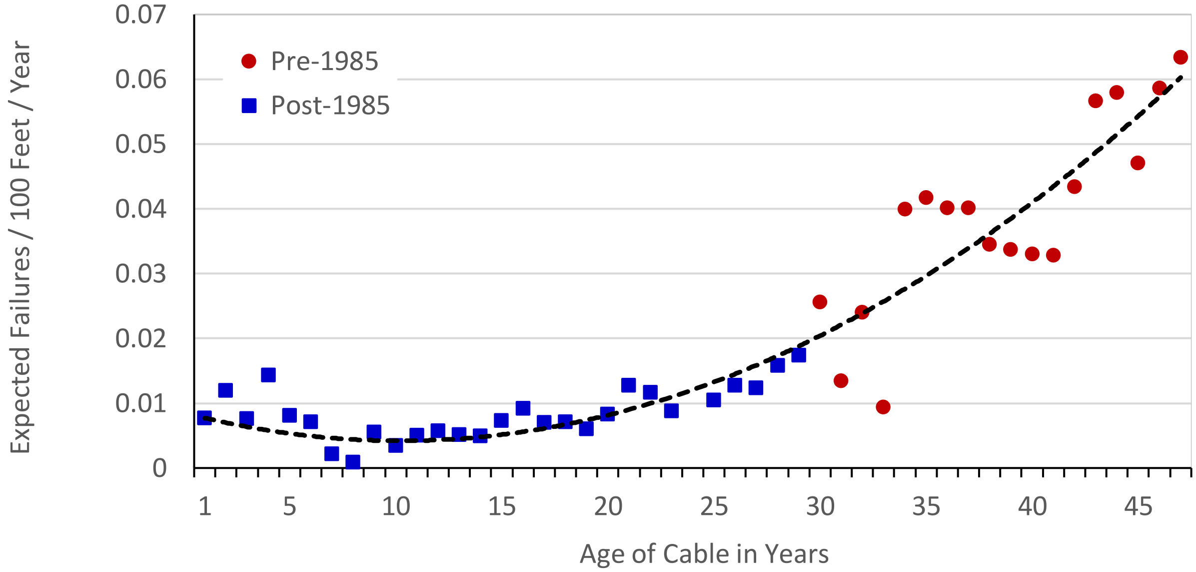
DTEE has approximately 51 million feet or 10,800 miles of underground residential distribution (URD) cable, with 87 percent of the URD cable on the 13.2 kV system. All subdivisions built since the early 1970s are served with URD cable. Buried underground, URD is not exposed to tree-related or other overhead related outages, however, it is more expensive to install and repair compared to overhead lines. URD cable failures are less frequent but take a long time to repair or replace. The average age of DTEE URD cable is 23 years. The age distribution is provided in Exhibit 4.16.1.

Exhibit 4.16.1 URD Cable Age Distribution



URD cable manufactured prior to 1985 (non-tree retardant XLPE) is considered for replacement. These cables are experiencing high failure rates due to a manufacturing defect in the insulation, as illustrated in Exhibit 4.16.2. Approximately 26 percent of the installed URD cable is of this type. The TR-XLPE (tree retardant XLPE) cable manufactured post-1985 does not have the insulation defects of its predecessor and is the preferred URD cable.

Exhibit 4.16.2 URD Cable Failure Rates



DTEE has a proactive replacement program to replace pre-1985 non-tree retardant URD cable. The replacement is prioritized based on multiple factors including previous failure history, impacts to the system and customers, loading, and partial discharge testing results. Partial discharge testing is used to measure small electrical currents from voids and imperfections in the URD cable insulation that are indicators of remaining life and precursors to failure.

Exhibit 4.16.3 URD Cable Program Summary

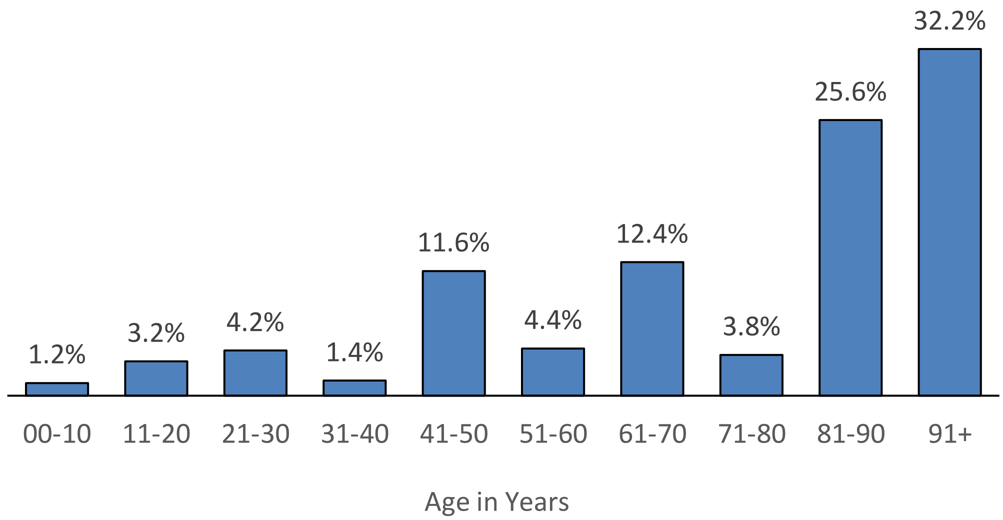
Program Summary	
Equipment	Underground residential distribution (URD) Cable
Preventive Maintenance Program	No
Proactive Replacement Program	Yes
Spend Projection 2018-2022	$48 million
Unit Projection 2018-2022	1.4 million feet (260 miles)
Entire Program Spend Projection (until 2035)	$400 - $600 million

4.17 Manholes

Underground system cables are pulled and spliced inside manholes. The cables are mounted on support arms on the manhole walls to maintain separation and allow safe entry into the manholes for work, as illustrated in Exhibit 4.17.1. Failures of any part of the manhole infrastructure have the potential to impact a large number of customers because multiple cables typically run through the same manhole, and a fault on one cable can damage adjacent cables. DTEE has approximately 17,000 manholes. Their age distribution is shown in Exhibit 4.17.2.

Exhibit 4.17.1 Manhole and Cables

Exhibit 4.17.2 Manhole Age Distribution



Whenever a manhole is entered to perform cable work, it is inspected and repairs are made as needed. DTEE estimates that approximately 8,500 (half of the population) manholes have not been entered in over 20 years. As a preventative measure, DTEE started a manhole inspection program in 2016 for these 8,500 manholes. Issues identified during manhole inspections include degradation of structural strength due to surface vibration, presence of ground water, etc. Any identified issues will be addressed either as part of the capital work or repair work.

Exhibit 4.17.3 Manhole Program Summary

Program Summary	
Equipment	Manholes
Preventive Maintenance Program	Yes

4.18 Vaults

DTEE has 21 vaults as part of the 8.3 kV system in the City of Pontiac. DTEE did not construct the 8.3 kV system but acquired it from CMS Energy in the 1980s (refer to Section 5.5.4 for DTEE's plan to address the 8.3 kV system). Theses vaults are typically located beneath city sidewalks with an overhead grating. Overhead style equipment (8.3 kV) is used in the vaults. Much of the equipment used in the vaults is obsolete and spare parts are no longer available. Due to the confined space in the vaults, there is also a shock hazard to personnel entering the vaults. The minimum arc flash distance may not exist, making it difficult or impossible to operate within the vaults. This can add considerable restoration time to an outage event. Exhibit 4.18.1 provides an interior view of an underground vault.

Exhibit 4.18.1 Underground Vault and Equipment

To address the safety hazards and operating limitations associated with the vaults, DTEE has started to replace or decommission the equipment in seven vaults with surface mounted equipment and convert the vaults to manholes. For the remaining 14 vaults, DTEE expects to replace the existing equipment with dual voltage (8.3 kV and 13.2 kV) submersible equipment. The submersible equipment utilizes the latest technology and will allow remote monitoring and control capability. This not only provides safe, reliable operation of the equipment in the vaults, but also standardizes the vault equipment to reduce the cost of future repairs. The dual voltage feature of the equipment will allow continued utilization of the equipment as the aging and islanded 8.3 kV system is converted to 13.2 kV (Section 5.5.5).

Exhibit 4.18.2 Underground Vault Program Summary

Program Summary	
Equipment	Vaults
Preventive Maintenance Program	No
Proactive Replacement Program	
Spend Projection 2018-2022	$17 - $34 million
Unit Projection 2018-2022	14 vaults
Entire Program Spend Projection (2018-2022)	$17 - $34 million

4.19 Advanced Metering Infrastructure

DTEE has replaced nearly all its electric meters with new AMI (Advanced Metering Infrastructure) technology, also known as smart meters.

Exhibit 4.19.1 Electric Meter Types

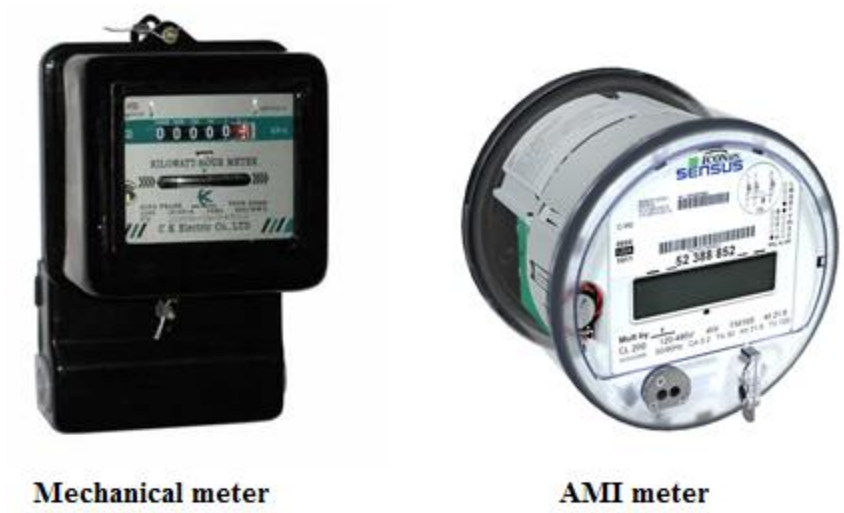
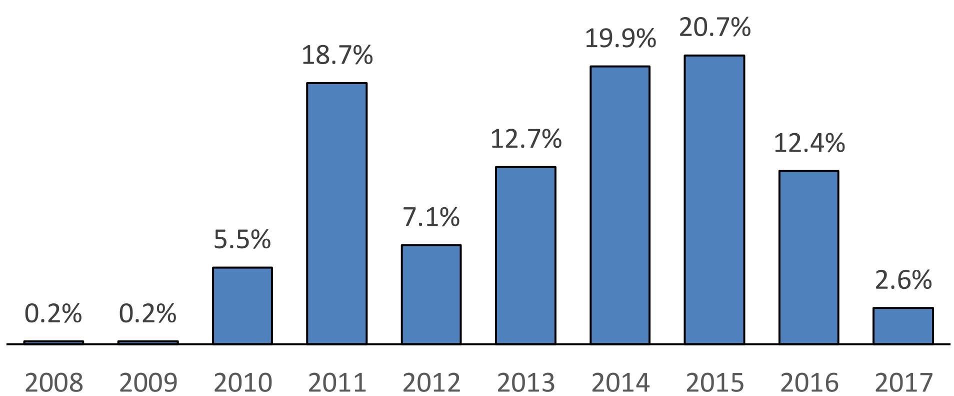


Exhibit 4.19.2 Electric Meter Replacements with AMI Technology



The average age of the AMI meters is 4.5 years. The expected life of the AMI meters is 20 years; however, meters may need to be replaced or upgraded earlier due to failures and technology changes.

AMI technology provides a number of benefits to DTEE customers:

1. Meter Reading

   AMI technology provides accurate daily and on-demand meter reads without the need for field visits or access to meters installed inside buildings. AMI provides customers with actual and accurate consumption data every month. Customers with multiple homes / buildings can have all their sites combined in one bill with the readings on the same day. Starting and stopping billing services can also be done remotely with accurate meter reads.

2. Billing Accuracy

   AMI technology eliminates human errors in reading the meter and manual entry of the data.

3. Outage Restoration Efficiency

   AMI technology provides DTEE notification on loss of power. DTEE has the ability to 'ping' any meter remotely to determine if it has power. This is particularly valuable during storm conditions to confirm customer restoration and improve restoration efficiency.

4. Safety Risk Reduction

   The remote meter read capability eliminates the potential risk of injury to meter readers due to slips, trips, falls and dog bites.

5. Customer Energy Usage

   Customers who use the free DTE Insight app with their AMI meters can see exactly how much energy they are using, which can help them find ways to be more energy efficient.

6. Turn On / Turn Off / Restore

   AMI technology allows remote connection and disconnection (in accordance with billing rules) of customers without field visits.

7. Theft and Tampering Notification

   The technology continuously monitors for meter tampering. In addition, the daily meter reads can be used to develop algorithms to identify unusual usage patterns that may be an indicator of theft.

Similar to mechanical meters previously used, AMI meters are replaced if malfunctioning or failing during service. In addition, two issues have been identified on the DTEE AMI system and need to be addressed with capital projects in the next five years.

First, telecommunication providers (Verizon and AT&T) will be retiring 3G technology and migrating to 4G by 2020. DTEE will need to replace approximately 6,000 large commercial and industrial customer 3G meters and 3,300 cellular 3G Cell Relays, serving 1.1 million residential customer meters. The Cell Relays serve as a communication “aggregator” or “gateway” for AMI meters. The Cell Relays communicate with DTEE data centers via either cellular telecommunications or Ethernet. As the Michigan telecommunication providers phase out 3G cellular, these devices will require replacement with a 4G cellular devices or some other compatible network device prior to 2020. Without the replacements, the meters serving 6,000 large commercial and industrial customers and 1.1 million residential customers would no longer be remotely accessible for billing, outage detection, voltage data or remote connect / disconnect capabilities, severely impacting customer service.

Second, existing AMI meters cannot detect a broken neutral connection. For these types of outages, the meter does not send power outages notifications nor is the condition revealed by “pinging” the meter. Incorporating a broken neutral detection capability into the meter firmware will further reduce or eliminate field visits for power on/off verification. DTEE continues to work with AMI vendors to resolve this issue. A capital project is budgeted in 2020 to address it once a cost-effective solution is identified.

Exhibit 4.19.3 lists the identified AMI technology projects in the next five years. Exhibit 4.19.4 shows the projected costs and timeline for the AMI technology projects.

Exhibit 4.19.3 AMI Upgrade Projects Summary

Project	Scope of Work	Drivers
AMI 3G Cellular Cell Relay Upgrade	• Replace 3,300 3G Cell Relays with 4G devices due to obsolescence of 3G telecommunication	• Telecommunication providers plan to phase out 3G in Michigan by 2020
AMI 3G Cellular Large Commercial and Industrial Meters Upgrade	• Replace 6,000 3G cellular meters serving large commercial and industrial customers with 4G devices • Among the 6,000 sites, approximately 1,500 of the 6,000 will be replaced with advanced power quality meters	• Telecommunication providers plan to phase out 3G in Michigan by 2020 • SCADA and more advanced power quality data needed at selected sites, given the size of their load or the percentage of load of circuits they are on
AMI Firmware Upgrade	• Upgrade AMI firmware on 2.5 million meters to enable detection of broken neutral connections without replacing existing meter hardware	• The advanced feature will help reduce unnecessary field visits, improve restoration efficiency, and reduce costs

Exhibit 4.19.4 Projected Costs and Timeline for AMI Upgrade Projects

Project	2018	2019	2020	2021	2022	2018-2022 Cost Estimate ($ million)
AMI 3G Cellular Cell Relay Upgrade						$31
AMI 3G Cellular Large Commercial and Industrial Meters Upgrade						$13
AMI Firmware Upgrade						$4 - $10

5 System Condition Assessment

In addition to asset condition assessments, DTEE evaluates system conditions on a regular basis, including system loading, substation outage risk, system reliability, grid technology, system design and reactive trouble costs. Capital programs and projects are developed to address issues identified from system condition assessments. This section provides a detailed description for each of these system conditions.

5.1 System Loading

5.1.1 Context

It is necessary to assess the load on the system and individual equipment in order to ensure that distribution system capacity exists to serve the load. Throughout this section, capacity refers to distribution assets' ability to deliver electrical power, not the ability to generate the power. There are areas within the system where the peak load is expected to increase. These increases may be the result of new load or customers relocating from one area to another. It is critical to identify expected capacity needs well in advance of the expected load increase in order to complete planning, siting, permitting and construction of necessary infrastructure.

Capacity needs are considered for two conditions: normal state and contingency state. The normal state exists when all equipment and components are in service and operating as designed. The contingency state exists when there is either a temporary planned equipment shutdown, the loss / failure of a component of the electric power system (e.g., subtransmission line), or the loss / failure of individual equipment (e.g., transformer, cable or breaker). Under contingency conditions, equipment in the rest of the system may see an increase in loading to compensate for the out-of-service equipment, and hence, requires additional capacity above normal state.

To meet the two state capacity requirements, most components and equipment have two ratings: day-to-day and emergency. These ratings are calculated to maintain the viability of an asset throughout its expected useful life. Operating equipment above their designated ratings can cause immediate failure or accelerate end-of-life.

- The **day-to-day** rating (for normal state conditions) is the load level that the equipment can be operated at for its expected life span.

- The **emergency** rating (for contingency state conditions) is higher than the day-to-day rating and is the load level that the equipment should be operated at for only short periods of time. Operating at the emergency rating adds stress to the equipment and shortens its lifespan. If a piece of equipment exceeds its emergency rating, DTEE's System Operations Center takes immediate steps to transfer load or shed load if necessary.

- For substations, there is also a **firm** rating. The substation firm rating is the maximum load the substation can carry under a single contingency condition and is based on the lowest emergency rating of all the substation equipment that is required to serve the load.

To ensure that expected load growth can be served within the equipment ratings, DTEE planning engineers conduct annual area load analyses (ALA). These analyses include verification of equipment ratings and substation firm ratings, past loading data, system conditions and configurations, known new loads, and input from large customers and municipal officials about potential development. Based on DTEE's 2016 ALA study, approximately 30 percent of distribution substations have various loading constraints, either substations being over their firm ratings or equipment being over its day-to-day rating during peak hours. Multiple trunk and tie lines on the subtransmission system are over their emergency ratings during contingency events. Since the study is conducted for peak load conditions, the over firm or over load assessments are usually of concerns for a small percent of hours annually, depending on loading characteristics of individual substations or subtransmission lines. As such, additional capacity is needed to prevent customer interruptions during a single contingency event and help maintain the useful life of the existing equipment.

Where the potential for contingency overloads exist, blocking schemes can be utilized. These schemes prevent the automatic throw-over (load transfer) at substations during single contingency events to avoid loads exceeding equipment emergency ratings. Utilization of blocking schemes protects assets but removes redundancy at the substation during peak hours that may result in customer interruptions that would have otherwise been avoided.

For areas and cities that have experienced steady and/or strong load growth, capital investment is required to add or upgrade overhead or underground lines (subtransmission and/or distribution) and/or to expand or build new substation capacity.

Often a strategic load relief project is the result of a combination of general load growth, specific customer connection requests, aging infrastructure replacement and reliability improvement needs. The project could be building a new general purpose substation that may have the added benefits of mitigating substation risk at neighboring substations and improving overall reliability for the area.

Load relief projects are discussed in detail in Section 5.1.3.

5.1.2 Load Relief Project Prioritization

As mentioned above, approximately 30 percent of DTEE's distribution substations are over their designed ratings based on DTEE's 2016 ALA study. A high-level cost estimate indicates it would take up to $1 billion to remove all the loading constraints from DTEE's system. Cost and resource availability make it infeasible to execute load relief projects on all these substations in a short period of time. Therefore, DTEE has developed a prioritization methodology to rank substation load relief projects based on criticality.

This methodology is based on three variables:

1) Substation Equipment Overload (peak load exceeding substation equipment day-to-day ratings or nearing substation equipment emergency ratings). A score of zero to five is given

to substations based on the ratio of load to rating. A score of five represents the most severe overload condition. Exhibit 5.1.1 illustrates the scoring methodology for this variable.

Exhibit 5.1.1 Substation Equipment Overload Scores

Score	Either % of Day to Day Rating		Or % of Emergency Rating	
	Min (>)	Max (<=)	Min (>)	Max (<=)
5	110%		90%	
3	100%	110%		
1	80%	100%		
0		80%		90%

2) Substation Over Firm (peak load exceeding substation firm rating under contingency conditions). A score of zero to five is given to substations that experience varying degrees of MVA load over their firm ratings with and without load transfer (or load jumpering). Under contingency conditions, any MVA load over substation firm rating represents customers that cannot be served by the substation itself. Some of this load can be subsequently transferred to adjacent substations for the duration of the contingency. This creates the difference in values and scoring in MVA over firm before load transfer and MVA over firm after load transfer. Exhibit 5.1.2 illustrates the scoring method for this variable.

Exhibit 5.1.2 Substation Over Firm Rating Scores

Score	Either MVA Over Firm after Load Transfer		Or MVA Over Firm Before Load Transfer	
	Min (>)	Max (<=)	Min (>)	Max (<=)
5	4 MVA			
4	3 MVA	4 MVA	8 MVA	
3	2 MVA	3 MVA	4 MVA	8 MVA
2	1 MVA	2 MVA		
1	0 MVA	1 MVA		
0		0 MVA		4 MVA

3) Customer connection requests. The priority ranking for a substation load relief project is increased by one level if the substation has known customer connection requests. Being able to create a project that not only serves this customer but also resolves the substation overload or over firm situation is preferred from the economic perspective.

The final priority ranking of substation load relief projects is a combination of the above three variables. Substations having a combined equipment overload and over firm score of six or more, or three or more with known customer connection requests, receive Priority 1 and are the focus of DTEE's load relief projects in the near term. Section 5.1.3 lists all the Priority 1 substations and their scoring based on this methodology.

5.1.3 Programs to Address System Loading

Exhibit 5.1.3 lists all the Priority 1 load relief substations and their key statistics. Exhibit 5.1.4 lists the scope of work for the same Priority 1 substation load relief projects. Exhibit 5.1.5 lists the projected costs and timeline for the substation load relief projects. It is important to note that the cost and timeline estimates for the identified projects are based on the best knowledge and information known today by DTEE. Actual project cost and timeline could deviate from the projection due to various unforeseen factors or new information/learnings.

Exhibit 5.1.3 Priority 1 Load Relief Substations Overview

Index	Substation	Voltage (kV)	Region	Community	Equipment Overload			Substation MVA Over Firm			Total Score	Customer Request	Priority
					% of Day-to-Day Rating	% of Emergency Rating	Score	Before Load Transfer	After Load Transfer	Score			
1	Diamond	13.2	SW	Dexter / Scio	94%	91%	5	20.6	4.2	5	10	Y	1
2	Argo	4.8	SW	Ann Arbor	120%	81%	5	5.8	0	3	8	Y	1
3	Elba	4.8	NE	Elba Twp	103%	73%	3	3.4	3.4	4	7	Y	1
4	White Lake	4.8 & 13.2	NW	White Lake	100%	82%	1	5.8	5.8	5	6	Y	1
5	Almont	4.8	NE	Almont Twp	91%	67%	1	5.4	4.6	5	6	Y	1
6	Berlin	13.2	SW	S. Rockwood	96%	95%	5	2.6	0	0	5	Y	1
7	Bloomfield	13.2	NW	Bloomfield	90%	77%	1	17.3	1	4	5	Y	1
8	Gilbert	13.2	SW	Romulus	85%	52%	1	17.2	2.1	4	5	Y	1
9	Carleton	4.8	SW	Carleton	106%	87%	3	2.1	0.1	1	4	Y	1
10	Reno	4.8	SW	Freedom / Bridgewater	90%	69%	1	2.9	2.9	3	4	Y	1
11	Grayling	13.2	NW	Shelby Twp	73%	63%	0	14.6	0	4	4	Y	1
12	Lapeer	4.8 & 13.2	NE	Lapeer	68%	62%	0	15.5	0	4	4	Y	1
13	Wixom	13.2	NW	Wixom	72%	57%	0	17	0	4	4	Y	1
14	Hancock	13.2	NW	Commerce Township	62%	53%	0	12.6	0	4	4	Y	1
15	Quaker	13.2	SW	Commerce Township	76%	69%	0	30.1	0	4	4	Y	1
16	Sheldon	13.2	SW	Belleville	59%	43%	0	15.1	0	4	4	Y	1
17	Zachary	13.2	SW	Belleville	76%	72%	0	10.7	0	4	4	Y	1
18	Cody	13.2	NW	Lyon Township	58%	48%	0	46.9	0	4	4	Y	1
19	Oasis	13.2	NW	Independence Township	67%	67%	0	4.3	3	3	3	Y	1
20	Trinity	13.2	SW	Monroe	54%	54%	0	5.2	0	3	3	Y	1

Exhibit 5.1.4 Priority 1 Load Relief Substation Projects Summary

Index	Project	Region	Community	Scope of Work
1	Diamond	SW	Dexter / Scio	• Upgrade 2 substation transformers and transfer some load to adjacent substations
2	Argo/Buckler (Also See Section 5.5)	SW	Ann Arbor	• Transfer three entire circuits and a portion of two circuits from Argo to Buckler, converting them to 13.2 kV
3/12	Lapeer-Elba (Also See Section 5.5)	NE	Lapeer / Elba Twp	• Build a new 13.2 kV substation • Convert Elba circuits to 13.2 kV • Decommission Elba and 40 kV tap to substation • Add a 3rd 13.2 kV transformer to Lapeer • Decommission the 4.8 kV portion of Lapeer • Combine and convert the two 4.8 kV circuits into a single 13.2 kV circuit
4	White Lake (Also See Section 5.5)	NW	White Lake	• Install a skid-mounted substation • Add 3 miles of underground cable • Rebuild 3 miles of overhead • Convert 15 miles of 4.8 kV to 13.2 kV • Install loop schemes for automatic load transfers • Transfer load from White Lake to new substation and decommission White Lake
5	Almont (Also See Section 5.5)	NE	Almont Twp	• Build a new 120:13.2 kV substation • Transfer approximately 50% of Almont load to new substation, converting it to 13.2 kV • Reconductor 4 miles of backbone • Establish new jumpering points
6	Berlin	SW	S. Rockwood	• Upgrade existing transformer and install a 2nd transformer • Build a new circuit
7	Bloomfield (Also See Section 5.5)	NW	Bloomfield	• Addressed as part of Pontiac 8.3 kV Conversion

Index	Project	Region	Community	Scope of Work
8/16/17	Sheldon/Gilbert/Zachary	SW	Romulus / Belleville	• Build a new 120:13.2 kV substation to relieve load on Sheldon, Gilbert and Zachary substations driven by strong economic and load growth in the area
9	Carleton	SW	Carleton	• Upgrade existing transformer and associated substation equipment, reconductor circuit backbone
10	Reno (Also See Section 5.5)	SW	Freedom / Bridgewater	• Build a new 120:13.2 kV substation • Transfer load from Reno, converting it to 13.2 kV • Expand Freedom substation • Decommission Reno
11	Grayling	NW	Shelby Twp	• Build a new substation • Build approximately 4 miles of cable • Build approximately 3 miles of overhead lines
12	Wixom	NW	Wixom	• Add a 3rd transformer to the substation • Replace the switchgear • Build 1.5 miles of cable • Build 5 miles of overhead
14/15	Hancock/Quaker	NW/SW	Commerce Township	• Add a 3rd transformer to Quaker • Build a new substation to relieve load off Quaker and Hancock substations
18	Cody/South Lyon (Also See Section 5.5)	NW	South Lyon	• Upgrade 2 transformers and switchgear at Cody substation • Add 6 miles of underground cable • Rebuild 5 miles of overhead • Convert 8 miles of 4.8 kV to 13.2 kV • Install loop schemes for automatic load transfers • Transfer load from South Lyon to Cody • Decommission South Lyon
19	Oasis	NW	Independence Township	• Replace transformers with higher rating units • Remove 3 breakers and install 9 position switchgear • Extend 3 miles of conduit and 5 miles of system cable • Extend 3 new circuits and rebuild 3 miles of overhead
20	Trinity	SW	Monroe	• Expand Trinity substation to relieve load

Exhibit 5.1.5 Projected Costs and Timeline for Priority 1 Load Relief Substation Projects[8]

Index	Project	2018	2019	2020	2021	2022	2018-2022 Cost Estimate ($ million)
1	Diamond[9]						$3
2	Argo/Buckler (Also See Section 5.5)						$6
3/12	Lapeer-Elba (Also See Section 5.5)						$48 (Total cost: $65)
4	White Lake (Also See Section 5.5)						$15
5	Almont (Also See Section 5.5)						$18
6	Berlin						$7
7	Bloomfield (Also See Section 5.5)						Part of 8.3 kV Conversion
8/16/17	Sheldon/Gilbert/Zachary						$12 (Total cost: $18)
9	Carleton						$1
10	Reno (Also See Section 5.5)						$9 (Total cost: $12)
11	Grayling						$19 (Total cost: $21)
12	Wixom						$17 (Total cost: $26)
14/15	Hancock/Quaker						$10
18	Cody/South Lyon (Also See Section 5.5)						$3 (Total cost: $26)
19	Oasis						$8 (Total cost: $34)
20	Trinity						$5 (Total cost: $7)

[8] This timeline not only reflects the priority of load relief substations, but also the overall priority ranking of the projects including the seven impact dimensions as discussed in Section 2.5

[9] Part of Diamond substation's overload is being addressed by Calla Circuit Conversion project discussed in Exhibit 5.5.7

Some of the load relief projects discussed in Exhibit 5.1.4 not only address system loading issues, but also provide other benefits. For example, the Lapeer-Elba expansion and circuit conversion will remove problematic subtransmission infrastructure at Elba, improve shut down capability for maintenance, address voltage and power quality issues, eliminate the stranded load associated with the islanded 4.8 kV system, decommission aging infrastructure in Lapeer substation, meet the general load growth (6-8% in 2017), and accommodate the Lapeer industrial park development in the coming years.

In addition to substation load relief projects, various subtransmission hardening projects at voltage levels of 24 kV, 40 kV and 120 kV are identified to address loading, reliability and power quality issues associated with the subtransmission system. While large scope subtransmission projects are listed individually in Exhibit 5.1.6 and 5.1.7, small scale projects, usually involving sections of trunk and tie line replacements, are grouped together under the Trunk and Tie Lines Hardening Program.

Exhibit 5.1.6 Subtransmission Projects Summary

Tie or Trunk	Community	Scope
Ann Arbor / UM System Strengthening	Ann Arbor	Construct two new substations and five miles of 120 kV lines, and reconfigure subtransmission tie lines and trunk lines
Tie 810 Strengthening	Richmond / Armada / Columbus / New Havens	Build a new 120-40 kV station and three 40 kV tie lines to relieve load from Tie 810
Tie 4104 Reconductoring	City of Minden / Deckerville	Reconductor ~10 miles of 3/0 ACSR 40 kV with 636 Aluminum wires including 6.2 miles of underbuilt distribution lines
Trunk and Tie Lines Hardening Program	Various	• Upgrade approximately 46 trunk lines and tie lines to higher rating or add subtransmission stations to meet contingency loading criteria • Rebuild approximately nine trunk and tie lines that caused over six SAIDI minutes annually in the past three years

Exhibit 5.1.7 Projected Costs and Timeline for Subtransmission Projects

Project	2018	2019	2020	2021	2022	2018-2022 Cost Estimate ($ million)
Ann Arbor / UM System Strengthening						$97
Tie 810 Strengthening						$17
Tie 4104 Reconductoring						$9
Trunk and Tie Lines Hardening Program (2018-2022 only)						$57

It is important to understand that the above load relief projects are proposed based on DTEE's assessments of area load growth and system loading conditions as of today. Future area load growth is constantly evolving due to changes in general economic trends and utilization of demand response and energy efficiency measures, etc. DTEE projects area load growth in future years and the timing needed to construct area infrastructure to ensure that adequate capacity exists to serve all customers. However, the uncertain nature of future load growth may cause changes to proposed projects from year to year. Based on project proposals known today, DTEE estimates the annual capital spend on load relief projects as shown in Exhibit 5.1.8. The projected capital spend excludes 4.8 kV/8.3 kV conversion and consolidation projects that are part of Section 5.5.

Exhibit 5.1.8 Projected Load Relief Capital Spend

	2018	2019	2020	2021	2022	5-Year Total
Load Relief Capital Spend ($ million)	$53	$50	$38	$50	$69	260

5.1.4 Non-Wire Alternatives to Address System Loading

DTEE continues to investigate Non-Wire Alternatives to provide load relief to the electrical system. Energy Efficiency (EE), Demand Response (DR), Distributed Generation (DG), and Energy Storage are the four types of alternatives to traditional electric distribution investments. Below is a summary of DTEE's major non-wire alternative pilots and programs.

Energy Efficiency (EE) Non-Wire Alternative Pilot Study: DTEE conducted a Non-Wire Alternative (NWA) study to determine the feasibility for geographically targeted energy efficiency measures to cost-effectively defer distribution system capital upgrades. The study assessed the viability of such an approach over a three-year timeframe at selected substations.

The study assessed technical and economic feasibility. Technical feasibility assessed whether the required peak load reduction at selected substations could be achieved by increasing energy efficiency incentives and marketing efforts. Economic feasibility assessed whether this non-wire alternative had a positive net present value. The study concluded that geographically targeted energy efficiency programs would not be a cost-effective solution to defer capital investment for the selected substations used in this study.

The methodology for energy efficiency non-wire alternative study will be further reviewed. Additional field tests will be implemented in the future to continue to explore this alternative.

Demand Response Programs (DR): DTEE continues to execute Demand Response Programs as described in DTEE's Demand Response annual report, Case No. U-17936, submitted on February 1, 2017.

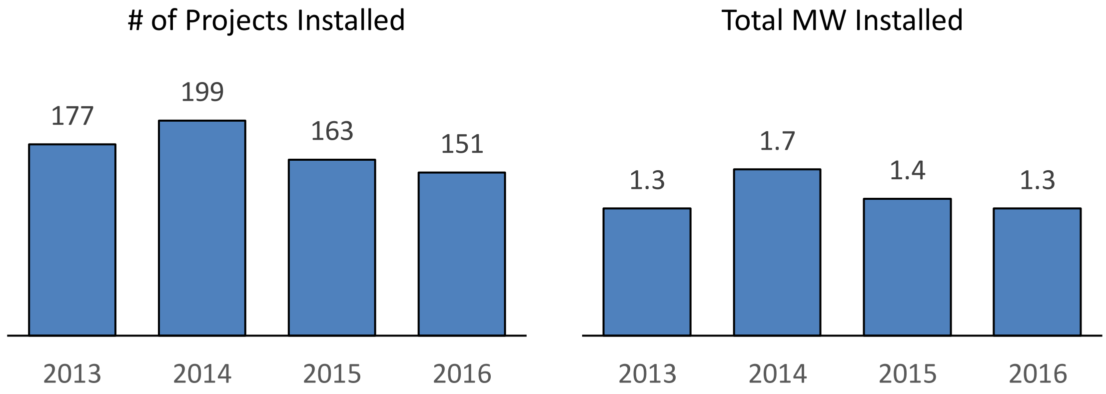
DTEE plans to continue conducting tests on the Interruptible Air Conditioning (IAC) program next summer to verify the amount of load relief this program could offer in selected heavily loaded areas in DTEE's service territory. Meanwhile, a cross-functional team is in place to examine and update the business processes and operating procedures so that Demand Response measures can be incorporated into distribution system planning and operations.

In addition to DTEE's existing Demand Response programs, DTEE is participating in the 6T-IRP (Integrated Resource Planning) working group as established in Public Act 342 (PA342) and the Demand Response workgroup established by MPSC Order U-18369. DTEE has also filed a main electric rate case, U-18255, in which DTEE plans to expand the existing Demand Side Management programs and establish new Demand Response pilots as discussed in the direct testimony of Company Witness Irene Dimitry in Case No. U-18255, pages 4 through 24.

Distributed Generation (DG): Customers with distributed generation who wish to connect to the electrical grid must follow the approved interconnection process. Based on the interconnection process, each request must be reviewed and, upon approval, engineered and studied by DTEE within a timeline mandated by the MPSC. The study determines necessary grid upgrades and equipment needed to ensure proper control and protection for DTEE's system and customers. The installation and testing of the equipment must be completed before a Parallel Operating Agreement (POA) is executed to allow for two-way power flow. For small generators, this usually requires a disconnect switch or other IEEE certified equipment. Larger generators may require more extensive grid updates and complex protection schemes, such as installing two-way power flow devices and transfer trip schemes at substations to comply with IEEE-1547. Currently, there are over 31 large solar parks connected to the DTEE's electric grid, for a total of 66 MW, that can power more than 14,000 homes.

The volume of requests for customer-owned DG in the DTEE service territory has been predominately residential rooftop solar. The typical project size is 5-10 KW for residential customers and 150-750 KW for commercial customers. Additionally, there are several multi-MW synchronous generators and dynamometers connected to the grid that are typically located at commercial and industrial facilities. Exhibit 5.1.9 shows the historical projects installed for small DG projects.

Exhibit 5.1.9 Historical Trend on Small DG Projects



DTEE recognizes the potential in certain instances that distributed generation could be used as non-wire alternatives to traditional electric distribution investments. At the same time, high penetration of distributed generation could cause various issues on the electric grid. Depending on the size, location and other characteristics of the distributed generation application, extensive system upgrades to switching, protection and wires may be needed to maintain power quality and reliability for the system and nearby customers. Utilities with higher solar density have shared empirical data and experience related to issues including frontline employee safety, voltage surge for nearby customers, false tripping and improper operation of protective equipment, burning of customer equipment, backfeed from inverters and grounding, excess inrush and short circuit current, and higher operating requirements for regulation equipment. System upgrades will be needed to address these issues. This will result in additional DTEE resource commitments, competing with the same resources required to execute the investment plan as discussed in this report. DTEE will continue monitoring the development of distributed generation on the electric grid and experimenting with distributed generation as a non-wire alternative. At the same time, DTEE continues to incorporate new design standards during system upgrades that can better accommodate deployments of distributed generation in the electric grid.

Energy Storage: DTEE has been actively evaluating the role of energy storage as an alternative to infrastructure upgrades. In 2013-2015, DTEE conducted a pilot study to install 1 MW of distributed

Community Energy Storage units and a grid connected storage battery on a circuit with a solar park as part of a Department of Energy grant. The pilot was used to develop the capabilities needed to integrate battery storage into the electric system and obtain experience in a set of use cases, such as peak shaving and frequency regulation. While the work validated the feasibility of the technology for the use cases, it also showed that battery storage is currently not economical for large-scale deployments.

DTEE has continued to evaluate battery storage as an alternative to distribution infrastructure upgrades. Most recently, DTEE completed a study to identify substation locations where battery storage can be utilized for load relief as an alternative for substation upgrades. The study indicated that battery storage cannot economically displace any substation upgrade projects identified in DTEE's five-year plan for two reasons:

1) Most of the load relief projects funded in DTEE's five-year investment plan focus on addressing substations that are 3 MVA or more over their firm rating, a size that is challenging to address via a battery solution. Most battery storage projects explored by other utilities as investment deferrals are 2 MVA or less.

2) Many of the load relief projects identified in DTEE's five-year plan bring additional benefits such as improved reliability, enhanced operational flexibility, and reduced risk associated with aging infrastructure. These benefits are not addressed through a battery solution.

In 2018-2019, DTEE is considering building a 2 MW trailer-mounted mobile battery storage unit. This battery storage trailer is intended to provide additional support during large outage events, facilitate execution of planned work that normally requires a system shutdown, and provide load relief during peak hours.

In addition, DTEE is working with the U.S. Coast Guard to assess the opportunity to install a combination of distributed generation (solar or wind) and battery storage to power the William B.

Livingston lighthouse year-round on the eastern edge of Belle Isle in lieu of installing underground cable.

Summary on Non-Wire Alternatives

To continue exploring non-wire alternatives to traditional electric distribution investments, DTEE is conducting benchmarking with peer utilities, partnering with leading industry experts, and developing comprehensive screening criteria to identify locations on the electric distribution system where non-wire alternatives make the most sense. DTEE plans to include the identified non-wire alternative projects in the Company's next electric rate case. Exhibit 5.1.10 shows the capital spend that is held as a placeholder for potential non-wire alternative projects.

Exhibit 5.1.10 Projected Non-Wire Alternatives Capital Spend

	2018	2019	2020	2021	2022	5-Year Total
Non-Wire Alternatives Capital Spend ($ millions)	$3	$2-5	$2-5	-	-	$7-13

Distributed energy resources are increasingly becoming an integral part of the electric system. At the same time, they are introducing variations and uncertainties that make the distribution system more complex to plan, manage and control. For DER to become a viable non-wire alternative, it is imperative that DTEE implement an Advanced Distribution Management System (ADMS) to increase grid visibility, allow flexible real-time operation, and provide appropriate balancing and control of power flow. The ADMS project is addressed in detail in Section 5.4. System upgrades such as wire sizes and SCADA-enabled switching and protection devices are needed to accommodate and manage DER resources on a real-time basis and to protect the distribution system from voltage and power variations.

It is also essential that DTEE has contractual agreements to ensure that customer generation, demand response measures, microgrids or any other distributed energy resources will operate when called upon during a capacity shortfall or abnormal system conditions. DTEE bears the ultimate responsibility to serve electric customers safely and reliably, with or without the DER resources, and needs to prepare for unplanned DER outage events or any malfunctioning or miscoordination of the system.

DTEE is actively benchmarking with other utilities and participating in various industry consortiums to learn the best practices for all forms of DER integration. DTEE is also reviewing substation and equipment design standards so that new substations will be able to accommodate future DER integration.

5.2 Substation Outage Risk

5.2.1 Context

The DTEE system has experienced an increasing number of major substation outage events in the past three years as substation equipment continues to age. Exhibit 5.2.1 shows a summary of the major substation events where DTEE experienced a temporary loss of an entire substation, with the details shown in Exhibit 2.5.2. Most of these major substation events were caused by aging, end-of-life critical assets. During events such as Benson and Alpha, DTEE was able to achieve full restoration within a few hours because the failure was isolated to a portion of the substation and capacity existed on adjacent substations to allow for quick load transfer. During events such as Webster, Apache, Arnold, Warren, and Plymouth, customers were not fully restored for 24 hours or more. These instances required combinations of mobile generators, portable substations, and the creation of temporary overhead jumpering points to transfer circuit loads. The number of customers affected and duration of the outages are dependent on the system configuration and the available capacity of surrounding substations to pick up the load.

Exhibit 5.2.1 Number of Major Substation Outage Events (Complete Loss of a Substation)

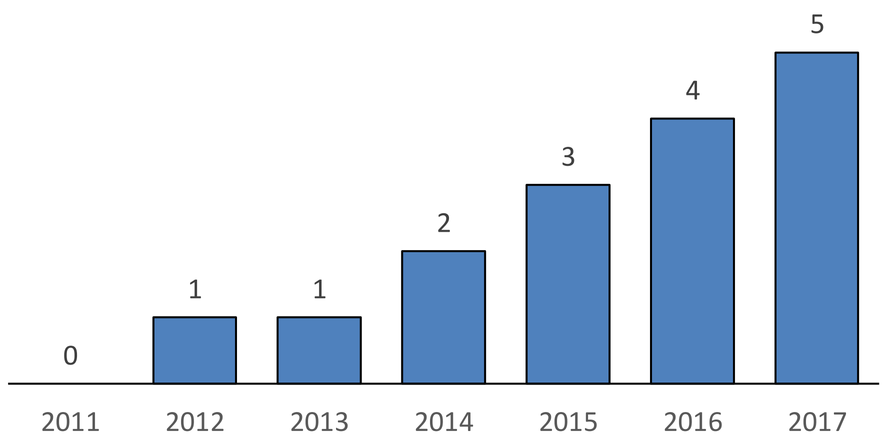


Exhibit 5.2.2 Major Substation Outage Event Details

Substation	Date	Cause	Customers Interrupted	Hours to Full Restoration (Temporary Repairs)	Contribution to System SAIDI
Webster	07/17/12	Breaker	9,519	48	7.3
Stephens	10/23/13	Transformer	5,943	8	0.8
McGraw	08/14/14	Flooding	4,424	11	0.3
Daly	09/07/14	Loading	3,832	7	0.5
Apache	07/23/15	Switchgear	9,486	34	3.8
Arnold	09/15/15	Cable	2,617	31	2.2
Warren	11/23/15	Switchgear	3,063	24	2.0
Benson	04/18/16	Switchgear	12,139	3	0.6
Liberty	01/04/16	Breaker	3,712	13	1.3
Drexel	07/18/16	Cable	3,213	13	0.7
Alpha	10/23/16	Circuit Switcher	6,678	7	0.6
Chandler	01/27/17	Transformer	6,135	9	1.1
Indian	05/26/17	Cable	5,422	13	1.9
Macon	08/08/17	Transformer	1,444	24	0.8
Plymouth	08/16/17	Transformer	3,910	32	2.6
Brazil	09/20/17	Cable	3,288	5	0.5

The loss of an entire substation can negatively impact customers for an extended duration, as illustrated by the Apache substation event (Exhibit 5.2.3). In July of 2015, Apache substation experienced a switchgear failure, causing the entire substation to be de-energized and interrupting approximately 10,000 customers. A portion of the customers were restored by transferring the load to adjacent substations. The remaining customers were restored by installing a portable substation and six portable generators on the site. It took a total of 34 hours to achieve full restoration for all customers. The substation was in abnormal configuration for approximately two months following the event to repair, replace, and test all the switchgear wiring (power and control) and to replace several breakers. Any additional failure during this time would have severely impaired DTEE's ability to serve these customers.

Exhibit 5.2.3 Apache Substation Outage – July 2015

Description

- Catastrophic failure led to the loss of all load served by Apache substation
- 10,000 customers affected

Restoration Strategy

- A portion of the customers were restored by jumpering to adjacent substations
- The remaining customers were restored using two portable substations and six portable generators (mobile generation fleet)
- The outage lasted 34 hours for some customers

Cost

- $2 million total spend
  - $1.5 million on restoration
  - $0.5 million on repair

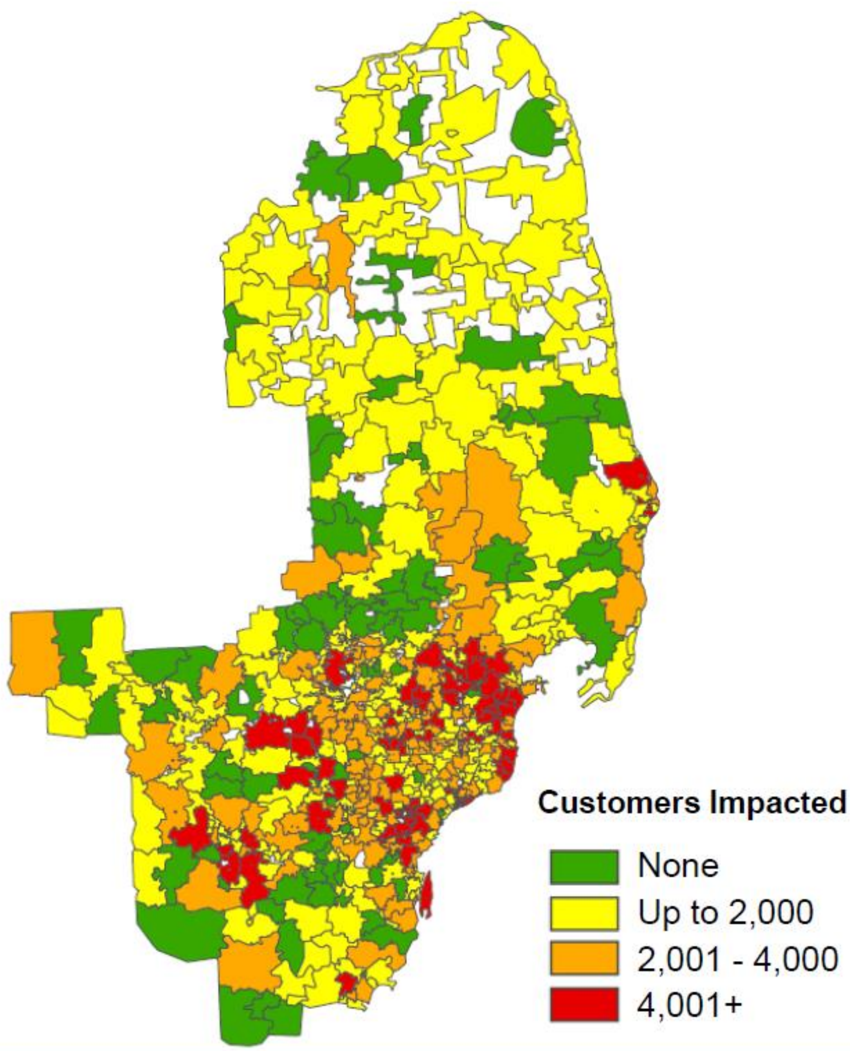
5.2.2 Substation Outage Risk Model

To help DTEE identify and mitigate the risk of additional Apache-like substation events, the substation outage risk model was developed. The model quantifies the relative substation outage risk scores and is used to help prioritize the capital spend to reduce this risk. The model calculates an outage risk score for each substation based on two factors: 1) stranded load at peak, and 2) asset conditions. Both factors will be discussed in further detail.

1. Substation stranded load at peak is the amount of load that cannot be restored by transferring load to adjacent circuits in the event of a substation outage during the peak hours due to capacity constraints. Exhibit 5.2.4 shows a stranded load map with red indicating substations that could result in 4,000 or more customers without power for more than eight hours (i.e.,

minimum time required to install mobile fleet to restore power) in a substation outage event during summer peak.

Exhibit 5.2.4 Potential Stranded Load Map During Complete Loss of a Substation



2. Substation asset condition risk represents the combined risk of four critical asset classes: switchgear, system cable, transformers, and breakers. The asset condition risk combines the asset condition assessments (see Section 4 of this report) with system considerations such as load impacted by the asset and the number of contingencies before the entire substation loses

power. Analysis indicates that switchgear in need of replacement is the most significant contributor to the substation outage risk, followed by aging system cable and breakers.

Combining stranded load risk and asset condition risk, the risk profile of distribution substations is generated, as shown in Exhibit 5.2.5. Substation outage risk scores are indexed between 0 and 100, with 100 representing the highest substation risk score. As illustrated in Exhibit 5.2.6, Malta has a risk score of 100 which is equivalent to a 2.4 percent probability of failure on an annual basis, with up to 63 MVA of stranded load after all possible load transfers are made.

Exhibit 5.2.5 Substation Risk Score Distribution

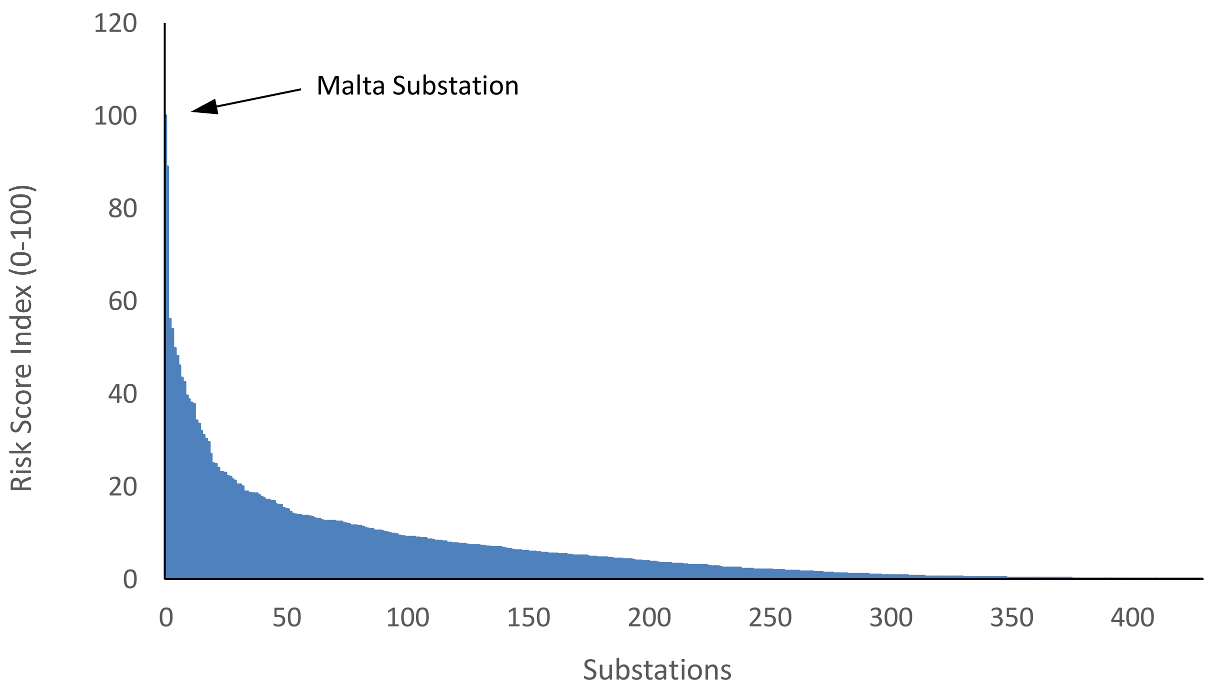


Exhibit 5.2.6 Highest Outage Risk Substations

Substation	Substation Outage Risk Score	Substation Outage Rate [1]	Stranded Load after Load Transfer (MVA)	Stranded Load after DG (MVA)
Malta	100	2.4%	63	29
Crestwood	60	2.9%	32	32
Bloomfield	45	3.0%	23	23
Savage	45	2.2%	32	32
Apache	42	2.0%	33	32
Chestnut	42	2.0%	32	20
Birmingham	33	2.3%	21	19
Jupiter	31	1.2%	41	10
Spruce	28	1.3%	34	20

1. *Annual Probability of Complete Loss of the Substation*

5.2.3 Programs to Address High Risk Substations

The substation outage risk model allows DTEE to identify the substations with the highest risk and prioritize capital projects to reduce this risk. Substation outage risk is being addressed with a two-pronged approach.

The Mobile Fleet program is expanding mobile generation, portable substations, and mobile switchgear in order to decrease restoration time for stranded substation load to within 24-48 hours of a substation failure. As proven in the Apache event, the mobile fleet provides relatively quick restoration compared to the time needed to repair the substation. Though expanding the mobile fleet capacity is relatively low cost, it does not reduce the substation outage risk. Moreover, the application of the mobile fleet during restoration is limited due to the feasibility of connecting it at substation sites and considerations on space, traffic, environmental and community impacts. Exhibit 5.2.7 shows a portable substation and mobile generator that are part of the fleet.

Exhibit 5.2.7 Mobile Fleet

Portable Substation

Mobile Generator

The Substation Outage Risk Reduction program involves changing the substation design to withstand contingency operations and replacing aging, at risk equipment (mostly switchgear) to reduce the probability of a failure. This approach permanently reduces substation outage risk; however, it is costly and difficult to execute due to site-related construction constraints and the need to continue serving customers during the process. As such, the plan is to limit initial implementation to substations that meet two criteria: 1) high substation outage risk (high probability of failure and high stranded load) as indicated by the substation outage risk model, and 2) where deployment of mobile fleet assets is limited and cannot restore the entire substation load; in other words, load will be stranded for more than 24 hours. The substation outage risk model provides a starting point to evaluate relative substation outage risk. DTEE uses the risk scores as the starting point for further evaluation of substation conditions before proposing capital projects.

Exhibit 5.2.8 shows the projected costs and timelines for the identified substation outage risk reduction projects. The timeline considers multiple factors including relative substation outage risk, resource availability, specific site conditions and other execution constraints. The cost and timeline estimates for the projects are based on the best knowledge and information known today by DTEE. Actual project costs and timeline could deviate from the projection due to various unforeseen factors or new information/learnings. Other projects underway in 2017 and to be completed in

2018 include the Nunneley and Drexel switchgear replacements in response to switchgear failures, and a project to provide a temporary solution to mitigate Malta stranded load risk.

Exhibit 5.2.8 Projected Costs and Timeline for Substation Outage Risk Reduction Projects

Project	2018	2019	2020	2021	2022	2018-2022 Cost Estimate ($ million)
Malta						$4
Crestwood (Also See Section 4.15)						Part of system cable program
Bloomfield						$8
Savage						$9
Apache						$10
Chestnut						$8
Birmingham (Also See Section 5.5)						$23 (Total cost: $46)
Jupiter						$21
Spruce						$8
Mobile Fleet						$9
Other ongoing projects to be completed in 2018						$4

Based on the identified projects, DTEE projects the annual capital spend on the substation outage risk reduction shown in Exhibit 5.2.9. The projected capital spend excludes the Crestwood project, which is part of system cable replacement program (Section 4.15) and the Birmingham project, which is part of the 4.8 kV conversion program (Section 5.5).

Exhibit 5.2.9 Projected Substation Outage Risk Reduction Capital Spend

	2018	2019	2020	2021	2022	5-Year Total
Substation Outage Risk Reduction Capital Spend ($ millions)	$17	$11	$17	$21	$15	81

5.3 System Reliability

5.3.1 Background

DTEE learns of unintentional customer power interruptions by various means: AMI power outage notifications, customers reporting outages via the company website, mobile app, or telephone. The outage management system is used to dispatch field personnel and track the restoration process. Post-restoration, each outage case is reviewed manually for accuracy with respect to the number of customers affected and outage duration. This review is currently necessary as the existing outage management system does not always correctly calculate the number of customers affected and relies on field personnel to input the time of the restoration. This reviewed data are the bases for DTEE's system reliability metrics of SAIFI, SAIDI, and CAIDI. Implementation of an ADMS would improve the accuracy of the reliability metrics and eliminate the need for manual intervention.

5.3.2 SAIFI, SAIDI and CAIDI

DTEE measures overall system reliability using electric utility standard industry indices. The indices are typically reported on an annual basis. Exhibit 5.3.1 provides a summary of the reliability indices.

Exhibit 5.3.1 Reliability Indices Definitions

Index	Full Name	Calculation
SAIFI	**S**ystem **A**verage **I**nterruption **F**requency **I**ndex	Total number of customer interruptions divided by the number of customers served
SAIDI	**S**ystem **A**verage **I**nterruption **D**uration **I**ndex	Total minutes of interruption divided by the number of customers served
CAIDI	**C**ustomer **A**verage **I**nterruption **F**requency **I**ndex	Total minutes of interruption divided by the total number of customer interruptions

SAIFI, SAIDI, and CAIDI are reliability performance indices defined in IEEE Standard 1366. In addition to all weather conditions, these indices are also calculated excluding Major Event Days (MEDs), which is any day in which there is a significant statistical difference in daily SAIDI; the details of the calculation are in IEEE Standard 1366. Excluding Major Event Days leads to a clearer picture of day-to-day system performance and the customers' experience absent significant weather events.

In addition to the IEEE Standard indices, DTEE also tracks reliability performance by various conditions: catastrophic storms, non-catastrophic storms, and excluding storms. Doing so allows better insight into reliability performance and root causes of customer outages.

Catastrophic Storms

In MPSC case U-12270, catastrophic conditions are defined as "severe weather conditions that result in service interruptions to 10 percent or more of a utility's customers." DTEE, however, has an internal catastrophic storm threshold of approximately five percent of its customers interrupted. That is the level at which all internal resources, contract crews, local foreign crews, and mutual assistance from other utilities will be engaged, depending on the scale of the storm, to restore customers in a timely fashion. Typically, all restoration crews work 16 hour shifts per day with around the clock coverage until the restoration is complete.

Non-catastrophic Storms

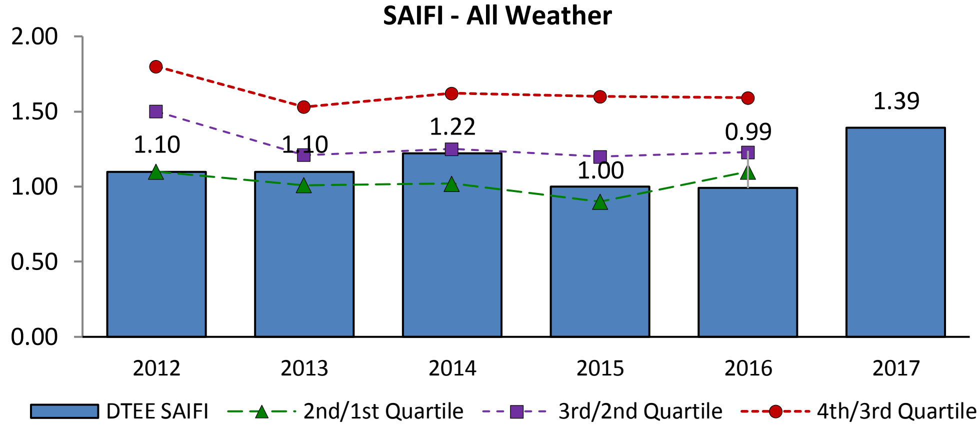
DTEE is in non-catastrophic storm mode whenever a catastrophic level is not yet reached but weather conditions result in customer outage cases that cannot be restored by the on-shift crews within 24 hours. For non-catastrophic storms, in addition to the DTEE restoration personnel, contract crews and local foreign crews may also be mobilized. Typically, the restoration crews work 16 hour shifts until the restoration is complete.

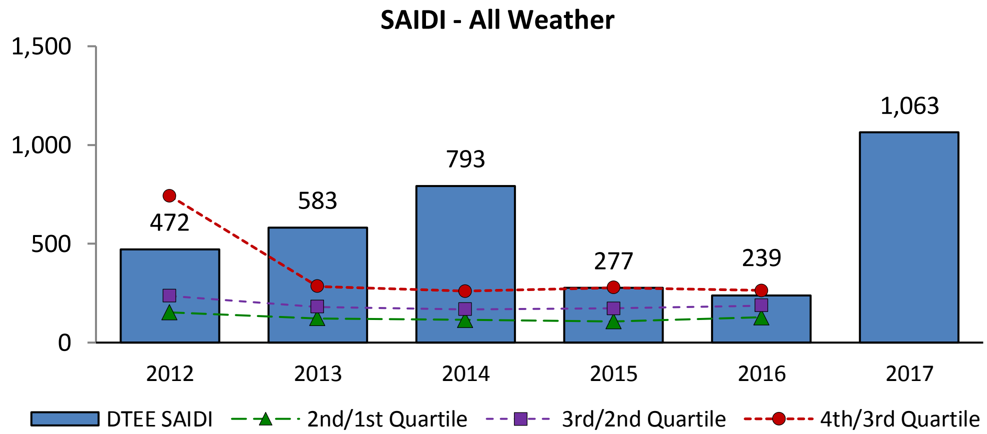
Storm Restoration

To ensure the most efficient restoration for customer outages during storms (catastrophic or non-catastrophic), each storm is managed through the Incident Command System (ICS) process. The

ICS commander has the overall responsibility for storm restoration and develops and monitors key restoration targets for the operating regions. The operating regions then manage the resources for various functions such as operating, dispatching or general support to meet the restoration targets. These resources have been trained to perform their tasks and are on a predetermined rotation so that they are available when needed. The size of ICS team is scaled to match the size of the storm to achieve desired restoration targets. During catastrophic storms, both the ICS and Emergency Headquarters (EH) are activated. Exhibits 5.3.2 – 5.3.6 show historical SAIFI, SAIDI, and CAIDI values for various conditions.

Exhibit 5.3.2 Reliability Statistics - All Weather





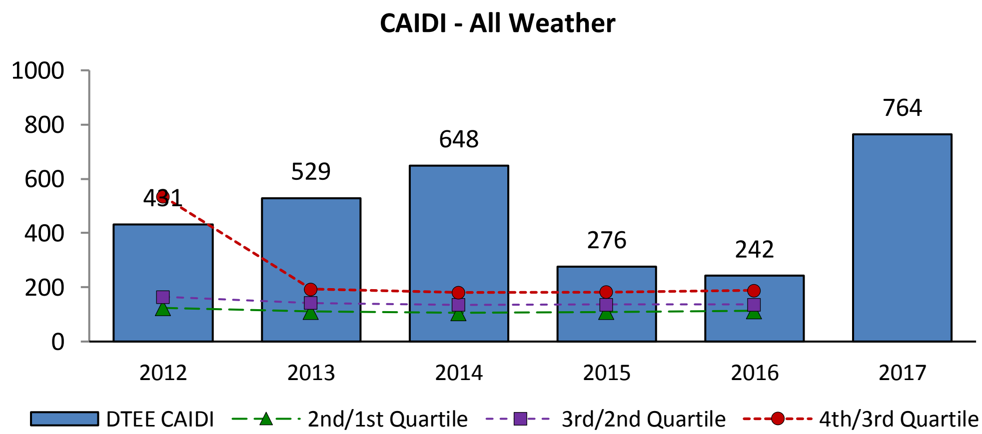
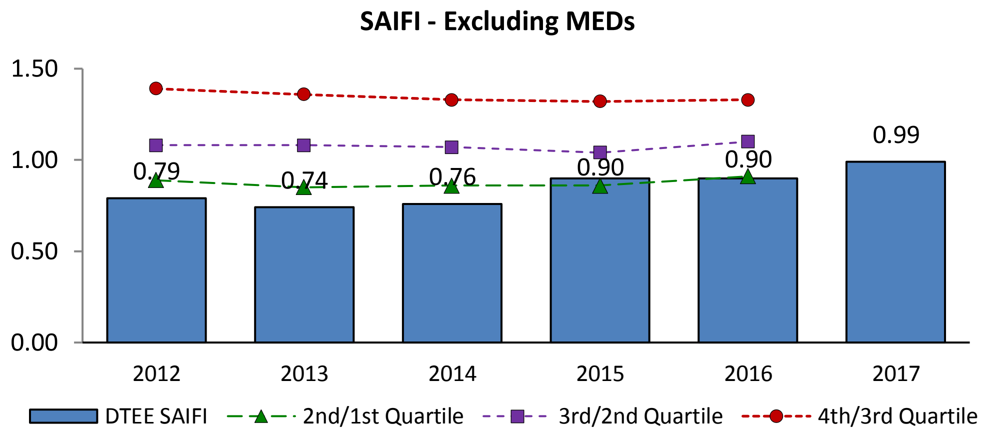
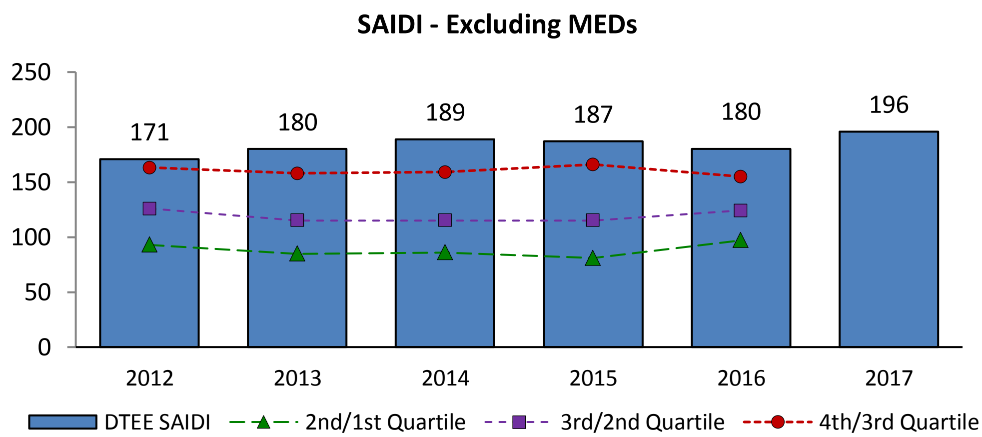


Exhibit 5.3.3 Reliability Statistics - Excluding MEDs





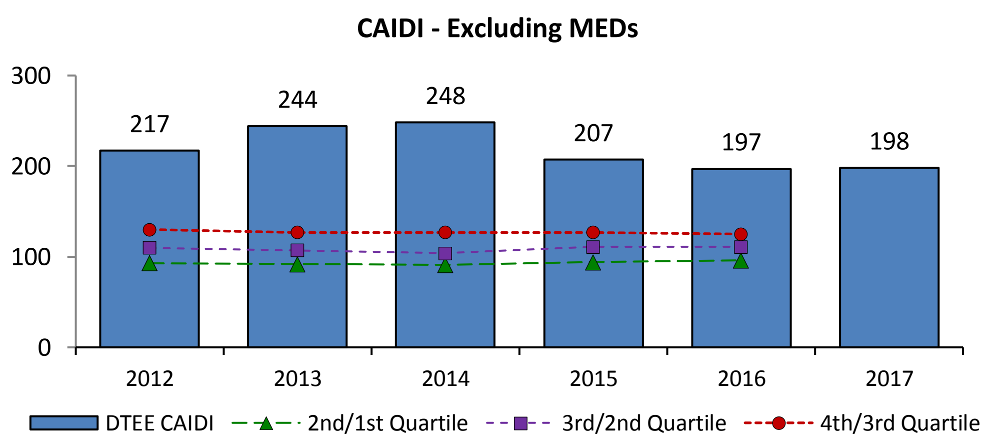


Exhibit 5.3.4 Reliability Statistics - Catastrophic Storms (DTEE Definition)

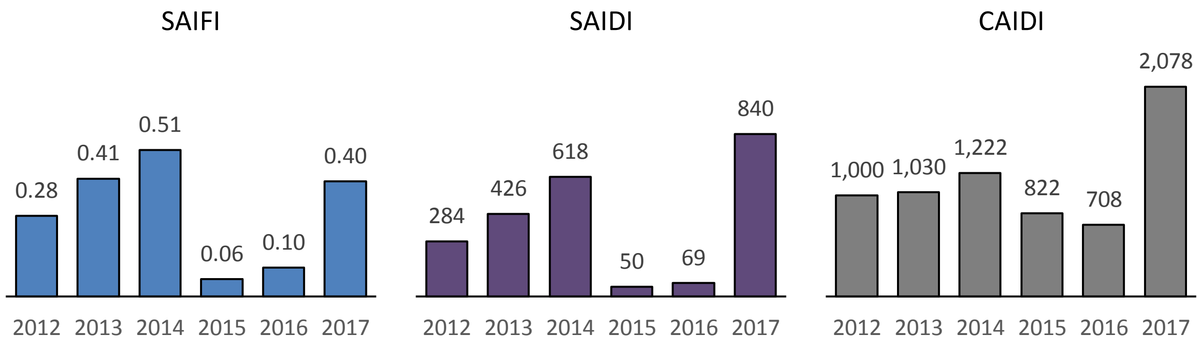


Exhibit 5.3.5 Reliability Statistics – Non-catastrophic Storms (DTEE Definition)

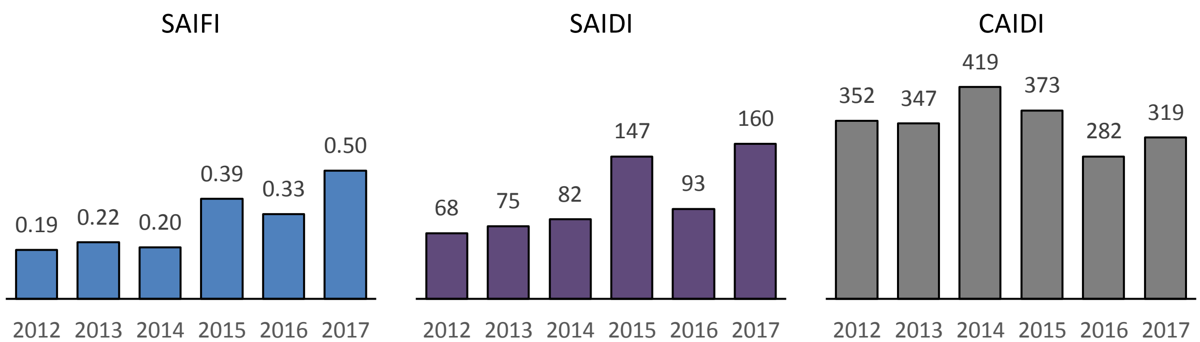
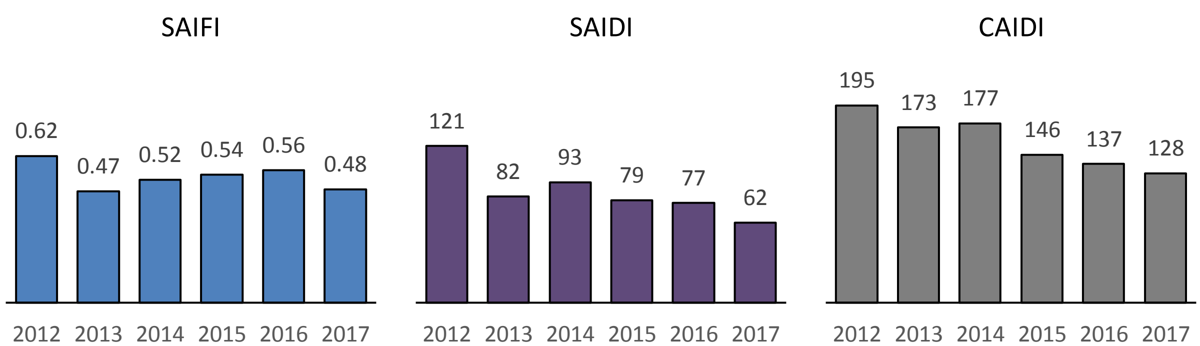
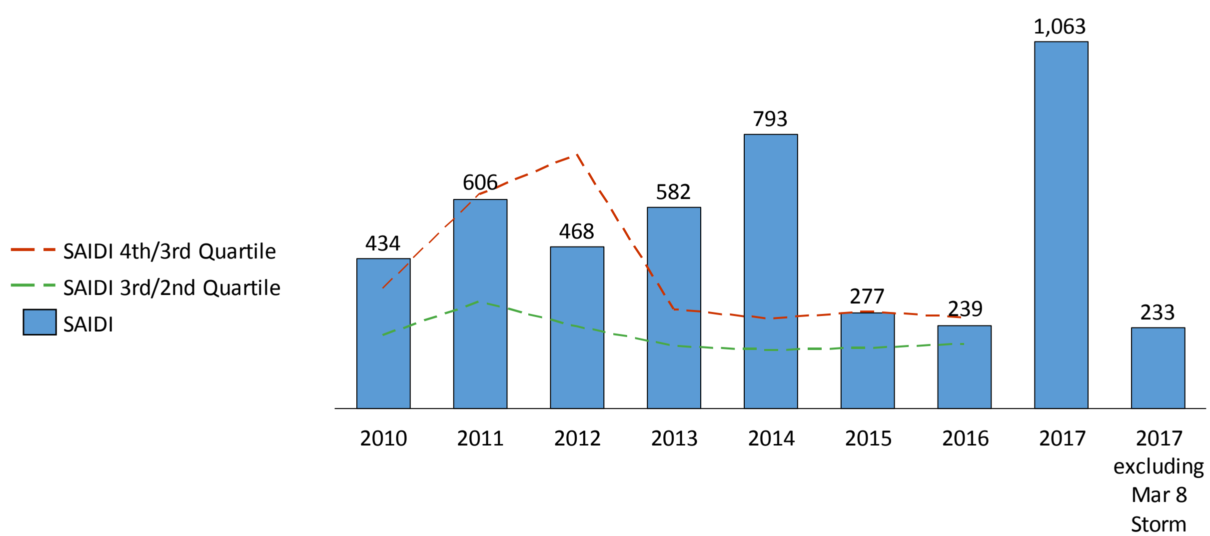


Exhibit 5.3.6 Reliability Statistics - Excluding All Storms



DTEE's all-weather SAIDI performance ranks in the 3rd or 4th quartile compared to industry peers (Exhibit 5.3.7). The better SAIDI performance in 2015 and 2016 was partially driven by mild weather conditions as indicated by the customer WEI-30 (Wind Exposure Index to gusts greater than or equal to 30 mph) and low storm occurrences as indicated by the numbers of catastrophic and non-catastrophic storms. However, DTEE also achieved better reliability in 2015 and 2016 even when compared to years that had similar WEI-30, such as 2010 and 2013. This suggests that the implementation of the reliability strategy and process improvements are leading to improvements of all-weather SAIDI.

Exhibit 5.3.7 SAIDI Performance (Minutes)



	2010	2011	2012	2013	2014	2015	2016	2017	2017 excluding Mar 8 Storm
# of DTE Catastrophic Storms	2	3	4	6	7	1	2	2	1
# of DTE Non-Catastrophic Storms	16	19	8	10	12	21	20	28	28
WEI – 30 (Hours)	123	183	211	151	185	154	138	230	206

Notes:

- The SAIDI minutes of 830 is attributed to March 8, 2017 catastrophic storm
- A storm is typically defined as "catastrophic" if more than 5% of customers (~110,000) experience a sustained service interruption
- A storm is typically classified as "non-catastrophic" if between 15,000 and 110,000 customers experience a sustained service interruption
- The Wind Exposure Index 30 (WEI-30) represents the average number of hours a customer experienced wind gusts of 30 mph or greater

5.3.3 CEMIn and CELIDt

In addition to SAIFI, SAIDI, and CAIDI, two other indices are used to measure customers' reliability experience: CEMIn and CELIDt. These indices are defined in IEEE Standard 1366 and summarized in Exhibit 5.3.8 below.

Exhibit 5.3.8 CEMIn and CELIDt Definitions

Index	Full Name	Calculation
CEMIn	**C**ustomers **E**xperiencing **M**ultiple **I**nterruptions of **n** or More	Count of the number of Customers with n or more interruptions
CELIDt	**C**ustomers **E**xperiencing **L**ong **I**nterruption **D**uration of **t** or More Hours	Count of the number of Customers with interruptions lasting t or more hours

Currently, calculations of CEMIn and CELIDt are done with un-reviewed raw real-time outage data, which are known to overstate the customers' actual experience. The indices also include scheduled outages and outages beyond our control such as public interference or transmission-related outages.

Once a potential CEMIn or CELIDt case is identified for remediation, it is reviewed by engineers and field personnel to verify the root cause and develop appropriate corrective actions. The actions may include: tree trimming, reconductoring, relocating lines, circuit reconfiguration, and adding sectionalizing equipment.

The historical CEMIn and CELIDt values are listed in Exhibits 5.3.9 and 5.3.10, respectively.

Exhibit 5.3.9 CEMIn by Year
(Number of Customers Having n or More Outages by Year)

CEMIn	2012	2013	2014	2015	2016	2017	2017 ex Mar Storm
CEMI1	1,482,953	1,443,749	1,421,322	1,273,402	1,245,866	1,528,465	1,302,141
CEMI2	788,531	786,657	779,176	622,180	596,814	859,466	648,574
CEMI3	380,037	399,349	388,076	282,709	270,676	423,990	297,999
CEMI4	175,709	192,366	178,812	125,496	121,110	193,470	129,299
CEMI5	79,285	97,726	76,180	58,121	51,279	86,695	54,959
CEMI6	32,892	44,130	30,307	25,957	24,692	37,508	24,485
CEMI7	13,662	18,916	11,152	11,485	12,334	16,524	10,613
CEMI8	5,420	7,092	5,143	5,432	4,634	7,711	4,958
CEMI9	2,371	2,741	1,943	3,236	1,712	2,813	2,228
CEMI10	1,562	1,395	1,204	2,737	605	1,483	1,134

Exhibit 5.3.10 CELIDt by Year
(Number of Customers Experiencing t or More Hours of Interruption by Year)

CELIDt	2012	2013	2014	2015	2016	2017	2017 ex Mar Storm
CELID24	147,617	198,407	325,136	54,429	31,309	497,511	28,872
CELID48	41,145	56,415	106,085	9,370	1,575	272,201	2,040
CELID72	15,078	14,782	32,333	216	40	140,194	117
CELID96	4,830	4,077	7,633	19	14	59,455	14
CELID120	1,029	1,998	1,241	10	7	22,424	8

5.3.4 Causes of Interruptions

Exhibits 5.3.11-5.3.13 illustrate percent contribution to customer minutes of interruption, customer interruptions, and outage events by cause. Tree/wind interference is the leading cause of DTEE's customer minutes of interruption (SAIDI) and customer interruptions (SAIFI). Therefore, a robust tree trimming program is needed to address system reliability including customer minutes of interruption and customer interruptions. Equipment failures are the leading cause of the outage events on DTEE system. Therefore, capital replacement programs need to be funded at appropriate levels to address the number of outage events and subsequent truck rolls.

Exhibit 5.3.11 Annual Average Customer Minutes of Interruption by Cause (SAIDI)

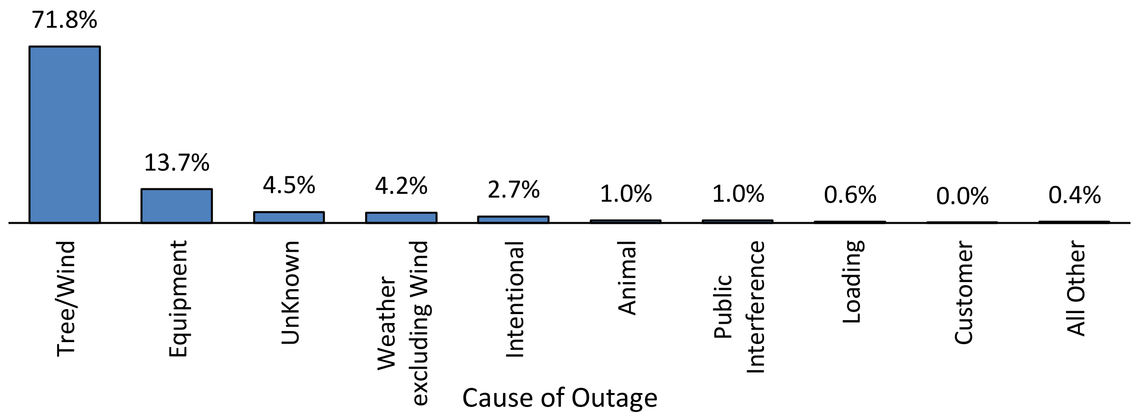


Exhibit 5.3.12 Annual Average Customer Interruptions by Cause (SAIFI)

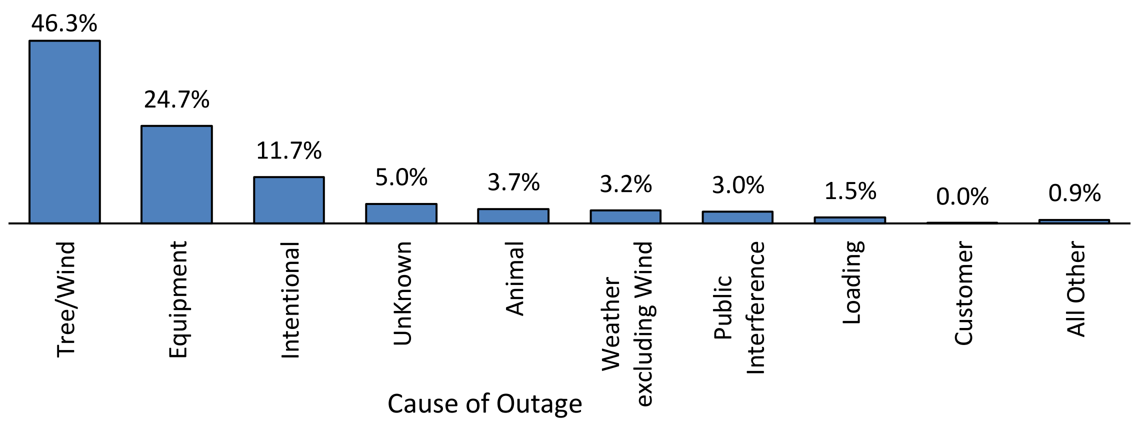
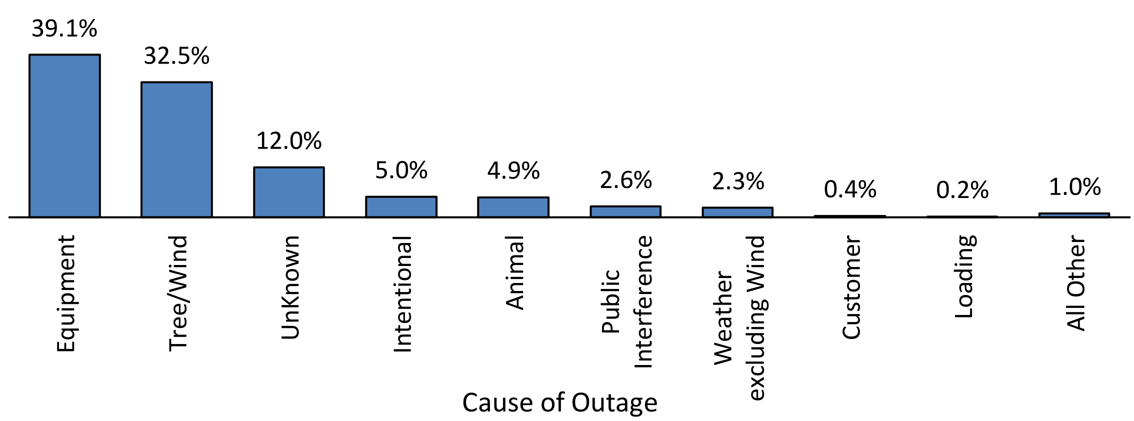


Exhibit 5.3.13 Annual Average Outage Events by Cause



Note: Equipment includes substation, underground and overhead equipment and hardware

5.3.5 Programs to Improve Reliability

DTEE has established a number of programs to specifically address reliability issues. These reliability programs continually evolve to address emerging problems using the best available equipment and techniques. The main recurring reliability programs are listed in Exhibit 5.3.14.

Exhibit 5.3.14 Reliability Programs Summary

Program	Scope of Work	Target Areas
Tree Trimming	See Section 6.1 for details	
System Resiliency	• Install sectionalizing and switching devices to localize outage events and enable restore before repair	• Remediate long-outage durations for circuits with few sectionalizing points
Frequent Outage (CEMI) including Circuit Renewal	• Perform tree trim • Underground portion of the circuits • Rebuild / reconductor / relocate overhead lines • Add or strengthen circuit ties • Provide circuit load relief • Install sectionalizing and switching devices, etc.	• Remediate small pockets of customers or single customers experiencing frequent outage events by focusing on removing root causes of reliability and power quality events • Address circuits with chronically poor reliability performance by focusing on removing root causes of reliability and power quality events
4.8 kV System Hardening	See Section 5.5 for details	
Pole and Pole Top Hardware	See Section 4.7 for details	

Circuits selected for the System Resiliency Program are circuits with low penetrations of switching and sectionalizing devices and little opportunity to localize outage events to perform Restore Before Repair (RBR). Restore Before Repair is the process whereby the faulted portion of the distribution circuit is isolated, customers outside the isolated area are quickly restored and then repairs are completed to restore the remaining customers.

The Frequent Outage program, also known as the CEMI (Customers Experiencing Multiple Interruptions) program, includes improvements to either circuit sections (customer pockets) or entire circuits. The number of CEMI customers, historical reliability performance, power quality complaints and MPSC complaints are considered in determining inclusion in the Frequent Outage program.

Exhibit 5.3.15 shows the projected annual capital spend for these reliability programs.

Exhibit 5.3.15 Projected Reliability Programs Capital Spend

Program	$ millions					
	2018	2019	2020	2021	2022	5-Year Total
Tree Trimming (Also See Section 6.1)	$84	$86	$88	$91	$93	$442
System Resiliency	$7	$7	$6	$6	$6	$32
Frequent Outage (CEMI) including Circuit Renewal	$27	$24	$23	$22	$22	$118
4.8 kV System Hardening (Also See Section 5.5)	$53	$59	$64	$70	$77	$323
Pole and Pole Top Hardware (Also See Section 4.7)	$33	$39	$39	$39	39	$189

5.3.6 Utilization of AMI Data for Reliability Indices

While the outage management system is necessary to dispatch field personnel and track the restoration process, full AMI saturation now allows DTEE to more accurately know each individual customer's reliability experience without relying on customer or personnel input or on a manual review of reliability data. However, it is impossible to know the cause of an interruption from AMI meter data alone (e.g., trees, equipment failure, public interference, etc.), as this can only be obtained by linking back to the outage management system and/or through further investigation. Currently, not all AMI outages can be linked with the outage management system; DTEE continues to investigate and resolve inconsistencies, which are attributable to several factors:

- One leg interruptions – one leg interruptions are when one of the two 120-volt service conductors is de-energized. AMI meter data may not indicate all instances of these interruptions due to the way in which the meter power supply is wired to the service conductors.
- Different interruption timestamps – for a given event, each meter may have a slightly different interruption time stamp, none of which may agree with the interruption timestamp in the outage management system (typically all are within seconds or minutes of each other). This may be a problem if there are multiple events occurring simultaneously.
- Outage management system interruption inaccuracies – even with manual reviews, the outage management data is not as accurate as data directly from the meters.
- Interruptions not captured by the outage management system – data from the AMI meters may indicate short duration sustained interruptions (five minutes or more in duration), while data from the outage management system may classify them as momentary interruptions (less than five minutes in duration) or low voltage events. This could be caused by lack of interruption verification by a customer from the outage management system (customer may be unaware of the interruption in real-time) or the failure of AMI meter real-time power outage notification.

Beginning in January 2018, DTEE implemented processes that utilize AMI meter data to determine reliability statistics to more accurately reflect our customers' reliability experience. Data are obtained nightly from the AMI meter registry and are the most complete and accurate customer reliability data available. It is important to note that DTEE will be among the first utilities, if not the first utility, in the country to report reliability statistics utilizing AMI data. Based on analyses of 2016-2017 data, utilization of AMI data for reliability statistics could result in higher SAIFI, SAIDI, CAIDI, CEMI and CELID values than what have been reported in the past.

5.4 Grid Technology Modernization

5.4.1 Context

A smart and integrated grid has four key characteristics: grid-wide situational awareness, integrated system with advanced analytics, flexible real-time operations of the grid, and distributed energy resource integration.

DTEE's self-assessment of grid technology, based on benchmarking discussions with other utilities and inputs from industry experts, indicates that DTEE is in the early stages of grid technology deployment and utilization, as summarized in Exhibit 5.4.1. DTEE faces many of the same challenges as other utilities, though these challenges are exacerbated by the age of much of the equipment, which was installed prior to the availability of smart technologies such as SCADA.

Exhibit 5.4.1 Assessment of DTEE Grid Technology

Characteristics	DTEE Assessment	Maturity
Grid-wide Situational Awareness	• 30% penetration of full remote monitoring	Low
Integrated System and Advanced Analytics	• Not integrated OMS, DMS, EMS and SCADA • Lack of robust interface among GIS, CIS, AMI and customer notification	Low
Flexible Real-time Operations	• 28% penetration of substation remote control • 23% penetration of circuit remote control • Outdated control center technology and facilities • Lack of remote Volt/VAR control	Low
Distributed Energy Resource Integration	• Grid protection must be redesigned for two-way power flow • Lack of real time Volt/VAR optimization • Lack of an integrated platform to enable real time analytics and operation of DER	Low

Grid-wide situational awareness includes real-time advanced sensing technology on substation and circuit devices to measure load, voltage and fault information and return the data to the System Operations Center (SOC).

DTEE has made significant progress on installing line sensors on circuit cable poles at the start of circuits and expects to complete the program by the end of 2019. Line sensors provide load and fault current data, which enables DTEE to locate faults during outage events; however, they do not provide breaker status or voltage. The penetration rate of DTEE's full remote monitoring, including breaker status and voltage, is only at 30 percent, which is significantly lower than other utilities. An even lower percentage of substations have fault data and power quality monitoring.

Integrated system and advanced analytics include an Advanced Distribution Management System (ADMS) that enables electronic switching and tagging, integrated dispatching, real time load studies, Fault Location, Isolation and Service Restoration, Volt/VAR Optimization and the ability to analyze equipment performance and health to prioritize maintenance and replacement. An integrated ADMS will also allow analysis that currently takes hours to be completed in minutes, enabling complex power flow calculations required for proper management of Distributed Energy Resources (DER).

DTEE's existing operational technologies such as Advanced Metering Infrastructure (AMI), Outage Management System (OMS), Generation Management System (GMS), Energy Management System (EMS) and Supervisory Control and Data Acquisition System (SCADA) are not yet fully integrated, and much of the analysis must be done manually, reducing efficiency and accuracy. Examples of current system gaps include: the Geographical Information System (GIS) is used for the OMS, but not for the EMS system; the EMS and SCADA systems are tied together for subtransmission and substations, but they are not linked to the OMS; AMI is partially integrated with the OMS for outage reports; there is no central location to receive and process data on system performance from multiple field devices such as line sensors, SCADA devices, AMI, Customer Information System / Customer360, power quality meters and substation alarms. These gaps cause DTEE to piece together information from multiple systems to perform analysis, reducing efficiency and accuracy.

Because of limitations on real-time field data acquisition, DTEE has limited ability to execute automated analysis including fault locating, switching, cascading load, and load shedding or forecasting and control of DER power flow. These inefficiencies result in longer outage duration for our customers.

Since successful ADMS implementation is dependent upon the accuracy of the data entered and stored in the systems, DTEE conducted a data gap analysis to provide a clear understanding of potential data issues in our current systems. The results, as seen in Exhibit 5.4.2, indicate that DTEE's data quality is below the recommended level to achieve full benefits from an ADMS.

Exhibit 5.4.2 DTEE Data Quality Gap Analysis Results

Data Quality	DTEE Data Gaps	Third Party Assessment
Spatial integrity accuracy	Displacement up to 200 feet with further misalignment	Below Industry Standard
Single operating model	Many models. Including AC, PQ View, GIS	Below Industry Standard
Controlled operational data	Device and asset data lack location and system control	Below Industry Standard
SCADA integration	Data lacks operationally consistent nomenclature; lack of incremental registration	Below Industry Standard
AMI data in operations	Load, voltage and connectivity not in use for operations	On Par with Industry Standard
Power flow models	Lack of power flow model integration to GIS	Below Industry Standard
Underground network, cable and duct bank	AC networks are not modeled	Below Industry Standard
Visibility to quality	Lack of correlative validation and visualization	Below Industry Standard
GIS network connectivity	GIS distribution connectivity with transformer to meter connectivity supplying OMS	On Par with Industry Standard
Secondary system	18,000 miles of secondary is not connected in the system	Below Industry Standard

Based on this analysis, DTEE plans to undertake an 18-month project to create a Network Model which will ensure all electrical network assets and their respective locations are accurately represented in one source. This project will focus on creation of a Network Model, along with initial data cleansing and migration, and hardware and software upgrades to better track and maintain data going forward. The sustainability plan of the project will include training for all employees involved in the processes, clear ownership and accountability for specific assets, and governance oversight protocols to ensure successful adoption of the new processes and quality insurance.

Flexible real-time operations include remote control of substations and circuits to allow feeder reconfiguration and outage isolation utilizing the ADMS. Distributed energy resources (e.g., demand response, storage, distributed generation) can be controlled remotely to shave peak load. Additionally, transformers, capacitors and regulators can be used to optimize system efficiency using Volt/VAR optimization.

DTEE's substation remote control capability has a 28 percent penetration rate today. DTEE's circuit remote control capability is 23 percent. Discussion with utility experts suggested that most, if not all, metropolitan utilities have close to 100 percent penetration of substation remote control capability. DTEE has corroborated this assessment through its own analysis. This gap is primarily driven by low penetration of technology in DTEE's metropolitan areas, particularly on the 4.8 kV system. Remote control allows for much faster restoration by quickly isolating the outage area and performing load transfers, compared to waiting for field crews to arrive at the site and manually operate devices. It also reduces the coordination and manpower needed after repairs are completed. Additionally, day-to-day operational efficiencies are gained through remote switching during maintenance and planned work.

DTEE's overhead line capacitors and regulators were primarily installed in the 1990s. At that time, technology for controlling them was extremely basic as discussed in Sections 4.13 and 4.14. Outside of the pilot described in Sections 4.13 and 4.14, none of the devices has SCADA monitoring and control capability, hence real-time Volt/VAR optimization will require retrofits and replacement of the field devices and their controls.

Furthermore, DTEE's System Operations Center (SOC), which manages substation, distribution system switching and higher voltage system events, is outdated and presents numerous challenges to support modernized grid operations including outdated technology and facilities, space limitations, and limited visibility of the performance of critical telecommunication assets required to monitor and control the distribution system.

- The existing control center operates with a magnetic pin board displaying the system configuration on an array of tiles – it does not have real-time monitoring/display capability. When system changes are made, individual tiles must be manually updated. Likewise, general alarms are manually placed on the pin board. All switching and protective tagging are done through a manual process. Very few, if any, major utilities operate in this manner.
- The SOC facility has limited redundancy of mechanical and electrical systems. There is insufficient space to co-locate the dispatch function within the SOC, which is a clear industry best practice. There is no ability to partition/separate the NERC-CIP (Critical Infrastructure Protection) environment, increasing risk and potential costs. The physical and procedural separation of the dispatch function from System Operations Center leads to inefficiencies in responding to system events and results in longer outage times for customers.
- There is limited capability to be aware of, or prioritize, telecommunication or other technology-related outages.

<u>Distributed Energy Resource (DER) integration</u> includes control and monitoring, integrated tracking and planning for DER applications, utilization of energy storage and adaptive protection for two-way power flow.

Each additional distributed energy resource increases the complexity of the distribution models and studies required to efficiently and reliably operate the grid. DTEE has tools and processes to ensure that the system maintains reliability and stability before a generator is authorized to be on the system, but the study is currently performed manually with tools that are not integrated. Small DERs such as rooftop solar typically do not present a significant issue to grid infrastructure unless there is a high penetration in a single area (greater than 10 percent of area load); however the lack of an integrated ADMS system means that multiple studies need to be conducted to process an interconnection request and authorize the interconnection. Larger DER systems, including battery storage, could require grid infrastructure upgrades due to the age of the equipment and limitations of the existing circuit design and equipment capacity. Without real-time metering being installed at a distributed resource site and an integrated control system in the ADMS, DTEE cannot use distributed energy as active grid resources, limiting or reducing the opportunity for all customers to benefit from their operation.

5.4.2 Programs to Enhance Grid Technology Deployment

DTEE is proposing multiple programs to enhance and modernize electric grid technology. The programs are summarized in Exhibit 5.4.3. Exhibit 5.4.4 provides the projected costs and timeline for the identified grid technology modernization programs. The projected cost for the technology pilot program includes budget placeholders for capital programs that could be established following the pilots. The cost and timeline estimates for the programs are based on the best knowledge and information known today by DTEE from benchmarking with peer utilities that have preceded us in grid technology deployment. Actual project costs and timeline could deviate from the projection due to various unforeseen factors or new information/learnings.

Exhibit 5.4.3 Grid Technology Modernization Programs Summary

Program	Scope of Work	Benefits
Line Sensors	• Install line sensors on cable poles and strategic locations along the circuit	• Enhance grid-wide situational awareness • A low-cost alternative to SCADA remote monitoring at substations
Energy Management System (EMS) / Generation Management System (GMS) Replacement	• Replace existing EMS/GMS systems	• Replace current end-of-life EMS/GMS • Provide more robust framework for NERC/CIP • Provide platform for ADMS implementation

Program	Scope of Work	Benefits
ADMS	• Install an Advanced Distribution Management System to integrate various operational technologies and analytical tools	• Provide the analytics to perform FLISR and improve reliability • Provide the infrastructure, technology platform and user interface for flexible real-time operations • Enable further integration of Distributed Energy Resources
SOC Modernization	• Modernize System Operations Center	• Improve ability to respond to major operational disruptions • Allow co-location of dispatchers and system supervisors to improve operational efficiency • Replace end-of-life facility • Mitigate NERC CIP risks and create modern high availability control center
13.2 kV Telecommunications	• Install and/or upgrade telecommunication and RTUs to prepare for SCADA capability at 13.2 kV substations • 4.8 kV Telecommunications are included in the 4.8 kV Detection Program (see Section 5.5.3)	• Provide the telecommunication package at substations to allow for SCADA upgrades
Substation Automation	• Install SCADA control at substations to allow for fully remote monitoring and control	• Add SCADA to substations, improving situational awareness and flexible real-time operations • Improve operational efficiency
Circuit Automation	• Retrofit existing circuits with SCADA reclosers and/or switches to allow for remote control of the circuits	• Add SCADA to circuits to allow for system-wide FLISR, reducing sustained outage events and improving reliability • Replace legacy switches and poor performers and upgrade communications on existing sites

Program	Scope of Work	Benefits
Pilot: Technology	2018 scope includes: • 40 kV automatic pole top switches • 4.8 kV automated pole top devices • Trip Savers • SCADA-controlled regulators • SCADA-controlled capacitor banks • Ground Switch Installation	• Test application of circuit automation devices for 4.8 kV and 40 kV system • Test application of SCADA regulators and capacitors for advanced Volt/VAR control • Test application of ground switches at 4.8 kV substations
AMI Technology	See Section 4.19 for details	

Exhibit 5.4.4 Projected Costs and Timeline for Grid Technology Modernization Programs

Project	2018	2019	2020	2021	2022	2018-2022 Cost Estimate ($ million)
Line Sensors						$14
EMS/GMS						$30
ADMS[10]						$58
SOC Modernization						$96
13.2 kV Telecommunications						$14
Substation Automation						$36
Circuit Automation						$36
Pilot: Technology						$43
AMI Technology	See Section 4.19 for details					

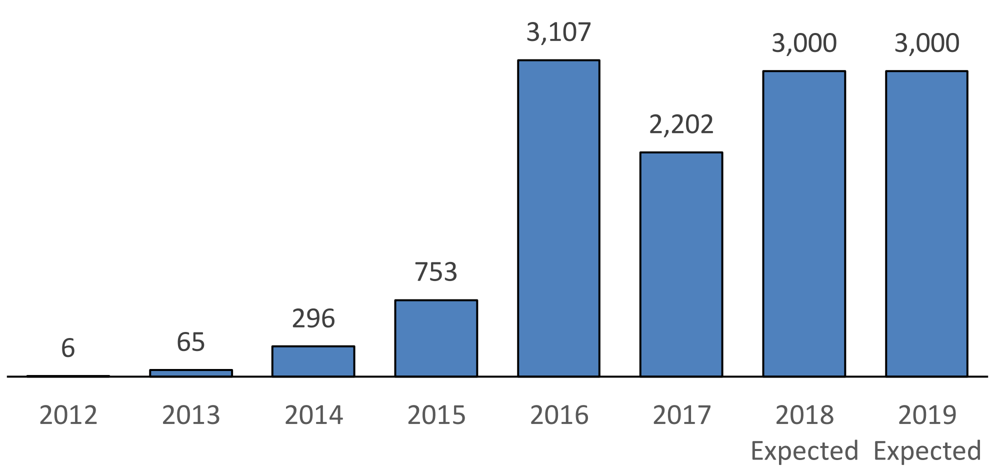
[10] In addition, the ADMS project requires $24 million of regulatory asset spend

Line Sensor Program installs sensors on circuit cable poles at the start of circuits. It is a low-cost option to monitor substation and circuit load and fault data on a near real-time basis (5-minute intervals), until the long-term solution of equipment upgrades and SCADA substation control solutions are fully implemented. As shown in Exhibit 5.4.5, at the end of 2017, DTEE had installed over 6,400 line sensors on 1,500 overhead circuits. By the end of 2019, the plan is to install line sensors on all distribution circuits that do not have SCADA monitoring and other strategic locations such as mid-points of 4.8 kV circuits. Additionally, line sensors have been installed on the downtown Detroit secondary network to get near real-time loading data and fault alarms.

Installation of line sensors provides more accurate load data for system planning and design. During outage events, these sensors help identify and locate faults and dispatch crews to the right location, reducing patrol time and hence outage duration.

Line sensors are projected to provide a total SAIDI reduction of approximately five minutes, driven by reduced patrol time and time to perform switching analysis and load jumpering.

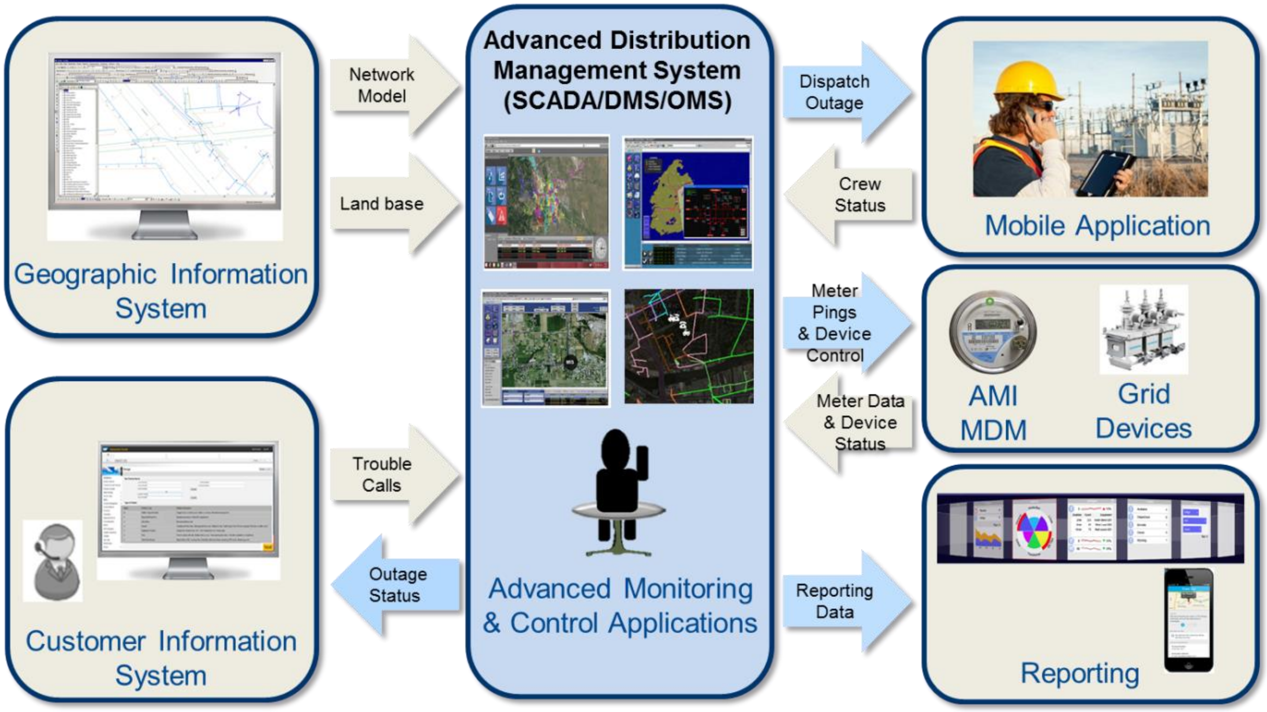
Exhibit 5.4.5 Line Sensors Installation by Year



EMS/GMS Replacement provides DTEE with a best-in-class Energy Management System (EMS) and Generation Management System (GMS) software. In addition to replacing the current end-of-life systems, the new product from OSI Inc, which has NERC-CIP rules built into the framework to ensure compliance, will allow reduction of NERC-CIP footprint by separating the EMS and GMS functions and lays the foundation for ADMS implementation.

ADMS is an advanced operating technology platform that will work as the foundation for improved system reliability by leveraging the enhanced technology deployed on the distribution system (such as line sensors, SCADA, etc.) and providing all users the same “as-operated” view of system performance. The ADMS will allow DTEE to fully integrate the Outage Management System (OMS), Distribution Management System (DMS), Energy Management System (EMS) and Supervisory Control and Data Acquisition System (SCADA), and provide seamless interface with the Geographical Information System (GIS), the Customer Information and Notification System (CIS / Customer360), and AMI. Exhibit 5.4.6 illustrates the ADMS as an integrated technology platform that will allow DTEE to perform advanced engineering and analytics, and provide our system operators industry leading functionality to monitor and control the electric grid to meet customers’ needs.

Exhibit 5.4.6 ADMS System - An Integrated Technology Platform



During the planning phase of this project, DTEE benchmarked multiple utilities that have implemented or are in the process of implementing an ADMS as shown in Exhibit 5.4.7. These utilities all had the same goal of improving reliability by setting a foundation for technology deployed in the field, and providing real-time views of the "as-operated" system. Implementation of ADMS varied among the utilities depending on their priorities. One key "lesson learned" that was common among utilities is that data quality is crucial and requires process improvements to ensure sustainability once ADMS is fully functional. The Network Model effort discussed in Section 5.4.1 will help meet this requirement.

Exhibit 5.4.7 Utilities with Partial or Full ADMS

Source: Accenture

The ADMS system connects and aggregates several operational functions to provide real-time situational awareness and a controllable distribution grid. Implementation of the ADMS system is expected to bring many benefits:

- Enhanced visibility and operational safety: the ADMS provides a tool for system supervisors to run "what-if" scenarios, perform pre-operation analysis checks for potential issues before issuing operating orders, and validate switching orders in "study mode" prior to execution.
- Improved system performance: the ADMS supports Volt/VAR optimization and can automatically balance line voltage and system reactive power to reduce power line losses, reduce peak demand, and improve the efficiency of the distribution grid.
- Improved system reliability: the ADMS reduces customer outage duration (SAIDI) by providing the following: automated outage verification, automated crew assignment

optimization, automated power flow analysis and fault location, switching studies to isolate faults and restore the maximum number of customers, and eventually remote switching and automatic isolation and restoration operations.

- Advanced data analytics: the ADMS provides a platform to analyze significant volumes of data from various portals and provides system supervisors the information in one place.
- Improved integration of distributed energy resources: the ADMS increases grid visibility, allows flexible real-time operation and provides appropriate balancing and control of power flow to accommodate increasing distributed energy resource penetration. The ADMS enables DTEE to use distributed energy as active grid resources, increasing the opportunity for all customers to benefit from DER operations.

Exhibits 5.4.8 summarizes the expected SAIDI benefits from ADMS. These benefits are based on the technology currently deployed in DTEE's system and do not reflect additional SAIDI improvements that will result from future investment of SCADA controllable devices in the system. In addition, the ADMS is expected to bring a net annual saving of $1.8 million of reactive capital.

Exhibit 5.4.8 Estimated SAIDI Benefits of ADMS

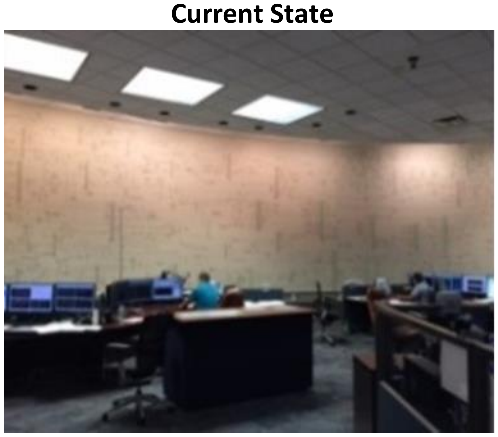
Benefit Driver	Description of Benefits	Estimated SAIDI Benefit
As-operated electrical Model Analysis	Utilize to view and analyze the as-operated electrical model to make informed decisions about how to restore customers	4-8 minutes
Trouble Call Analysis	Utilize remote monitoring capabilities to confirm trouble locations when devices in the field have opened and transmitted their status	4-8 minutes
Assign the Appropriate Crew	Utilize the as-operated model to determine the appropriate resources (e.g., OH vs. UG) to respond to an outage	1 minute
Nested Outage Notification	Utilize the as-operated model to identify incidents of nested outages (trouble behind trouble) to better direct restoration crew efforts	1 minute
Closest Crew Assignment	Utilize the as-operated model integrated with vehicle GPS to locate the closest available crew to an outage	2-3 minutes
Fault Location Identification	Provide a visual indication of the possible fault locations, allowing SOC to better develop a restoration strategy and the field crew to more quickly locate the troubled section of the circuit	5-10 minutes
Momentary Interruption Analytics	Utilize Momentary Interruption Analytics to produce daily reports of the number and location of momentary faults; patrol and resolve before momentary outages become sustained outages	0-1 minute
Switch Order Management System	Utilize the Switch Order Management System to quickly determine switching solutions for restore-before-repair	1-3 minutes
Restoration Switching Analysis	Utilize Restoration Switching Analysis to develop multi-step plans for optimal switching to restore customers based on current system conditions	4-14 minutes
Simulation Tools for Outage Restoration	Utilize Simulation tools to conduct contingency studies to simulate the impact of a restoration plan on the broader electrical system	2-3 minutes
Storm Damage Assessment	Utilize ADMS to assess initial storm damage to better direct resources for restoration efforts	3-4 minutes
Improve SCADA Availability	Monitor the health and availability of SCADA devices to minimize down time and maximize control and monitoring capability	2-4 minutes
Total Estimated Benefits		**29-60 minutes**

SOC Modernization will address the physical constraints existing in the current facilities. DTEE plans to build a modern SOC, a backup SOC, and a Network Operations Center (NOC) with space to house all supporting personnel. The new SOC facility will allow for co-location of dispatchers and operators, and improve DTEE's ability to manage significant operational disruptions, thus improving the resiliency of the system. The new NOC will improve visibility regarding the status and availability of field telecommunications, thus improving our ability to respond to issues quickly. The benefits of co-location include improved communication and coordination among groups, improved safety for field employees and faster outage restoration. The facilities will include electronic displays and improved console designs to meet dispatcher and operator needs, as illustrated in Exhibit 5.4.9. This will improve situational awareness, thus improving safety and reliability.

The backup SOC is required to provide DTEE the ability to move SOC operations nearly seamlessly to a fully functional alternate site in the event the primary SOC is unavailable. The design of the SOC and backup SOC is based on extensive benchmarking discussions with many of the top utilities and industry experts.

Exhibit 5.4.9 Current and Future State Example of SOC Facility

Current State



Future State

The 13.2 kV Telecommunications program installs secure and reliable telecommunications infrastructure to all 13.2 kV substations. All new substations constructed today are built to a standard with telecommunication and SCADA capability. This project will extend the telecommunication network through a combination of supplementing the existing WiFi Mesh, building fiber to existing substation sites, and establishing a telecommunications network inside existing substations to connect relays and metering. The scope includes installing standardized telecommunications and SCADA cabinets in each substation and building the telecommunications path to the substations.

The 13.2 kV Telecommunications program provides substations with the capability for full supervisory control and data acquisition as the infrastructure is replaced, retrofitted and modernized. Once SCADA controllable devices, such as new breakers or relay panels, are installed within substations, they can be connected and controlled remotely from the System Operations Center, in line with best practices. This program will also eliminate dial-up modems for substation remote access. The cost estimate for the 13.2 kV Telecommunications is shown in Exhibit 5.4.4.

A similar telecommunications program exists for 4.8 kV substations. It is included in the 4.8 kV Ground Detection program, which is discussed in detail in Section 5.5.3.

Substation Automation program installs SCADA control at all DTEE substations to allow for full remote monitoring and control. This program is designed to retrofit existing substations with advanced monitoring and control technology. This program will greatly improve operational efficiency during substation planned work and improve restoration efficiency during trouble and storm events. This program is part of DTEE's long-term strategy to modernize the electric grid to significantly improve reliability and operational efficiency.

Circuit Automation program installs SCADA reclosers and pole top switches, replacing outdated SCADA devices (such as Form 3 and Form 5 Reclosers discussed in Section 4.10 and Bridges SCADA Pole Top Switches discussed in Section 4.11), upgrading controls and protocols, or adding SCADA controllable devices to existing circuits. All new circuits constructed today are installed with SCADA controllable reclosers and switches as the standard design. Any circuit improvement projects may also include SCADA reclosers and switches as part of the toolbox to improve circuit reliability.

This program is part of DTEE's long-term strategy to modernize the electric grid and will demonstrate its full potential for reliability improvements in conjunction with ADMS. These devices will be used to isolate faults and provide service restoration automatically or under the direction of the ADMS and System Operations Center. DTEE's benchmarking shows that other electric utilities have had significant reliability improvements after implementing circuit automation technology.

Technology Pilot Program tests new technologies and concepts on a small scale to ensure system compatibility and economic justification before executing them system-wide. The identified pilot program for 2018 includes testing 40 kV automatic pole top switches, automatic pole top devices for the 4.8 kV system, trip savers, and SCADA-enabled overhead capacitors and regulators. Capital programs can be set up after proving the technology and obtaining solid cost estimates from the pilot studies.

The annual capital spend on grid technology is shown in Exhibit 5.4.10. The projected spend does not include the AMI 3G to 4G upgrade or firmware upgrade, which is addressed in Section 4.19.

Exhibit 5.4.10 Projected Grid Technology Modernization Capital Spend

Grid Technology Modernization Programs	$ millions 2018	2019	2020	2021	2022	5-Year Total
Line Sensors	$7	$7	-	-	-	$14
Energy Management System (EMS) / Generation Management System (GMS)	$22	$8	-	-	-	$30
Advanced Distribution Management System (ADMS) [11]	$7	$25	$19	$7	-	$58
System Operations Center (SOC) Modernization	$25	$40	$30	$1	-	$96
13.2 kV Telecommunications	$1	$3	$5	$5	-	$14
Substation Automation	-	-	-	$12	$24	$36 (Estimated total cost: $100)
Circuit Automation	-	-	-	$12	$24	$36 (Estimated total cost: $400)
Pilot: Technology (including capital programs post pilot)	$3	$5	$7	$14	$14	$43
Total	**$65**	**$88**	**$61**	**$51**	**$62**	**$327**

[11] In addition, the ADMS project requires $24 million of regulatory asset spend

5.5 4.8 kV and 8.3 kV System

5.5.1 Context

The 4.8 kV system was the primary design of the electrical distribution system prior to the 1970s. The 8.3 kV system was purchased from Consumers Energy in the 1980s and serves the City of Pontiac. The preferred construction method for new circuits built today is 13.2 kV.

The voltage map for DTEE's distribution system is shown in Exhibit 5.5.1. Comparisons among the three distribution system voltages are shown in the Exhibits 5.5.2-5.5.4.

Exhibit 5.5.1 DTEE Distribution System Voltage Map

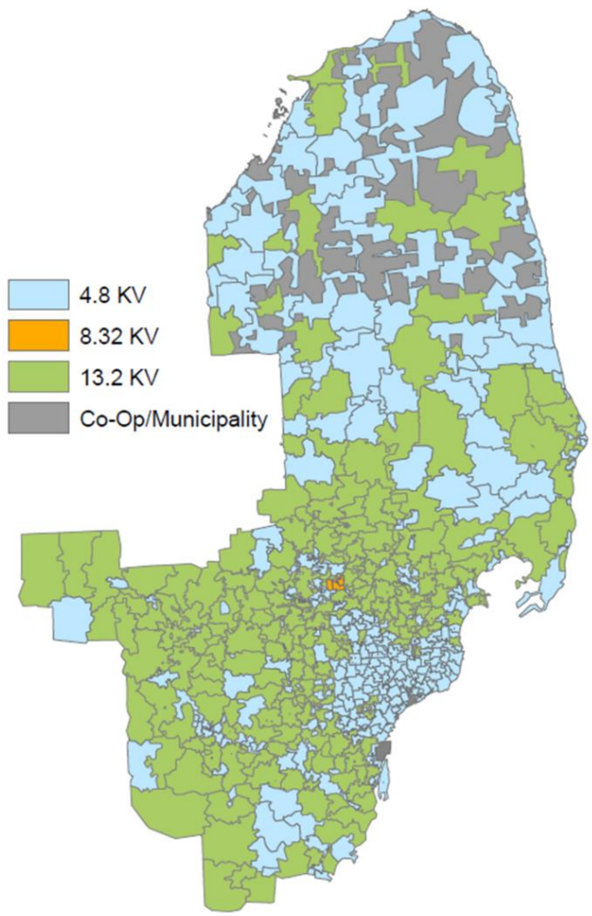


Exhibit 5.5.2 Percentage of Substations, Circuits, and Circuit Miles by Distribution Voltage

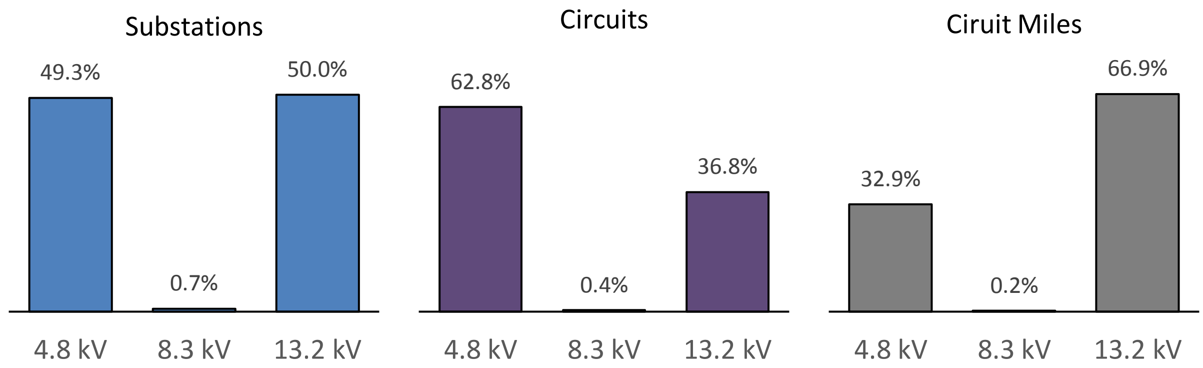


Exhibit 5.5.3 Percentage of Customers, Average Annual Downed Wire Events, and Average Annual Trouble Events by Distribution Voltage

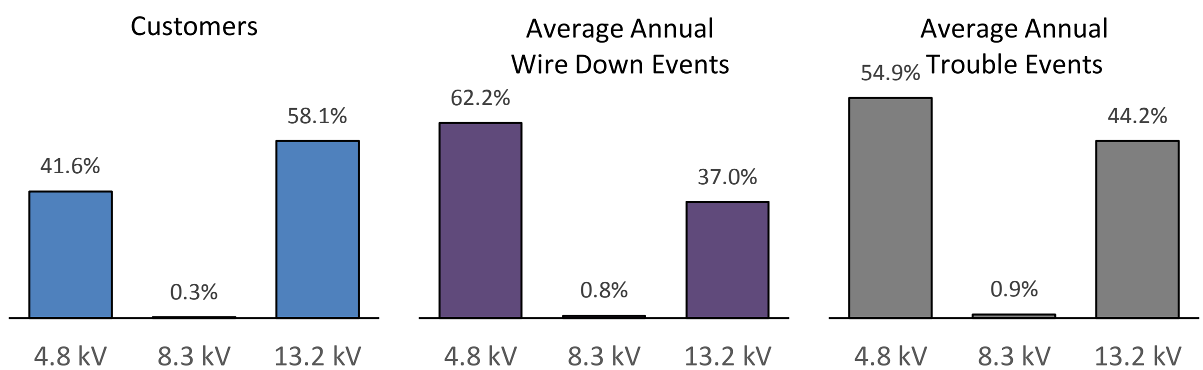
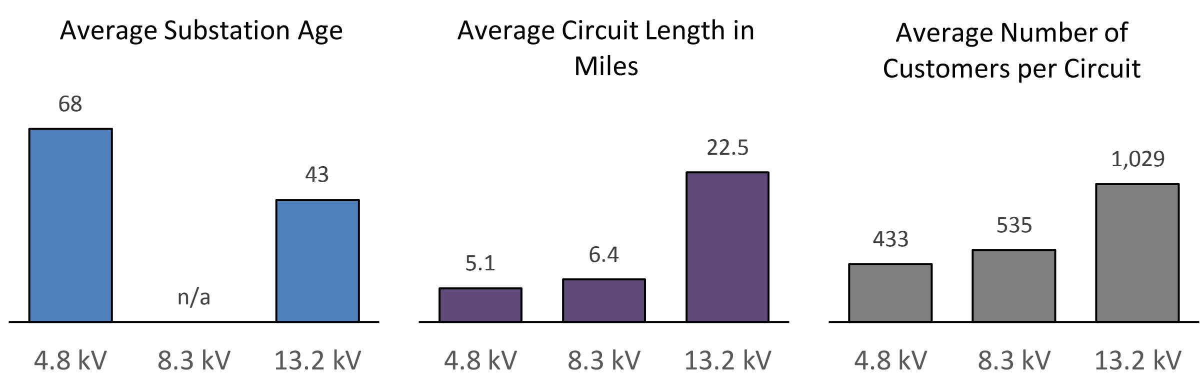


Exhibit 5.5.4 Substation Average Age, Average Circuit Length in Miles, and Average Number of Customers per Circuit by Distribution Voltage



5.5.2 4.8 kV System

DTEE's original distribution system voltage was 4.8 kV. The delta configuration and banked secondary of the 4.8 kV system provided very low occurrence of outage events for our customers. In many neighborhoods, the 4.8 kV system was constructed rear-lot -- aesthetical preferable to front-lot construction. Initially, right-of-way truck access was readily available through municipally maintained alleys. Starting in the mid-1900s, municipalities began to abandon alleys and allowed property owners to extend their fence lines, preventing DTEE truck access to the poles and wires. Consequently, the time to locate and repair trouble on the 4.8 kV system significantly increased as did the time to perform tree trimming and maintenance work. The average restoration time for an outage on the 4.8 kV system is 70% longer than on the 13.2 kV system. In addition, other key issues impacting the reliability and operability of DTEE's 4.8 kV system are summarized below:

- Most of the #6 copper, #4 ACSR and #4 copper conductors, which are weaker in strength compared to current standard wires, are on the 4.8 kV system.
- The 4.8 kV system has lower capacity and more significant voltage drops than the 13.2 kV system.
- The 4.8 kV system is an ungrounded delta configuration, making detection, location and protection of single phase downed wires challenging.
- Ringed circuit and banked secondary designs make maintenance, fault identification, troubleshooting and restoration more difficult and longer in duration. Opening the rings on 4.8 kV circuits may result in low voltage and/or more outage events for customers.
- The 4.8 kV system has a low penetration rate for remote monitoring and control capability. Due to equipment age, the retrofits on 4.8 kV substations and circuits to enhance remote monitoring and control capability are challenging. The original 4.8 kV substation design included individual relays for individual functions, usually on a 3-foot-by-7-foot panel. When a new breaker is installed, the entire relay panel and all the wiring must be replaced to accommodate the new technology.

5.5.3 Programs to Address 4.8 kV System

DTEE has made a strategic decision to phase out the 4.8 kV system design and replace it with 13.2 kV. Because higher voltages are more efficient, the conversion to 13.2 kV allows for the consolidation of two or more 4.8 kV substations into a single 13.2 kV substation. The conversion and consolidation of the 4.8 kV system will require substantial investment and will take decades to complete. Therefore, other measures are being developed as intermediate solutions to address system risk, reliability and cost.

As summarized in Exhibits 5.5.5 and 5.5.6, the 4.8 kV System Hardening, Ground Detection, and Targeted Secondary Network Cable Replacement programs are designed to harden and stabilize the 4.8 kV distribution system and extend the life of 4.8 kV circuits until DTEE completes the 4.8 kV Conversion and Consolidation to 13.2 kV over the next several decades.

Most of the near-term 4.8 kV conversion and consolidation projects are driven by system capacity needs due to new load and DTEE’s commitment to not expand the aging 4.8 kV system. These projects are expected to bring multi-faceted benefits of load relief, safety improvements, risk reduction, reliability improvements, technology modernization and cost reduction. The 4.8 kV conversion and consolidation projects are evaluated on a substation-by-substation basis to ensure that the appropriate substations are selected to achieve the highest customer benefits for the given investment. The 4.8 kV conversion and consolidation projects planned for the next five years are discussed in details in Exhibits 5.5.7 and 5.5.8.

Exhibit 5.5.5 4.8 kV System Programs Summary

Program	Drivers	Scope of Work
4.8 kV System Hardening	• Harden and stabilize the 4.8 kV distribution circuits to improve safety, reliability and storm resiliency • Extend the life of 4.8 kV circuits until DTEE completes the 13.2 kV conversion over several decades • Claim circuit right-of-way by trimming and removing trees • Improve truck accessibility and operational efficiency	• Replace crossarms or use armless construction when feasible • Replace or reinforce poles as needed • Remove banked secondary and reduce quantity of wires as needed • Remove overhead service wires for abandoned houses • Trim trees to enhanced specification • Coordinate with PLD to remove abandoned PLD arc wires • Conduct pilots to rebuild targeted primary sections, underground circuits and move primary from rear lot to front lot to allow truck access
Ground Detection (4.8 kV Relay Improvement Program)	• Allow System Operations Center to automatically detect and receive alerts of wire down events • Allow quick response to wire down events	• Install and/or upgrade telecommunication and RTUs for substation remote monitoring • Install substation ground/wire down alarms
Targeted Secondary Network Cable Replacement	• Reduce secondary network cable failures and manhole events in downtown City of Detroit	• Replace targeted sections of the 4.8 kV secondary network cable system that have a higher probability of failure
4.8 kV Conversion and Consolidation	• Replace aging infrastructure (oldest part of the DTEE system) • Reduce wire down events • Improve reliability and power quality for 4.8 kV customers • Reduce O&M costs by decreasing the number of assets in the field and the number of trouble events • Enhance grid technology and automaton, including DER integration	• Convert and consolidate two to three 4.8 kV substations and their circuits into one 13.2 kV substation and circuits (applicable to strong load growth areas) • Consolidate multiple 4.8 kV substations into one 4.8 kV substation (applicable to lightly loaded and blight areas) • Will require ~$15 billion over several decades (30+ years) to complete

Exhibit 5.5.6 Projected Costs and Timeline for 4.8 kV System Programs

Program	2018	2019	2020	2021	2022	2018-2022 Cost Estimate ($ million)
4.8 kV System Hardening (2018-2022 Only)						$323
Ground Detection (4.8 kV Relay Improvement Program)						$18
Targeted Secondary Network Cable Replacement						$8
4.8 kV Conversion and Consolidation (2018-2022 Only)						$571

4.8 kV System Hardening Program is a targeted program designed to harden and stabilize the 4.8 kV distribution circuits for improved safety, reliability and storm resiliency, extend the life of the 4.8 kV circuits and claim circuit right-of-way by trimming and/or removing trees until DTEE completes the 13.2 kV conversion over the next several decades. The scope of the program includes replacing crossarms, replacing or reinforcing poles as needed, removing targeted banked secondary wires, removing overhead service wires on abandoned homes/businesses, coordinating with PLD to remove abandoned PLD arc wires, and conducting pilots to rebuild targeted primary sections, underground circuits or move primary wires from rear lot to front lot to improve truck accessibility. Prioritization of the circuits in this program will leverage a set of factors including the number of wire down events, PLD arc wire presence, estimated foot traffic and customer density, tree density, reliability performance, volume of trouble events and trouble expenses. This program will also coordinate with other programs addressing the performance of the 4.8 kV system such as 4.8 kV conversion and consolidation, pole and pole top maintenance, and PLD distribution programs to avoid duplicating efforts.

As the Company concentrates on ramping up the 4.8 kV system hardening program, the actual spend and timeline could deviate from the projection due to resource constraints or unforeseen challenges in field conditions and execution complications.

Ground Detection Program (4.8 kV Relay Improvement Program) allows the System Operations Center to receive alarms for 4.8 kV wire down events so that actions can be taken quickly to remediate and make repairs. Because the 4.8 kV system is an ungrounded delta configuration, single phase downed wires do not produce fault currents that are large enough to trip protection devices such as substation breakers.

The first step of the Ground Detection Program is to install or upgrade telecommunications at 4.8 kV substations as most 4.8 kV substations are of a vintage that precedes SCADA (a similar telecommunications program exists for 13.2 kV substations, see Section 5.4.2). The second step is to install a ground detection panel at 4.8 kV substations. The ground detection panel will identify real-time wire down events seen at the substation bus. Knowing that a ground wire exists in real-time allows for immediate crew dispatch to locate and repair the downed wire, reducing the amount of time needed for repair.

Targeted Secondary Network Cable Replacement Program will replace targeted sections of the 4.8 kV secondary network cable that serve downtown Detroit and have a higher probability of failure. This program is designed to reduce secondary network cable failures and manhole events.

4.8 kV Conversion and Consolidation Program is expected to take decades to complete at a cost in excess of $15 billion. DTEE evaluates conversion and consolidation projects on a substation-by-substation basis, using the benefit-cost evaluation methodology described in Section 2 of the report. In the next five years, several conversion and consolidation projects are planned as listed in Exhibits 5.5.7 and 5.5.8, most of which are driven by strong area load growth and system capacity needs. While the scope of work in Exhibit 5.5.7 refers to the entire project, which can extend beyond the next five years, the cost estimate in Exhibit 5.5.8 captures the projected spend in the next five years. Since many of these projects will extend beyond the next five years due to their size and complexity, the total cost to complete the project is also provided in Exhibit 5.5.8. As noted earlier, the cost and timeline estimates for these projects are based on the best knowledge and information known today by DTEE. Actual project costs and timeline could deviate from the projections due to various unforeseen factors or new information/learnings.

Exhibit 5.5.7 4.8 kV Conversion and Consolidation Projects

Project	Community	Drivers	Scope of Work
Cortland / Oakman / Linwood Consolidation	Detroit	• Reduce trouble events and O&M expenses by decommissioning two aging, underutilized 4.8 kV substations	• Started in 2016, this project consolidated 4.8 kV Oakman and Linwood into 4.8 kV Cortland substation to decommission aging substation equipment and system cable
Hilton Substation and Circuit Conversion Phase One	Ferndale Hazel Park	• Provide load relief to Ferndale area • Replace aging infrastructure • Reduce trouble events and O&M expenses • Improve reliability in the Ferndale and Hazel Park areas	• Started in 2013, the project constructed a new 13.2 kV Hilton substation and is in the final stage of converting 10 existing 4.8 kV circuits from Ferndale and Hazel Park to four new 13.2 kV circuits
Downtown City of Detroit Infrastructure Modernization (Downtown CODI)	Detroit	• Provide sufficient capacity to serve fast growing Detroit core downtown areas • Reduce secondary network cable failures and manhole events • Replace aging infrastructure • Improve reliability and power quality • Reduce trouble events and O&M expenses by decommissioning eight 4.8 kV substations	• Started in 2013, Public Lighting Department (PLD) customer transition program constructed 13.2 kV Temple and Stone Pool substations in the Detroit core downtown area • DTEE is currently pursuing the new 13.2 kV Corktown substation • Leveraging the three new 13.2 kV substations, DTEE will decommission 4.8 kV Amsterdam, Charlotte, Garfield, Gibson, Howard, Kent, Madison and Orchard substations, and convert circuits and secondary network cables from 4.8 kV to 13.2 kV

Project	Community	Drivers	Scope of Work
Belle Isle Substation and Circuit Conversion	Detroit	• Replace aging infrastructure • Reduce trouble events and O&M expenses • Provide sufficient capacity to serve fast-growing Detroit west riverfront developments	• Construct a new 13.2 kV Belle Isle substation • Convert existing 4.8 kV circuits from Walker, Gibson and Pulford • Decommission Walker (built in 1923) and Pulford (built in 1926) substations
I-94 Substation and Circuit Conversion	Detroit	• Replace aging infrastructure • Reduce trouble events and O&M expenses • Provide capacity to emerging businesses such as I-94 industrial park	• Construct a new 13.2 kV substation • Convert existing 4.8 kV circuits from Lynch and Lambert • Decommission Lynch and Lambert substations
Herman Kiefer Substation and Circuit Conversion	Detroit	• Replace aging infrastructure • Reduce trouble events and O&M expenses • Provide capacity for emerging businesses	• Construct a new 13.2 kV substation • Convert existing 4.8 kV circuits from Grand River and Pingree • Decommission Grand River (built in 1916) and Pingree (built in 1926) substations
Ariel Substation and Circuit Conversion	Birmingham	• Provide load relief and capacity needs for downtown Birmingham • Improve reliability in the area	• Started in 2014 • Construct a new 13.2 kV substation • Convert seven existing 4.8 kV circuits from Dudley, Birmingham and Quarton Road substations to three new 13.2 kV circuits at Ariel substation
Birmingham Decommission and Circuit Conversion	Birmingham	• Reduce substation outage risk • Replace aging infrastructure • Reduce trouble events and O&M expenses	• Construct a new 13.2 kV substation • Convert existing 4.8 kV circuits to 13.2 kV • Decommission Birmingham substation

Project	Community	Drivers	Scope of Work
White Lake Decommission and Circuit Conversion	White Lake	• Provide load relief • Replace aging infrastructure • Allows for jumpering (existing 4.8 kV is islanded – surrounded by 13.2 kV)	• Install a skid-mounted substation • Add three miles of underground cable • Rebuild three miles of overhead • Convert 15 miles of 4.8 kV to 13.2 kV • Install loop schemes for automatic load transfers • Transfer load from White Lake to new substation and decommission White Lake
Cody Upgrade and South Lyon Decommission	South Lyon	• Provide load relief • Replace aging infrastructure • Allows for jumpering (existing 4.8 kV is islanded – surrounded by 13.2 kV) • Eliminate potential for stranded load	• Upgrade two transformers and switchgear at Cody substation • Add six miles of underground cable • Rebuild five miles of overhead • Convert eight miles of 4.8 kV to 13.2 kV • Install loop schemes for automatic load transfers • Transfer load from South Lyon to Cody and decommission South Lyon
Lapeer-Elba Expansion and Circuit Conversion	Lapeer / Elba Twp	• Provide load relief • Replace aging infrastructure • Increase jumpering capability • Eliminate 40 kV tap that has a history of poor reliability performance	• Add a 3rd 13.2 kV transformer to Lapeer substation • Build a new 13.2 kV substation • Convert and consolidate 4.8 kV circuits from Elba and Lapeer substations to 13.2 kV • Decommission the 4.8 kV portion of Lapeer substation • Decommission Elba and 40 kV tap to substation

Project	Community	Drivers	Scope of Work
Almont Relief and Circuit Conversion	Almont Twp	• Provide load relief • Replace aging infrastructure • Increase jumpering capability • Improve circuit voltage	• Build a new 120:13.2 kV substation • Transfer approximately 50% of Almont load to new substation, converting it to 13.2 kV • Reconductor four miles of backbone • Establish new jumpering points
Argo / Buckler Load Transfer	Ann Arbor	• Provide load relief and capacity needs for downtown Ann Arbor • Increase jumpering capability	• Transfer three entire circuits and a portion of two circuits from Argo to Buckler, converting them to 13.2 kV
Calla Circuit Conversion	Dexter	• Provide load relief and capacity needs for Dexter • Improving reliability • Increase jumpering capability	• Rebuild approximately 1.6 miles of 4.8 kV Diamond circuits to 13.2 kV and transfer this portion to Calla substation • Transfer northern portion of a Lima circuit to Calla substation
Reno Decommission and Circuit Conversion	Freedom / Bridgewater	• Provide load relief and capacity needs for west Ann Arbor • Replace aging infrastructure • Increase jumpering capability	• Build a new 120:13.2 kV substation • Transfer load from Reno, converting it to 13.2 kV • Expand Freedom substation • Decommission Reno substation
Zenon Substation and Circuit Conversion	Detroit	• Provide load relief and capacity needs for the City of Detroit, west of downtown. • Improve reliability in the area	• Started in 2012 • Construct a new 13.2 kV substation • Convert or transfer circuits from aging McKinstry, West End and Artillery substations to Zenon

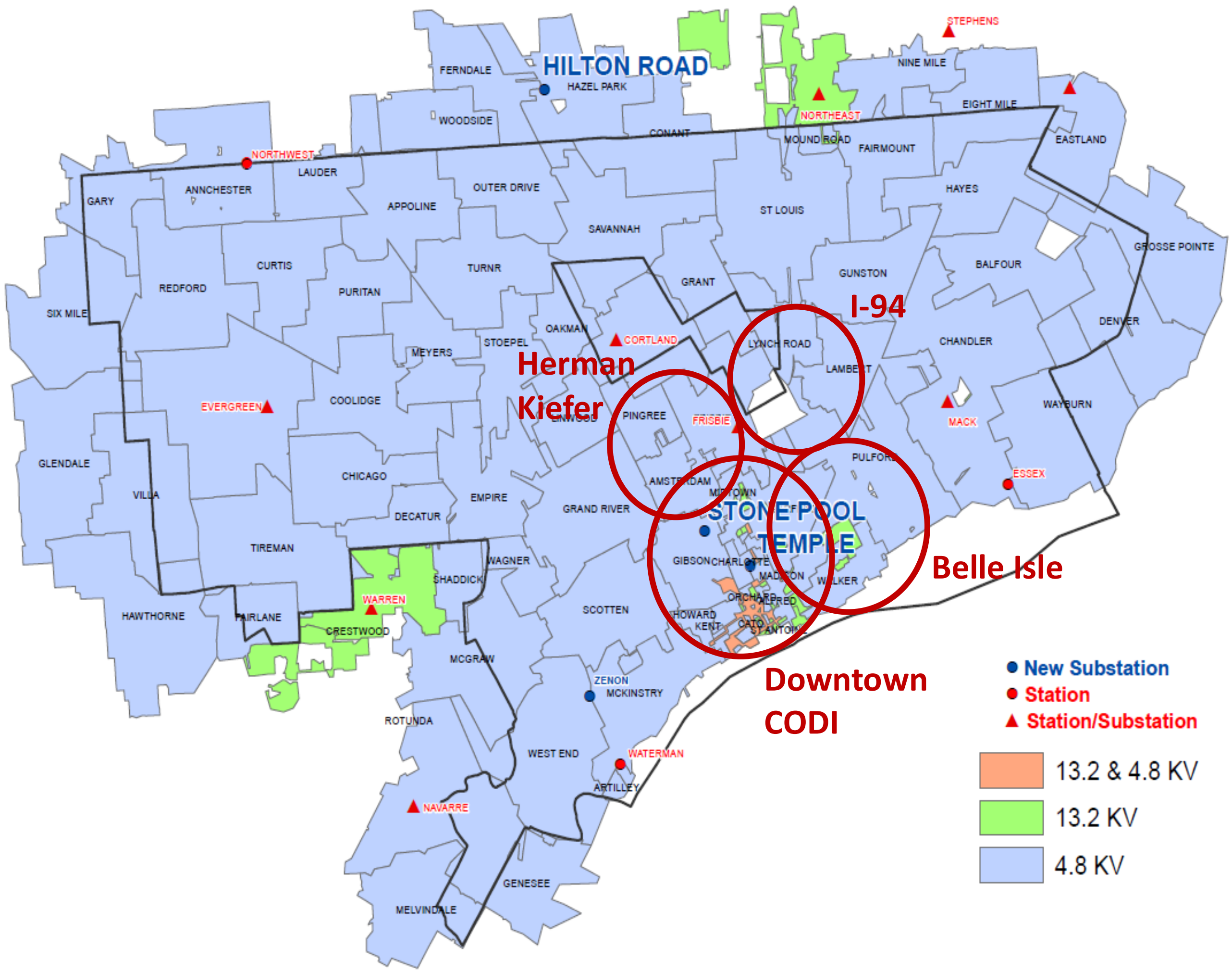
Exhibit 5.5.8 Projected Costs and Timeline for 4.8 kV Conversion and Consolidation Projects

Project	2018	2019	2020	2021	2022	2018-2022 Cost Estimate ($ million)
Cortland / Oakman / Linwood Consolidation						$10
Hilton Substation and Circuit Conversion Phase One						$14
Downtown City of Detroit Infrastructure Modernization (Downtown CODI)						$220 (Total Cost[12]: $750)
Belle Isle Substation and Circuit Conversion						$81 (Total Cost: $192)
I-94 Substation and Circuit Conversion						$75 (Total Cost: $83)
Herman Kiefer Substation and Circuit Conversion						$39 (Total Cost: $91)
Ariel Substation and Circuit Conversion						$5
Birmingham Decommission and Circuit Conversion						$23 (Total Cost: $46)
White Lake Decommission and Circuit Conversion						$15
Cody Upgrade and South Lyon Decommission						$3 (Total Cost: $26)
Lapeer-Elba Expansion and Circuit Conversion						$48 (Total Cost: $65)
Almont Relief and Circuit Conversion						$18
Argo / Buckler Load Transfer						$6
Calla Circuit Conversion						$2
Reno Decommission and Circuit Conversion						$9 (Total Cost: $12)
Zenon Substation and Circuit Conversion						$3

[12] Total cost includes the anticipated spend through project completion beyond 2022

To provide further details on the identified 4.8 kV conversion and consolidation projects in Detroit, Exhibit 5.5.9 provides a map to illustrate the project's footprint, followed by a further description of the projects.

Exhibit 5.5.9 Detroit 4.8 kV Conversion and Consolidation Map



Detroit 4.8 kV Conversion and Consolidation — I-94 Substation and Circuit Conversion Project

The Detroit Economic Growth Corporation (DEGC) has assembled the I-94 Industrial Park site – a 186-acre site north of I-94 between Mt. Elliott and Van Dyke on Detroit's east side. It is part of the 3,203-acre Mt. Elliot Development Zone, which is the single largest industrial district in Detroit and encompasses automotive, metal, transportation and logistics clusters. The zone is home to stakeholders including GM Detroit Hamtramck Assembly Plant, Detroit Chassis, Futuramic Tool and Engineering Company, LINC Logistics, and Flex-N-gate Detroit, with land available for additional businesses.

It offers access to major transportation assets such as I-94, the Detroit North Rail Yard and Freight Rail and the Coleman A. Young International Airport. The site is a federally designated Historically Underutilized Business (HUB) Zone and a state designated Renaissance Zone.

Recent new loads were fed from the aging Lynch and Lambert 4.8 kV substations. These substations have little capacity for additional load, and currently have limited throw-over and jumpering options.

This project will construct a new 13.2 kV class substation, decommission the aging Lynch and Lambert substations, increase reliability and power quality for the existing industrial customers and provide capacity for further development of the industrial park.

Detroit 4.8 kV Conversion and Consolidation — Herman Kiefer Substation and Circuit Conversion

Additional new loads are expected for the area near the John C Lodge Freeway and West Grand Boulevard including the Herman-Kiefer Complex, Henry Ford Cancer Center, and Henry Ford Hospital. This area is currently served by the aging Grand River and Pingree 4.8 kV substations. This project will construct a new 13.2 kV substation, decommission the Grand River and Pingree 4.8 kV substations, and convert their circuits to 13.2 kV. As a result, power quality will be greatly improved, substation capacity will be available for the new loads, loading at Amsterdam substation will be relieved (load transferred to the new substation) and circuit capacity will be increased to allow more jumpering options and restore-before-repair capability.

Detroit 4.8 kV Conversion and Consolidation — Belle Isle Substation and Circuit Conversion

Belle Isle substation is to be sited east of downtown Detroit near the riverfront. New loads have been added along the Detroit riverfront (Orleans landing, DuCharme Place, Harbortown Apartments) and additional development is anticipated in the future.

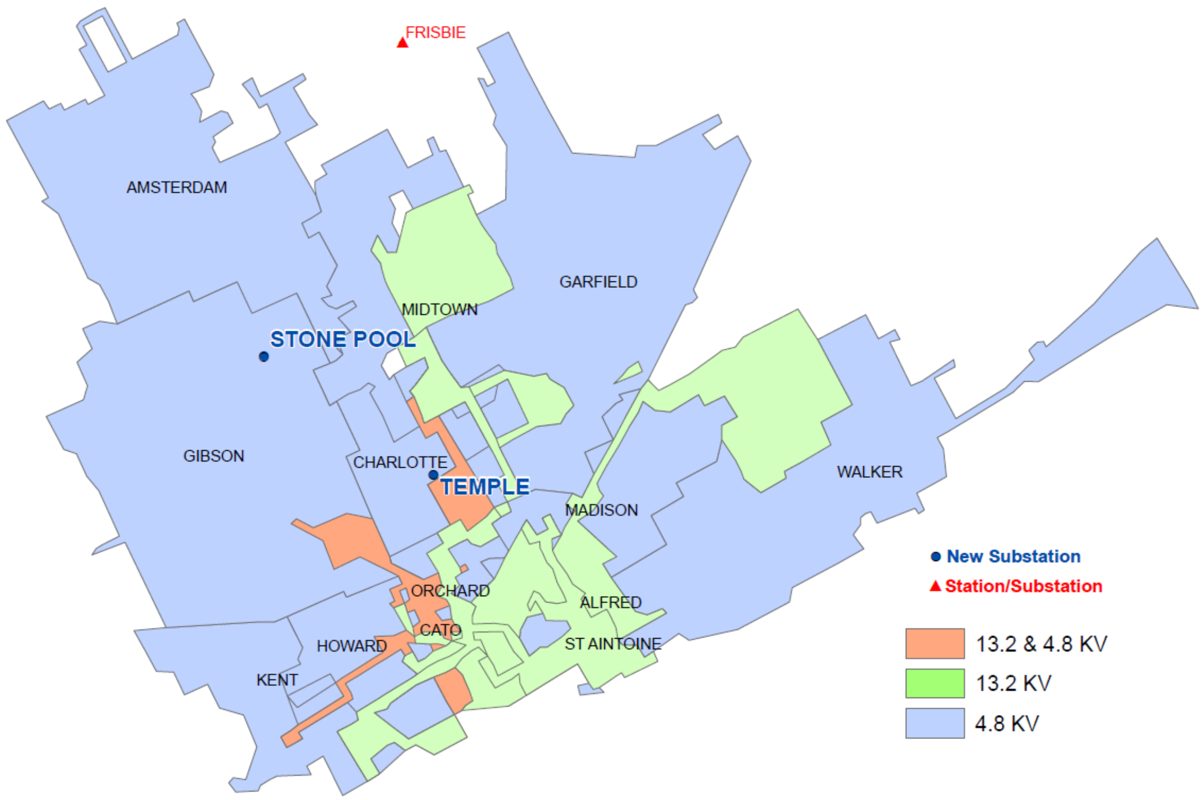
The new substation will allow for the decommissioning of Pulford and Walker substations, which have been in service since the 1920s. Circuits from these and other nearby substations will be converted from 4.8 kV to 13.2 kV and will be served by the new substation. Belle Isle substation will also provide capacity to serve customers being transitioned from the Detroit PLD system to the DTEE system.

Detroit 4.8 kV Conversion and Consolidation — Downtown City of Detroit Infrastructure Modernization (Downtown CODI)

Electrical system infrastructure in the City of Detroit dates to the early 20th century. A significant portion of the infrastructure is at end-of-life. The resurgence of development in the greater downtown Detroit area in recent years has resulted in increased loading on the end-of-life assets. The downtown CODI program is different from other conversion and consolidation projects due to presence of large amounts of system cable and secondary network cable, which add to the complexity of operating, maintaining and upgrading this part of the system.

Exhibit 5.5.10 provides a map to illustrate the area that will be affected by the downtown CODI program.

Exhibit 5.5.10 Downtown City of Detroit Substation Areas (Downtown CODI)



The Downtown CODI program consists of 12 projects. The high-level scope of work and estimated timelines are listed in Exhibit 5.5.11.

Exhibit 5.5.11 Downtown City of Detroit Infrastructure Modernization (Downtown CODI)

Project	Key Scope of Work	Estimated Timeline
CODI – Midtown Substation Expansion	Expand 13.2 kV Midtown substation by installing 3rd transformer and a 12-position switchgear	2018-2019
CODI – Alfred Substation Expansion	Expand 13.2 kV Alfred substation by installing 3rd transformer and a 12-position switchgear	2019-2020
CODI – New Corktown Substation	Build a new general purpose substation named Corktown	2018-2020
CODI – Charlotte Network Conversion	• Rebuild 30 miles of secondary network cable • Rebuild seven miles of system cable • Replace or remove 68 netbank transformers • Convert eight primary customers • Convert the circuits to 13.2 kV fed by Temple substation • Decommission Charlotte substation	2018-2022
CODI – Garfield Network Conversion	• Rebuild 36 miles of secondary network cable • Rebuild 32 miles of system cable • Replace or remove 78 netbank transformers • Convert 26 primary customers • Convert 24 miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Stone Pool substation • Decommission Garfield substation	2018-2024
CODI – Kent Network Conversion	• Rebuild six miles of system cable • Convert one primary customer • Convert seven miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Corktown substation • Decommission Kent substation	2020-2024
CODI – Gibson Network Conversion	• Rebuild 10 miles of system cable • Convert 22 miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Corktown substation • Decommission Gibson substation	2020-2024

Project	Key Scope of Work	Estimated Timeline
CODI – Howard Conversion	• Rebuild 15 miles of secondary network cable • Rebuild 30 miles of system cable • Replace or remove 89 netbank transformers • Convert 26 primary customers • Convert three miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Corktown substation • Decommission Howard substation	2021-2024
CODI – Amsterdam Conversion	• Rebuild 22 miles of secondary network cable • Rebuild 50 miles of system cable • Replace or remove 60 netbank transformers • Convert 28 primary customers • Convert seven miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Stone Pool substation • Decommission Amsterdam substation	2022-2026
CODI – Madison Conversion	• Rebuild 31 miles of secondary network cable • Rebuild 30 miles of system cable • Replace or remove 92 netbank transformers • Convert 24 primary customers • Convert three miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission Madison substation	2023-2027
CODI – CATO Conversion	• Rebuild 17 miles of system cable • Convert 15 primary customers • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission CATO substation	2024-2027
CODI – Orchard Conversion	• Rebuild 12 miles of secondary network cable • Rebuild 13 miles of system cable • Replace or remove 80 netbank transformers • Convert 12 primary customers • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission Orchard substation	2024-2027

4.8 kV System Program Summary

Summarizing the programs and projects above, DTEE projects the annual capital spend to address 4.8 kV system in the next five years in Exhibit 5.5.12. The projected 4.8 kV system capital spend includes 4.8 kV system hardening, ground detection, targeted secondary network cable replacement, and 4.8 kV conversion and consolidation. The downtown City of Detroit infrastructure program, conversion and consolidation projects discussed in Section 5.1 (System Loading) and Section 5.2 (Substation Outage Risk) are included in the projected 4.8 kV conversion and consolidation capital spend.

Exhibit 5.5.12 Projected 4.8 kV System Capital Spend

4.8 kV System Programs	$ millions					
	2018	2019	2020	2021	2022	5-Year Total
4.8 kV System Hardening	$53	$59	$64	$70	$77	$323
Ground Detection (4.8 kV Relay Improvement)	$3	$3	$4	$4	$4	$18
Targeted Secondary Network Cable Replacement	$2	$2	$2	$2	-	$8
4.8 kV Conversion and Consolidation	$54	$55	$85	$152	$225	$571
Total	**$112**	**$119**	**$155**	**$228**	**$306**	**$920**

5.5.4 8.3 kV System

DTEE did not construct the 8.3 kV system that serves the city of Pontiac. Located within DTEE's service territory, it was acquired from CMS Energy in the 1980s. The 8.3 kV system is served by four substations: Bartlett, Paddock, Rapid Street and Stockwell, and their 18 distribution circuits.

Unlike the 4.8 kV and 13.2 kV systems, contingency options are limited for the 8.3 kV system. Because the 8.3 kV system is an island surrounded by the 13.2 kV system, it is impossible to transfer load from 8.3 kV circuits to neighboring facilities. This results in a high risk for stranded load in the event of an 8.3kV substation outage event.

In addition, replacement parts are no longer available for 8.3 kV breakers, other substation equipment and equipment in the underground vaults due to their obsolescence. Non-standard clearances require substation shutdowns for operations and maintenance. This leads to extended customer interruptions during outage events and leaves the system in an abnormal state for extended periods of time if any 8.3 kV equipment fails.

Crews must be trained to operate and maintain the 8.3 kV system, adding to training and operation and maintenance costs.

Meanwhile, the City of Pontiac is experiencing an economic rebound, with an estimated 40 MVA (37 percent) load growth in the next 5-10 years.

5.5.5 Plan to Address 8.3 kV System

The plan to address the 8.3 kV system has been developed, reviewed and refined in the past several years. A small portion of the circuit conversion has been executed. The next step is to build a new 13.2 kV substation in the Pontiac area and convert and transfer all Bartlett circuits and a portion of Rapid Street circuits to the new substation. The remaining Rapid Street overhead circuits will be converted to 13.2 kV and transferred to Bloomfield substation. All Paddock circuits and the Stockwell overhead circuits will be converted to 13.2 kV and transferred to Catalina substation. As a result of the project, over the next five years, both Bartlett and Paddock substations will be decommissioned; only two Rapid Street underground circuits and three Stockwell underground circuits will be left on the 8.3 kV system for conversion post 2022, but upgraded with submersible vault equipment as discussed in Section 4.18. Exhibit 5.5.13 illustrates the geographic locations of the substations under discussion. Exhibit 5.5.14 provides a summary capital spend of the project.

Exhibit 5.5.13 Potential Stranded 8.3 kV Load in Pontiac

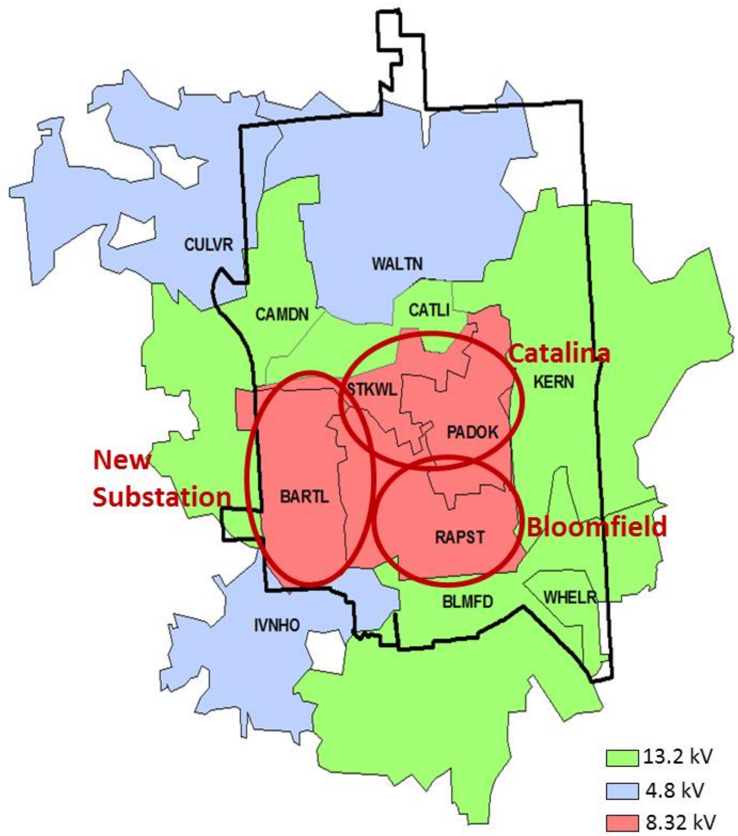


Exhibit 5.5.14 Pontiac 8.3 kV Overhead Conversion Capital Spend

	2018	2019	2020	2021	2022	5 Year Total
Pontiac 8.3 kV Overhead Conversion Capital Spend ($ millions)	$1	$5	$12	$19	$11	$48

5.6 Reactive Trouble and Storm Costs

5.6.1 Context

As DTEE's electric distribution system ages, reactive work related to trouble events is placing an increasing demand on costs and resources. Data show that DTEE responds to an average of 240,000 trouble calls each year, with approximately two-thirds of those calls for non-outage events. Typical non-outage events include low voltage, flickering lights, hazards (e.g., sagging wires, defective lightning arrestors), and downed 4.8 kV wires.

Exhibits 5.6.1 and 5.6.2 show the non-storm trouble event costs and storm event costs for the past several years.

Exhibit 5.6.1 Non-Storm Trouble Event Cost ($ million)

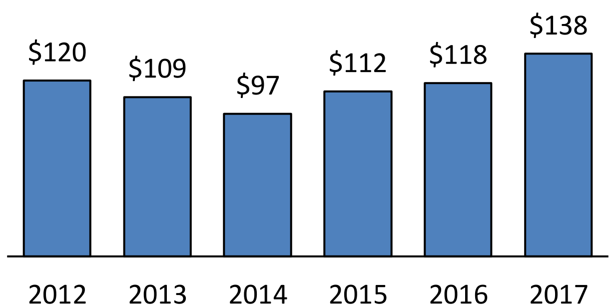
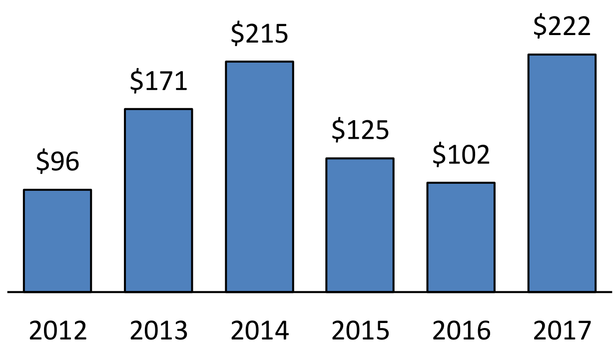


Exhibit 5.6.2 Storm Event Cost ($ million)



Storm costs are driven by several factors, including: the severity of the storms and the resulting damage (including trees) to the electrical system, the number of contract and foreign crews needed for a timely restoration, the number of field support personnel including damage assessors and public safety teams, and the number of office support personnel. A history of DTEE storm restoration events since 2012 is listed in Appendix III.

5.6.2 Measures to Address Reactive Trouble and Storm Costs

To manage costs, DTEE is monitoring truck rolls and costs on an individual circuit basis with the intent to reduce them through various measures, including: tree trimming, capital replacement programs, reliability programs targeting root causes, 4.8 kV system hardening, and 4.8 kV system conversion and consolidation. These measures will replace aging infrastructure, increase storm resiliency and reduce day-to-day trouble events. Grid technology programs will also help improve operational efficiency, increase productivity and reduce costs to operate the system.

In addition to capital investments, DTEE is actively pursuing process and operational measures to improve productivity and reduce costs.

These measures will help reduce reactive trouble and storm capital spend, and, to some extent, offset O&M increases that are driven by continued system aging and inflation. The projected reactive trouble and storm capital spend and O&M costs are discussed in Section 2.6.

5.6.3 Storm Insurance Options

DTEE has not had storm insurance for the past 10 years. Prior to that, DTEE had several claims that resulted in full limit losses to the insurer. This resulted in premium increases, which then made storm insurance an uneconomical option.

For standard policies, insurers have a large base to spread their losses over. With a large base, the law of large numbers applies, i.e., the average results obtained from a large number of trials should be close to the expected value and tend to become closer as more trials are performed. For the insurer, the law of large numbers guarantees stable long-term results for the averages of some random events. This allows the insurer to know the expected cost and to price the policy accordingly.

Storm insurance for a utility is a specialty policy unique to the insured. For a specialty policy, there is no large base, hence the law of large numbers does not apply. Instead the policy is based on the insured's loss history. Typically, the insurer requires 10 years of loss history to underwrite a specialty policy. As with any insurance policy, variables to consider are the deductible, maximum payout, and the premium.

DTEE regularly reviews the economics of insuring the distribution system. Should an economical insurance option become available, DTEE will consider procuring a policy.

6 Distribution Maintenance Plan

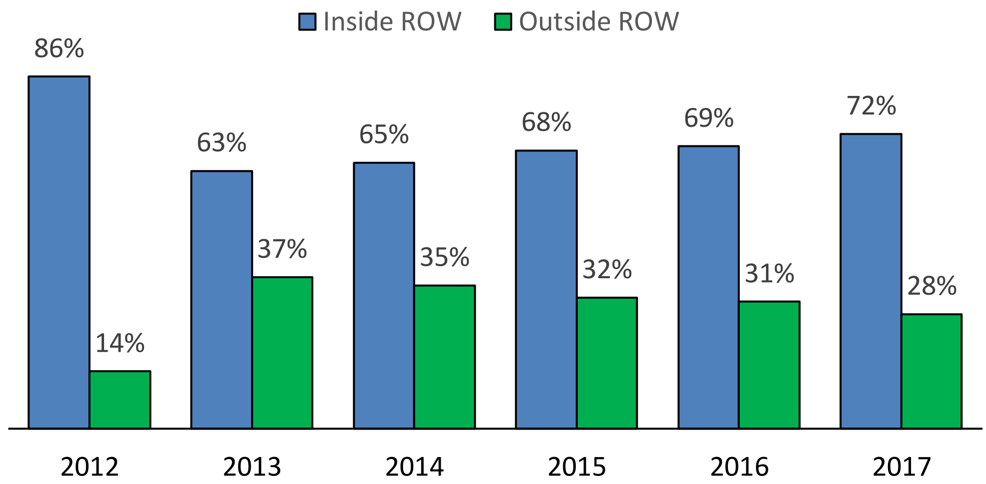
6.1 Tree Trimming

Trees and tree-related events are responsible for more than two-thirds of the time DTEE customers are without power and account for approximately one-third of the outage events. Preventing tree outages is the most effective method to reduce both SAIDI and reactive trouble and storm costs.

Based on extensive benchmarking with other utilities that have better reliability and system performance, DTEE has taken steps to update its tree trimming specification. The prior practice of trimming to the clearance circle did not provide the desired system reliability. The latest evolution of the tree trimming specification occurred in 2016 with the introduction of the Enhanced Tree Trimming Program (ETTP), with the intent of achieving a significant reduction in tree-related outages. The key elements of the ETTP that drive the largest impact on reliability at an optimal cost are as follows:

- Designate circuit zones based on the circuit configuration and the number of customers potentially affected by an outage
- Differentiate tree trimming specifications based on zone. More extensive trimming is performed in the zones that affect more customers and less extensive trimming is performed in the zones that affect fewer customers
- Where feasible, remove hazardous trees outside the right-of-way (ROW) that are dead, dying, or diseased and threaten to interrupt services to customers. On average, 30 percent of customer outages are caused by trees outside the right-of-way as shown in Exhibit 6.1.1

Exhibit 6.1.1 Inside vs. Outside the ROW Outages



Circuits trimmed per the ETTP had an average annual reduction of approximately 60 percent in the number of tree-related customer interruptions and an average annual reduction of approximately 70 percent in the number of customer minutes of interruption. This is significantly better than the prior tree trimming specification, which yielded an average annual reduction of approximately 10 percent in the number of customer minutes of interruption.

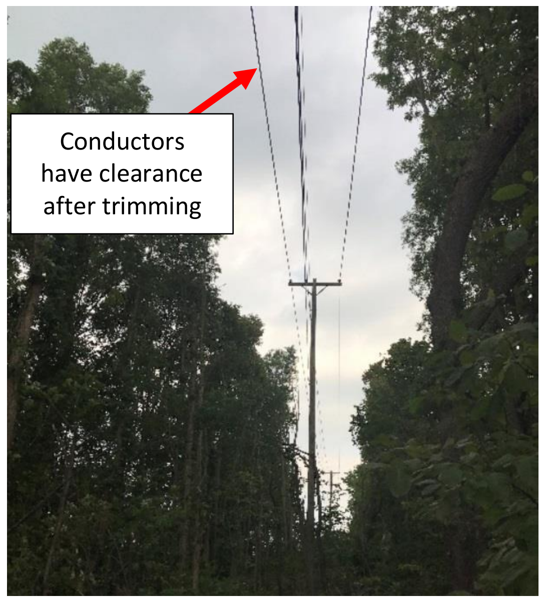
Based on benchmarking, DTEE has identified eight key attributes that define the quality of utility tree trimming programs. Exhibit 6.1.2 provides a summary of these eight attributes and how DTEE's current practices compare to industry best practices.

Exhibit 6.1.2 DTEE Tree Trimming Program Assessment

#	Program Attribute	Best Practices	DTEE Current Practice
1	Cycle Length	• Cycle length = 3-5 years based on growth study • Stay on cycle with a minimum maintenance specification in parallel with reclamation	• Target cycle = 5 years based on growth study; 2018 rate case = 10 years based on proposed funding • Focused on reclamation
2	Herbicide Use	• Cut-stump treatment for removals • Foliar spray in rural areas • Basal bark treatment	• Expansion of herbicide program in 2018
3	Planning Strategy	• Highly prescriptive planning (i.e., by units) for easement reclamation work; toggled back once steady state is achieved	• Prescriptive unit-by-unit planning for reclamation; plans to toggle back once steady state is achieved
4	Auditing Strategy	• Audit at least a statistical sample of tree work performed • Identify and remediate defects with a cycle time of days or weeks	• Auditing 100% of work • Remediation cycle time of ~18 days for new defects • Continued roll-out of Clearion work management system will result in reduced cycle time for defect remediation
5	Work Management	• Fully digital system from work assignment through billing / invoicing	• On track for completion in 2018 via rollout of Clearion work management system
6	Contract Structure	• Time & Expense contract with incentives contract for easement reclamation with a transition to fixed-price for maintenance work	• Begin transitioning to fixed-price for maintenance work in 2018
7	Resourcing	• Outsourced planners (typically sole sourced) during reclamation • In-house auditing • Crew to arborist ratio = 6-10:1	• Outsourced planners • Mix of in-house and outsourced auditors • Crew to arborist ratio = ~35:1
8	Cost per Mile	• Average cost of $20k-$40k per line mile when controlling for specification, tree density and bucket accessibility	• Average annual cost in line with industry benchmarks and driven by tree density

With respect to cost per mile, DTEE's program benchmarks well when the comparison considers work scope, system configuration, and tree density – the number of trees trimmed or removed per linear mile of overhead circuit. DTEE's work scope is intended to significantly improve the vegetation conditions on rights-of-way, and typically involves high percentages of overhead branch removals and complete tree removals as shown in Exhibit 6.1.3.

Exhibit 6.1.3 Conductor Clearance Before and After Trimming to ETTP



Based on this benchmarking work, DTEE is implementing several improvements as its tree trimming program continues to mature:

- Implementing a fully automated process for planning, trimming, auditing and invoicing (i.e., Clearion) to improve operational efficiency and reduce trimming cost per mile
- Improving contract structure to pay for work conducted on a fixed-price basis to drive productivity improvements
- Conducting a full system assessment on tree density to optimize the plan in the future
- Implementing an herbicide program to control vegetation re-growth and to reduce long-term costs

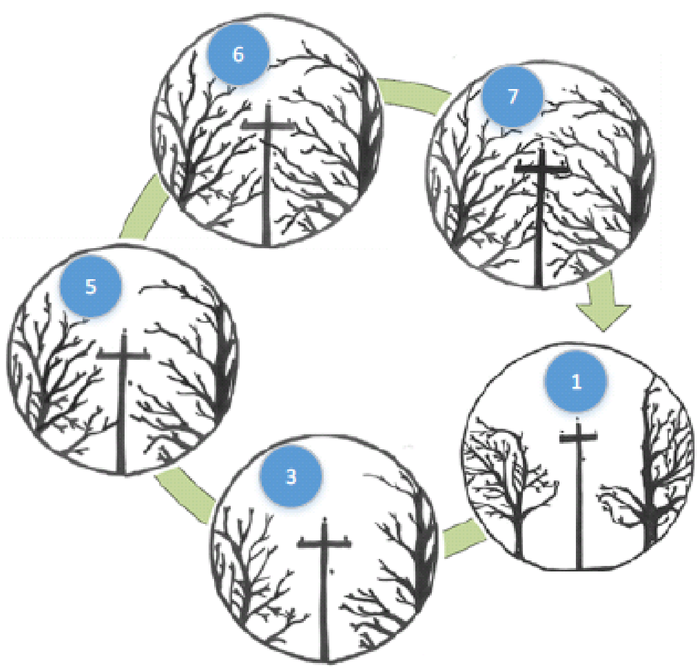
Currently, the tree trimming program has been funded to an annual investment level of approximately $84 million with inflation as shown in Exhibit 6.1.4.

Exhibit 6.1.4 DTEE Tree Trimming Five-Year Plan

Current Rate Case Allowance Minimum Investment Program	2018	2019	2020	2021	2022	5 Year Total
Projected Spend ($ millions)	$84	$86	$88	$91	$93	$442
Projected Line Miles	3,050	3,180	3,225	3,715	4,400	17,570

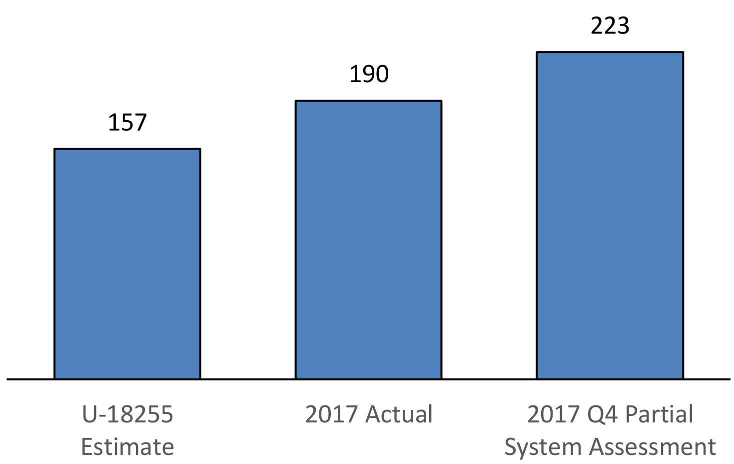
At this funding level, DTEE would not be able to trim the 6,400 miles needed per year to maintain a five-year cycle (Exhibit 6.1.4), or would have to trim the circuits less extensively (i.e., change the tree trimming specification). Either option would create a significant number of adverse impacts on system safety, reliability, resiliency, and reactive trouble and storm costs. In addition, delaying tree trimming today would increase costs to perform tree trimming in the future due to the increased number of trees growing within the right-of-way that need trimming or removing, as depicted in Exhibit 6.1.5.

Exhibit 6.1.5 Conceptual Diagram of Years Since Trimming on Tree Growth



In DTEE’s current rate case (U-18255), DTEE’s tree trimming program was based on an average density of 157 trees per line mile to be removed or trimmed. However, the actual miles trimmed in 2017 and a 2017 fourth quarter partial system assessment on nearly 8,500 circuit miles indicated that the tree density in DTEE’s right-of-way is significantly higher than the value used in Case U-18255, as shown in Exhibit 6.1.6. As tree density is the primary driver of trimming costs, the higher projected density results in an average cost per line mile of approximately $24,000 per line mile in comparison to the previously assumed average cost of $19,600 per line mile, reflecting a 20 percent increase.

Exhibit 6.1.6 Average Tree Density per Line Mile



Based on today’s estimate on tree trimming cost per line mile, an annual tree trimming investment of $84 million with inflation could be expected to provide an approximately 15 percent reliability improvement by 2032 as shown in Exhibit 6.1.7. At this funding level, DTEE does not expect to achieve a 5-year trimming cycle within the next 15 years, as illustrated in Exhibit 6.1.8.

To further refine the average tree trimming cost per line mile, DTEE will be completing a full system density assessment in early 2018.

Exhibit 6.1.7 DTEE Tree-Related System SAIDI Contribution (Minutes)

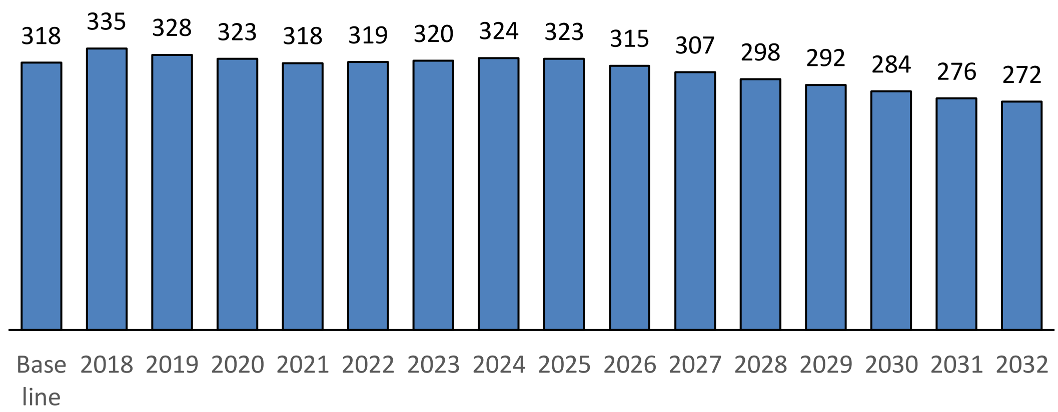
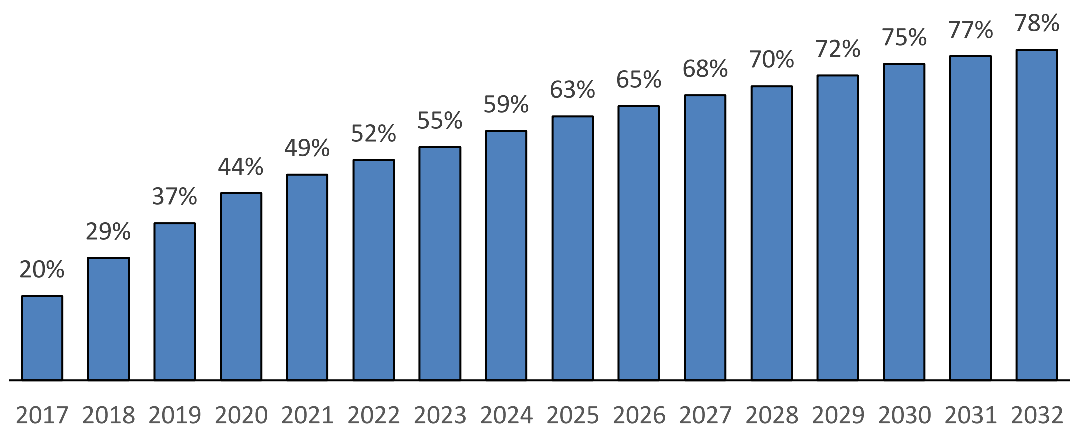
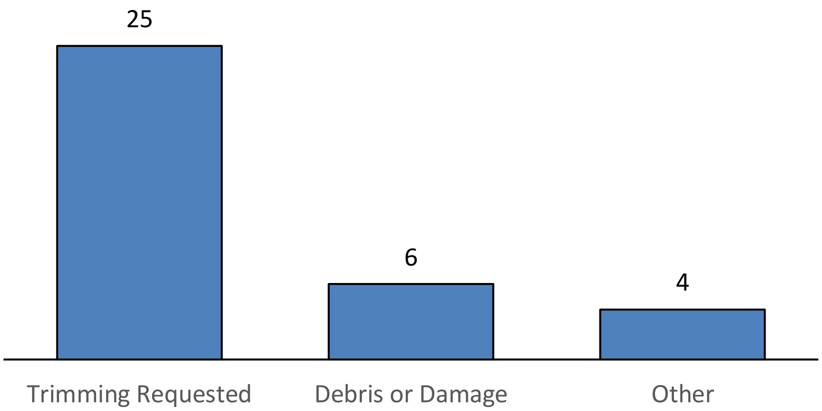


Exhibit 6.1.8 Percentage of DTEE Line Miles on a 5-year Cycle



Tree trimming is the single largest driver in addressing system safety, reliability and storm resiliency. As discussed in Section 2.5, tree trimming continues to provide the highest customer benefits of any program in the five-year investment portfolio. As demonstrated in Exhibit 6.1.9, DTEE's customers support tree trimming for its positive impacts on reliability and costs.

Exhibit 6.1.9 Tree Trimming Program Customer Complaints to the MPSC in 2017



It is imperative for DTEE to increase the annual miles of tree trimming completed and reduce the cycle time to five years. No other programs discussed in this report will have the same impact on reliability as the tree trimming program. As a result, DTEE is evaluating alternative scenarios to determine the right level of investment and program structure to optimize customer affordability and reliability experience. The program structure will allow DTEE to mitigate affordability concerns by aligning the timing between operational cost savings and investment recovery. The details of the program, including projected costs, savings, reliability improvements, and recovery mechanism will be discussed in a subsequent filing.

6.2 Preventive Maintenance Program

Preventive Maintenance (PM) is performed to achieve three primary objectives:

1) Maximize the total life expectancy of the equipment at minimum lifecycle cost while maintaining an expected level of reliability and safety.
2) Acquire timely asset performance and condition data to support trend data analysis and identify potential issues.
3) Control or reduce unplanned equipment-related outages.

An effective PM program is critical in managing asset conditions and capital and O&M costs. Risks of not performing preventive maintenance include compromised equipment performance during service and/or increased trouble costs due to equipment failing prematurely.

The PM program was developed by DTEE Engineering based on DTEE's maintenance policies which set the inspection scope and intervals based on:

- Manufacturers recommendations
- Industry standards
- Historical inspection results and equipment condition data
- Engineering studies
- Benchmarking with utility peers

Annual savings of more than $2 million in PM costs have been realized through continuous refinement of the maintenance policies. The refinements include:

- Changing inspection intervals based on engineering analyses of inspection results and equipment failures (condition-based maintenance).
- Using Substation Predictive Maintenance (SPdM) data to drive inspection timelines instead of time-based inspections, to be aligned with condition-based maintenance principles and to achieve cost efficiency.
- Reducing maintenance activities by using new technologies (e.g., smart relays).

- Coordinating inspection intervals on different equipment to reduce the need for multiple shutdowns.

Furthermore, DTEE has developed condition-based maintenance plans to maximize maintenance efficiency. By evaluating certain monitored data available on some assets, engineers can prioritize equipment on the maintenance schedule and where appropriate, may defer some equipment to the next inspection cycle. One successful example is the prioritization of substation power transformer maintenance using dissolved gas analyses and infrared thermal imaging inspections. These data are early predictors of transformer failures and drive the priority of transformer maintenance activities.

When advanced remote monitoring equipment is installed at substations, there is a potential to use breaker operation data to assess breaker and relay functions. If the equipment is assessed to be performing as designed, it may be possible to defer equipment maintenance activities. Due to the limited remote monitoring capability at substations today, DTEE has not yet been able to widely apply this methodology to defer breaker or relay inspections. DTEE's telecommunications, breaker replacement, and substation automation programs will increase the penetration of such advanced remote monitoring technology and enable the application of condition-based maintenance on breakers and relays.

As partially discussed in asset condition assessments (Section 4), DTEE's preventive maintenance programs inspect the equipment listed in Exhibit 6.2.1. The projected O&M spend associated with the distribution preventive maintenance programs is shown in Exhibit 6.2.2.

Exhibit 6.2.1 DTEE Distribution Preventive Maintenance Programs

Category	Asset	General Inspection Cycles (Years)
Substation	Circuit Breakers (Cycle depends on voltage, type, application, number of operations, etc.)	3/10/12
	120 kV Disconnect Switches	10
	Buses	10
	Substation Regulators	10
	Single Tap Substations	10
	Network Banks	5
	Network Bank Structures	10
	13.2 kV Enclosed Capacitor Banks	1
	Relays (Cycle depends on type and application)	5/7/10
	Substation Predictive Maintenance Inspections (SPdM)	3
	Batteries	1
	Transformers & Regulators (Dissolved Gas Analysis)	1
Distribution System	40 kV Pole Top Switches	8
	Overhead Distribution SCADA Reclosers and Pole Top Switches (Cycle depends on types of devices and type of control)	4/8
	Primary Switch-Cabinets (Cycle depends on type and location)	5/10/15
	Manholes	10
	Steel Towers	10
	DTEE Equipment in High Rise Structure	20
	Overhead Capacitor & Regulator Controls	1
	Overhead Distribution Device (SCADA) Batteries	4
	Voltage Controls	1

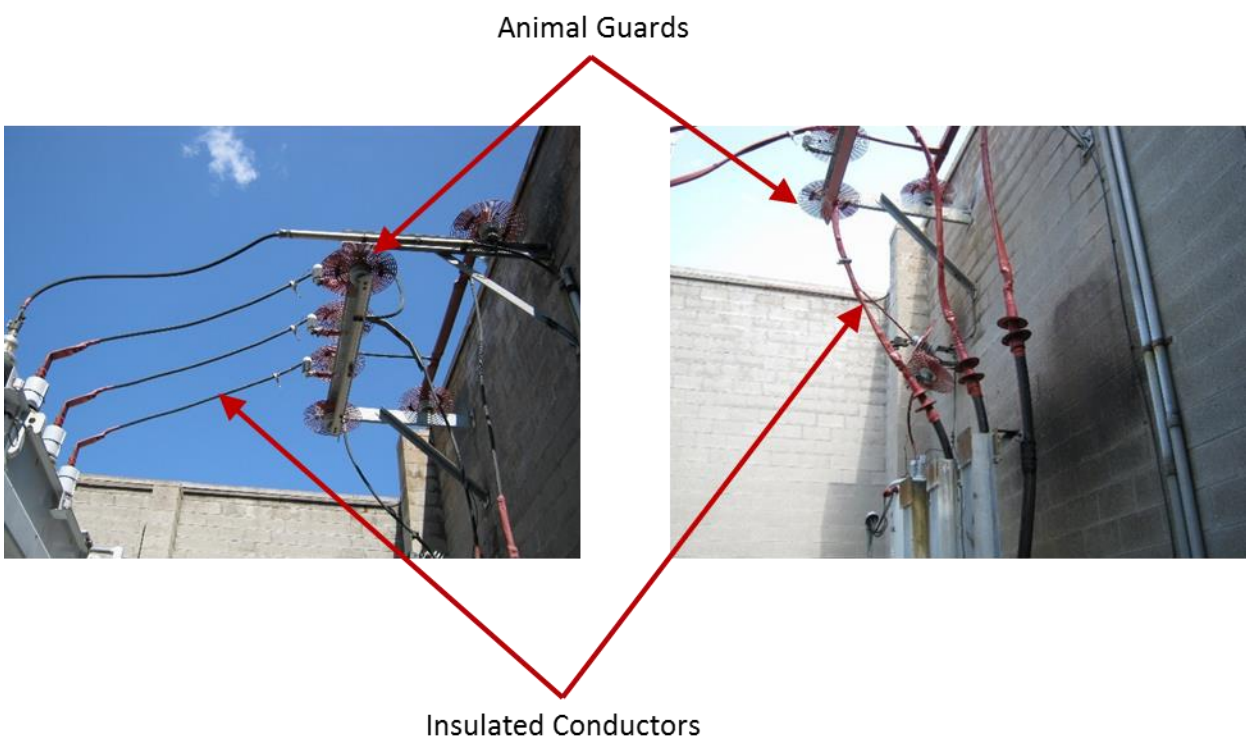
Exhibit 6.2.2 Projected Preventive Maintenance Programs O&M Spend

	2018	2019	2020	2021	2022	5-Year Total
Preventive Maintenance Spend ($ million)	$12	$12	$12	$13	$13	$62

6.3 Animal Interference Prevention

DTEE takes measures to minimize animal interference. Animal interference accounts for less than one percent of the SAIDI minutes on average. All new substations are designed and built with animal protection. In existing substations, where multiple animal interference events occur, the equipment is retrofitted with animal protection devices. Animal protection consists of either installing guards or insulating conductors to prevent phase-to-phase or phase-to-ground faults due to animals bridging the insulators or open-air clearance (Exhibit 6.3.1). Similar devices and insulated conductors are installed on overhead equipment where animal interference is problematic.

Exhibit 6.3.1 Animal Protection in Substations



7 Key Enablers

7.1 Industry Benchmarking

DTEE Distribution Operations uses benchmarking to compare its performance with industry peers and learn best practices. DTEE takes an active role in the industry in structuring and improving these benchmarking studies so that the results can be more meaningful and useful to all participants. DTEE participates in annual benchmarking exercises and surveys, which allow DTEE and peer utilities to share insights that may not be apparent from the survey data.

Various criteria are used to determine the best peer set for DTEE to be compared against based on attributes such as location, number of customers, vegetation, age of infrastructure, climate, etc. In many cases, DTEE engages in additional dialogue with these peers to collect and compare ideas beyond the survey data.

DTEE uses the benchmark data to identify performance gaps to its peers and establish metrics to close those gaps. The gaps are researched in greater detail, often with specific outreach to other utilities that benchmark well in the specific metric of interest. The detailed gap analysis helps determine the impact that structural issues (e.g., level of system automation) and operational issues (e.g., high volume of tree events) have on DTEE's performance compared to our peers. Through this process, improvement opportunities are identified and plans are developed for the most critical gaps. Once the plans are approved and implemented, progress is monitored to verify that the intended results are being achieved.

DTEE uses benchmarking to develop annual and multi-year targets for key operational and reliability metrics, with the goal of improving and attaining long-term aspirational targets. This process helps DTEE create "line of sight" between operational improvements and the aspiration of becoming the best-operated energy company in North America.

7.2 Workforce Planning

DTEE understands the fundamental importance its people play in operating, maintaining and improving the electric grid and works to proactively manage its changing workforce needs through a rigorous workforce planning process. Exhibit 7.2.1 illustrates DTEE's overall workforce planning process and Exhibit 7.2.2 provides the details on how the overall process translates into detailed analyses and recommendations.

Exhibit 7.2.1 DTEE's Strategic Workforce Planning

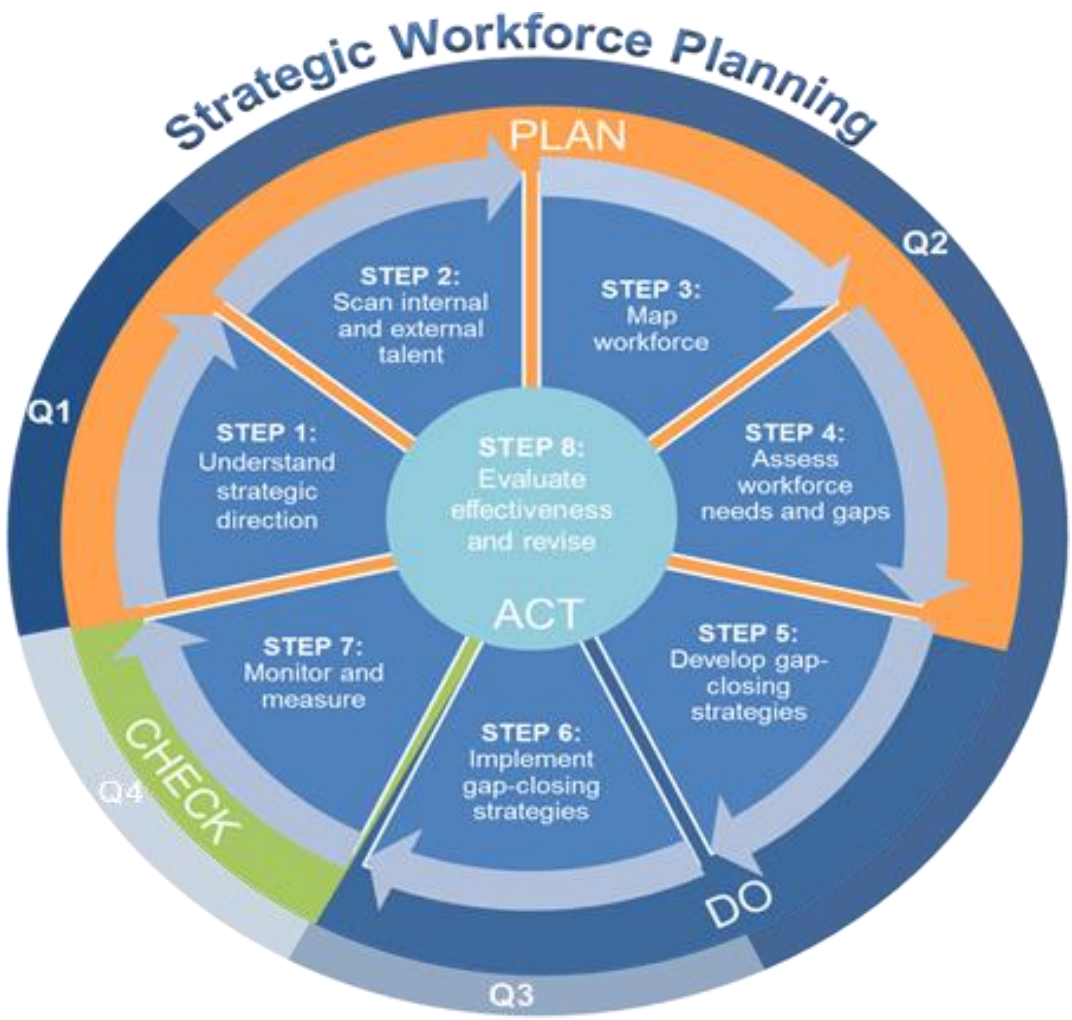
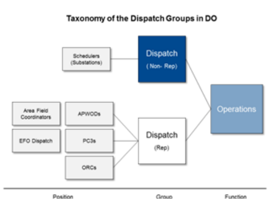


Exhibit 7.2.2 Strategic Workforce Planning Detailed Process (Illustrative)

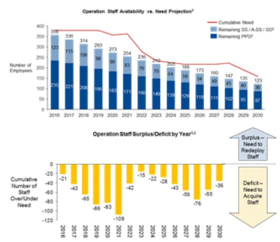
Develop Position Taxonomy → **Develop Workforce Need and Availability Profiles** → **Determine Workshop Needs** → **Conduct Workshops**

Develop Position Taxonomy



- Over 100 DO positions categorized into 51 groups and 6 functions

Develop Workforce Need and Availability Profiles



- Workforce demand for each function calculated based on work drivers for each group
- Workforce attrition modeled based on data from HR
- Capacity gaps identified

Determine Workshop Needs

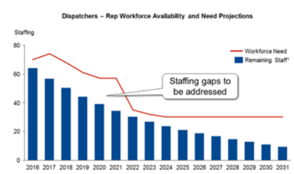
Workshop

Monitor and Backfill as Needed

Attrite with No Backfill

- 11 groups identified where workshops needed
- 8 groups identified as "Backfill as Needed"
- 6 groups identified for no backfill

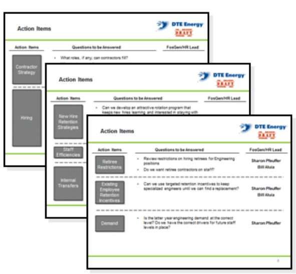
Conduct Workshops



- Workshops focused on identifying ways to address *Strategic Hiring Needs* and *Manage the Need for Staff*
- Multiple levers identified in each category to address staffing gaps

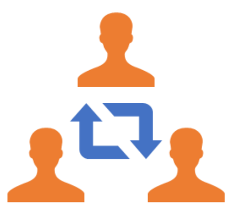
Conduct Recommendation Follow Up → **Review Recommendation Feasibility** → **Conduct an Integrated Review of Recommendations** → **Engage the Labor Unions**

Conduct Recommendation Follow Up



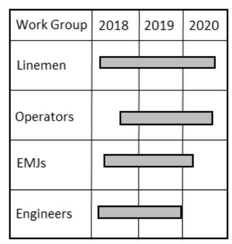
- Follow up on decisions within the workshops
- Teams assigned to answer key questions to determine the feasibility of recommendations

Review Recommendation Feasibility



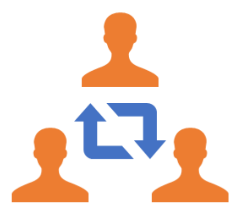
- Recommendations reviewed by the DO leadership team
- Determinations made on whether components are consistent with the overall labor strategy

Conduct an Integrated Review of Recommendations



- Recommendations reviewed across groups to determine dependencies and connection points
- Workforce plan established

Engage the Labor Unions



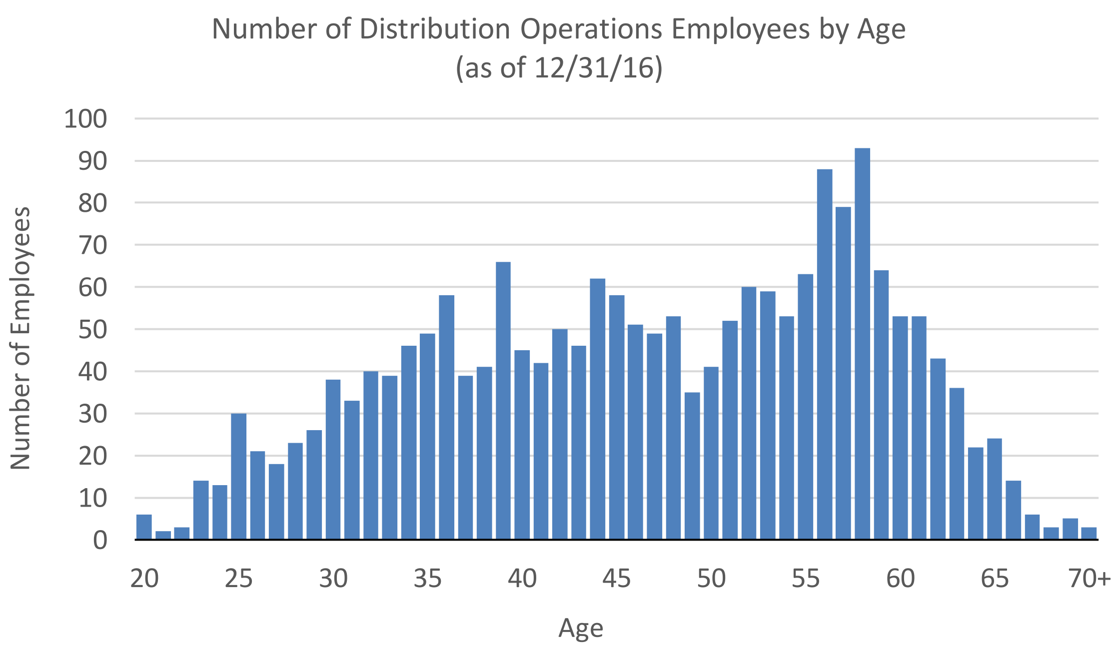
- DO leadership engages union leadership for mutual understanding and implementation of workforce plan

In developing its workforce plan and strategy, DTEE focuses on:

- Understanding the drivers of attrition, which enables a projection of attrition levels for different employee groups
- Understanding the drivers of work for each employee group and how the investment plans will impact the volume of work and number of employees required
- Identifying talent pipelines for each employee group and the lead time it takes to recruit, hire, and train those employees
- Understanding the impact of productivity initiatives including the utilization of new technologies
- Developing a strategic plan for the use of contract labor to supplement the DTEE workforce to address work peaks and leverage outside expertise

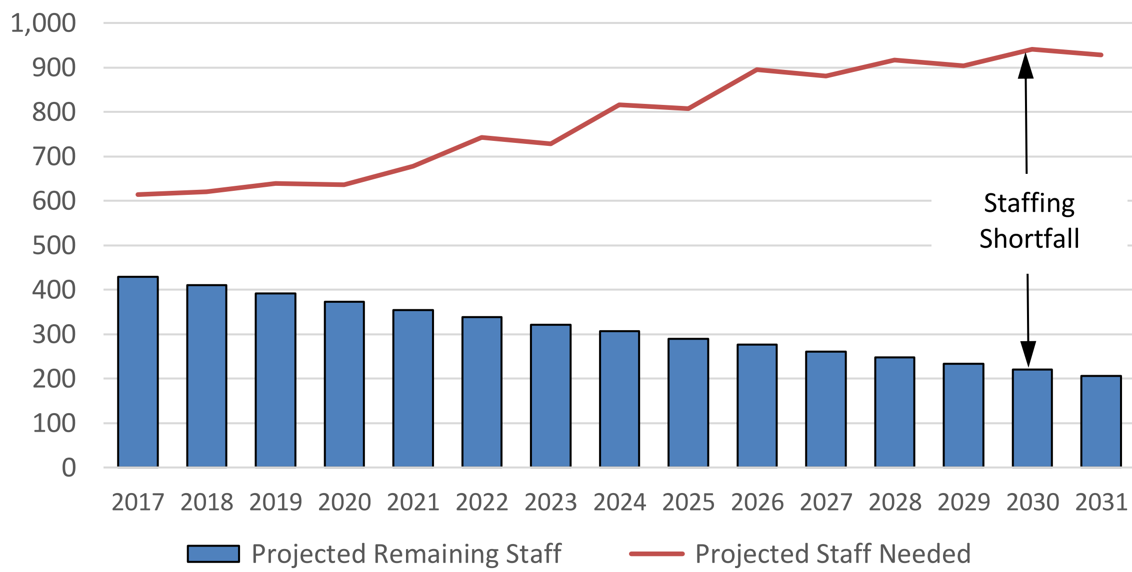
The main driver of attrition for employee groups within Distribution Operations is retirement. DTEE's workforce is aging and a significant increase in attrition in the coming years is expected. Exhibit 7.2.3 shows the employee age distribution in DTEE's Distribution Operations.

Exhibit 7.2.3 Workforce Age Distribution in DTEE's Distribution Operations



It is projected for many employee groups that 50 percent or more of the workforce will retire or leave the company within the next 15 years, driven by the aging workforce and increased job opportunities within the region. As one example, Exhibit 7.2.4 shows the projected 54 percent attrition for linemen and increased resource needs in the future.

Exhibit 7.2.4 Preliminary Analysis on DTEE Overhead Linemen Workforce Gaps



The strategic investment plan dictates the type and volume of work required in the future. In conjunction with the attrition rate for each work group, potential shortfalls can be estimated. These shortfalls can then be addressed through hiring additional employees, strategic reliance on contract labor, and technology innovation.

Advanced planning is required to meet the required workforce needs in a cost-effective way and allow for sufficient knowledge transfer. For certain roles, potential employees can be sourced and trained quickly, but for others, an understanding of the talent landscape and training requirements are critical. For many skilled trades, there is a significant apprenticeship period required before employees can be fully productive and safe members of the team. For other roles, there is significant competition for talent locally as well as nationally, especially when the economy is strong. Understanding the talent market and training requirements for the differing roles is crucial to the workforce planning strategy. Additionally, as DTEE looks to further modernize the electric grid, the skills required for certain roles will change. A prime example is the change from legacy substation controls with wires, paper schematics, and separate mechanical devices to modern controls based on standards such as IEC 61850, which are comprised of minimal wiring, fiber optic computer networks, interoperable data models, and logic programming. With these changes, the need for employees with strong analytical and technical backgrounds will continue to grow.

Additionally, part of developing the workforce plan for each employee group involves projecting what impact, if any, future improvements in productivity will have on our workforce needs. Increased productivity, either through improved technology or more efficient processes, will increase the efficiency of employees, enabling them to accomplish more tasks per day. Productivity improvement rates vary based on the employee group and their specific tasks, historical improvement rates, and projections for specific technologies or process improvement initiatives.

The last piece required to develop the workforce plan is determining how to best leverage outside contractors to supplement our internal workforce. The use of contractors has numerous benefits. It allows DTEE to quickly ramp up or down its workforce during times of fluctuating need, it provides access to specific skills that the organization may not need to maintain in-house, and it can help mitigate unexpected attrition.

Combining these initiatives allows DTEE to put together a fully integrated workforce plan. This plan is monitored and adjusted as strategic objectives change. Having these plans in place allows DTEE to be proactive in how it addresses its future talent needs and ensures we have the people we need to continue serving our customers.

7.3 Capital Project Approval and Planning Process

Projects are approved through a structured and rigorous process to ensure that the best engineering solutions are developed and capital is prudently invested. As described in this report, projects are varied in nature, from relocating distribution circuits to building new substations.

By leveraging the available Distribution Design Orders and the combined experiences of the engineering and operations teams, a project is developed by identifying and evaluating a range of alternatives. All projects are discussed among engineers, project designers and field construction leaders within the project region for review and approval. For large projects, the project engineer presents project options to representatives from all four regions as well as equipment and construction experts. This discussion includes a more in-depth review of the project with a strong focus on technical details.

The next step is to present the project to engineering leadership and subject matter experts from various areas including Substations, Service Operations, Equipment Engineering, Planning Engineering, Standards, etc. During the discussion, the project engineer presents the project including the project drivers, scope of work, technical feasibility, estimated cost, and expected benefits. Questions are discussed by all stakeholders with the goal of identifying the best possible solution for the overall electrical system.

Finally, the engineer presents the project to the Project Governance Review Board (PGRB) to obtain a final review and approval of the scope, costs and schedule from Distribution Operations' leadership team (Business Unit Vice President and Directors). Prioritization of the project is also reviewed to ensure it aligns with Distribution Operations' Investment and Maintenance Plan. Some capital projects require additional review from Staff functions, the Company's senior executives or the Board of Directors, depending on size.

Upon approval from the PGRB or the appropriate level, a project manager is assigned and the project then follows the project management through field execution. This includes every aspect of the project from obtaining property or rights-of-way, municipal approvals, permitting, construction, inspection, testing and in-commissioning. Substation projects require the siting and purchase of available land that is suitable for construction, environmental testing, municipal approval and permitting. Circuit work could potentially require obtaining easements or rights-of-way from customers, surveys by MISS DIG and manhole pumping/testing. The project scope and location determine the necessary customer or municipal rights-of-way, easements, approvals or permits. Any issues in completing these steps can result in delays to the project schedule, cost increases and redesign of the project. Any major deviations in project schedule, cost and scope of work need to be presented to the PGRB for change review and approval. The project managers closely monitor the work and schedule as the project moves through all phases to completion.

7.4 Distribution Design Standards

DTEE maintains a comprehensive set of Distribution Design Standards (DDS) that are the basis for the electrical system design and construction. These standards have evolved as DTEE's distribution system has evolved over time. They incorporate industry best practices gained from DTEE's involvement in the Edison Electric Institute (EEI), Electric Power Research Institute (EPRI) and Institute of Electrical and Electronics Engineers (IEEE). The DDS are reviewed and updated based on new equipment or technologies, as dictated by developments in the industry, or based on asset and system performance / field experience. The DDS are the "single design source of knowledge" that is shared throughout DTEE.

On rare occasions, the planning engineer may encounter extenuating circumstances where implementation of the DDS may be impossible, impractical or result in excessive cost. In these cases, the planning engineer may develop an alternate approach. This exception to the DDS must be presented to a technical peer group for discussion and review. If acceptable to the peer group, the exception is then presented to the director of Electrical Engineering for review and approval before it is implemented. Exceptions to the DDS are tracked as a basis for potential future modifications to the DDS.

The DDS consist of specific Distribution Design Orders (DDOs), which address individual topics within the DDS. In addition, there are Job Aids to supplement the DDOs. The Job Aids contain step-by-step instructions and any additional information useful for the planners or engineers.

The DDOs dictate the equipment to be used. The equipment specified considers many factors, including continuous rating, contingency rating, fault capability, standard sizes available from manufacturers, impact on system operability (capacity for switching and jumpering) and efficiencies in inventory.

Over the years, the Company has increased the minimum standards for construction to further harden the system and better sustain impacts from inclement weather and tree interference. These improved design standards, grade B construction, are based on NESC (National Electric

Safety Code) factors and industry best practices. The structural upgrades include using armless construction or fiberglass crossarms, larger conductors, polymer insulators that are four times stronger than pin insulators, and standard poles that are one and a half times stronger, as illustrated in Exhibit 7.4.1. These structural upgrades are intended to standardize overhead construction materials and specifications to significantly streamline the design and construction of overhead facilities, and to increase the structural strength to improve system reliability and storm resiliency. In addition, new circuit designs are established to improve circuit configuration and allow crews to more quickly restore customers during outage events. Examples of these types of design standards include ensuring valid jumpering points on circuits with properly sized operating equipment, installing fault indicators to reduce outage patrol time and installing loop schemes for automatic restoration of sections of circuits during an outage, as illustrated in Exhibit 7.4.2.

The topics covered by the DDS and DDO are summarized in Appendix IV.

Exhibit 7.4.1 DDO Structural Upgrades to Distribution Circuits
(Stronger Poles, Stronger Conductors, and Polymer Insulators)

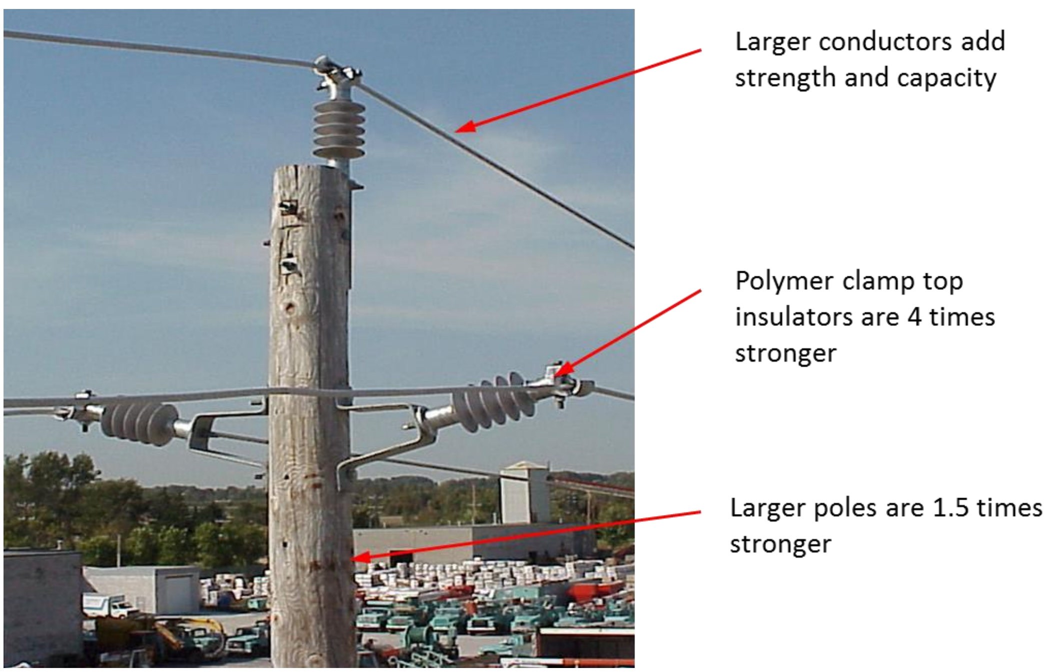
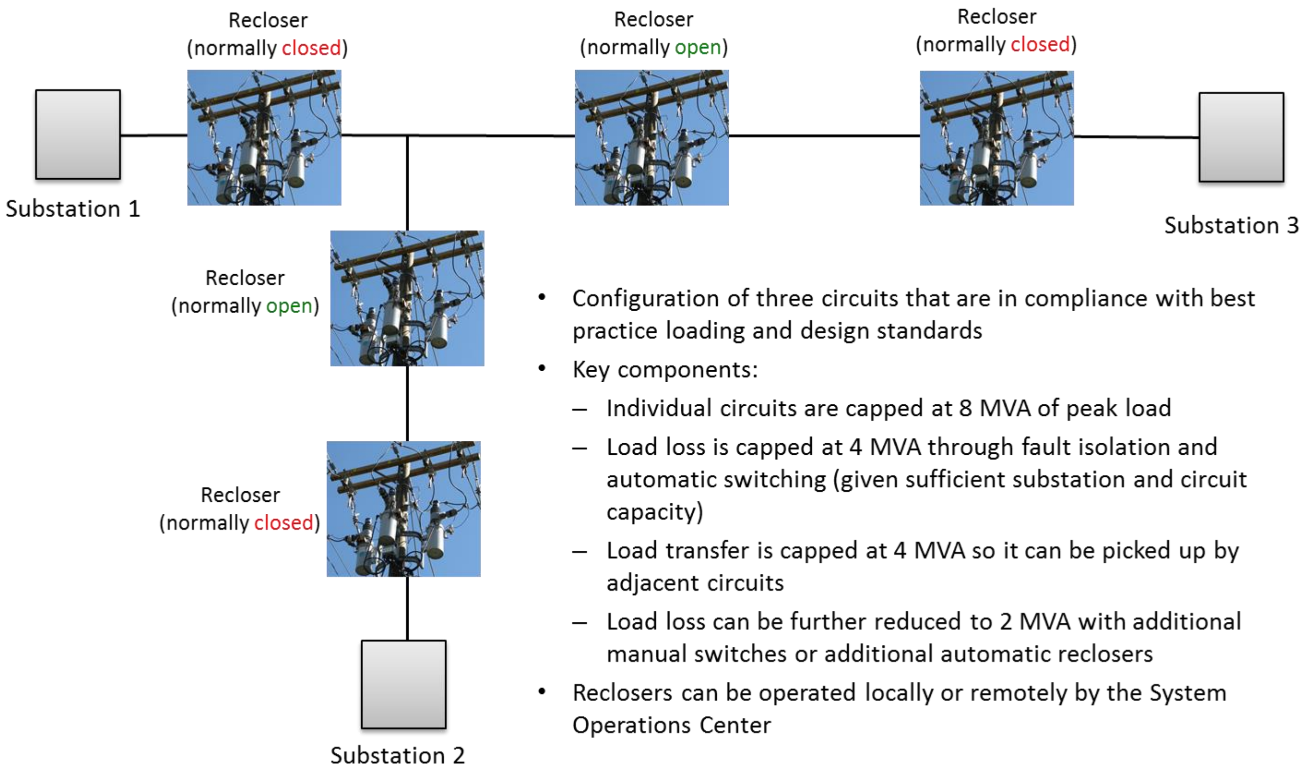


Exhibit 7.4.2 13.2 kV DDO Restore-Before-Repair Design

(Automatic Loop Schemes)



- Configuration of three circuits that are in compliance with best practice loading and design standards
- Key components:
  - Individual circuits are capped at 8 MVA of peak load
  - Load loss is capped at 4 MVA through fault isolation and automatic switching (given sufficient substation and circuit capacity)
  - Load transfer is capped at 4 MVA so it can be picked up by adjacent circuits
  - Load loss can be further reduced to 2 MVA with additional manual switches or additional automatic reclosers
- Reclosers can be operated locally or remotely by the System Operations Center

7.5 Replacement Unit and Spare Parts Management

A replacement unit is an entire asset whereas a spare part is a component of an asset. A replacement unit can be as generic and simple as a crossarm, to as specific and significant as a substation power transformer.

Replacement Units

For the generic replacement units, inventory is typically controlled through automatic reordering when a specified inventory level is reached. The reorder level is based on past usage and considers any surge in the number of units that may be required due to storm damage.

Major equipment (transformers, breakers, switchgear, etc.) typically has a long lead time, is unique to the location or installation and is relatively expensive.

For example, substation power transformers exist on the system for various voltage transformations: 120:40 kV, 120:24 kV, 120:13.2 kV, 120:4.8 kV, 40:13.2 kV, 40:8.3 kV, 40:4.8 kV, 24:13.2 kV, 24:4.8 kV, as well as some voltages unique to peaker units or large customers. In addition, there are locations where electrical clearance distances limit the physical size (thus the power rating) of the unit that can be installed. A significant and unexpected increase in substation power transformer failures of a certain voltage and size could result in extended customer outages and/or reconfiguration of the system and loads for extended periods until additional units can be obtained. The typical lead time for a substation power transformer is 10-12 months or longer.

As such, major equipment such as transformers or breakers have a dedicated engineer to manage asset performance and inventory based on known new projects, planned replacements, and any unplanned replacements based on historic failure rates and equipment condition assessments.

Some major equipment, such as switchgear, is built to specifications for individual substations and circuit configurations. Therefore, DTEE does not keep inventory of this equipment; the purchase order is placed after conceptual engineering for the project, approximately 9-12 months prior to the planned installation to ensure on-time delivery of the equipment for construction.

Spare Parts

Some assets have serviceable components (e.g., breakers, pole top switches, reclosers, etc.). For example, pole top switch components include automatic controls, an operating mechanism, and the switch itself. Each of these may have serviceable sub-components. An inventory of spare parts provides a cost-effective and expedient way to restore the asset to full operation depending on the extent of the failure.

Compounding the complexity of spare parts inventory is the existence of many different manufacturing models and vintages. There are nearly 2,500 distinct spare parts for substation breakers alone. Newer equipment generally has fewer replacement parts. For instance, the obsolete FK breaker has 37 spare parts whereas its replacement model has only five and is designed for easier maintenance of those parts. Inventories of most spare parts are controlled through automatic reordering when specified inventory levels are reached. Some of the spare parts are managed based on past failure history and recommended maintenance activities.

When the spare parts for a specific make, model and vintage become excessively costly or are no longer available from manufacturers/vendors, it typically results in replacement rather than repair.

8 Potential Capital Cost Recovery Mechanisms

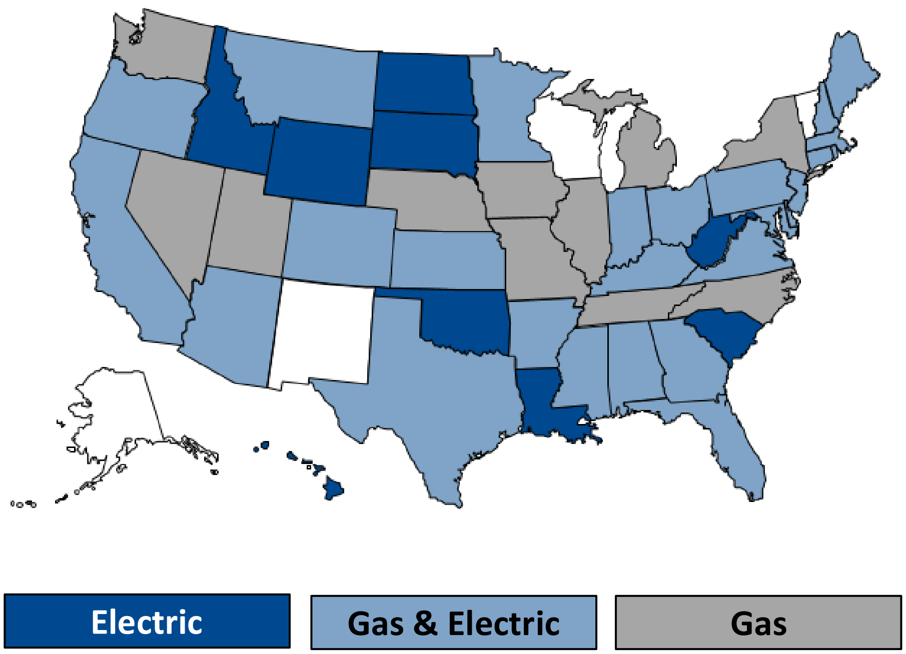
In this report, DTEE has laid out its detailed plan of required investment programs and projects to ensure the safety and reliability of its electric grid. As discussed, many of these investment programs will be phased in as part of a multi-year investment plan, requiring significant capital and resources to engineer, plan, and execute. To ensure an efficient and effective rollout of these improvement programs, DTEE will work with the MPSC Staff on a potential mechanism for recovery of capital associated with these investments.

8.1 Commonality of Similar Rate Mechanisms

Across the United States, it is becoming increasingly more common for utilities to use multi-year recovery mechanisms to recover costs associated with providing electric services to their customers. A study in 2015 by the Edison Electric Institute noted that 70% of states have implemented capital cost recovery mechanisms for their electric utilities, as shown in Exhibit 8.1.

The size and structure of these mechanisms vary from utility to utility, but it is not uncommon for utilities to have several of these mechanisms in place at one time. While DTE Electric does not have a multi-year rate mechanism covering its reliability capital investments, DTE Gas does have an Investment Recovery Mechanism (IRM) in place for recovery of capital investments related to main renewal and meter move-out programs. This mechanism has been in place for five years and has been instrumental in allowing DTE Gas to continue its ambitious programs to provide safe and reliable gas service to their customers. The DTE Gas IRM provides many lessons learned as DTEE continues to work with the MPSC on a potential DTEE mechanism.

Exhibit 8.1 Recent Energy Utilities Capital Cost Recovery Mechanisms Precedents by State



8.2 Potential Structure of DTE Electric Mechanism

The potential mechanism could be structured to capture capital costs for programs related to the improvement of the electric grid. Many of the programs that make up the four key investment pillars discussed in Sections 2.3 and 2.4 could be included. DTEE will work with the MPSC Staff to determine potential programs to be included based on the following criteria:

1. Align with the priorities of our customers and have a positive impact on reliability, safety, and resiliency
2. Have a well-defined scope, cost, and execution plan, and thus are highly likely to be executed successfully
3. Provide tangible benefits to customers that can be measured and tracked

9 Conclusion

DTEE appreciates the Michigan Public Service Commission's foresight and leadership, which led to the submission of this Five-Year Investment and Maintenance Plan. DTEE is facing the same aging infrastructure challenges that many others are experiencing. The American Society of Civil Engineering says the country has a lot of work to do to upgrade roads, bridges, dams and the energy grid. As the American Society of Civil Engineering pointed out in its 2017 Infrastructure Report Card,

> "*The U.S. energy sector faces significant challenges as a result of aging infrastructure, including supply, security and reliability, and resiliency issues in the face of severe weather events, all posing a threat to public safety and the national economy.*"

Michigan is among the states most in need of infrastructure investments. The 21st Century Infrastructure Commission, which was created by Governor Snyder's Executive Order 2016-5, concluded that:

> *"Michigan's infrastructure is aging, and maintenance has been deferred for decades, leaving us in a state of disrepair. Failing infrastructure interrupts daily life, slows commerce, jeopardizes public health, pollutes the environment, and damages quality of life."*

The rebound in the Southeast Michigan's economy and the revitalization of many of its business and population centers require that the electrical infrastructure be upgraded to continue to serve customers in a safe and reliable manner. In addition, as new technology comes to the energy sector (e.g., distributed resources, storage, demand response, etc.), the grid must be upgraded in a way that will enable evolving customer and public policy needs to be met.

To better serve Michigan's residents and businesses for many decades to come, DTEE has developed a Distribution Investment and Maintenance Plan based on detailed asset condition assessments and comprehensive benefit cost analyses to optimize system improvements on risk, reliability and costs.

DTEE's Investment and Maintenance Plan is built on four pillars: Tree Trimming, Infrastructure Resilience & Hardening, Infrastructure Redesign, and Technology & Automation. This report provides the details of the plan for the five-year period of 2018-2022, including asset and electrical system issues that drive the investment and maintenance programs and the projected benefits associated with the plan.

Exhibit 9.1 DTEE Distribution Investment and Maintenance Framework

Tree Trimming

- Enhance the tree trimming plan – with a particular focus on specifications and quality of work – to improve reliability and lower trouble costs

Infrastructure Resilience & Hardening

- Harden the 4.8 kV system to address customer outages and increase storm resiliency
- Install sectionalizing devices to reduce outage size and restoration time
- Replace aging infrastructure to reduce major failure events

Infrastructure Redesign

- Eliminate substation loading constraints to serve area load growth and enhance operational flexibility
- Convert the existing 4.8 kV and 8.3 kV electric circuits to a modern 13.2kV distribution system

Technology & Automation

- Invest in remote monitoring and control devices, an Advanced Distribution Management System (ADMS), and System Operations Center modernization
- Upgrade the smart meter network, enhance cybersecurity, and improve distributed energy resource integration

Objectives

- Reduce Risk
- Improve Reliability
- Manage Costs

DTEE strives to provide safe, reliable, and affordable electricity to our customers and ensure superior customer satisfaction. DTEE's ongoing efforts to continuously improve our services, programs and processes have resulted in significant improvements in customer satisfaction since 2007. DTEE measures customer satisfaction through J.D. Power, a global marketing information company that represents the voice of the customer, and their extensive consumer studies in the utility industry. DTE Energy ranked highest in the 2017 J.D. Power Electric Utility Business Customer Satisfaction study in the Midwest large utility segment and fifth in the nation. DTE Energy ranked second in the 2017 J.D. Power Electric Utility Residential Customer Satisfaction study in the Midwest large utility segment and fifteenth in the nation. Our goal is to achieve and maintain the number one ranking.

The Company is confident that successful execution of the plan will result in a modernized electric distribution system that maximizes our customer benefits, meets the needs of the 21st century economy, and achieves best-in-class customer satisfaction.

Appendix I Interruption Cost Estimate Calculator

The Interruption Cost Estimate Calculator (ICE) is a tool for estimating the interruption costs and/or the benefits associated with reliability improvements, developed by Nexant through funding by the Lawrence Berkeley National Laboratory and the U.S. Department of Energy. The tool is accessible at (http://www.icecalculator.com/). The SAIFI, SAIDI, and CAIDI outputs from DTEE's Capital Reliability Model are used as inputs to the ICE tool.

First, a "Constrained Investment scenario" Capital Reliability model is constructed with only the "base capital" as defined in Section 2.4. The model outputs the overall SAIFI, SAIDI, and CAIDI impact based on the contribution of each of the individual programs and projects. The SAIFI, SAIDI, and CAIDI values are inputs to the ICE tool along with the additional parameters unique to DTEE (see tables below). The ICE tool then calculates the total cost of sustained interruptions to DTEE customers.

The above process is then repeated using the "Five-Year Investment scenario" annual spends, as provided in Section 2.4. The difference in the ICE tool cost of sustained interruptions to customers between the "Five-Year Investment scenario" and the "Constrained Investment scenario" is the projected savings to DTEE customers.

This analysis is conducted with different assumptions on potential reliability experience for commercial & industrial customers as compared to residential customers. Based on these different assumptions, DTEE estimated a range of economic benefits for our customers from the five-year investment and maintenance plan.

It is important to note that the average costs of outages for large commercial & industrial customers assumed in the ICE tool appear to be lower than DTEE's knowledge of the large commercial & industrial customers in its service territory. Therefore, the estimated economic benefits from the ICE tool could be conservative for DTEE's customers.

The inputs to the ICE model are shown below, reflecting the input screen of the ICE tool.

Exhibit A-1 Key ICE Model Parameters for DTEE

Customer Category	Approximate Number of Customers	Average Annul Usage (MWh)	Basis
Medium and Large C&I	43,249	661.2	DTEE 2016
Small C&I	155,875	11.0	DTEE 2016
Residential	1,925,200	8.1	DTEE 2016

C&I Industry Percentages	Medium and Large C&I	Small C&I	Basis
Construction	2%	10%	ICE Calculator Michigan default - Census
Manufacturing	20%	6%	ICE Calculator Michigan default - Census
All Other Industries	78%	84%	ICE Calculator Michigan default - Census

Percent of C&I Customers with:	Medium and Large C&I	Small C&I	Basis
No or Unknown Backup Equip	55%	71%	ICE Calculator Michigan default - Census
Backup Gen or Power Cond	37%	26%	ICE Calculator Michigan default - Census
Backup Gen and Power Cond	8%	3%	ICE Calculator Michigan default - Census

Residential Customer Characteristics	Estimate		Basis
Median Household Income	$ 48,888		ICE Calculator Michigan default - Census

Distribution of Outages by Time of Day	Estimate		Basis
Morning (6 am to 12 pm)	24%		DTEE 2012-2016 Average
Afternoon (12 pm to 5 pm)	27%		DTEE 2012-2016 Average
Evening (5 pm to 10 pm)	29%		DTEE 2012-2016 Average
Night (10 pm to 6 am)	20%		DTEE 2012-2016 Average

Distribution of Outages by Time of Year	Estimate		Basis
Summer (Jun thru Sep)	47%		DTEE 2012-2016 Average
Non-Summer (Oct thru May)	53%		DTEE 2012-2016 Average

Appendix II SAIFI and SAIDI Distribution Curves

Exhibits A-2 to A-5 are circuit SAIFI and SAIDI distribution curves. For each index, there are two exhibits – one on a system basis and the other on a circuit basis. All the curves have the same general shape.

For the system-based curves, the reliability index numerator is the number of interruptions or minutes of interruption (for SAIFI and SAIDI, respectively) for each circuit; the denominator is the total number of DTEE customers served.

For the circuit-based curves, the reliability index numerator is the number of interruptions or minutes of interruption (for SAIFI and SAIDI, respectively) for each circuit; the denominator is the number of DTEE customers served for each circuit.

The system-based indices show the contribution of any circuit to the overall system performance. The circuit-based indices are more indicative of the actual customers' experience on a circuit. Examples of circuit-based and system-based calculations are shown in the following tables.

Example: Circuit 1 Outage History

Circuit	Customers Served	Outage Number	Customers Interrupted	Outage Duration in Minutes	Customer-Minutes Interrupted
Circuit 1	500	1	500	60	30,000
Circuit 1	500	2	250	180	45,000
Circuit 1	500	3	250	180	45,000
Total	**500**		**1,000**		**120,000**

Example: Circuit 2 Outage History

Circuit	Customers Served	Outage Number	Customers Interrupted	Outage Duration in Minutes	Customer-Minutes Interrupted
Circuit 2	2,000	1	2,000	90	180,000
Circuit 2	2,000	2	2,000	150	300,000
Total	**2,000**		**4,000**		**480,000**

Example: Circuit 3 Outage History

Circuit	Customers Served	Outage Number	Customers Interrupted	Outage Duration in Minutes	Customer-Minutes Interrupted
Circuit 3	3,000	1	1,500	90	135,000
Circuit 3	3,000	2	750	150	112,500
Circuit 3	3,000	3	3,000	120	360,000
Circuit 3	3,000	4	750	150	112,500
Total	**3,000**		**6,000**		**720,000**

Example: SAIFI Calculations (Assume system serves 2,000,000 customers)

Circuit	Customers Interrupted	Circuit Customers Served	Circuit SAIFI	System Customers Served	System SAIFI
Circuit 1	1,000	500	= 1,000/500 = 2.0	2,000,000	= 1,000/2M = 0.0005
Circuit 2	4,000	2,000	= 4,000/2,000 = 2.0	2,000,000	= 4,000/2M = 0.0020
Circuit 3	6,000	3,000	= 6,000/3,000 = 2.0	2,000,000	= 6,000/2M = 0.0030

Example: SAIDI Calculations (Assume system serves 2,000,000 customers)

Circuit	Customer-Minutes Interrupted	Circuit Customers Served	Circuit SAIDI	System Customers Served	System SAIDI
Circuit 1	120,000	500	= 120,000/500 = 240.0	2,000,000	= 120,000/2M = 0.060
Circuit 2	480,000	2,000	= 480,000/2,000 = 240.0	2,000,000	= 480,000/2M = 0.240
Circuit 3	720,000	3,000	= 720,000/3,000 = 240.0	2,000,000	= 720,000/2M = 0.360

Exhibit A-2 Circuit SAIFI Distribution – System Basis

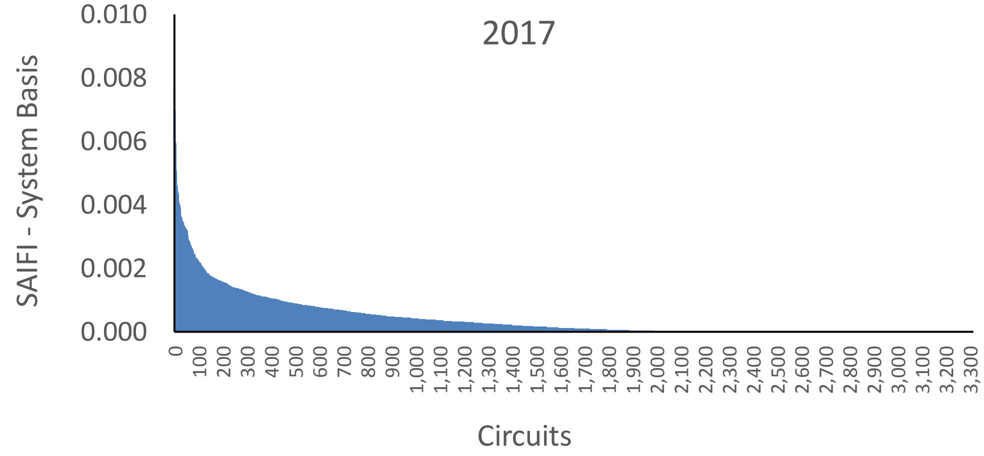


Exhibit A-3 Circuit SAIFI Distribution – Circuit Basis

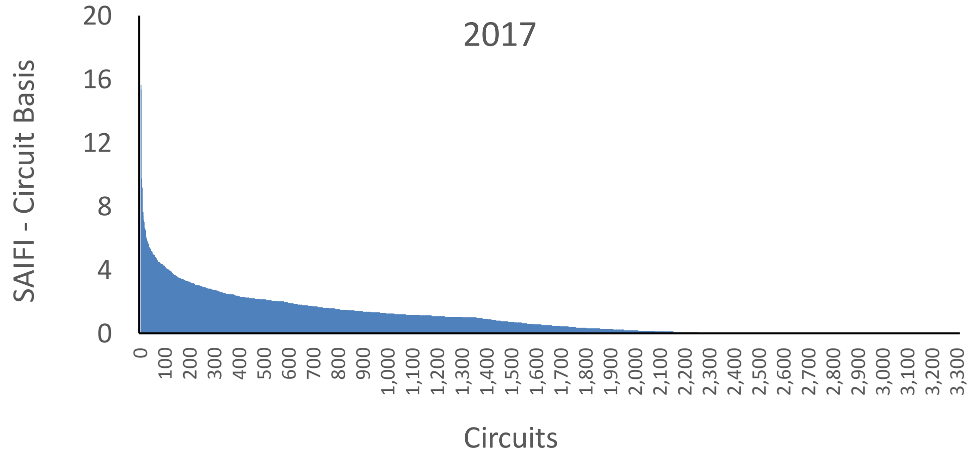


Exhibit A-4 Circuit SAIDI Distribution – System Basis

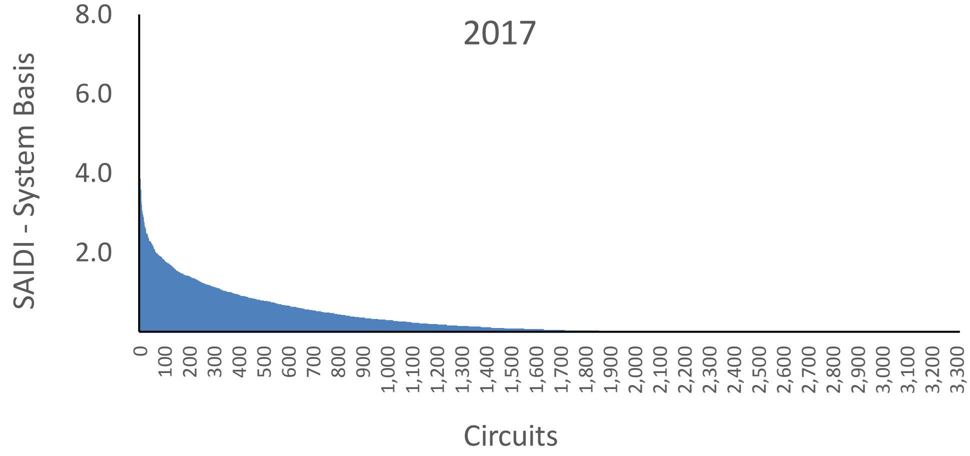
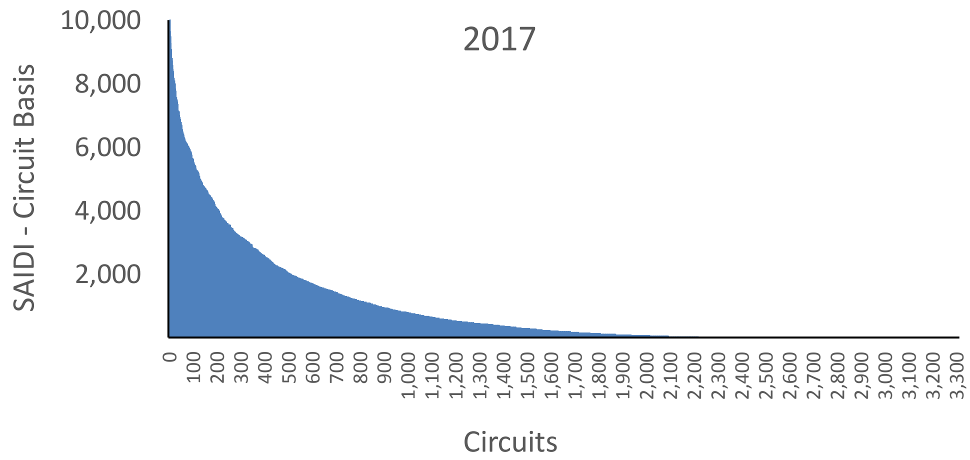


Exhibit A-5 Circuit SAIDI Distribution – Circuit Basis



Appendix III Historical Storm Events

Exhibit A-6 Storm Event and Restoration Duration History

Storm #	Conditions W - Wind; L - Lightning R - Rain; I - Ice; S - Snow H - Hot; C - Cold	Storm Start and Restoration Duration in Hours		Customers Affected	Cost $ million
2012001	W - R - - -	01/01/12 12:10	31.3	19,335	n/a
2012002	W L R - - -	03/02/12 21:00	67.5	100,543	n/a
2012003	W - - - - -	04/16/12 07:00	67.0	92,552	n/a
2012004	W - - - - -	04/23/12 10:00	35.5	32,116	n/a
2012005	W L R - - -	05/28/12 23:00	42.0	19,490	n/a
2012006	W - - - - -	06/02/12 15:00	51.2	33,117	n/a
2012007	W L R - - H	06/21/12 05:00	48.5	32,032	n/a
2012008	W L R - - H	07/03/12 06:00	216.0	364,277	n/a
2012009	W L R - - -	07/26/12 01:00	76.0	51,059	n/a
2012010	W - R - - -	10/13/12 17:00	78.5	49,508	n/a
2012011	W - R - - -	10/28/12 17:00	141.5	112,796	n/a
2012012	W - R - - C	12/20/12 06:00	71.5	35,408	n/a
2013001	W - - - - C	01/20/13 00:00	90.0	107,485	n/a
2013002	- - R I S -	01/27/13 22:00	38.0	45,850	n/a
2013003	W - - I S C	02/26/13 16:00	66.0	50,245	n/a
2013004	W L R - - -	04/18/13 13:00	62.5	91,286	n/a
2013005	W L R - - -	05/22/13 15:00	32.0	31,793	n/a
2013006	W L R - - -	05/30/13 12:00	54.0	36,807	n/a
2013007	W L R - - -	06/17/13 16:00	48.0	25,365	n/a
2013008	W L R - - -	06/26/13 17:00	98.0	99,951	n/a
2013009	W L R - - -	07/08/13 14:00	75.5	53,130	n/a
2013010	W L R - - H	07/15/13 17:00	95.0	60,575	n/a
2013011	W L R - - H	07/19/13 16:00	103.0	153,265	n/a

Storm #	Conditions W - Wind; L - Lightning R - Rain; I - Ice; S - Snow H - Hot; C - Cold	Storm Start and Restoration Duration in Hours		Customers Affected	Cost $ million
2013012	W L R - - -	08/30/13 21:00	52.0	24,525	n/a
2013013	W L R - - -	09/11/13 16:00	91.0	107,279	n/a
2013014	W - R - - -	10/31/13 07:30	62.5	51,825	n/a
2013015	W L R - - -	11/17/13 07:00	158.5	305,424	n/a
2013016	- - R I S C	12/21/13 18:00	192.2	128,408	n/a
2014001	W - R - S -	02/21/14 07:30	37.5	33,693	$ 4.454
2014002	W - - - - -	04/10/14 12:00	19.5	15,500	$ 0.459
2014003	W L R - - -	04/12/14 19:00	108.5	162,561	$ 18.129
2014004	W L R - - -	04/28/14 23:30	47.0	28,411	$ 4.158
2014005	W L R - - -	05/13/14 14:00	30.5	19,079	$ 3.725
2014006	W - - - - -	06/03/14 07:30	38.0	18,323	$ 3.520
2014007	W L R - - H	06/17/14 07:30	104.0	127,571	$ 12.334
2014008	W L R - - -	07/01/14 02:30	69.0	105,189	$ 13.384
2014009	W L R - - -	07/08/14 07:30	46.0	25,394	$ 4.635
2014010	W L R - - -	07/27/14 16:00	101.0	158,528	$ 22.395
2014011	- - R - - -	08/11/14 15:30	59.0	42,612	$ 6.479
2014012	W L R - - -	08/19/14 17:00	47.0	27,662	$ 4.234
2014013	W L R - - -	08/26/14 15:30	80.5	120,041	$ 16.772
2014014	W L R - - -	09/01/14 16:00	44.5	19,355	$ 4.399
2014015	W L R - - H	09/05/14 15:30	172.0	374,284	$ 54.881
2014016	W L R - - -	09/20/14 19:00	52.5	28,657	$ 4.075
2014017	W - R - - -	10/03/14 07:30	38.0	17,182	$ 5.998
2014018	W - - - - -	10/31/14 15:30	53.0	45,245	$ 8.954
2014019	W - - - - -	11/24/14 12:00	89.5	151,801	$ 21.622
2015001	W - R I S -	03/03/15 11:00	40.5	34,691	$ 5.317
2015002	W - R - - -	03/25/15 06:30	32.5	16,920	$ 3.314

Storm #	Conditions W - Wind; L - Lightning R - Rain; I - Ice; S - Snow H - Hot; C - Cold	Storm Start and Restoration Duration in Hours		Customers Affected	Cost $ million
2015003	W - R - - -	04/10/15 12:00	27.0	35,744	$ 5.563
2015004	W - R - - -	05/25/15 11:00	80.0	52,812	$ 6.162
2015005	W L R - - -	05/30/15 11:00	55.0	38,966	$ 6.385
2015006	- - - - - -	03/01/15 10:00	27.0	57,454	no w/o
2015007	W L R - - -	06/22/15 15:00	61.5	62,736	$ 8.144
2015008	W - R - - -	06/27/15 05:30	89.0	131,086	$ 17.985
2015009	- - - - - -	08/02/15 14:00	82.0	95,860	$ 13.489
2015010	W L R - - H	08/14/15 18:00	50.0	25,299	$ 4.015
2015011	W L R - - -	08/19/15 15:00	49.0	20,289	$ 3.657
2015012	W L R - - H	09/03/15 11:00	58.0	55,261	$ 7.720
2015013	- L R - - -	09/19/15 00:00	50.5	17,283	$ 4.015
2015014	W L R - - -	10/23/15 02:00	67.5	26,703	$ 2.266
2015015	W - R - - -	10/28/15 02:00	50.5	34,636	$ 3.897
2015016	W - R - - -	10/02/15 09:00	56.0	30,333	no w/o
2015017	- - - - - -	11/06/15 06:00	51.5	39,208	$ 5.069
2015018	W - - - - -	11/12/15 06:30	47.0	48,371	$ 5.309
2015019	W - R - - -	11/18/15 14:30	49.0	32,118	$ 2.600
2015020	- - R - S -	11/21/15 14:00	75.0	72,496	$ 10.238
2015021	W - R - - -	12/23/15 16:00	49.5	18,972	$ 2.421
2015022	W - R I S -	12/28/15 08:00	60.5	45,696	$ 6.908
2016001	W - - - S -	01/10/16 05:30	39.0	42,871	$ 5.746
2016002	W - - - - -	02/19/16 12:00	77.5	112,419	$ 10.416
2016003	W - R I S C	02/24/16 07:30	53.5	26,590	$ 4.509
2016004	W - R I S C	02/28/16 19:00	36.5	20,052	$ 2.058
2016005	- - R - - -	03/13/16 10:00	35.0	20,519	$ 1.757
2016006	W - R - - -	03/16/16 07:30	75.5	54,601	$ 10.970

Storm #	Conditions W - Wind; L - Lightning R - Rain; I - Ice; S - Snow H - Hot; C - Cold	Storm Start and Restoration Duration in Hours		Customers Affected	Cost $ million
2016007	W - R - - -	06/04/16 12:00	71.0	41,376	$ 6.288
2016008	W - - - - H	06/11/16 12:00	35.0	33,444	no w/o
2016009	W - - - - H	06/19/16 14:00	56.0	46,495	$ 6.477
2016010	W L R - - H	07/08/16 00:00	91.0	100,228	$ 11.194
2016011	W L R - - H	07/12/16 16:00	76.0	54,799	$ 7.357
2016012	W - - - - H	07/17/16 15:00	50.0	26,933	$ 7.363
2016013	W L R - - H	07/21/16 12:00	59.5	36,313	no w/o
2016014	W L R - - -	07/29/16 14:00	57.5	23,158	no w/o
2016015	- L R - - -	08/12/16 15:00	59.5	43,902	$ 4.725
2016016	W - R - - -	08/16/16 00:00	37.0	28,692	$ 5.330
2016017	W L R - - H	09/07/16 13:00	32.0	24,553	$ 4.613
2016018	W L R - - -	09/10/16 04:00	44.5	17,312	no w/o
2016019	W L R - - -	09/29/16 05:00	58.0	32,104	no w/o
2016020	W L R - - -	11/18/16 19:00	80.0	57,216	$ 6.682
2016021	W - - - - -	11/28/16 20:00	33.5	52,256	$ 4.339
2016022	W - - - - -	12/26/16 00:00	24.0	33,644	$ 1.758
2017001	W - - - - -	01/10/17 15:00	65.9	74,371	$ 8.337
2017002	- L R - S -	01/16/17 15:00	36.1	19,301	$ 0.870
2017003	W - R - s -	02/12/17 10:00	34.3	17,934	$ 1.180
2017004	- L R - S -	02/24/17 16:00	26.5	8,223	$ 0.896
2017005	W - - - - -	02/28/17 22:00	46.5	39,339	$ 3.831
2017006	W - - - - -	03/08/17 08:00	202.0	749,511	$ 91.426
2017007	W - - - s -	03/18/17 02:00	40.2	26,915	$ 6.373
2017008	W - R - s -	03/30/17 09:00	51.8	26,179	$ 0.732
2017009	W - - - - -	04/05/17 21:00	142.4	100,839	$ 10.732
2017010	W - - - - -	04/26/17 15:00	53.0	24,702	$ 1.900

Storm #	Conditions W - Wind; L - Lightning R - Rain; I - Ice; S - Snow H - Hot; C - Cold	Storm Start and Restoration Duration in Hours		Customers Affected	Cost $ million
2017011	W L R - - -	04/30/17 22:00	48.0	15,748	$ 0.801
2017012	W - - - - -	05/17/17 08:00	133.3	92,221	$ 11.422
2017013	W - - - - H	06/10/17 07:00	229.0	128,406	$ 11.939
2017014	W - R - - -	06/22/17 09:00	92.0	93,330	$ 8.419
2017015	- - R - - H	06/29/17 21:00	66.8	28,651	$ 3.647
2017016	W - R - - -	07/06/17 23:00	52.0	56,145	$ 4.887
2017017	W L R - - -	07/10/17 10:00	83.1	54,192	$ 7.017
2017018	- L R - - H	07/23/17 03:00	40.1	26,099	$ 0.921
2017019	W - - - - H	07/28/17 15:00	32.5	10,688	$ 0.678
2017020	W L R - - -	08/02/17 16:00	85.4	67,461	$ 9.310
2017021	W L R - - H	08/11/17 05:00	58.5	14,189	$ 1.051
2017022	W L R - - H	08/16/17 20:00	46.0	25,497	$ 1.600
2017023	- L R - - -	08/28/17 18:00	44.5	26,299	$ 1.526
2017024	W L R - - H	09/04/17 16:00	55.3	19,118	$ 2.228
2017025	W - R - - -	10/07/17 13:00	61.9	30,103	$ 4.904
2017026	W - R - - -	10/11/17 05:00	38.2	34,854	$ 4.252
2017027	W L R - - -	10/14/17 18:00	80.1	79,164	$ 7.237
2017028	W - R - - -	10/23/17 18:00	73.3	51,957	$ 9.955
2017029	W L R - - -	11/15/17 15:00	27.6	13,636	$ 1.890
2017030	W - - - - -	12/05/17 04:00	20.0	27,597	$ 2.165

Appendix IV Distribution Design Standards and Distribution Design Orders

Exhibit A-7 Distribution Design Standards and Distribution Design Orders

DDS Section 10 DDO Number	General Information Topic
DDO-0010-001	General Information
DDO-0010-002	DDO Writer's Guide
DDO-0010-003	DDO Procedures and Attachments
DDO-0010-004	DDO Index

DDS Section 20 DDO Number	Overhead Topic
DDO-0020-001	OH Construction Standards
DDO-0020-002	Subtransmission Systems Construction Voltage
DDO-0020-003	Distribution System Construction Voltage
DDO-0020-004	Overhead Construction Type
DDO-0020-005	Distribution Circuit Construction Grade
DDO-0020-006	Circuit Accessibility Construction
DDO-0020-007	Distribution Construction Pole Size
DDO-0020-008	Subtransmission Circuit Standard Conductor Sizes
DDO-0020-009	Distribution Circuit Backbone Standard Conductor Sizes
DDO-0020-010	Distribution Circuit Lateral Standard Conductor Sizes
DDO-0020-011	Distribution Circuit Crossings Standard Conductor Sizes
DDO-0020-012	Distribution Circuit Tree Exposure Standard Conductor Sizes
DDO-0020-013	Distribution Circuit Lightning Protection
DDO-0020-014	Overhead Construction Shield Wire
DDO-0020-015	Overhead Circuit Sectionalizing- Reclosers
DDO-0020-016	Overhead Circuit Sectionalizing- Switches
DDO-0020-017	Overhead Loop Schemes
DDO-0020-018	Overhead Jumpering Points
DDO-0020-019	Overhead Circuit- DG Interconnection Point
DDO-0020-020	Sectionalizing and Jumpering Points Requirements
DDO-0020-021	Circuit Laterals Sectionalizing
DDO-0020-022	Overhead Fault Indicators

DDS Section 20 DDO Number	Overhead Topic
DDO-0020-023	Secondary Construction
DDO-0020-024	Secondary Standard Conductor Type
DDO-0020-025	Distribution Transformers
DDO-0020-026	Services
DDO-0020-027	Circuit Tree Trimming

DDS Section 30 DDO Number	Underground Topic
DDO-0030-001	Underground Construction Standards
DDO-0030-002	Underground Conduit Design
DDO-0030-003	Underground System Cable
DDO-0030-004	URD Front Lot Design
DDO-0030-005	Cable Size and Type for Three Phase URD Loops
DDO-0030-006	Cable Size and Type for Single Phase URD Loops
DDO-0030-007	Residential Padmount Transformer Size
DDO-0030-008	UG Fault Indicators

DDS Section 40 DDO Number	Substation Topic
DDO-0040-001	Substation Construction Standards
DDO-0040-002	Substation Property
DDO-0040-003	Substation Blocking
DDO-0040-004	Station Class Standard
DDO-0040-005	Substation Class Standard
DDO-0040-006	Industrial Substation Standard
DDO-0040-007	Class A and R Substation Transformer Size
DDO-0040-008	Class T Substation Transformer Size
DDO-0040-009	Portable Substation
DDO-0040-010	Subtransmission Distributed Resource

DDS Section 50 DDO Number	Circuit Protection Topic
DDO-0050-001	Substation Fault Current
DDO-0050-002	Minimum Fault Current

DDS Section 50 DDO Number	Circuit Protection Topic
DDO-0050-003	Protection Device Coordination
DDO-0050-004	Fuses and Oil Reclosers Loading
DDO-0050-005	Fault Current Interrupting
DDO-0050-006	Minimum Fault Current
DDO-0050-007	Primary Fuse Saving
DDO-0050-008	Maximum Number of Devices

DDS Section 70 DDO Number	Voltage Topic
DDO-0070-001	Primary Voltage Limits
DDO-0070-002	Secondary Voltage Limits
DDO-0070-003	Voltage Unbalance
DDO-0070-004	Voltage Flicker
DDO-0070-005	Power Factor
DDO-0070-006	Harmonics
DDO-0070-007	Subtransmission Power Service

DDS Section 80 DDO Number	Project Benefit Evaluation Topic
DDO-0080-001	Project Benefit Evaluation

DDS Section 90 DDO Number	Loading Topic
DDO-0090-001	Maximum Outage Duration
DDO-0090-002	Peak Demand Load
DDO-0090-003	Substation Loading
DDO-0090-004	Load Imbalance
DDO-0090-005	13.2 kV Normal Circuit Loading
DDO-0090-006	13.2 kV Emergency Circuit Loading
DDO-0090-007	4.8 kV Normal Circuit Loading
DDO-0090-008	4.8 kV Emergency Circuit Loading
DDO-0090-009	13.2 kV Load Loss
DDO-0090-010	13.2 kV Single Phase URD Loading
DDO-0090-011	13.2 kV Three Phase URD Loading

DDS Section 90 DDO Number	Loading Topic
DDO-0090-012	Redundancy

DDS Section 100 DDO Number	System Automation Topic
DDO-0100-001	Device Monitoring, Power Quality, AMI and Industrial Metering
DDO-0100-002	System Network Model and Asset Data Model
DDO-0100-003	System Automation
DDO-0100-004	Telecommunications
DDO-0100-005	Interconnection
DDO-0100-006	Technology Maturity

DDS Section 110 DDO Number	Urban Networks Topic
DDO-0110-001	Network Feeder Configuration
DDO-0110-002	Urban AC Network Substation Configuration
DDO-0110-003	Network Feeder Routing
DDO-0110-004	Contingency Design Criteria
DDO-0110-005	Feeder Group Configuration
DDO-0110-006	Feeder Cable Size
DDO-0110-007	Feeder Sectionalizing
DDO-0110-008	Network Platforms
DDO-0110-009	In-Building Installations
DDO-0110-010	Netbank Cable Size
DDO-0110-011	Netbank Voltage Configuration
DDO-0110-012	Netbank Size
DDO-0110-013	Netbank Protector SCADA
DDO-0110-014	Secondary Areas
DDO-0110-015	Secondary Main Size
DDO-0110-016	Secondary Main Protection
DDO-0110-017	Secondary Moles
DDO-0110-018	Secondary Services

Table of Exhibits

Glossary

ADMS	Advanced Distribution Management System
ALA	Area Load Analysis
AMI	Advanced Metering Infrastructure
APTS	Automatic Pole Top Switch
CAIDI	Customer Average Interruption Duration Index
Capacity	Amount of electrical demand that a single piece or group of electrical equipment can deliver based on safety and preservation of the asset
CELIDt	Customers Experiencing Long Interruption Durations of t hours or more
CEMIn	Customers Experiencing Multiple Interruptions of n or more
CODI	City of Detroit Infrastructure (Downtown)
Customer 360	DTEE's customer information and billing system
DDO	Distribution Design Orders
DDS	Distribution Design Standards
DER	Distributed Energy Resource
DGA	Dissolved Gas Analysis
DO	Distribution Operations Organization of DTE Electric Company
DOE	Department of Energy
DTEE	DTE Electric Company
EEI	Edison Electric Institute
E-ISAC	Electricity Information Sharing and Analysis Center
EMS	Emergency Management System

EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
ETTP	Enhanced Tree Trimming Program
FLISR	Fault Location, Isolation and Service Restoration
Gas Breaker	Circuit breaker where the interrupting arc quenching is done with compressed gas
Gas Cable	Underground cable which requires pressurized gas to maintain the insulation integrity
GIS	Geographical Information System
ICS	Incident Command System
IEEE	Institute of Electrical and Electronics Engineers
Industrial Control System	A general term that encompasses several types of control systems and associated instrumentation used in industrial production technology, including supervisory control and data acquisition (SCADA) systems, distribution management systems (DMS), and other smaller control system configurations often found in the industrial sectors and critical infrastructure
IRP	Integrated Resource Planning
Line losses	Electrical power loss resulting from an electric current passing through a resistive element (e.g., conductor)
Jumpering Point	A location on a distribution circuit in proximity to a second distribution circuit where the two can be electrically tied together
Line Sensors	Devices installed on distribution circuits that provide load and fault data
Manhole	An underground structure for cable pulling and splicing

MED	Major Event Day - defined in IEEE Standard 1366 as any day in which the daily SAIDI exceeds a threshold value
MPSC	Michigan Public Service Commission
NEETRAC	National Electric Energy Testing, Research and Applications Center
NERC	North American Electric Reliability Corporation
NERC CIP	North American Electric Reliability Corporation Critical Infrastructure Protection
NESC	National Electric Safety Code
Netbank	Distribution network design used in heavy-load-density city areas which provides high reliability
Oil Breaker	Circuit breaker where the interrupting arc quenching is done in oil
O&M	Operation and Maintenance
OMS	Outage Management System
Overload	Electrical demand that exceeds the electrical capacity to serve
PCB	Polychlorinated biphenyl - now considered an environmental contaminant
PILC	Paper in Lead Cable - refers to the type of insulation/jacket on an underground cable
PM	Preventative maintenance - routine scheduled maintenance based on time or number of operations
PON	Power Outage Notification
Primary	Any part of the electrical system energized at 4.8 kV, 8.3 kV, or 13.2 kV
PTM	Pole Top Maintenance
PTS	Pole Top Switch

RBR	Restore Before Repair. It is the practice that customers (load) are transferred to adjacent circuits or substations to restore power before repair can be completed on the failed section of the circuit
Recloser	Sectionalizing device which opens upon detection of fault current
Redundancy	Ability to continue to serve in the event of a contingency condition
Relay	Electrical switch used to initiate operations of other electrical equipment
ReliabilityFirst	One of the eight regional entities that are responsible for ensuring the reliability of the North American bulk power system under Federal Energy Regulatory Commission approved delegation agreements with the North American Electric Reliability Corporation, pursuant to the Energy Policy Act of 2005. DTEE's service territory is in ReliabilityFirst region
RM	Reactive maintenance resulting from a misoperation or malfunction
ROW	Right-of-Way
RTU	Remote Terminal Unit that sends or receives telemetry data to or from a master control
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
Secondary	Any part of the electrical system energized at 120/240 volts
Service	The conductor / cable and equipment that connects a customer to the electrical system
SOC	System Operations Center
Stranded load	Under contingency conditions, electrical demand that cannot be readily served through available jumpering or mobile generation

Subtransmission	Any pa1rt of the electrical system energized at 24 kV, 40 kV, 120 kV, or higher
Substation	A facility of the electrical power grid that allows for the connection and/or switching of circuits and/or the transformation of voltage from one level to another
Through Fault	A fault occurring on the secondary side of a power transformer which may damage the insulation of the transformer
Tie line	A subtransmission circuit that interconnects two or more substations with power flow normally from any of the substations
Trunk line	A radial subtransmission circuit with power flow normally in one direction to serve substation or individual customer loads at 24 kV or 40 kV
TR-XLPE cable	Tree retardant cross-linked polyethylene - refers to the type of insulation on an underground cable
URD	Underground Residential Distribution
Vacuum Breaker	Circuit breaker where the interrupting arc quenching is done in a vacuum
Vault	An underground structure for cable pulling and splicing that also contains power equipment such as transformers and switches
VCL Cable	Varnished Cambric Lead - refers to the type of insulation/jacket on an underground cable
WEI-N	Wind Exposure Index N - the average number of hours that customers experience wind gusts of N mph or greater
XLPE cable	Cross-linked polyethylene - refers to the type of insulation on an underground cable4