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DTE Energy

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June 30, 2017

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 Draft Report. if you have any questions, please feel free to contact me.

Very truly yours,

Michael J. Solo

Digitally signed by: Michael J. Solo
DN: CN = Michael J. Solo email = michael.solo@dteenergy.com C = AD O = DTE Energy OU = General Counsel Organization
Date: 2017.06.30 12:06:14 -05'00'

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Encl.

DTE Electric Company

Distribution Operations Five-Year (2018-2022)

Investment and Maintenance Plan

Draft Report

July 1, 2017

MPSC Case No. xxx

Table of Contents

1 Introduction

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 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) cost / benefit 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.

In this draft report submission, DTEE seeks to set the context for the five-year distribution investment and maintenance plan, with a strong emphasis on the technical assessment of asset and system conditions, along with the description of capital and maintenance programs DTEE is pursuing to address them. The cost / benefit analysis for specific programs and projects, and the recommended prioritization and funding levels for these programs and projects, will be addressed in the final report. DTEE expects to work closely with the MPSC in the coming months to refine the five-year investment plan and ensure that it provides the maximum level of benefits for customers.

1.1 Aging Infrastructure Challenges

DTEE is facing the same aging infrastructure challenges that other utilities and sectors are experiencing. As the American Society of Civil Engineering pointed out in its 2017 Infrastructure Report Card, America's infrastructure, over 16 sectors from bridges, roads and schools to energy, gets a cumulative score of D+, reflecting *"the significant backlog of needs facing our nation's infrastructure writ large"* and *"underperforming, aging infrastructure remains a drag on the national economy."* The energy sector infrastructure is rated at D+ as well. The Report further stated:

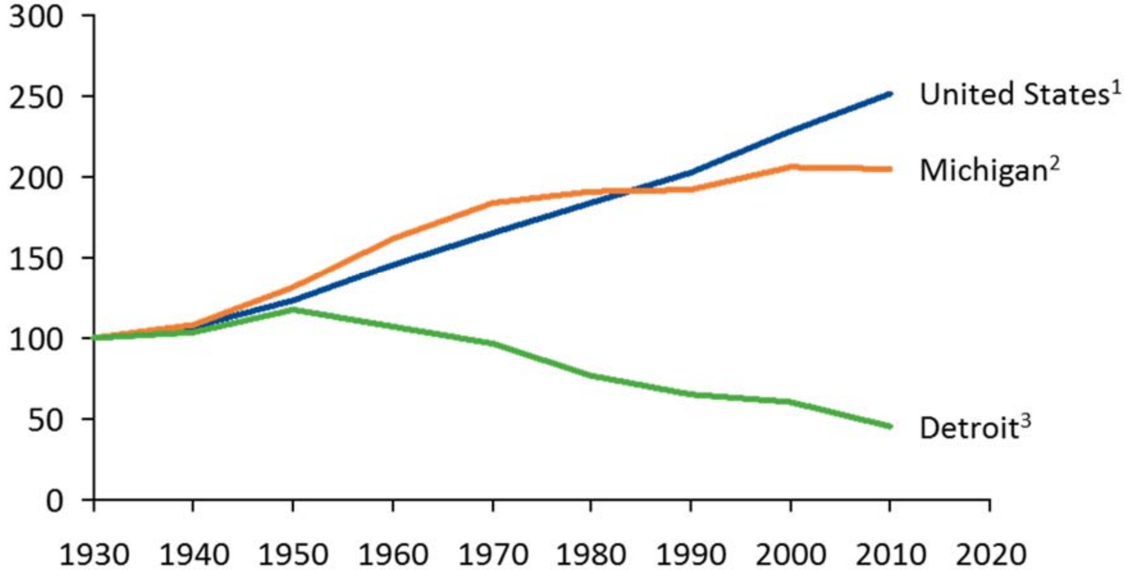
> "*The U.S. energy sector faces significant challenges as a result of aging infrastructure, including supply, security and reliability, and resiliency issues in the face of severe weather events, all posing a threat to public safety and the national economy. Between 2003 and 2012, weather-related outages, 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 investment. The reason for this is easy to understand. 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 period. Flat to declining population for the state and its major cities over the past 30 years made it financially challenging for government entities and public utilities to replace infrastructure, so the focus became to stretch the life of these assets as long as possible. We are now reaching a point at which extending asset lives is no longer feasible and replacing critical infrastructure is necessary.

In November of 2016, the 21st Century Infrastructure Commission, which was created by Executive Order 2016-5 of Governor Snyder, 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."*

Exhibit 1.1.1 U.S., Michigan and Detroit Population Change (Indexed to 1930 Population)



1. *U.S. population in 1930: 123,202,624*
2. *Michigan population in 1930: 4,842,325*
3. *Detroit City population in 1930: 1,568,662*

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*".

Due to historical factors and positive growth in recent years, the condition of the electric infrastructure in the Detroit metropolitan area is becoming particularly pressing. The decline in the city's population was unparalleled at a national level, as shown in Exhibit 1.1.1. To keep electric rates as affordable as possible, DTEE focused on maintaining its assets in the most cost effective way it could for as long as possible.

However, most of these assets are reaching an age and condition that require they be replaced in the coming years. The rebound in the city's economy and the revitalization of many of its business and population centers requires 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. 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.

1.2 Report Outline

This report provides a comprehensive description of DTEE's distribution investment and maintenance programs for the five-year period from 2018-2022. It provides details regarding asset and system issues that drive the investment and maintenance programs and the projected benefits associated with the plan. [Cost and projected benefits for the programs will be provided in the final report]

This report is organized to help readers quickly understand DTEE's five-year distribution investment and maintenance plan, which is summarized in Section 2, with supporting details provided in Sections 4 - 7. The organization of the report is as follows:

- **Section 2** starts with a discussion of the five-year plan objectives and development. A plan framework is presented illustrating how various programs are categorized into the five focus areas, along with key enablers needed to support the plan execution. This is followed by a summary of the five-year investment and maintenance plan and the program drivers.
- **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 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 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 on key enablers, including industry benchmarking, workforce planning, distribution design standards, and spare parts management.

This report focuses on key strategic components of DTEE's investment plan. It does not include discussion of base O&M costs other than tree trimming or preventive maintenance. It also does not include discussion of capital expenditures for emergency replacements, customer connections, and customer relocation activities, as defined below.

1. Emergency Replacement capital is used to perform capital replacements during trouble and storm events. This capital expenditure is reactive in nature and necessary to bring customers back to service during an outage or abnormal system condition.
2. Customer Connection capital is used to provide service for specific customers. New customer requests range from simple service connections, line extensions for a commercial business or housing development, to industrial substations for manufacturing facilities.
3. Customer Relocation capital is used to accommodate customer 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

DTE Electric strives to provide safe, reliable, and affordable electricity to our customers. As such, DTEE's distribution investment and maintenance plan is aimed at reducing risk, improving reliability, and managing costs.

Exhibit 2.1.1 DTEE Distribution Operations Objectives

DTEE is committed to implementing an investment and maintenance plan that maximizes customer benefits and provides a modern electric distribution system that meets the needs of the 21st century economy.

2.2 Plan Development

DTEE's Distribution Investment and Maintenance Plan was developed over a 12-month period that started in late 2014. More than 50 subject matter experts (SMEs), including industry leading consultants, 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 feedback from field operations personnel. These options were then evaluated and compared through a series of engineering peer 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 3-5 years (e.g., Advanced Distribution Management System). Others are of long duration, taking 15 years or longer to complete due to the volume of work required (e.g., breaker replacements, system cable replacements, URD 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 targeted end-of-life oil breakers with more reliable vacuum breakers to improve operability and reduce operation 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 become available from industry benchmarks and best practices, increased understanding of the assets and system conditions, and evaluation of program effectiveness. DTEE will continue to fine-tune its long-term plan on an annual basis to ensure that maximum customer benefits are achieved through the various capital and maintenance programs.

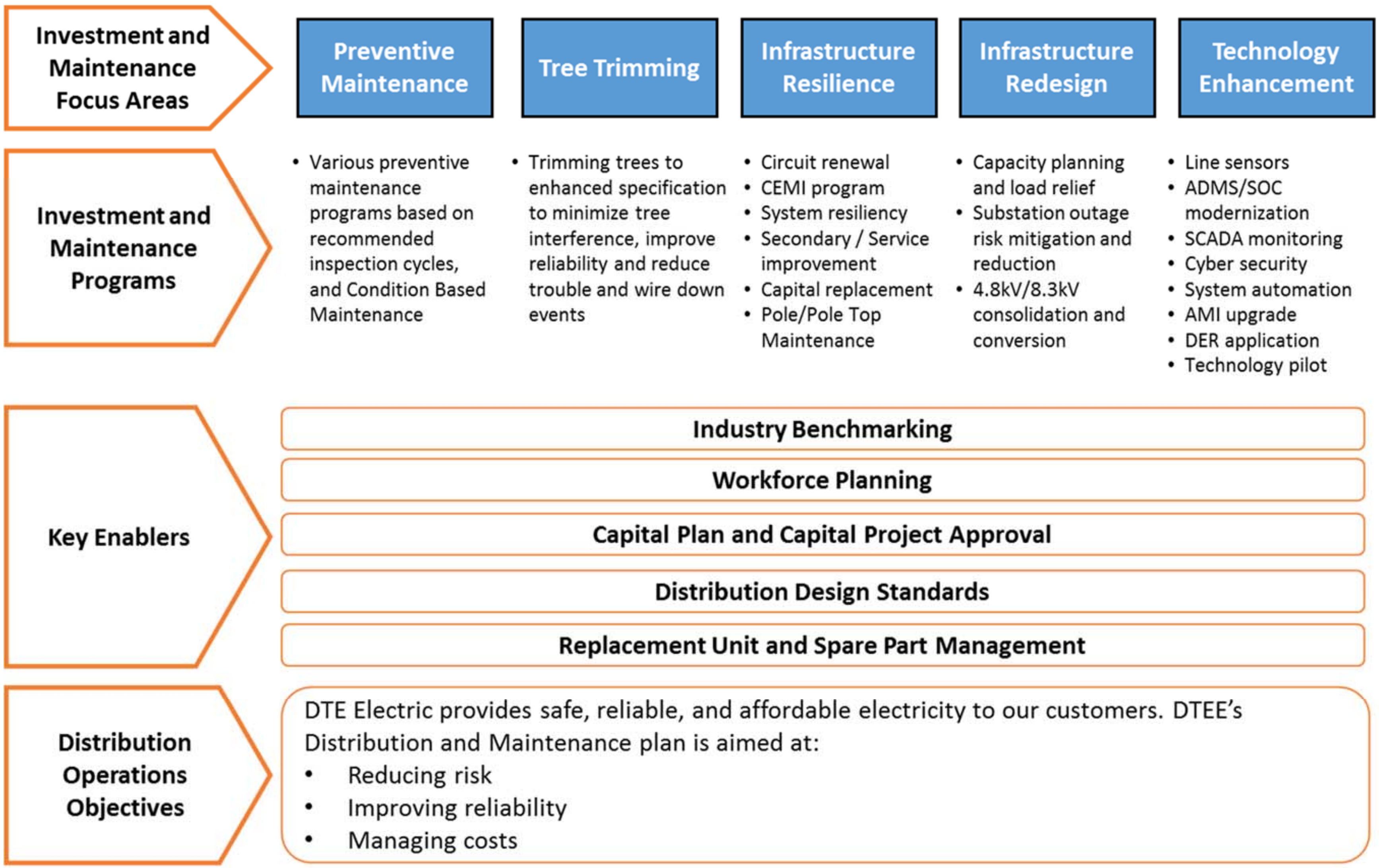
2.3 Plan Framework

The DTEE Distribution Investment and Maintenance Plan consists of five focus areas: preventive maintenance, tree trimming, infrastructure resilience, infrastructure redesign and technology enhancements. Individual programs are classified into one of the five focus areas based on their scope and focus.

- Preventive maintenance: inspecting equipment on a regular basis to minimize equipment failures and maximize its useful life with minimum lifecycle costs
- Tree trimming: trimming trees to enhanced clearance specifications to minimize tree interference with the electrical system, improve reliability, and reduce trouble and wire down events caused by trees
- Infrastructure resilience: improving the condition of specific asset classes or addressing known asset or system issues (e.g., system cable replacement)
- Infrastructure redesign: redesigning substations and circuits to manage design obsolescence and improve conditions of multiple asset classes
- Technology enhancements: leveraging technology to improve grid operability and flexibility to integrate distributed energy resources

In addition, key enablers such as industry benchmarking, workforce planning, capital plan and capital project approval, distribution design standards and spare part management ensure the plan can be executed in the most effective and sustainable manner. Exhibit 2.3.1 illustrates the DTEE Distribution Investment and Maintenance Plan Framework.

Exhibit 2.3.1 DTE Distribution Investment and Maintenance Framework



2.4 Investment and Maintenance Program Summary

DTEE distribution investment and maintenance programs are summarized in Exhibit 2.4.1.

Exhibit 2.4.1 Five-Year DTEE Distribution Investment and Maintenance Program Summary

Focus Area	Programs	Drivers	$ million						Reference Section #
			2018	2019	2020	2021	2022	Total 5-Year	
Preventive Maintenance	Preventive Maintenance	• Asset condition • Manufacturer's recommendation							Section 4 Section 6.2
Tree Trimming	Tree Trimming	• Reliability • Cost							Section 6.1
Infrastructure Resilience	Circuit Renewal	• Reliability							Section 5.3
	System Resiliency	• Reliability							Section 5.3
	Repetitive Outage (CEMI) Program	• Repetitive outage customers • Customer satisfaction							Section 5.3
	Secondary and Service Improvement	• Reliability • Cost							Section 5.5
	4.8kV Circuit Rebuild	• Obsolescence • Reliability • Cost							Section 5.5
	System Cable Replacement	• Risk • Reliability							Section 4.15
	URD Replacement	• Reliability • Cost							Section 4.16

To be provided in the final report

Focus Area	Programs	Drivers	$ million 2018	2019	2020	2021	2022	Total 5-Year	Reference Section #
	Breaker Replacement	• Risk • Cost							Section 4.3
	Relay	• Risk							Section 4.5
	Subtransmission Disconnect	• Operational safety							Section 4.4
	Faulty Fuse Cutout	• Reliability							Section 4.9
	40 kV APTS	• Obsolescence • Reliability							Section 4.12
	Pole / Pole Top Maintenance	• Condemned poles • Defective overhead equipment • Reliability							Section 4.7
	Pontiac Vaults	• Obsolescence • Operational safety							Section 4.18
Infrastructure Redesign	Load Relief	• System loading and capacity needs							Section 5.1
	Demonstration Projects: Non-Wire Alternatives	• System loading and capacity needs • Emergency backup							Section 5.1
	System Conversion and Consolidation	• Obsolescence • Reliability • Cost • Capacity needs							Section 5.5
	Substation Outage Risk Mitigation and Reduction	• Risk							Section 5.2

To be provided in the final report

Focus Area	Programs	Drivers	$ million 2018	2019	2020	2021	2022	Total 5-Year	Reference Section #
Technology Enhancement	Line Sensors	• Grid-wide situational awareness							Section 5.4
	ADMS / SOC Modernization	• Grid-wide situational awareness • Integrated system and advanced analytics • DER integration							Section 5.4
	SCADA and Telecom Baseline	• Grid-wide situation awareness • Cybersecurity							Section 5.4
	Substation Automation	• Real-time grid flexible operation							Section 5.4
	Distribution Automation	• Real-time grid flexible operation							Section 5.4
	Capacitor and Regulator Controls Upgrade	• Real-time grid flexible operation • DER integration							Section 4.13 Section 4.14 Section 5.4
	AMI 3G Cellular Cell Relay Upgrade	• Telecommunication providers plan to phase out 3G in Michigan by 2020							Section 4.19
	AMI 3G Cellular Large Commercial and Industrial Meters Upgrade	• Telecommunication providers plan to phase out 3G in Michigan by 2020 • SCADA and more advanced power quality data needed at selected sites							Section 4.19
	AMI Firmware Upgrade	• Cost • Operational efficiency							Section 4.19
	Pilot: Technology	• Real-time grid flexible operation • DER integration							Section 5.4

To be provided in the final report

2.5 Cost / Benefit Analysis and Program Prioritization

DTEE assesses the impacts of capital programs and projects on each of its objectives: risk reduction, 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 also considered to refine the prioritization. Execution factors such as resource availability and system operational constraints are then considered to develop a detailed execution plan.

[Additional details to be provided in the final report]

2.6 Projected System Impact

[To be provided in the final report]

3 DTEE Distribution System Overview

DTEE started developing and operating the electrical system in southeastern Michigan in 1903 and has continued to expand the system to serve approximately 2.2 million customers today. DTEE's distribution system key statistics are listed in Exhibits 3.1-3.4. The DTEE system consists of six voltage levels: 120 kV, 40 kV, 24 kV, 13.2 kV, 8.3 kV, and 4.8 kV as illustrated in Exhibit 3.5.

Exhibit 3.1 DTEE Substations

Substation Type	Total Number of Substations	Number of Substations by Low Side Voltage							
		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

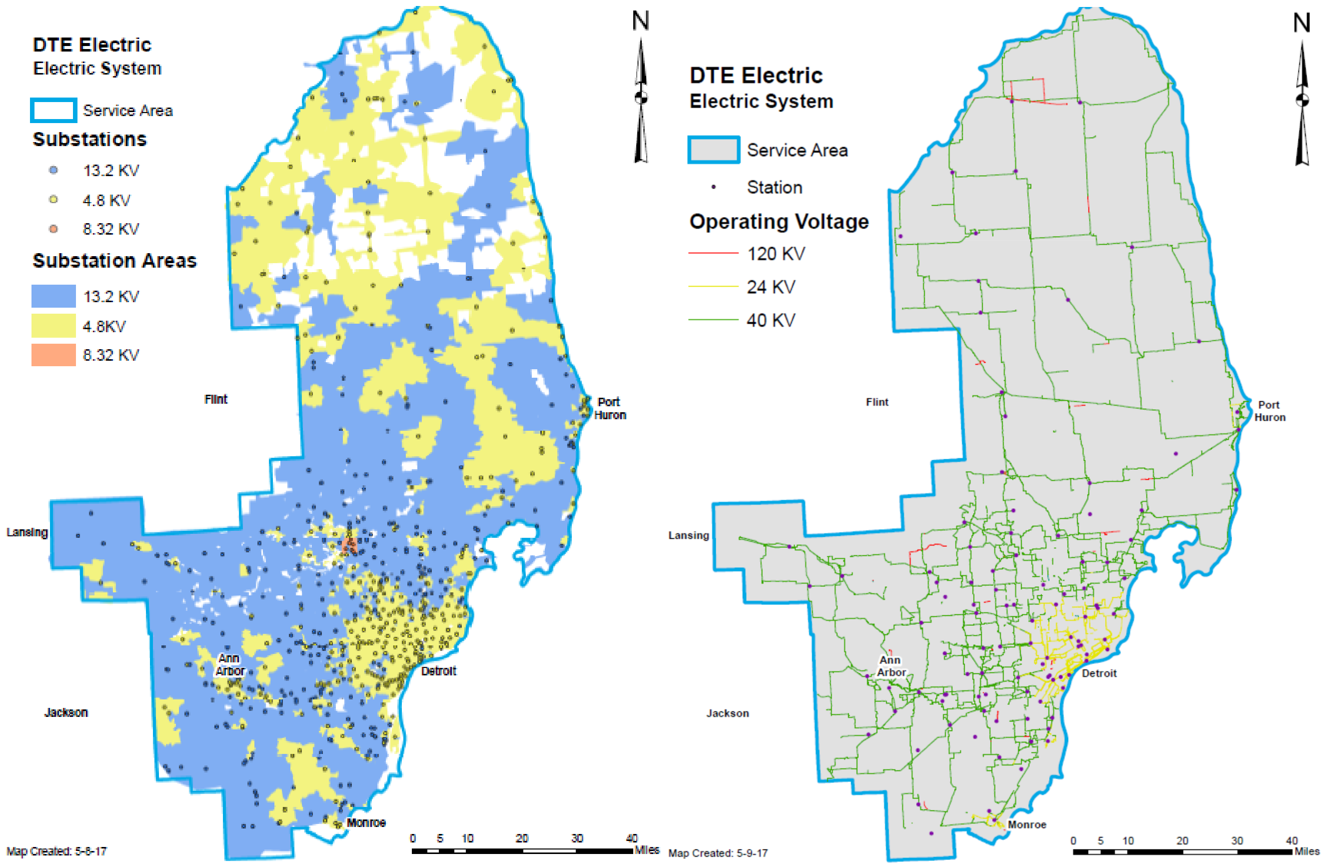
Exhibit 3.3 DTEE Subtransmission Circuits

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	17,153	11,894	29,047
8.3 kV	13	52	14	66
4.8 kV	2,082	11,254	3,050	14,304
Total	3,317	28,459	14,958	43,417

Exhibit 3.5 DTEE Distribution System



4 Asset Condition Assessment

DTEE engineers regularly conduct asset condition assessments on a total of 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 asset classes 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 age 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.

It is important to understand that the asset condition assessments provided in the report are the assessment 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.

Exhibit 4.1 Asset Age Summary

Section	Asset	Average Age (Years)	Age Range (Years)	Life Expectancy (Years)
4.1	Substation 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+	10 – 50
4.6	Switchgear	34	0 – 64	35 – 45
4.7	Poles and Pole Top Equipment	44	0 – 90+	40 – 50
4.8	Small Wire (i.e., #6 Copper, #4 ACSR, and #4 Copper)	70+	Not available	Not available
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 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	AMI Meters	4.5	0 – 11	20

Replacement costs within each asset class vary significantly depending on the voltage, location, capacity, size, model, configuration, etc. Exhibit 4.2 shows the range of the replacement cost per asset class during proactive replacements. The assets listed in Exhibit 4.2 are the assets for which DTEE tracks individual replacement costs. Reactive replacements performed during storm or as a result of trouble will generally have higher replacement costs than what are listed in Exhibit 4.2.

Exhibit 4.2 Estimated Per Unit Replacement Costs

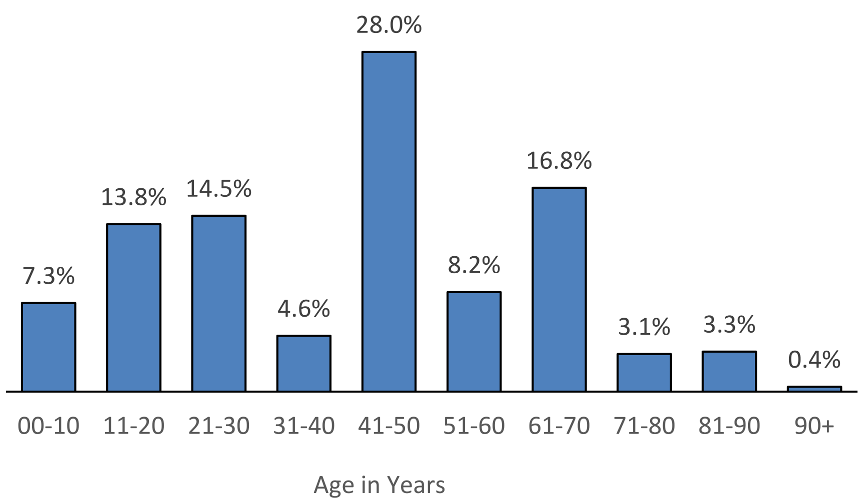
Asset	$ / unit or $ / mile
Substation Transformers	$500,000 – $1,700,000
Circuit Breaker	$100,000 – $350,000
Subtransmission Disconnect Switches	$11,000 – $47,000
Relays	$40,000 – $60,000
Poles Replacement	$5,800 – $11,200
Fuse Cutouts	$500 – $1,000
40-kV Automatic Pole Top Switches	Estimated $125,000
System Cable (per mile)	$600,000 – $1,500,000
Underground Residential Distribution Cable (per mile)	$52,000 – $102,000

4.1 Substation Transformers

DTEE has approximately 1,600 substation transformers, which connect 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 transformer. Exhibit 4.1.2 shows the age distribution of substation transformers connected on the DTEE system. The average age of substation transformers is approximately 41 years.

Exhibit 4.1.1 Substation Transformer

Exhibit 4.1.2 Substation Transformer Age Distribution



A 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 4.1.3). Failures of substation 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% of transformers are candidates for replacement.

Exhibit 4.1.3 Substation 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 (Dissolved Gas Analysis) testing on all substation transformers once a year. DGA testing is an industry proven methodology (also known as Substation Predictive Maintenance Inspection, or SPdM) to identify internal transformer degradation and to predict potential transformer failures. Based on results from routine inspection and DGA testing, DTEE determines when to either proactively replace or repair substation transformers that fail the inspection. Substation 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 the transformer such as load tap changers or bushings.

Exhibit 4.1.4 Substation Transformer Program Summary

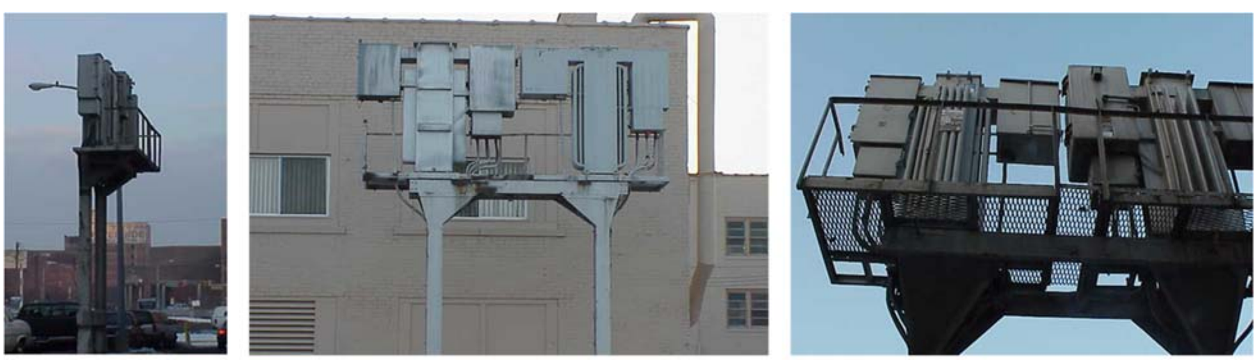
Program Summary	
Equipment	Transformers
Preventive Maintenance Program	Yes: DGA Testing, Routine Inspection
Proactive Replacement Program	Yes: driven by DGA testing results

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 area 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 Inspection (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 on transformer tanks for corrosion, signs of water and oil sludge, PCB (Poly Chlorinated Biphenyl) and DGA oil analysis, and high voltage testing (e.g., meggar 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, 8 (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 4.8kV conversion effort, as discussed in Section 5.5.

Exhibit 4.2.2 Netbank Program Summary

Program Summary	
Equipment	Net-bank
Preventive Maintenance Program	Yes: Electrical Integrity Inspection; Pole Inspection; Steel Structure Inspection
Proactive Replacement Program	No

4.3 Circuit Breakers

A circuit breaker is an automatically operated electrical switch designed to isolate faults that occur on substation equipment, bus or a circuit position, and protect substation equipment from damage caused by excess fault current. Its basic function is to interrupt current flow after a fault is detected to minimize equipment damage and isolate the faulted asset from the electrical system. Exhibit 4.3.1 illustrates an oil breaker installed in the 1940's versus a recently installed vacuum breaker.

Exhibit 4.3.1 Circuit Breakers

Traditional 4.8kV Oil Breakers

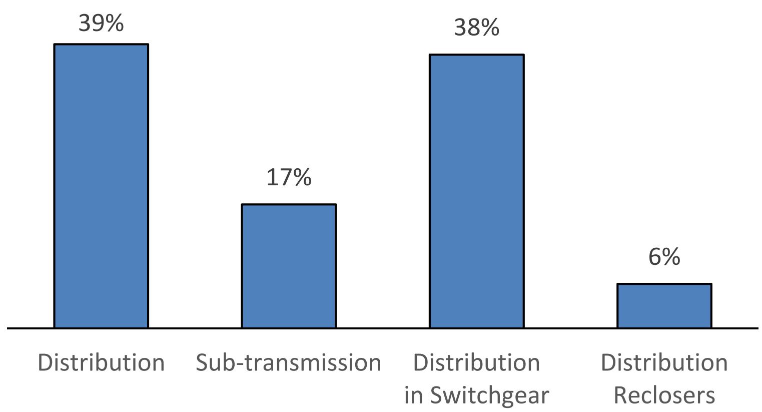
Modern Distribution Vacuum Breakers

Traditional 120kV Oil Breakers

Modern 120kV Gas Breakers

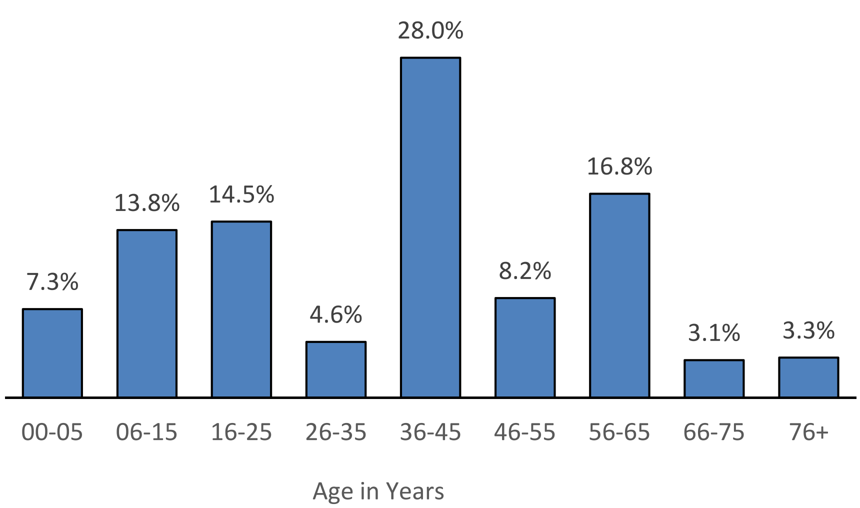
DTEE has approximately 6,000 circuit breakers on its system, which include distribution breakers, subtransmission breakers, switchgear breakers, and substation reclosers (Exhibit 4.3.2).

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 is considered to have a life expectancy of 30 years. 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, approximately 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
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
Safety Risk	• Possibility of violent failures due to oil interrupting medium
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 of time during repairs. Depending on the extent of the failure and adjacent collateral damage, thousands of customers could be impacted for an extended duration.

DTEE performs regular periodic inspections of circuit breakers based either on time interval or number of breaker operations recommended by manufacturers. Circuit breakers that fail during inspection are either repaired (if economical to do so), or replaced. In addition, DTEE has a proactive breaker replacement program to eliminate targeted breakers from the system. To the extent possible, breaker replacements are coordinated with other capital or maintenance work in order 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 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 4.3.5 Circuit Breaker Program Summary

Program Summary	
Equipment	Breaker
Preventive Maintenance Program	Yes
Proactive Replacement Program	Yes
Proactive Replacement Program Timeline	[To be provided in the final report]
Budget Projection 2018-2022	[To be provided in the final report]
Budget Projection (Entire Program)	[To be provided in the final report]

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 out of service to obtain the clearance required to continue the work.

A disconnect switch is considered for potential replacement if it lacks replacement parts or is a model with a known problem. Approximately 258 Cap & Pin style and 76 PM-40 model disconnect switches are candidates for replacement (Exhibits 4.4.1 – 4.4.3).

Exhibit 4.4.1 Cap and Pin Disconnect Switch

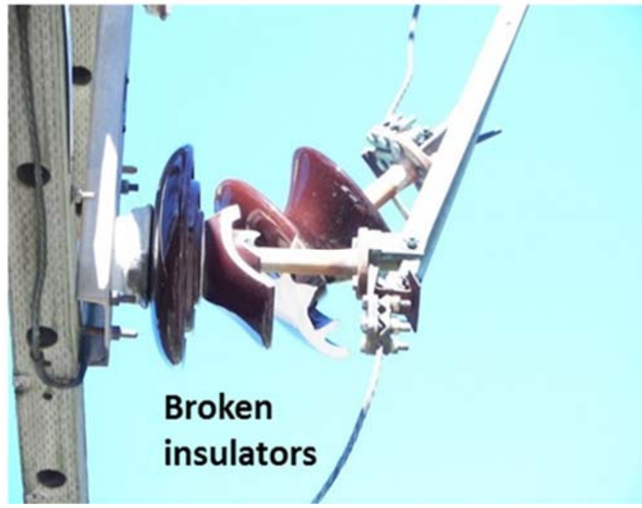


Exhibit 4.4.2 PM-40 Disconnect Switch

Exhibit 4.4.3 Subtransmission Disconnect Switch Replacement Factors

Factors	Impact
Cap and Pin Disconnects	Insulators are problematic and could fail during operation Employee safety concern upon failure during manual operation
Known Manufacturer Issues on PM-40 (120kV)	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.

Exhibit 4.4.4 Subtransmission Disconnect Switch Program Summary

Program Summary	
Equipment	Subtransmission Disconnect Switch
Preventive Maintenance Program	Yes
Proactive Replacement Program	Yes
Proactive Replacement Program Timeline	[To be provided in the final report]
Budget Projection 2018-2022	[To be provided in the final report]
Budget Projection (Entire Program)	[To be provided in the final report]

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 illustrated in Exhibit 4.5.2.

Exhibit 4.5.1 Relays Design Types

Electro Mechanical

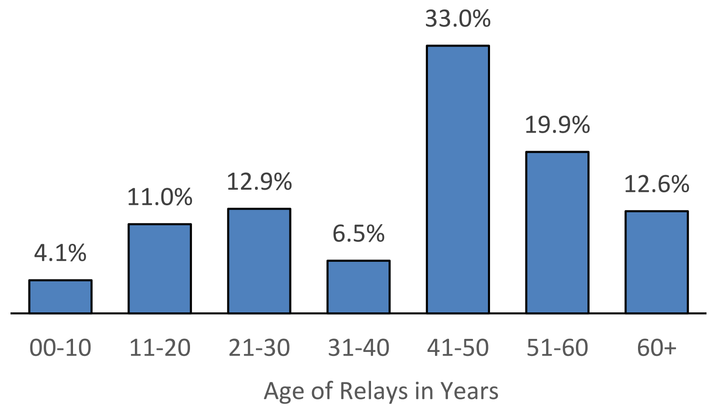
Solid State

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	• Very reliable – contain no electronics • Long life • Low maintenance • Settings easily adjusted	• No SCADA or Communication • No fault location detection • No metering or power flow monitoring • Unavailable parts
Solid state (5% of Total)	40 years	• Settings easily adjusted • No moving parts – mechanism does not wear out	• No SCADA or Communication • No fault detection • No metering or power flow monitoring • Unavailable parts
Micro-processor (10% of Total)	10 – 20 years	• SCADA • Fault detection • Metering • Can replace 5+ electro mechanical relay functions • No preventive maintenance required due to self-checking capability • Provides condition-based information for breakers and transformers • Can apply relay settings remotely	• Relatively short life span • Requires computers and software / firmware updates to change settings

Exhibit 4.5.3 Relay Age Distribution



The average age of DTEE relays is 46 years old, with 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.

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 additional customer minutes for a momentary outage due to inability of breaker 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 out over time • Electrolytic Capacitors internal to relay dry out over time – causing non-correctable calibration issues • Lack of or expensive replacement parts • Potential system shut-down requirements to work on the relay

DTEE has a preventive maintenance program for relays. Relays failing during PM or in service are replaced or repaired. Many of the relay replacements are coordinated and included as part of the breaker replacement program. In addition, DTEE has a proactive capital replacement program to replace relays for positions that have lost redundancy due to previous relay failures. Relay replacements may require long shutdowns due to extensive rewiring, installation, programing and testing, which limits redundancy and operability of the system. Relay replacements enable the equipment to be SCADA controllable, increasing penetration rates of substation remote control capability (see Section 5.4 for detailed discussion on remote control capability).

Exhibit 4.5.5 Relay Program Summary

Program Summary	
Equipment	Relays
Preventive Maintenance Program	Yes
Proactive Replacement Program	Yes
Proactive Replacement Program Timeline	[To be provided in the final report]
Budget Projection 2018-2022	[To be provided in the final report]
Budget Projection (Entire Program)	[To be provided in the final report]

4.6 Switchgear

Switchgear is 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 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

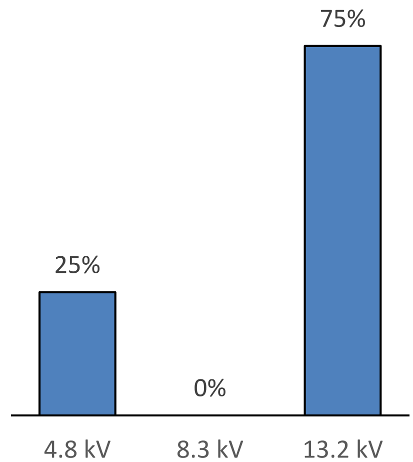
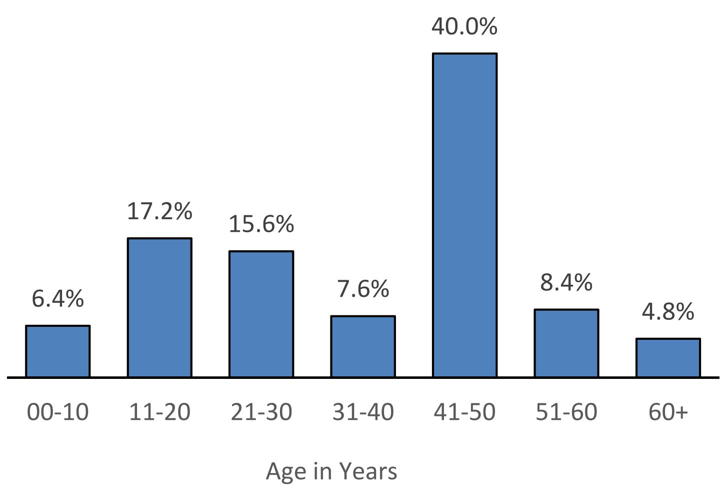


Exhibit 4.6.4 Switchgear Age Distribution



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 hazard
Spare parts	• Vendors have stopped supplying manufacturing parts for some older vintage switchgear

Exhibit 4.6.6 Calvert Bus

There is not a stand-alone preventive maintenance program on 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 extensive substation re-build. It includes pouring new concrete pads and 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. Additional load pressure 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 switchgear
Proactive Replacement Program	Yes: Substation Outage Risk Reduction Program (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 (such as 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 life expectancy can vary based on field conditions.

Exhibit 4.7.1 DTEE Owned Wood Pole Age Distribution

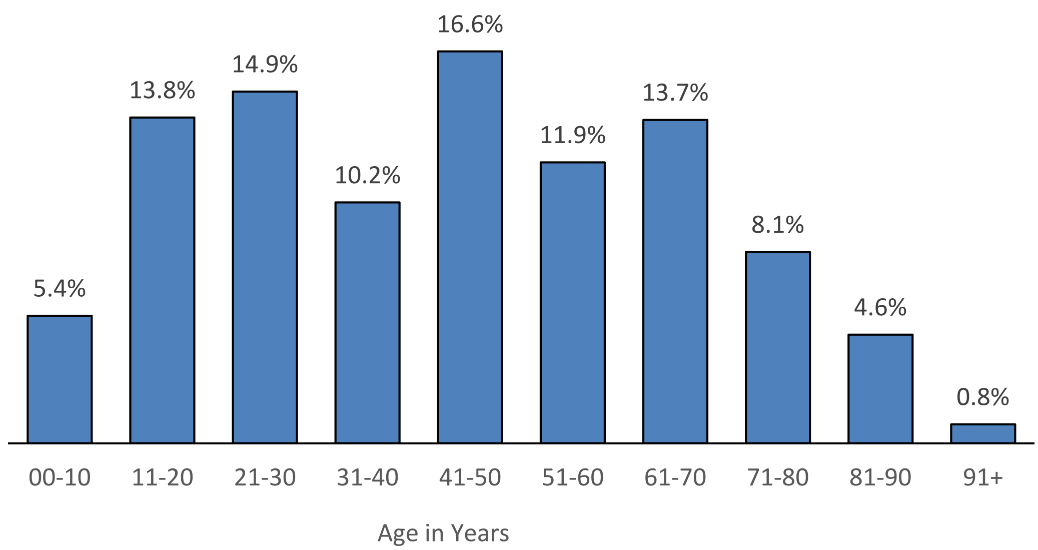
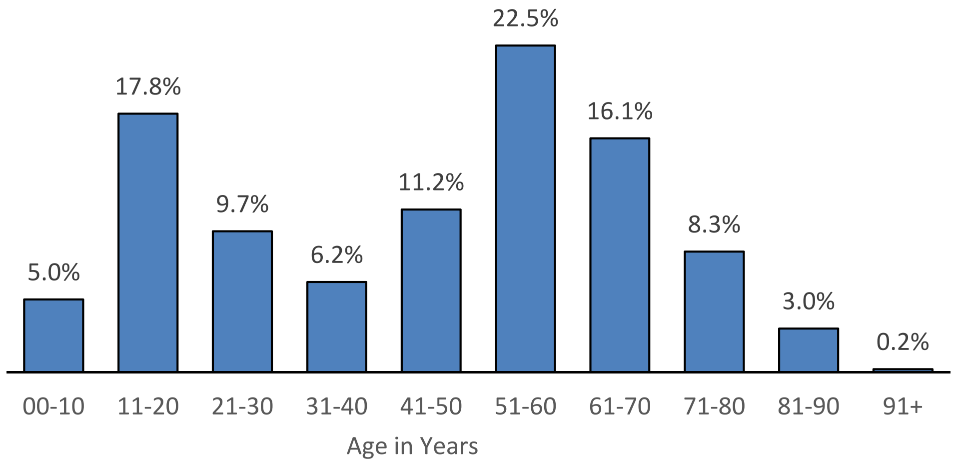


Exhibit 4.7.2 Non-DTEE Owned Wood Pole Age Distribution



The Pole and Pole Top Maintenance Program is a proactive program to test poles and inspect pole top hardware to identify and repair or replace weakened and/or broken pole or pole top hardware. Annually, foot patrols are done on a portion of the system to inspect poles and pole top hardware. Data from these patrols shows that pole replacement or reinforcement is required on approximately 5-7 percent of the total poles inspected.

Historically, DTEE replaces or reinforces approximately 9,000 – 10,000 poles each year either as part of the trouble / storm events, Pole and Pole Top Maintenance Program, or other system reliability and strengthening programs.

Exhibit 4.7.3 Pole and Pole Top Maintenance Program Summary

Program Summary	
Equipment	Poles and Pole Top Hardware
Preventive Maintenance Program	Yes
Proactive Replacement Program	Yes
Proactive Replacement Program Timeline	[To be provided in the final report]
Budget Projection 2018-2022	[To be provided in the final report]
Budget Projection (Entire Program)	[To be provided in the final report]

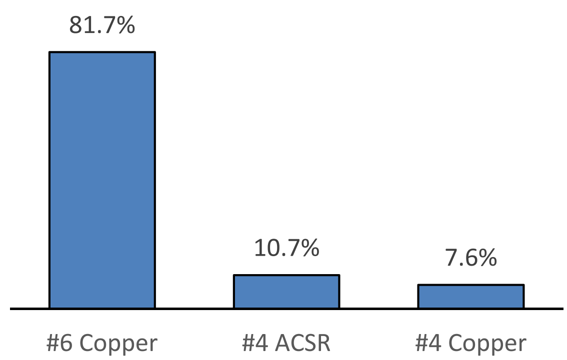
4.8 Small Wire

The overhead distribution primary system has approximately 13,000 wire 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 age (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 strength that are 2-3 times stronger than the small wire.

There is no stand-alone proactive replacement program for small wire presently. However, the small wire replacements are performed in the course of other capital work to support load growth, system strengthening, or reliability improvement.

Exhibit 4.8.1 Percent of 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	Yes: visual inspection is performed as part of PTM program
Proactive Replacement Program	No

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, overloads, or equipment failure.

DTEE has approximately 644,000 fuse cutouts on its system. Based on cutout performance and failure history, approximately 89,000 (14 percent) are considered in need of replacement, as shown in Exhibit 4.9.1. The majority of those (67 percent) are S&C R10/R11 porcelain cutouts (Exhibit 4.9.2) manufactured between 2005 and 2007, which are known to have higher failure rates and can cause outages.

Other defective cutouts include AB Chance Porcelain and Durabute Polymer. Past programs replaced most of these devices; those that remain on the system are being identified on PTM patrols and replaced.

Defective cutouts are estimated to fail at a rate of approximately 6.8 percent annually, representing 70-76 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
AB Chance Porcelain	28,000	Premature failure
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 50 percent of the defective fuse 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 cutout
Preventive Maintenance Program	No
Proactive Replacement Program	Yes
Proactive Replacement Program Timeline	[To be provided in the final report]
Budget Projection 2018-2022	[To be provided in the final report]
Budget Projection (Entire Program)	[To be provided in the final report]

4.10 Three-Phase Reclosers

An overhead three-phase recloser is a sectionalizing device that is usually 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. Using a recloser can effectively 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 will automatically attempt to reclose after a predetermined amount of time. The open and reclose cycle is designed to allow a temporary fault to clear from the circuit and restore 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 loop scheme involves at least two separate 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. Approximately 13 percent of three phase reclosers are part of a loop scheme.

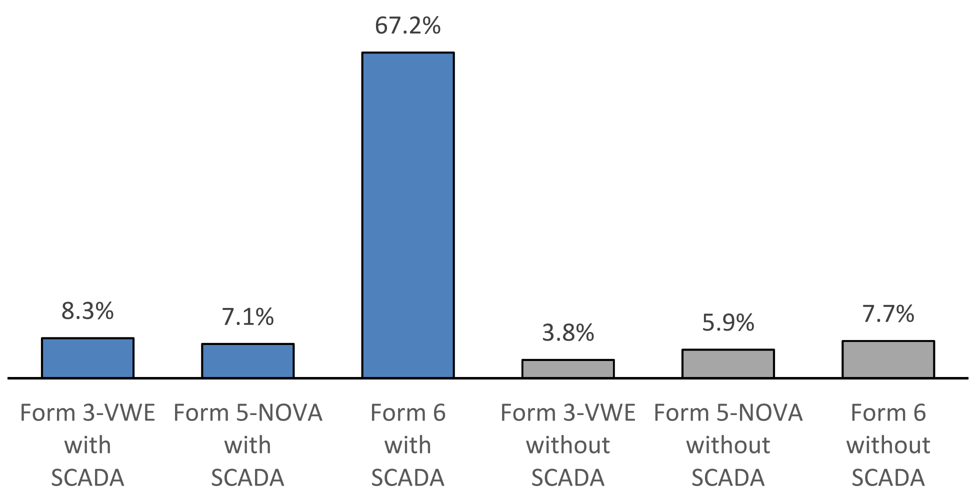
Exhibit 4.10.1 Three-Phase Recloser Design Types

VWE Recloser

NOVA Recloser

Triple Single Recloser & Form 6 Control

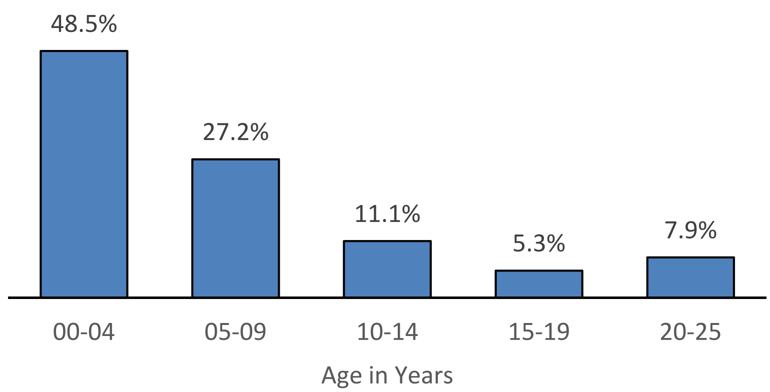
Exhibit 4.10.2 Three-Phase Recloser Type Distribution



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), 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 program for overhead three-phase reclosers. Reclosers failing during PM or 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 Recloser
Preventive Maintenance Program	Yes
Proactive Replacement Program	No

4.11 SCADA Pole Top Switches

A complete SCADA PTS (pole top switch) 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 SOC (System Operations Center) 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

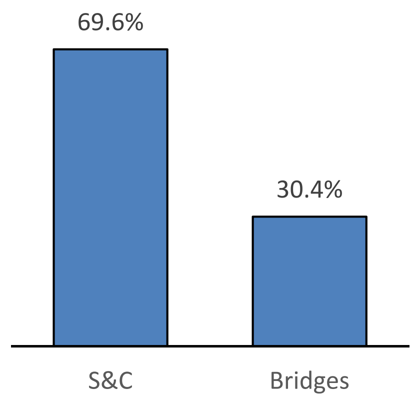
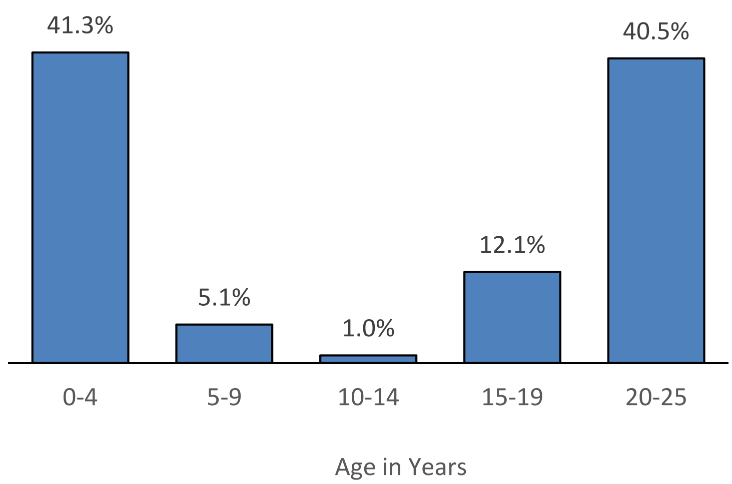


Exhibit 4.11.3 SCADA Pole Top Switches Age Distribution



The average age of all SCADA PTS 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 1.8 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 PTS's 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 time. DTEE has a preventive maintenance program on SCADA PTS's. S&C SCADA units failing during PM or service are either repaired or replaced. Bridges SCADA units failing during PM or service are generally replaced.

Exhibit 4.11.4 SCADA Pole Top Switch Program Summary

Program Summary	
Equipment	SCADA PTS
Preventive Maintenance Program	Yes
Proactive Replacement Program	No

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. 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 failures and increase technical capability.

DTEE has both a preventive maintenance program and a proactive replacement program on 40-kV APTS's. Our goal is to replace the entire population of the 40-kV APTS's.

Exhibit 4.12.1 40-kV Automatic Pole Top Switch

Exhibit 4.12.2 40-kV Automatic Pole Top Switch Program Summary

Program Summary	
Equipment	40-kV Automatic Pole Top Switch
Preventive Maintenance Program	Yes
Proactive Replacement Program	Yes
Proactive Replacement Program Timeline	[To be provided in the final report]
Budget Projection 2018-2022	[To be provided in the final report]
Budget Projection (Entire Program)	[To be provided in the final report]

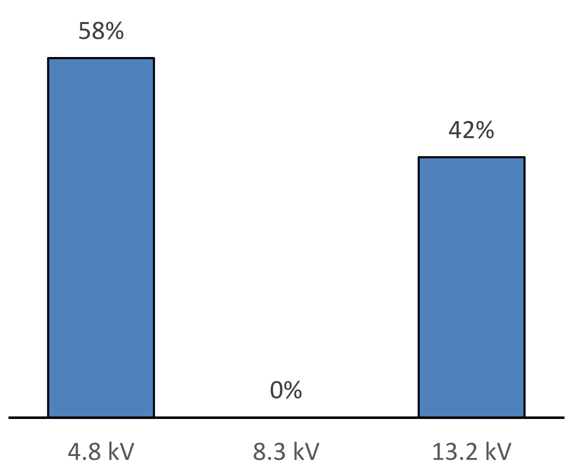
4.13 Overhead Capacitors

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 operates approximately 3,300 overhead capacitors on 1,788 overhead circuits. They provide approximately 2,000 MVAR of reactive power. 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 for overhead capacitors. Reactive replacements are made for in-service failures or for failures during PM. 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

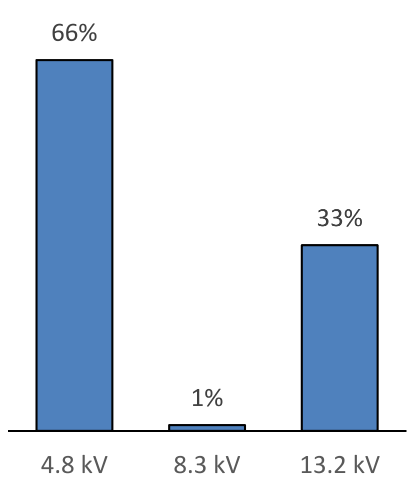
Program Summary	
Equipment	Overhead Capacitors
Preventive Maintenance Program	Yes
Proactive Replacement Program	Yes: Pilot
Proactive Replacement Program Timeline	[To be provided in the final report]
Budget Projection 2018-2022	[To be provided in the final report]
Budget Projection (Entire Program)	[To be provided in the final report]

4.14 Overhead Regulators

Overhead voltage 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. 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 in-service failures or for failures during PM. 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	Yes: Pilot
Proactive Replacement Program Timeline	[To be provided in the report]
Budget Projection 2018-2022	[To be provided in the report]
Budget Projection (Entire Program)	[To be provided in the report]

4.15 System Cable

DTEE's distribution and subtransmission system has approximately 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 path. Manholes and switch-cabinets provide locations where sections of cable can be pulled through the conduit and spliced together. System cable typically provides better reliability 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

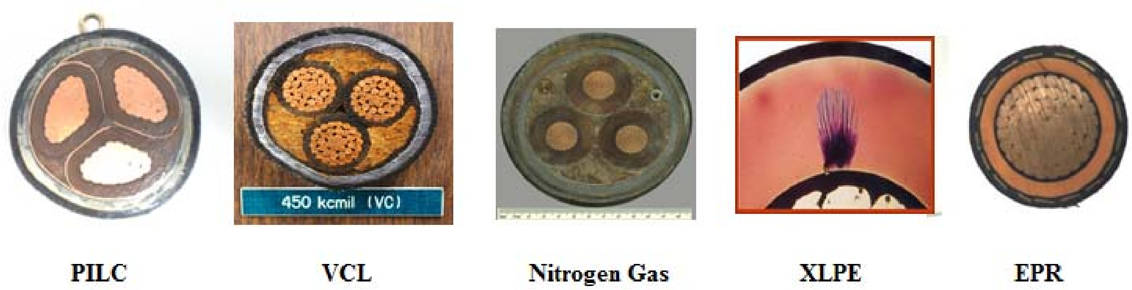


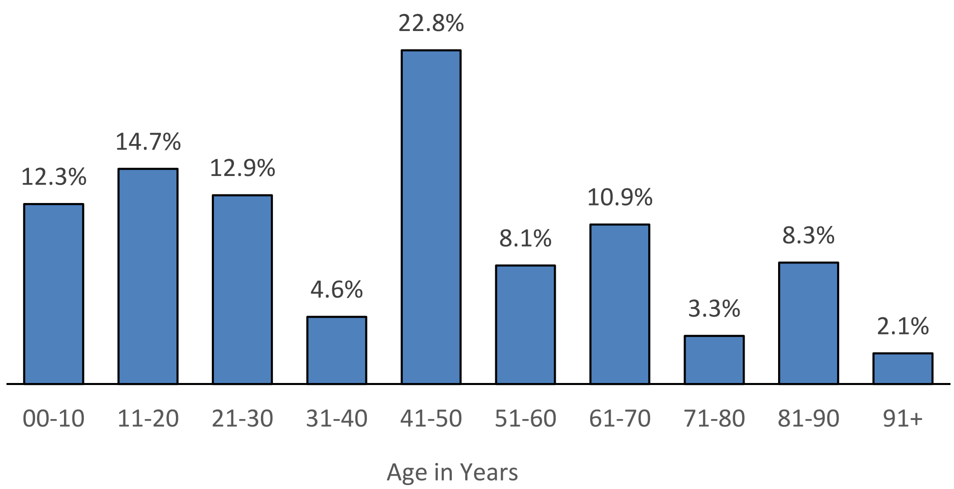
Exhibit 4.15.1 illustrates the five major types of underground system cable installed in DTEE's distribution system. The XLPE (cross-linked polyethylene) cable shown in Exhibit 4.15.1 is a non-tree retardant XLPE cable. Exhibit 4.15.2 shows the types and quantities of system cable in the DTEE system. The average life expectancy of system cables is 40 years or less.

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	74%	17%	4%	2%	3%	1%
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 50 percent of DTEE system cable is beyond its typical life expectancy.

Exhibit 4.15.3 Underground System Cable Age Distribution



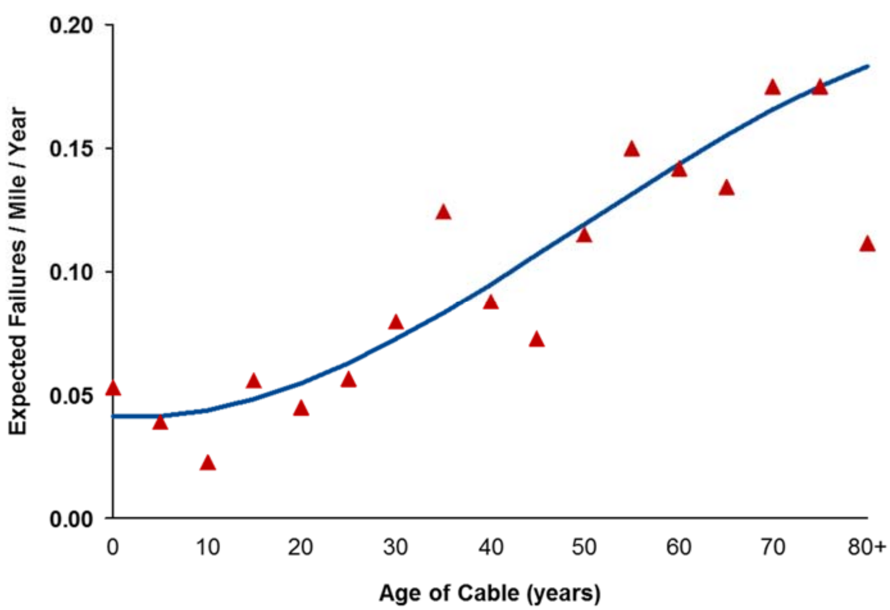
System cable is a critical component for both the subtransmission and distribution systems. A failure typically interrupts a large number of customers for an extended period of time. Approximately 34 percent of the system cable is candidate for replacement. This includes XLPE cable installed before 1985 (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 and need to 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 is prioritized based on multiple factors including cable type, vintage, previous failure history, impacts to the system, cable loading and O&M costs.

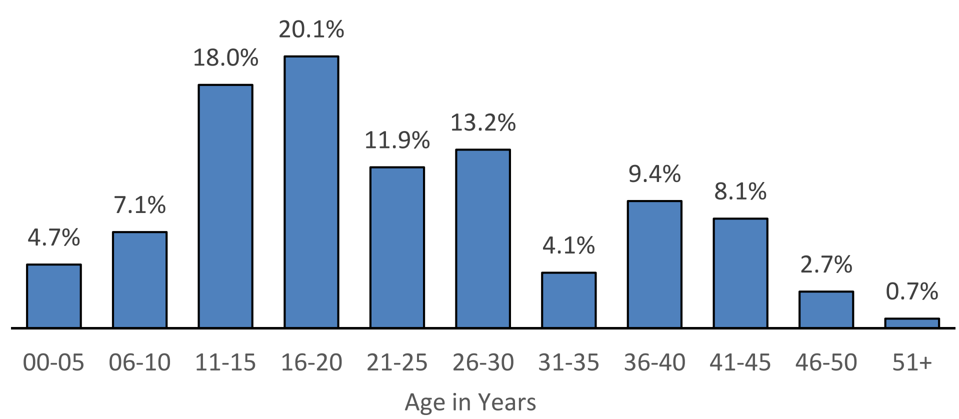
Exhibit 4.15.5 Underground System Cable Program Summary

Program Summary	
Equipment	System cable
Preventive Maintenance Program	No
Proactive Replacement Program	Yes
Proactive Replacement Program Timeline	[To be provided in the final report]
Budget Projection 2018-2022	[To be provided in the final report]
Budget Projection (Entire Program)	[To be provided in the final report]

4.16 Underground Residential Distribution (URD) Cable

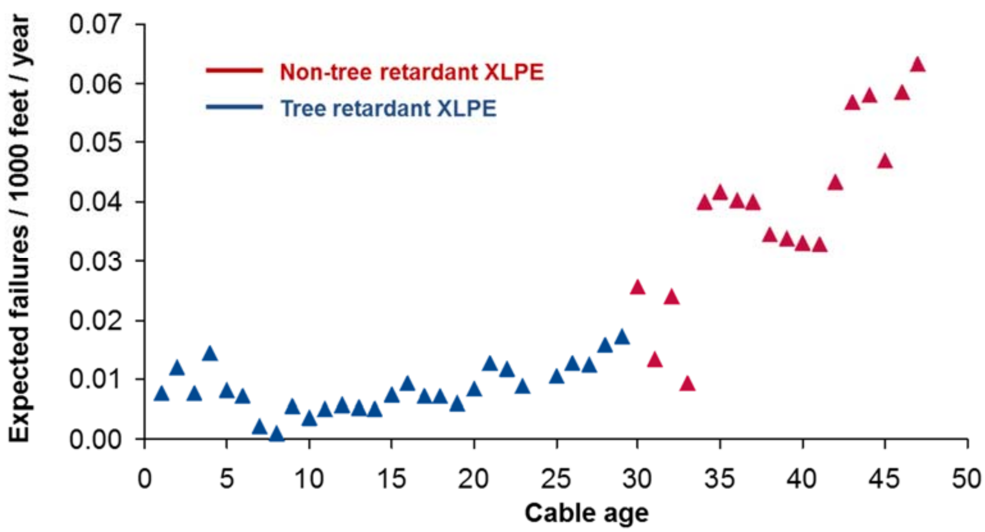
DTEE has approximately 10,800 miles of URD cable, with 87 percent of the population on the 13.2 kV system. All new subdivisions (built since early 1970s) are served with URD cable. URD is more expensive to install and repair compared to overhead lines. URD cable failures are less frequent but take a 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 in need of 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 preferred URD cable type is tree retardant XLPE cable (TR-XLPE).

Exhibit 4.16.2 URD Cable Failure Rates



DTEE has a proactive replacement program to replace 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	URD Cable
Preventive Maintenance Program	No
Proactive Replacement Program	Yes
Proactive Replacement Program Timeline	[To be provided in the final report]
Budget Projection 2018-2022	[To be provided in the final report]
Budget Projection (Entire Program)	[To be provided in the final report]

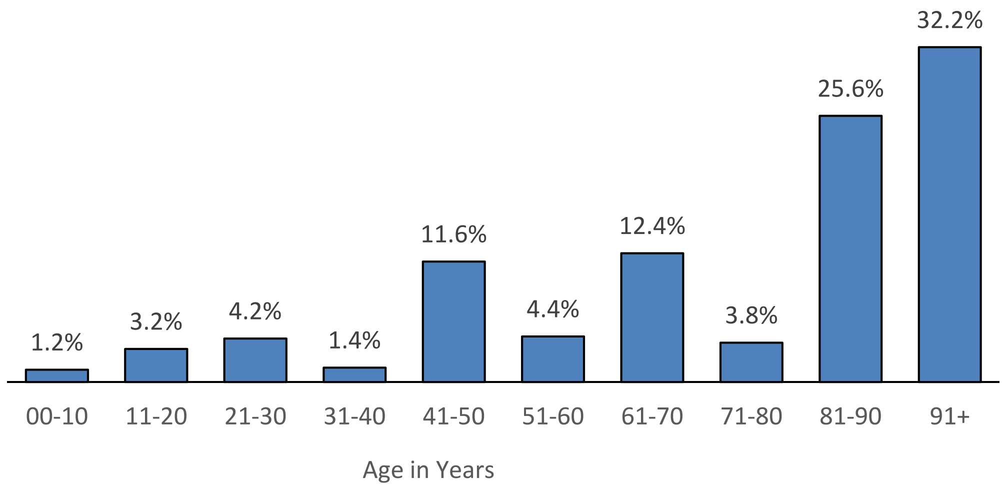
4.17 Manholes

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. More than 78 percent of manholes are over 50 years old (Exhibit 4.17.2).

Exhibit 4.17.1 Manhole and Cables

Exhibit 4.17.2 Manhole Age Distribution



In 2016, DTEE started a manhole inspection program and inspected 137 manholes. Issues identified during manhole inspections include degradation of structural strength due to surface vibration and presence of ground water, etc. The plan is to continue this effort, inspecting approximately 850 manholes each year until all have been inspected. 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
Capital Replacement Program	No

4.18 Vaults

DTEE has 21 vaults. Theses vaults are all in the City of Pontiac and 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 the equipment in six vaults with surface mounted equipment and convert the vaults to manholes. For the remaining 15 vaults, DTEE expects to replace the existing equipment with submersible equipment. The submersible equipment utilizes the latest technology and will allow remote monitoring and control capability. This not only provides safe, reliable operations of the equipment in the vaults, but also standardizes the vault equipment to reduce the cost of future repairs.

Exhibit 4.18.2 Underground Vault Program Summary

Program Summary	
Equipment	Vaults
Preventive Maintenance Program	No
Proactive Replacement Program	Yes
Proactive Replacement Program Timeline	[To be provided in the final report]
Budget Projection 2018-2022	[To be provided in the final report]
Budget Projection (Entire Program)	[To be provided in the final report]

4.19 Advanced Metering Infrastructure

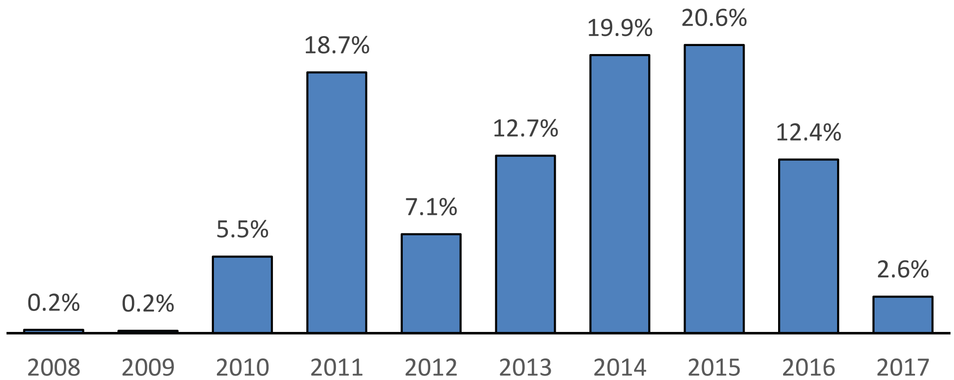
DTEE has replaced nearly all its electric meters with new AMI (Advanced Metering Infrastructure) technology, also known as smart meters.

Exhibit 4.19.1 Electric Meter Types

Mechanical meter

AMI meter

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 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 are able to 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. 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.

4. Turn On / Turn Off / Restore

   AMI technology allows remote connection and disconnection (in accordance with billing rules) of customers without field visits.
5. 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.
6. 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.
7. 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.

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) are expected to retire 3G technology and migrate 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. Incorporating a broken neutral detection capability into the meter firmware will reduce or eliminate field visits for power on/off verification. This feature will reduce operating costs and improve restoration efficiency, particularly during storm conditions.

Exhibit 4.19.3 lists the identified capital projects in the next five years.

Exhibit 4.19.3 AMI Technology Program Summary

Program	Scope of Work	Drivers	Cost Estimate ($million)
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	[To be provided in the final report]
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	[To be provided in the final report]
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	[To be provided in the final report]

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, 4.8kV and 8.3kV 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 know (or estimate) load on the system and individual equipment in order to ensure that capacity exists to serve the load. There are areas within the system where the peak load is expected to increase. These increases may be the result of new load or load 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 states: normal state and contingency state. A contingency refers to planned equipment shutdown, the loss / failure of a component of the electric power system (e.g., a tie line or a truck line), or the loss / failure of individual equipment (e.g., transformer, bus). Most equipment has two ratings – day-to-day and emergency. Substations are rated based on their firm capacity.

- The **day-to-day** rating (also referred to as the normal rating) is the level that the equipment can be operated at for its expected lifespan.

- The **emergency** rating (also referred to as the contingency rating) is higher than the normal rating and is the level that the equipment can be operated at for only short periods of time (typically 24 hours or less). 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 shed or transfer load.

- For substations, a **firm** rating exists. The substation firm rating is the maximum load the substation can carry under contingency conditions based on the emergency ratings of every piece of equipment that is required to serve load.

To ensure that expected load growth can be met within the equipment ratings, DTEE regional planning engineers conduct annual area load analyses (ALA). These analyses include equipment 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 19 percent of distribution substations are over their firm ratings and multiple trunk and tie lines on the subtransmission system are over their emergency ratings during contingency events. As such, they need to be addressed with expanded capacity to prevent customer interruptions during a single contingency event.

As a temporary load relief solution, a "blocking" scheme can be utilized. The "blocking" prevents the automatic throw-over (load transfer) at substations during single contingency events to avoid equipment loading exceeding its emergency rating. Utilization of the "blocking" scheme protects assets but removes redundancy at the substation during peak hours of the year, negatively impacting the system's ability to restore customers quickly.

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. Load relief projects are discussed in detail in Section 5.1.3.

5.1.2 Load Relief Project Prioritization

As mentioned earlier, approximately 19 percent of DTEE's distribution substations are over their firm ratings based on DTEE's 2016 ALA study. It is impossible to propose and execute load relief projects on all these substations in a short period of time. To address that, DTEE developed a prioritization methodology to focus on substations that need the most load relief.

This methodology is based on three variables:

1) Substation Equipment Overload (peak load exceeding substation equipment day-to-day rating or close to substation equipment emergency rating). A score of zero to five is given to substations that experience varying degrees of % day-to-day or emergency loading. A higher percentage (%) of day-to-day or emergency loading creates a higher stress on the equipment and shortens its expected life. A score of five represents the worst equipment overload condition. Exhibit 5.1.1 illustrates the scoring method for this variable

Exhibit 5.1.1 Substation Equipment Overload Scores

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

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 substation firm rating with and without load transfer (or load jumpering). Under contingency conditions, any MVA load over substation firm rating represents the number of customers that cannot be served by the substation itself. Some of this load can be transferred to adjacent substations and minimize the loss of customers. 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 (<=)	Mini (>)	Max (<=)
5	4 MVA			
4	3 MVA	4 MVA	8 MVA	
3	2 MVA	3 MVA	4 MVA	
2	1 MVA	2 MVA		
1	0 MVA	1 MVA		
0		0 MVA		

3) Customer connection requests. The priority for a substation with known customer connection requests is increased by one level. Upon receiving a customer connection request, DTEE is obligated to invest in the system and serve the customer. 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 a cost economic perspective.

The final priority ranking of substation load relief projects are a combination of the above three variables. Substations having a total score of no less than six or no less than three with known customer connection requests receive priority one (1) and are the focus of DTEE's load relief projects in the near term. Section 5.1.3 lists all the priority one (1) substations and their respective variables.

5.1.3 Programs to Address System Loading

Exhibit 5.1.3 lists all the priority one (1) substation load relief projects. Exhibit 5.1.4 lists the scope of work for the same priority one (1) substation load relief projects

Exhibit 5.1.3 Priority Load Relief Substations - Overview

Index	Substation	Region	Community	% of Day-to-Day Rating	% of Emergency Rating	Equip Overload Score	MVA Over Firm Before Load Transfer	MVA Over Firm After Load Transfer	Substation Over Firm Score	Total Score	Customer Request	Priority
1	Diamond	SW	Dexter / Scio	94%	91%	5	20.6	4.2	5	10	Y	1
2	Argo	SW	Ann Arbor	120%	77%	5	4.9	0	3	8	Y	1
3	Elba	NE	Elba Twp	103%	73%	3	3.4	3.4	4	7	Y	1
4	White Lake	NW	White Lake	101%	59%	1	5.8	5.8	5	6	Y	1
5	Almont	NE	Almont Twp	91%	59%	1	5.4	4.6	5	6	Y	1
6	Berlin	SW	S. Rockwood	96%	95%	5	1.5	0	0	5	Y	1
7	Bloomfield	NW	Bloomfield	90%	77%	1	17.3	1	4	5	Y	1
8	Bunert	NE	Warren Roseville	90%	66%	1	9.6	0	4	5	Y	1
9	Carleton	SW	Carleton	106%	87%	3	2.1	0.1	1	4	Y	1
10	Reno	SW	Freedom / Bridgewater	90%	62%	1	2.9	2.9	3	4	Y	1
11	Grayling	NW	Shelby Twp	73%	63%	0	14.6	0	4	4	Y	1
12	Lapeer	NE	Lapeer	68%	62%	0	15.5	0	4	4	Y	1
13	Wixom	NW	Wixom	72%	57%	0	17	0	4	4	Y	1
14	Duvall	SW	Northville	65%	56%	0	20.5	0	4	4	Y	1

Index	Substation	Region	Community	% of Day-to-Day Rating	% of Emergency Rating	Equip Overload Score	MVA Over Firm Before Load Transfer	MVA Over Firm After Load Transfer	Substation Over Firm Score	Total Score	Customer Request	Priority
15	Hancock	NW	Commerce Township	62%	53%	0	12.6	0	4	4	Y	1
16	Quaker	SW	Commerce Township	76%	69%	0	24.6	0	4	4	Y	1
17	Sheldon	SW	Belleville	59%	43%	0	16.9	0	4	4	Y	1
18	Trinity	SW	Monroe	54%	54%	0	5.2	0	3	3	Y	1
19	Zachary	SW	Belleville	76%	72%	0	5.6	0	3	3	Y	1

Exhibit 5.1.4 Priority Load Relief Substations - Scope of Work

Index	Substation	Region	Community	Scope of Work	Cost Estimate ($ million)
1	Diamond	SW	Dexter / Scio	• Upgrade 2 substation transformers and transfer some load to adjacent substations	[To be provided in the final report]
2	Argo	SW	Ann Arbor	• Transfer three entire circuits and a portion of two circuits from Argo to Buckler, converting them to 13.2 kV	[To be provided in the final report]
3	Elba	NE	Elba Twp	• Build a new 13.2 kV substation • Convert Elba circuits to 13.2 kV • Decommission Elba and 40 kV tap to substation	[To be provided in the final report]
4	White Lake	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	[To be provided in the final report]

Index	Substation	Region	Community	Scope of Work	Cost Estimate ($ million)
5	Almont	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	[To be provided in the final report]
6	Berlin	SW	S. Rockwood	• Upgrade existing transformer and install a 2nd transformer, build a new circuit	[To be provided in the final report]
7	Bloomfield	NW	Bloomfield	• Will be addressed as part of Pontiac 8.3 kV Conversion (refer to Section 5.5.5)	[To be provided in the final report]
8	Bunert	NE	Warren Roseville	• Build a new 120:13.2 kV substation • Decommission the existing 24:13.2 kV and 24:4.8 kV Bunert substation and transfer circuits to the new substation	[To be provided in the final report]
9	Carleton	SW	Carleton	• Upgrade existing transformer and associated substation equipment, reconductor circuit backbone	[To be provided in the final report]
10	Reno	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	[To be provided in the final report]
11	Grayling	NW	Shelby Twp	• Build a new substation, approximately 4 miles of cable and 3 miles of overhead lines	[To be provided in the final report]
12	Lapeer	NE	Lapeer	• 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 • Provide capacity for future load growth	[To be provided in the final report]
13	Wixom	NW	Wixom	• Add a 3rd transformer to the substation, replace switchgear, build 1.5 miles of cable and 5 miles of overhead	[To be provided in the final report]
14	Duvall	SW	Northville	• Build a new substation to relieve Duvall and provide capacity for anticipated new industrial load in the area	[To be provided in the final report]
15	Hancock	NW	Commerce Township	• Add a 3rd transformer to Quaker and building a new substation to relieve load off Quaker and Hancock substations	[To be provided in the final report]

Index	Substation	Region	Community	Scope of Work	Cost Estimate ($ million)
16	Quaker	SW	Commerce Township	• Same as #15	[To be provided in the final report]
17	Sheldon	SW	Belleville	• Build a new class A, 13.2kV-120kV, substation to relieve load on Sheldon and Zachary	[To be provided in the final report]
18	Trinity	SW	Monroe	• Expand Trinity substation to relieve load	[To be provided in the final report]
19	Zachary	SW	Belleville	• Same as #17	[To be provided in the final report]

In addition to substation load relief projects, various subtransmission hardening projects at voltage levels of 24kV, 40kV and 120kV are identified to address loading, reliability and power quality issues associated with DTEE's subtransmission system. While large scope subtransmission projects are listed individually in Exhibit 5.1.5, small scale projects, usually involving a small section of trunk and tie line replacements, are listed together under the Trunk and Tie Line Load Relief Program.

Exhibit 5.1.5 Subtransmission Hardening Projects

Tie or Trunk	Area	Scope	Cost Estimate ($ million)
Ann Arbor / UM System Strengthening	Ann Arbor	Construct two new substations and five miles of 120kV lines, and reconfigure subtransmission tie lines and trunk lines	[To be provided in the final report]
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	[To be provided in the final report]
Tie 810 Strengthening	Richmond / Armada / Columbus / New Havens	Build a new 120-40kV station and three 40 kV tie lines to relieve load from Tie 810	[To be provided in the final report]
Trunk 4245 Cable Relocation	St Clair Shores	Rebuild conduit run under I-94 / 9 mile Rd bridge for four subtransmission and five distribution cables	[To be provided in the final report]
Boyne Station Load Relief	Chesterfield / Macomb Twp	Build a second transformer at the station and build a new trunk to reduce overloads on Trunk 7909	[To be provided in the final report]
Trunk and Tie Line Load Relief Program	All	Upgrade approximately 46 trunk lines and tie lines to higher rating to meet contingency loading criteria	[To be provided in the final report]

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 condition as of today. The area load growth is constantly evolving due to changes in customers' connections, utilization of demand response and emergency efficiency measures, and the general economic trends, etc. DTEE has the obligation to serve customers and works to project load growth in future years and the timing needed for infrastructure construction to ensure that all customers will be served with adequate capacity. However, the uncertain nature of future load growth will cause changes to proposed projects from year to year. By assessing project proposals known today, DTEE estimates the annual capital spend on load relief projects as shown in Exhibit 5.1.6.

Exhibit 5.1.6 Projected Load Relief Capital Spend

Year	Projected Capital Spend ($ million)
2018	[To be provided in the final report]
2019	[To be provided in the final report]
2020	[To be provided in the final report]
2021	[To be provided in the final report]
2022	[To be provided in the final report]

5.1.4 Non-Wire Alternatives to Address System Loading

DTEE continues to investigate non-wire alternatives or Distributed Energy Resources (DER's) to provide load relief to the electrical system, including energy efficiency (EE), demand response (DR), and distributed generation (DG). Below is a summary of major pilots and programs that are underway.

- Non-wire Energy Efficiency Alternative Pilot Study: DTEE conducted a non-wire alternative pilot study to determine the potential for geographically targeted (geo-targeted) energy efficiency to cost-effectively defer a distribution system upgrade. As a result of the study, DTEE concluded that geo-targeted energy efficiency programs alone would not be a cost-effective solution to defer capital investment for substation upgrades.

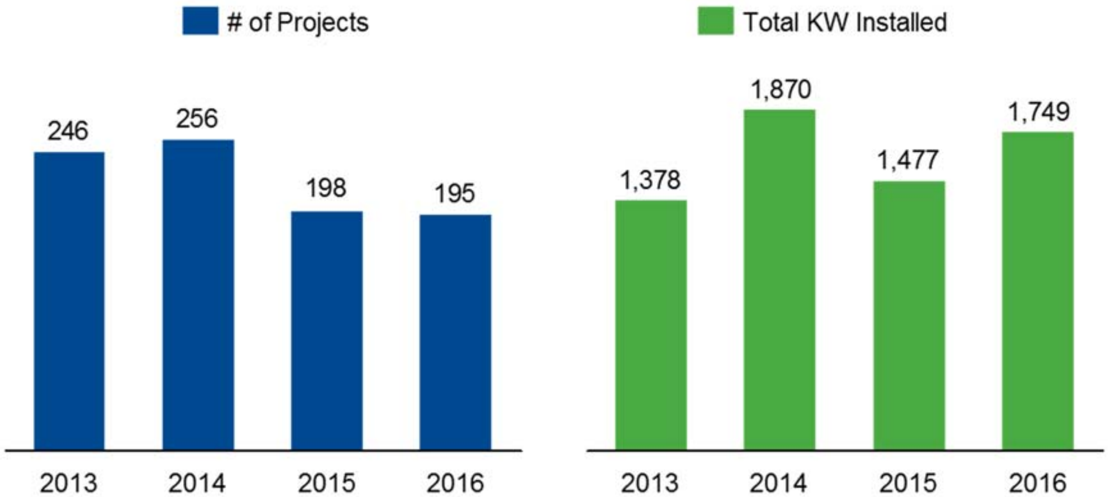
- Demand Response Programs: DTEE continues to execute Demand Response Programs as described in DTEE's Demand Response annual report, Case No. U-17936, submitted on Feb 1, 2017. In addition to DTEE's existing Demand Response Programs, DTEE is participating in the 6T-IRP (Integrated Resource Planning) 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 direct testimony of Company Witness Irene Dimitry in Case No. U-18255, pages 4 through page 24.

- Distributed Generation (DG): DTEE accommodates all customers with DG who wish to connect to the electrical grid through the interconnection process. After a study is completed, the required equipment to control and protect the system and other DTEE customers must be installed and tested before a Parallel Operating Agreement (POA) is executed to allow two-way power flow. In the case of small interconnections, this requires a disconnect switch or IEEE certified equipment. Larger generators may require grid updates and protection schemes such as Transfer Trip. 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 DER in the DTEE service area is 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 a number of multi-MW synchronous generators and dynamometers connected to the grid that are typically located at commercial and industrial facilities. DTEE has rates for customers that wish to operate their generation parallel to the grid and act as grid resources that can be monitored and controlled by DTEE.

  Interconnection applications have ranged between 1,300 MW and 1,900 MW installation each year in the last few years as shown in Exhibit 5.1.7., showing little to no growth. DTEE recognizes that if DG grew at a faster pace, distribution infrastructure would potentially need additional capital investments to meet the needs of DG interconnection, especially with regards to switching and protection. However, at this point, DTEE does not see sufficient evidence of demand increase to confidently project the location or the timing of DG interconnection that would justify infrastructure upgrades.

Exhibit 5.1.7 Historical Trend on Small DG Projects and Installed kW



- Energy Storage Pilot and Demonstration Projects: DTEE is actively evaluating the role of distributed technologies, including energy storage, as alternatives to infrastructure upgrades. In 2013-2015, DTEE conducted a pilot study to install 1 MW of distributed Community Energy Storage (CES) units and a grid connected storage battery on a circuit with a solar park as part of a DOE 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 the costs of battery storage are still too high to be economically justifiable for a large-scale deployment.

  Since 2015, DTE has continued to track and evaluate battery storage as an alternative for distribution infrastructure upgrades. Given the declining costs of battery storage, DTEE is currently developing a number of demonstration projects for 2018 to investigate whether energy storage could be a cost-effective alternative to provide emergency backups, micro-grid / islanding and to help delay capital for infrastructure upgrades in the near- to mid-term. These battery storage demonstration projects will also help further build DTEE's experience with advanced technologies in this space.

DER could potentially delay infrastructure upgrades driven by capacity needs. In order for distributed energy resources to be considered as non-wire alternatives, it is essential that the distributed resources have the appropriate control equipment to isolate or curtail their power flow and that DTEE be able to verify the operation. Additionally, it is crucial that DTEE has a contractual or rate agreement to ensure that customer generation or demand response through islanded microgrid will operate when called upon in a capacity shortfall or abnormal system condition.

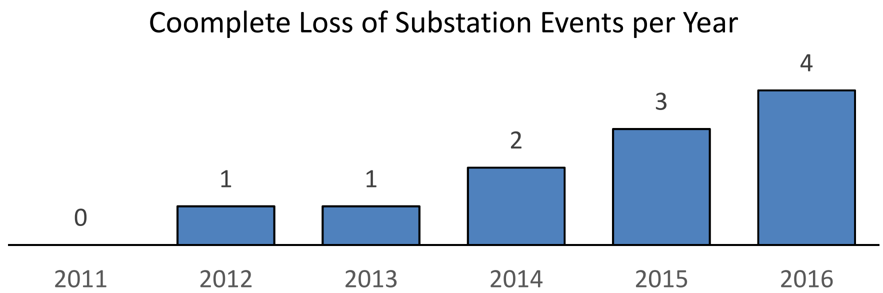
DTEE is actively benchmarking with other utilities and participating in various industry consortiums to learn the best practices for all forms of DER integration. DTEE is also reviewing substation and equipment design so that new substations will be able to accommodate DER integration in the future. One of the most important initiatives that will help DTEE better accommodate increasing DER participation in the future is the implementation of Advanced Distribution Management System (ADMS), which will be addressed in detail in Section 5.4. The proposed ADMS project will have a Distributed Energy Resource Management module specifically designed to manage distributed energy resources.

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 lists a summary of the major substation events where DTEE experienced a temporary loss of an entire substation. 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 load was transferred quickly to other substations or circuits. On the other hand, during events such as Webster, Apache, Arnold, and Warren, 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.

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



Substation	Date	Cause	Customers Interrupted	Hours to Full Restoration
Webster	07/17/12	Breaker	9,519	48
Stephens	10/23/13	Transformer	5,943	8
McGraw	08/14/14	Other Equipment	4,424	11
Daly	09/07/14	Loading	3,832	7
Apache	07/23/15	Switchgear	9,486	34
Arnold	09/15/15	Cable	2,617	31
Warren	11/23/15	Switchgear	3,063	24
Benson	04/18/16	Switchgear	12,139	3
Liberty	01/04/16	Breaker	3,712	13
Drexel	07/18/16	Cable	3,213	13
Alpha	10/23/16	Circuit Switcher	6,678	7

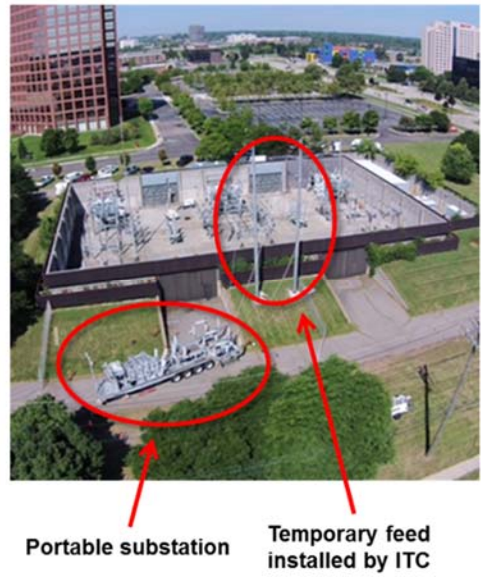
The loss of an entire substation negatively impacts customers, as illustrated by the Apache substation event (Exhibit 5.2.2). In July of 2015, Apache substation experienced a switchgear failure, causing the entire substation to be de-energized and interrupting approximately 10,000 customers. A portion 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 total event cost was approximately $2 million.

Exhibit 5.2.2 Apache Substation Outage – July 2015

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

Restoration strategy
- A portion of customer load was transferred to adjacent substations
- The remaining load was picked up by a portable substation and six portable generators (mobile generation fleet)
- The outage lasted 34 hours for some customers

Cost
- $2M total spend
  - $1.5M spent on restoration
  - $0.5M spent on repair



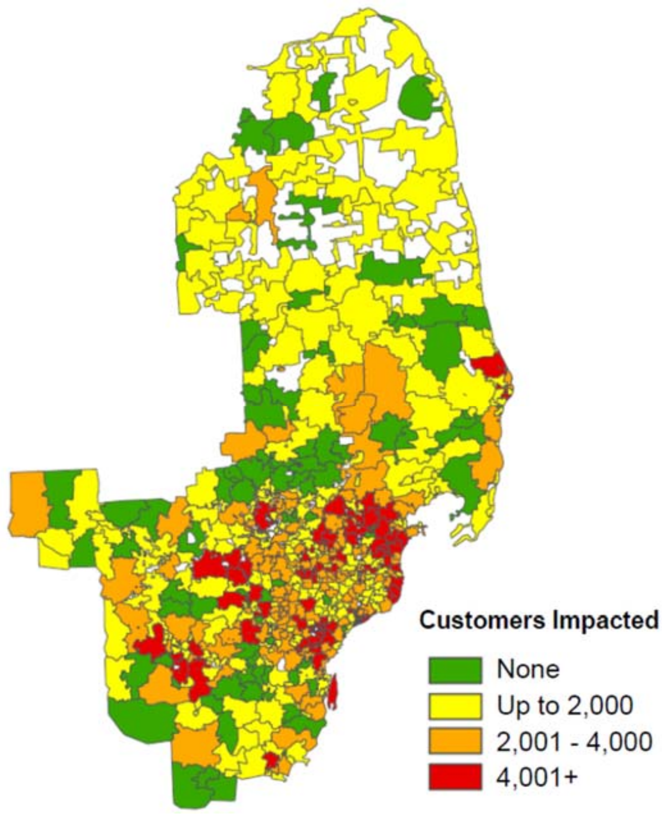
In the aftermath, analyses indicated that other substations also have aging, at-risk critical assets and under certain conditions customers would not be restored for several days in the event of a total substation loss.

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.

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 5.2.3 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 in a substation outage event during summer peak.

Exhibit 5.2.3 Stranded Load Map During Complete Loss of a Substation



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 5.2.4. Substation outage risk scores are indexed between 0 and 100, with 100 representing the highest substation risk score. As illustrated in Exhibit 5.2.5, 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 5.2.4 Substation Risk Score Distribution

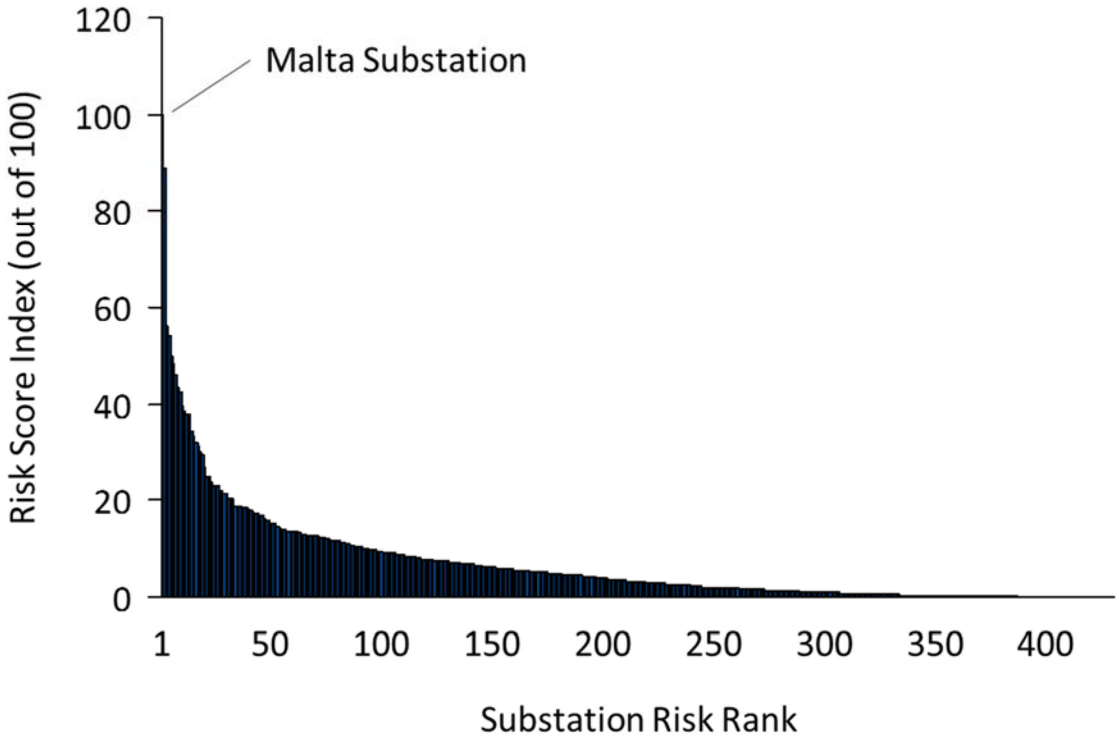


Exhibit 5.2.5 Highest Outage Risk Substations

Substation	City	Substation Outage Risk Score	Substation Outage Rate [1]	Stranded Load after Load Transfer (MVA)	Stranded Load after DG (MVA)
Malta	Sterling Heights	100	2.4%	63	29
Crestwood	Dearborn	56	2.6%	32	32
Bloomfield	Pontiac	48	3.1%	23	23
Savage	Troy	43	2.0%	32	32
Apache	Troy	42	1.9%	33	33
Chestnut	Madison Heights	40	1.8%	32	20
Jupiter	Allen Park	38	1.4%	41	10
Spruce	Ann Arbor	31	1.4%	34	20
Birmingham	Birmingham	30	2.1%	21	19

1. *Annual Probability of Complete Loss of Substations*

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, installing mobile assets provides relatively quick restoration compared to the time needed to make substation repairs. Though expanding the mobile fleet capacity is relatively low cost, it does not reduce the substation outage risk. Moreover, the application of mobile fleets for restoration is limited due to the feasibility of connecting mobile fleet at substation sites, space and traffic considerations, as well as environmental and community impacts.

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. It is important to note that the substation outage risk model provides a starting point to evaluate relative substation outage risk. DTEE engineers take the risk scores as the starting point and then further evaluate the substation conditions before determining capital projects to address them. Exhibit 5.2.6 shows the directional timeline for the substation outage risk reduction program through 2022. The timeline considers multiple factors including: relative substation outage risk, resource availability, specific site conditions and other execution constraints. The actual timing of project execution may change from the plan due to these factors.

Exhibit 5.2.6 Estimated Timeline for Substation Outage Risk Reduction Programs

Project	Municipality	2017	2018	2019	2020	2021	2022	Cost Estimate ($ million)
Malta	Sterling Heights							[To be provided in the final report]
Crestwood	Dearborn							[To be provided in the final report]
Bloomfield	Pontiac							[To be provided in the final report]
Savage	Troy							[To be provided in the final report]
Apache	Troy							[To be provided in the final report]
Chestnut	Madison Heights							[To be provided in the final report]
Jupiter	Allen Park							[To be provided in the final report]
Spruce (SCIO)	Ann Arbor							[To be provided in the final report]
Birmingham	Birmingham							[To be provided in the final report]
Mobile Fleet	All							[To be provided in the final report]

Based on the identified projects, DTEE projects the annual capital spend on the substation outage risk reduction as shown in Exhibit 5.2.7

Exhibit 5.2.7 Projected Substation Outage Risk Reduction Capital Spend

Year	Projected Capital Spend ($ million)
2018	[To be provided in the final report]
2019	[To be provided in the final report]
2020	[To be provided in the final report]
2021	[To be provided in the final report]
2022	[To be provided in the final report]

5.3 System Reliability

5.3.1 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). A MED 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 MEDs 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, small (non-catastrophic) storms, and excluding storms. Doing so allows better insight into reliability performance and root causes of customer outages.

<u>Catastrophic Storms</u>

In MPSC 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 5 percent of its customers interrupted – That is the level at which mutual assistance from other utilities is typically required in addition to contract crews and local foreign crews – in order 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.

<u>Small Storms</u>

DTEE is in small storm mode whenever catastrophic conditions are not yet reached but weather conditions result in outage cases that are significantly more than the on-shift crews can restore in a reasonable amount of time. For small 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 days until the restoration is complete.

To ensure the most efficient restoration from storm related interruptions, each storm (catastrophic and small) is managed by a storm director who has overall responsibility for the storm restoration process. All day-to-day functions of operating, dispatching, and support are supplemented with additional personnel to the degree needed during storm restoration. These additional personnel have been trained to perform the necessary tasks and are on a predetermined rotation so that they are prepared when needed. The DTEE Emergency Headquarters (EH) is typically operational only during catastrophic storms. For small storms, the EH may or may not be operational, but the same types of restoration functions occur in the dispatch center or elsewhere.

Below are several series of charts (Exhibits 5.3.2 – 5.3.6) that show historic SAIFI, SAIDI, and CAIDI values for various conditions.

Exhibit 5.3.2 Reliability Statistics - All Weather

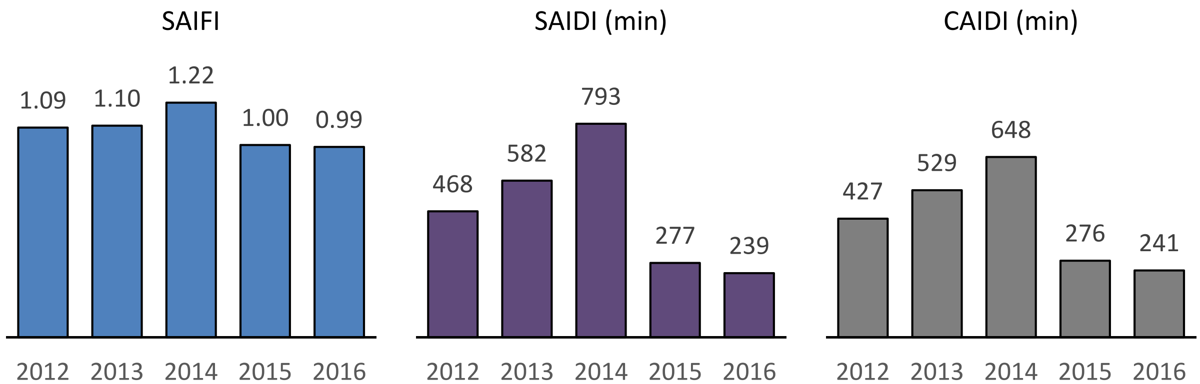


Exhibit 5.3.3 Reliability Statistics - Excluding MEDs

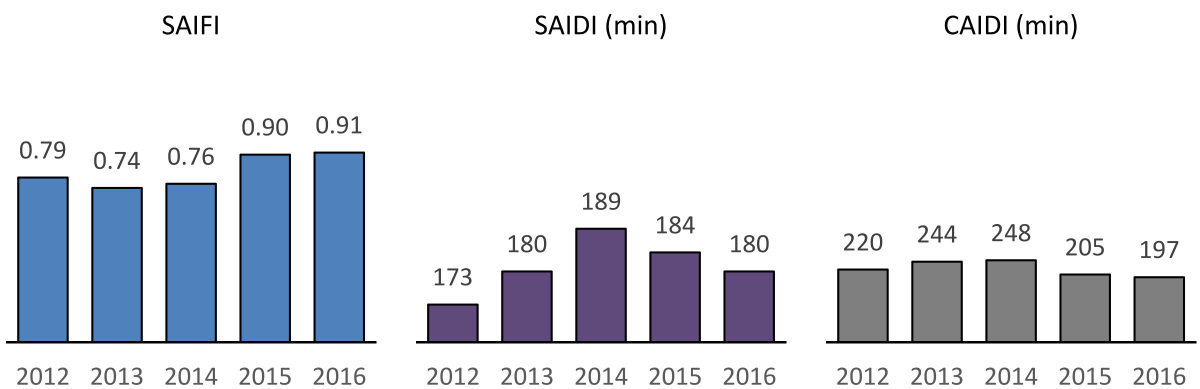


Exhibit 5.3.4 Reliability Statistics - Catastrophic Storms (DTEE Definition)

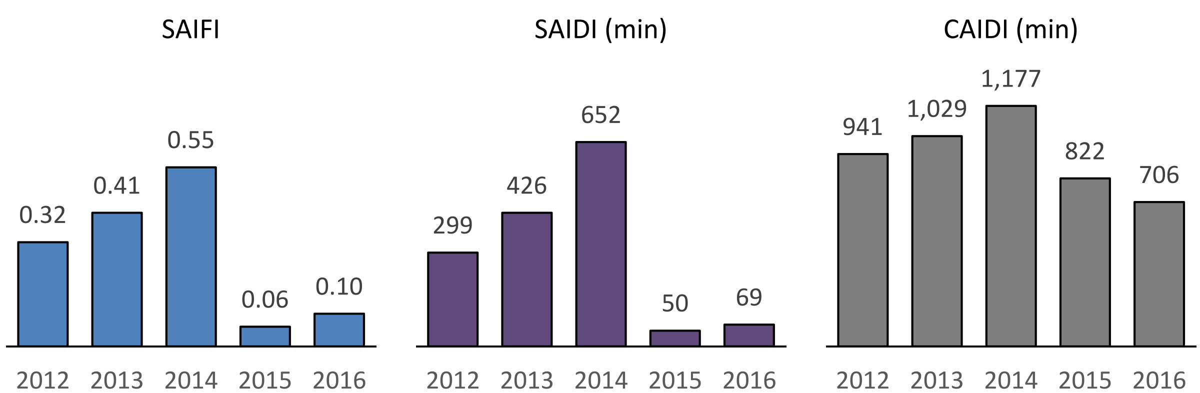


Exhibit 5.3.5 Reliability Statistics - Small Storms (DTEE Definition)

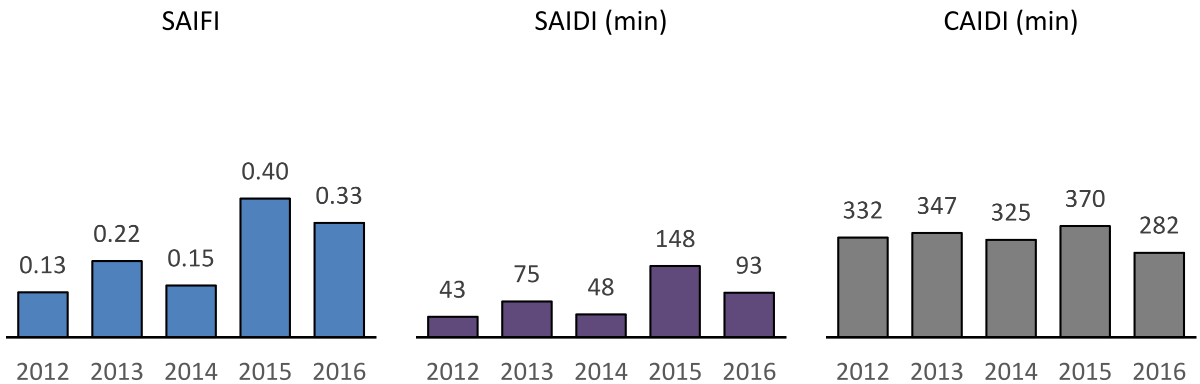
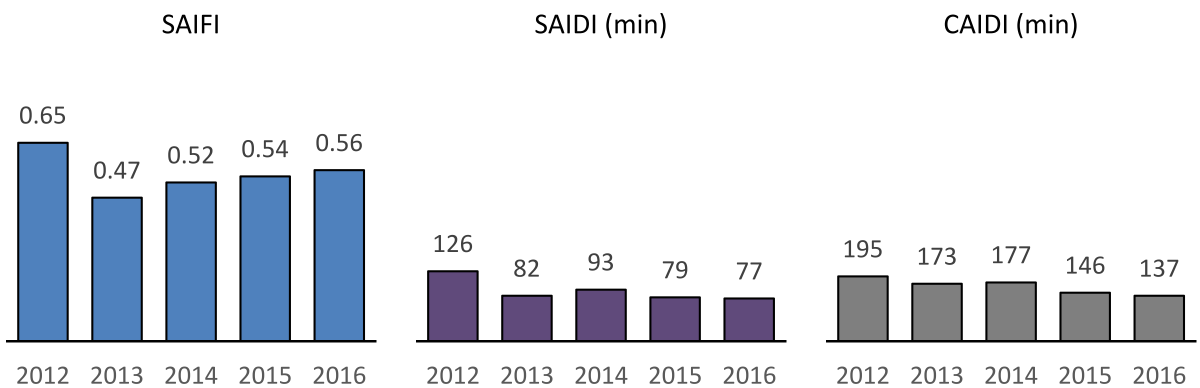
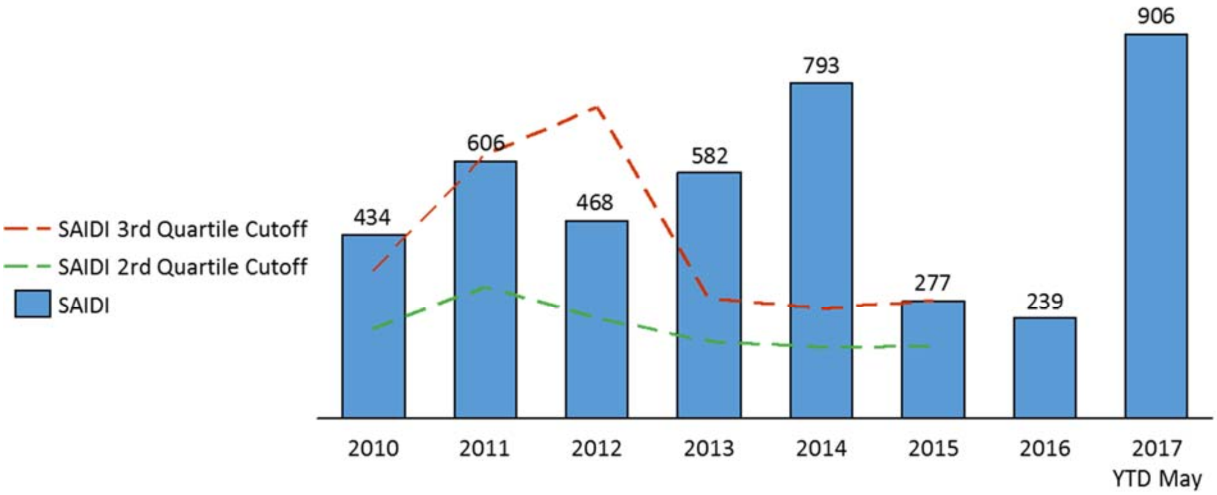


Exhibit 5.3.6 Reliability Statistics - Excluding Storms



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 small 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 significant improvements on all-weather SAIDI.

Exhibit 5.3.7 SAIDI Performance (Minutes)



	2010	2011	2012	2013	2014	2015	2016	2017 YTD May
# of DTE Catastrophic Storms[1]	2	3	4	6	6	1	1	1
# of DTE Small Storms[2]	16	19	9	10	13	21	21	6
WEI – 30 (Hours)[3]	123	183	211	151	185	154	138	157

1. *A storm is typically defined as "catastrophic" if more than 5% of customers (~110,000) experience a sustained service interruption*
2. *A storm is typically classified as "small" if between 15,000 and 110,000 customers experience a sustained service interruption*
3. *The Wind Exposure Index 30 (WEI-30) represents the average number of hours a customer experienced wind gusts of 30 mph or greater*

Note: 2016 SAIDI quartiles are not available

5.3.2 CEMIn and CELIDt

In addition to SAIFI, SAIDI, and CAIDI, two other indices are used to gauge 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, calculation of CEMIn and CELIDt are done with un-reviewed raw real-time outage data which is known to overstate the values by 25 percent to 30 percent. The overstatements on the CEMIn and CELIDt values are due to mapping discrepancies, misclassification of the outage events (e.g., low voltage vs. outage), and duplicate events in the raw data, etc. The CEMIn and CELIDt values are inflated in an absolute sense, but in a relative sense they provide a basis for further investigation and verification. At this time, procedures to use AMI meter data to more accurately identify CEMIn and CELIDt are being evaluated and are beginning to be implemented.

DTEE's CEMIn and CELIDt values include scheduled outages and outages beyond our control such as public interference. Once a potential CEMIn or CELIDt case has been identified, it is reviewed by engineers and field personnel to verify its root cause. Through the Repetitive Outage program (also known as CEMI program), the root causes of the interruptions are determined and appropriate remediation is taken. This may include: reconductoring and/or relocating lines, circuit reconfiguration, tree trimming, and adding sectionalizing equipment.

Exhibit 5.3.9 CEMIn by Year

CEMIn	2012	2013	2014	2015	2016
CEMI 0	2,100,000	2,181,974	2,166,391	2,167,276	2,187,144
CEMI 1	1,482,953	1,443,749	1,515,612	1,273,402	1,245,866
CEMI 2	788,531	786,657	866,980	622,180	596,814
CEMI 3	380,037	399,349	454,658	282,709	270,676
CEMI 4	175,709	192,366	219,181	125,496	121,110
CEMI 5	79,285	97,726	96,271	58,121	51,279
CEMI 6	32,892	44,130	40,263	25,957	24,692
CEMI 7	13,662	18,916	16,043	11,485	12,334
CEMI 8	5,420	7,092	6,683	5,432	4,634
CEMI 9	2,371	2,741	2,897	3,236	1,712
CEMI 10	1,562	1,395	1,514	2,737	605

Exhibit 5.3.10 CELIDt by Year

CELIDt	2012	2013	2014	2015	2016
CELDI 0	2,100,000	2,181,974	2,166,391	2,167,276	2,187,144
CELID 24	147,617	198,407	325,136	54,429	31,309
CELID 48	41,145	56,415	106,085	9,370	1,575
CELID 72	15,078	14,782	32,333	216	40
CELID 96	4,830	4,077	7,633	19	14
CEMI 120	1,029	1,998	1,241	10	7

5.3.3 Causes of Interruptions

Tree / wind interference causes the most number of minutes DTEE customers spend without power, underscoring the importance of the tree trimming program. However, equipment failures are the leading cause of the number of outages (though they do not lead to the greatest number of outage minutes). Additionally, equipment related outages are projected to continue increasing without infrastructure replacement.

DTEE's current outage data collection system does not track interruption data by asset class, so performance metrics by asset class are not available. Regardless, the interruption data alone does not represent the overall performance of the electric system. Due to redundancy in substations and the subtransmission systems, an equipment failure at the substation and subtransmission level may or may not result in an interruption of service to customers.

The average outages and customer interruptions by cause are shown in Exhibits 5.3.11-5.3.12. It should be noted that equipment failures are the leading cause of the number of outages, though they do not lead to the greatest number of outage minutes.

Exhibit 5.3.11 Annual Average Minutes of Interruption by Cause

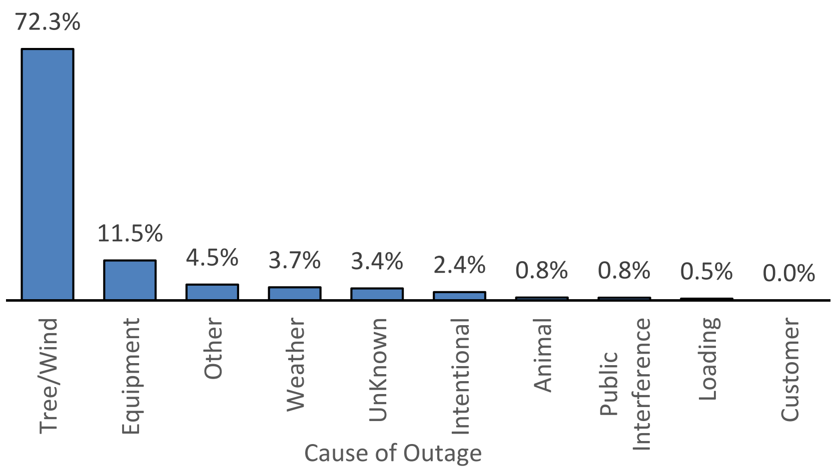
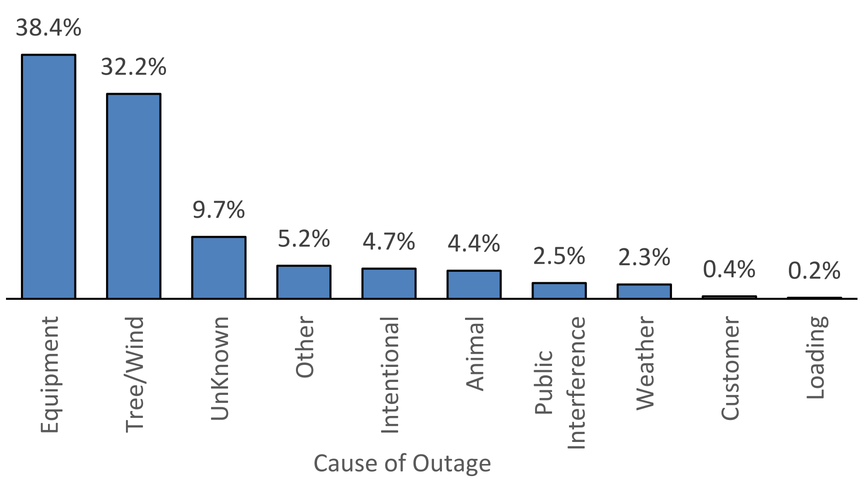


Exhibit 5.3.12 Annual Average Outage Cases by Cause



Source: January 1, 2010 – April 30, 2017 system outage data

5.3.4 Programs to Improve Reliability

In addition to tree trimming (discussed in Section 6) and Pole / Pole Top Maintenance (discussed in Section 4.7), DTEE has established a number of programs to specifically address reliability issues. These reliability programs have evolved and will continue to evolve over the years to address emerging problems with the best available equipment and techniques. The main recurring reliability programs are listed in Exhibit 5.3.13.

Exhibit 5.3.13 Reliability Programs

Program	Scope of Work	Targeted Areas
Circuit Improvement: System Resiliency	• Install sectionalizing and switching devices to localize outage events and enable restore and repair	Remediate long-outage duration for circuits with few sectionalizing points
Circuit Improvement: Circuit Renewal	• 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.	Address circuits with chronically poor reliability performance by focusing on removing root causes of reliability and power quality events
Repetitive Outage Program (also known as CEMI program)	• Similar to Circuit Renewal	Remediate small pockets of customers or single customers experiencing repetitive outage events by focusing on removing root causes of reliability and power quality events
Tree Trimming	See Section 6 for details	
Pole and Pole Top Maintenance	See Section 4.7 for details	
Secondary / Service Improvement Program	See Section 5.5 for details	
Pilot: 4.8kV Circuit Rebuild	See Section 5.5 for details	

Circuits selected for the System Resiliency Program are circuits with low penetration of switching and sectionalizing devices, and little opportunity to localize outage events to perform Restore Before Repair (RBR). Restore Before Repair is the practice when customers (load) are transferred to adjacent circuits or substations to restore power before repair can be completed on failed sections of the circuit.

Circuits selected for the Circuit Renewal Program are circuits with poor historical reliability performance. About 29 DTEE circuits had circuit SAIFI greater than 1 and circuit SAIDI greater than 475 minutes in both 2015 and 2016. An additional 38 circuits had circuit SAIFI greater than 0.85 and circuit SAIDI greater than 250 minutes in both years. These circuits are prioritized for the Circuit Renewal Program accordingly.

On the other hand, the number of CEMI 4 customers, power quality complaints and MPSC complaints are considered in determining customer pockets or portions of circuits for the Repetitive Outage Program (CEMI program). Different from the previous two programs, the Repetitive Outage Program (CEMI program) is a reactive program that follows the latest performance of the circuits in proposing projects.

Exhibit 5.3.14 shows the projected annual capital spend for these reliability programs.

Exhibit 5.3.14 Reliability Program Capital Spend

Year	Projected Capital Spend ($ million)
2018	[To be provided in the final report]
2019	[To be provided in the final report]
2020	[To be provided in the final report]
2021	[To be provided in the final report]
2022	[To be provided in the final report]

5.4 Grid Technology Modernization

5.4.1 Context

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

DTEE's self-assessment on grid technology, based on benchmarking discussions with other utilities and inputs from consulting firms, 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 its equipment, which was installed prior to the availability of smart technologies such as SCADA. DTEE's proposal to enhance and modernize electric grid technology is detailed in Section 5.4.2.

Exhibit 5.4.1 Assessment of DTEE Grid Technology

Characteristics	DTE 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
Cybersecurity	• SCADA network has high security and maturity level to meet NERC / CIP requirements • Legacy Devices in the field may need to be retrofitted before they are added to the SCADA network • Legacy hardware that needs cybersecurity upgrades to be placed on the network	Medium
Distributed Energy Resource Integration	• Grid protection must be redesigned for two-way power flow • Lack of real time Volt/VAR optimization	Low

Grid-wide situational awareness includes real-time advanced sensing technology on devices in substations and on circuits to measure load, voltage and fault information and return the data to the control center for analysis.

DTEE has made some progress on installing line sensors on circuit cable poles at the start of circuits and expects to complete the program by 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 below the industry average. An even lower percentage of substations have fault data and power quality monitoring.

Integrated system and advanced analytics include an Advanced Distribution Management System that enables electronic tagging and protection, integrated dispatching, real time load studies, Fault Location, Isolation and Service Restoration (FLISR), Volt/VAR Optimization (VVO) and the ability to analyze equipment performance and health to prioritize maintenance and replacement.

DTEE's existing operational technologies such as Advanced Metering Infrastructure (AMI), Outage Management System (OMS), 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. However, an integrated ADMS (Advanced Distribution Management System) will allow analysis that currently takes hours to be done in minutes. 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 Outage Management System. 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. Analysis of system performance data requires piecing together information from multiple systems, 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.

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, 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 at Navigant Consulting suggested that most, if not all, metropolitan utilities have close to 100 percent penetration of substation remote control capability. This assessment has been confirmed by discussion with other utilities. This gap is primarily driven by extremely 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 a truck 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 regulators and capacitors were primarily installed in the 1990s. At that time, technology for controlling them was extremely basic and is now obsolete 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 have 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 more than 30-years old and presents numerous challenges to support modernized grid operations. First, the control center operates with a magnetic pin board which requires physically changing tiles to reflect system changes and only gives indications of a general alarm. Switching and protective tagging are done through a manual process. Also, the SOC facility has limited redundancy in mechanical and electrical systems. It has limited space available for expansion and collaboration with the Central Dispatch team that handles distribution circuit and customer meter events dispatch. The physical and procedural separation of the Central Dispatch team from System Operations Center leads to inefficiencies in responding to system events and results in longer outage times for customers. Co-locating System Operations and dispatching functions is a well understood industry best practice.

Cybersecurity at DTEE has a multi-level defense strategy. Sites that meet NERC-CIP guidelines follow the relevant procedures and requirements for physical and cyber protection. Critical devices on the Industrial Control System network go through a cybersecurity review. Many NERC CIP cyber security controls are also applied to sites that are below NERC voltage levels to provide similar security hardening and policies / procedures for employees to access the network.

The SCADA network is separated through firewalls and security applications from any corporate or public infrastructure. The devices on the communications network utilize end-to-end encryption. Unrecognized and unsolicited traffic is alarmed and disallowed. Unused and insecure access protocols and passwords are blocked.

DTEE participates in a national threat detection network through the US government and third party researchers to actively address real-time and emerging cybersecurity threats, including the Electricity Information Sharing and Analysis Center (E-ISAC) and the Cybersecurity Risk Information Sharing Program (CRISP). Steps are being taken to embed and mature the implementation of DOE cybersecurity and NIST cybersecurity frameworks and governance to prioritize risks to the business units.

DTEE also operates its own resilient communications network to isolate the grid from service attacks and major outages of telecommunication providers. Continued investment in cybersecurity is required as the grid becomes more complex and integrated, and the level of automated and sophisticated threats increases. Cybersecurity is a key requirement of the ADMS system review. In addition, efforts are underway to procure and establish an enterprise level cyber asset management system to identify threats and respond quickly to allow for remediation steps to be taken in a timely fashion.

In 2016, a cybersecurity standard was established for all new substations based on the IEC 61850 standard, and this standard is being extended to legacy substations, pole top devices and DER sites. Additionally, the SCADA system is in scope for NERC-CIP compliance and is actively audited by ReliabilityFirst to ensure compliance. DTEE has also completed an external Operational Technology (OT) security assessment by a 3rd party (Ernst & Young), and initiated a "Cyber Excellence Program" to implement additional cyber security controls and governance identified by this assessment. Additional 3rd party assessments will be done to review cybersecurity vulnerabilities for Operational systems and hardware.

Distributed energy resource (DER) integration includes control and monitoring of DERs, integrated tracking and planning for DER applications, and utilization of energy storage and adaptive protection for two-way power flow.

Each additional DER 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; however the lack of an integrated ADMS system means that multiple studies need to be conducted to process the 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 near real-time metering being installed at a distributed resource site and an integrated control system in the ADMS, DTEE cannot use DERs 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 5.4.2.

Exhibit 5.4.2 Grid Technology Modernization Programs

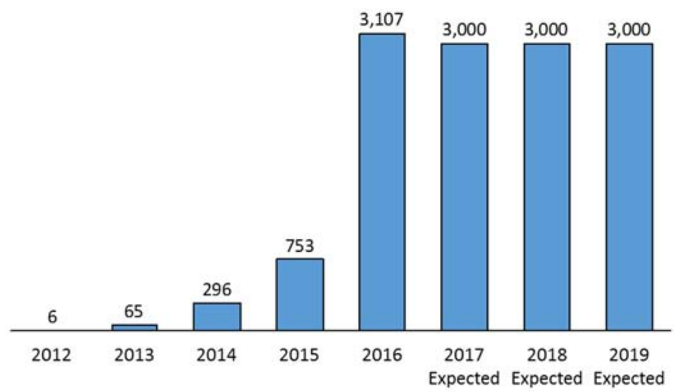
Program	Scope of Work	Drivers	Cost Estimate ($ million)
Line Sensors	• Aggressively pursue Line Sensor installation on cable poles and strategic locations along the circuit	• Enhance grid-wide situational awareness • A low-cost alternative to SCADA remote monitoring at substations	[To be provided in the final report]
ADMS / SOC Modernization	• Install an Advanced Distribution Management System to integrate various operational technologies and analytical tools • Modernize System Operations Center	• Provide the analytics to perform FLISR and improve reliability • Provide the infrastructure, technology platform and user interface for flexible real-time operations • Allow co-location of dispatchers and system supervisors to improve operational efficiency	[To be provided in the final report]
SCADA and Telecom Baseline	• Install and/or upgrade telecommunication and RTU's to prepare for SCADA capability	• Provide the communication package at substations to allow for SCADA upgrades	[To be provided in the final report]
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	[To be provided in the final report]
Distribution 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 • Initially replace legacy switches and poor performers and upgrade communications on existing sites	[To be provided in the final report]

Program	Scope of Work	Drivers	Cost Estimate ($ million)
Capacitor and Regulator Controls Upgrade	• Retrofit existing regulators and capacitors with new controls, sensing and communication that will allow operation by the ADMS	• Enable Volt/VAR Optimization to automate line losses reduction and voltage control • DTEE's existing capacitor control is no longer being supported or manufactured, as sites need to be replaced and new controls need to be installed	[To be provided in the final report]
Pilot: Technology	2018 scope includes: • 4.8 kV automated pole top devices • SCADA-controlled regulators • SCADA-controlled capacitor banks	• Test application of circuit automation devices for 4.8kV system • Test application of SCADA regulators and capacitors for advanced Volt/VAR control	[To be provided in the final report]
AMI	See Section 4.19 for details		

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 real-time basis, until the long-term solution of equipment upgrades and substation control solutions are fully implemented. As shown in Exhibit 5.4.3, at the end of 2016, DTEE had installed over 4,000 line sensors on 800 overhead circuits. By the end of 2017, DTEE expects to install additional 3,000 sensors and reach line sensor coverage on 1,500 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 real-time loading data and fault alarms.

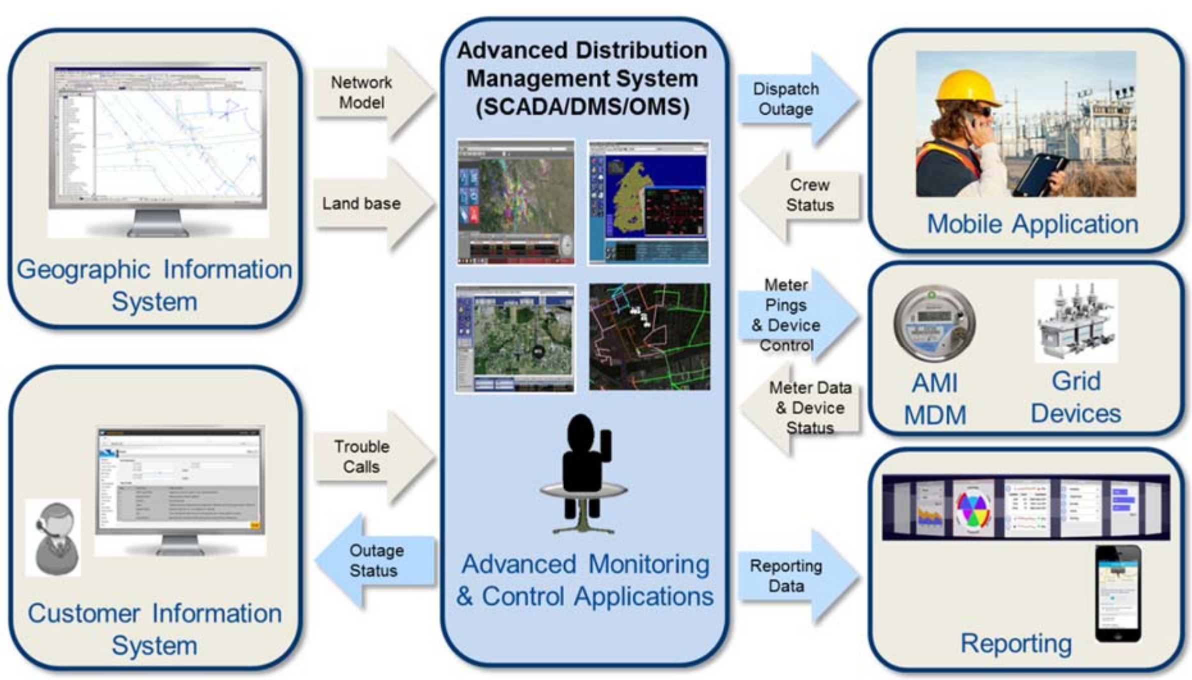
Installation of line sensors allows us to use much more accurate load data for system planning and design. During outage events, these sensors enable us to identify and locate faults and dispatch crews to the right location, significantly reducing patrol time.

Exhibit 5.4.3 Line Sensors Installation by Year



ADMS / SOC Modernization installs an Advanced Distribution Management System 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 provides seamless interface with Geographical Information System (GIS), Customer Information and Notification System (CIS / Customer360), and AMI. Exhibit 5.4.4 illustrates the ADMS as an integrated technology platform that will greatly improve the way DTEE monitors and controls the electric grid to meet our customers' needs.

Exhibit 5.4.4 ADMS System - An Integrated Technology Platform



The ADMS system connects and aggregates many energy grid operational functions to enable a highly visible and controllable distribution grid. The 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 operations, 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 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 data portals and provide system supervisors all the information they need in one place

To fully leverage the ADMS system, part of the program is to construct a new SOC facility. The new SOC will provide the space, security, technology, and infrastructure redundancy to support flexible real-time operations.

Many peer utilities have implemented or are in the process of implementing ADMS as illustrated in Exhibit 5.4.5.

Exhibit 5.4.5 Utilities with ADMS Implementation

Source: Accenture

<u>SCADA and Telecom Baseline Program</u> installs a secure and reliable communications package to all substations that DTE plans to continue operating. All new substations are built to a standard with SCADA and telecommunication capability. As only 30 percent of DTEE substations have SCADA communications, this project will extend the communication network through a combination of supplementing the existing WiFi Mesh, building fiber to the substation sites, and establishing a communication network inside substations to connect relays and metering. The scope includes installing a standardized communication and SCADA cabinet into each substation and building the communications path to the substations.

This is a baseline program to enable substations for a full SCADA data acquisition and control capability in the future and to retrofit obsolete protocols and hardware. Once SCADA controllable devices such as new breakers or relay panels are installed within substations, they can then be connected and controlled remotely from the System Operations Center. This program will also address cybersecurity issues that are not covered in the ADMS and equipment replacement programs, such as eliminating dial up modems for substation remote access.

Substation Automation installs SCADA control at all DTEE substations to allow for full remote monitoring and control. This program is designed to retrofit the 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.

Distribution Circuit Automation installs SCADA reclosers and pole top switches, either replacing outdated SCADA devices (such as Form 3 and Form 5 Reclosers – Section 4.10 and Bridges SCADA Pole Top Switches – Section 4.11), upgrading controls and protocols, or adding SCADA control devices to existing circuits. All new circuits constructed today will be 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 the ADMS system. These devices will be used to isolate faults and provide service restoration automatically or under the direction of the ADMS and System Operations Center. Significant reliability improvements have been observed by other electric utilities after deploying distribution automation.

Capacitor and Regulator Upgrades address the end of life of the existing capacitor and regulator controls on the DTEE system. These devices are no longer manufactured or supported by the vendor. New controls were identified to allow the devices to be controlled by the ADMS and report equipment health and monitoring. ADMS control of the devices will allow greater use of Volt/VAR optimization. Currently DTEE has only a handful of remotely controllable regulators and capacitors on the distribution circuits.

Technology Pilot Program tests new technologies and concepts on a very small scale to ensure system compatibility and economic justification before executing them system wide. The identified pilot program for 2018 includes automated pole top switches for the 4.8 kV system and SCADA enabled overhead capacitors and regulators.

DTEE projects the annual capital spend on grid technology in Exhibit 5.4.6.

Exhibit 5.4.6 Grid Technology Capital Spend

Year	Projected Capital Spend ($ million)
2018	[To be provided in the final report]
2019	[To be provided in the final report]
2020	[To be provided in the final report]
2021	[To be provided in the final report]
2022	[To be provided in the final report]

5.5 4.8 kV and 8.3 kV design

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 was purchased from Consumers Energy in the 1980s and serves the City of Pontiac. The 13.2 kV system is the preferred construction method for new circuits built today.

Comparisons among the three distribution system voltages are shown in the Exhibits 5.5.1-5.5.3. The voltage map for DTEE's distribution system can be found in Exhibit 5.5.4.

Exhibit 5.5.1 Percentage of Substations, Circuits, and Circuit Miles by Distribution Voltage

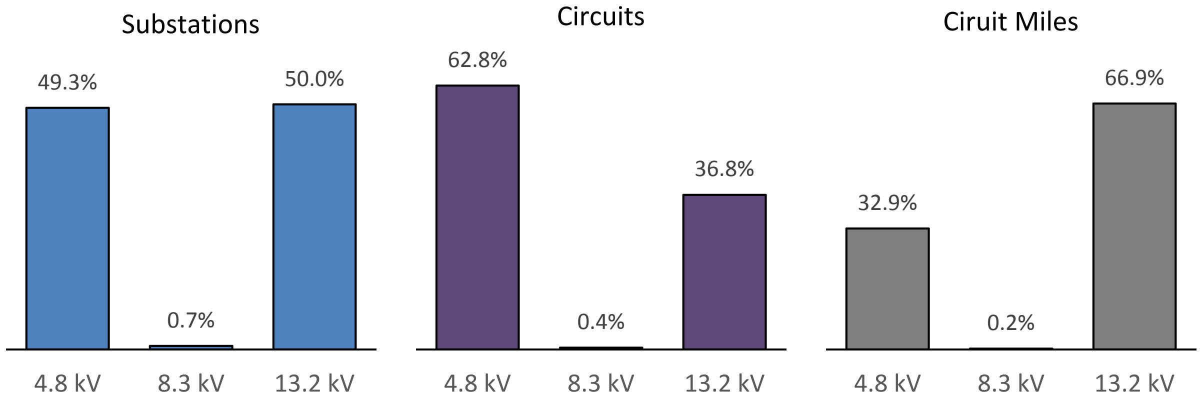


Exhibit 5.5.2 Percentage of Customers, Average Annual Downed Wire Events, and Average Annual Trouble Events by Distribution Voltage

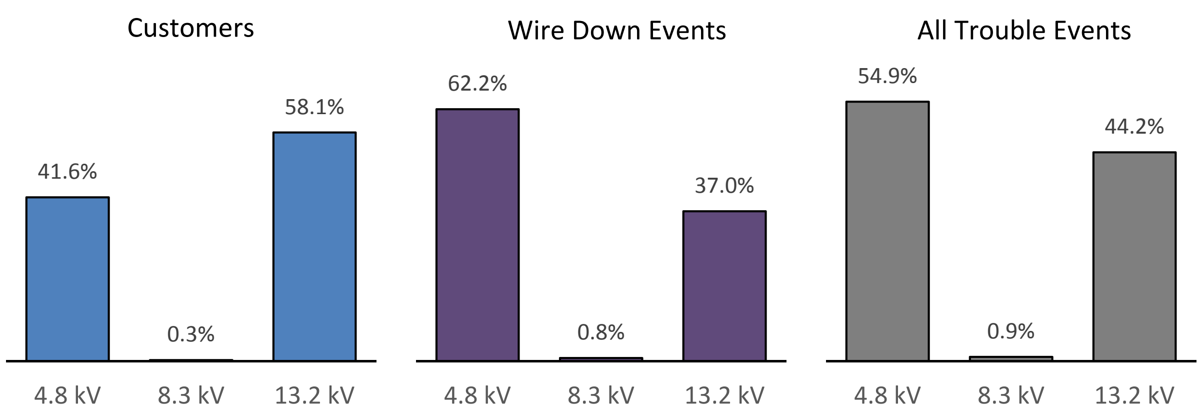


Exhibit 5.5.3 Substation Age, Average Circuit Length in Miles, and Average Number of Customers per Circuit by Distribution Voltage

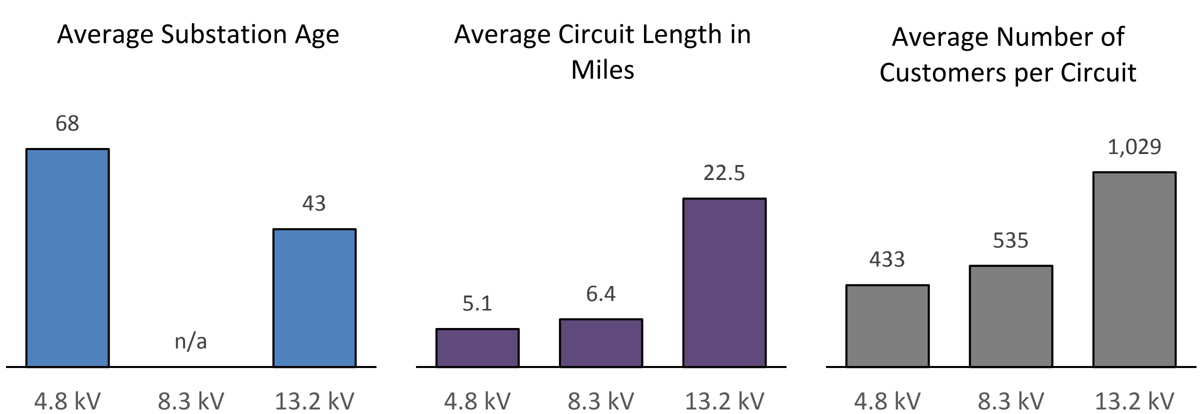
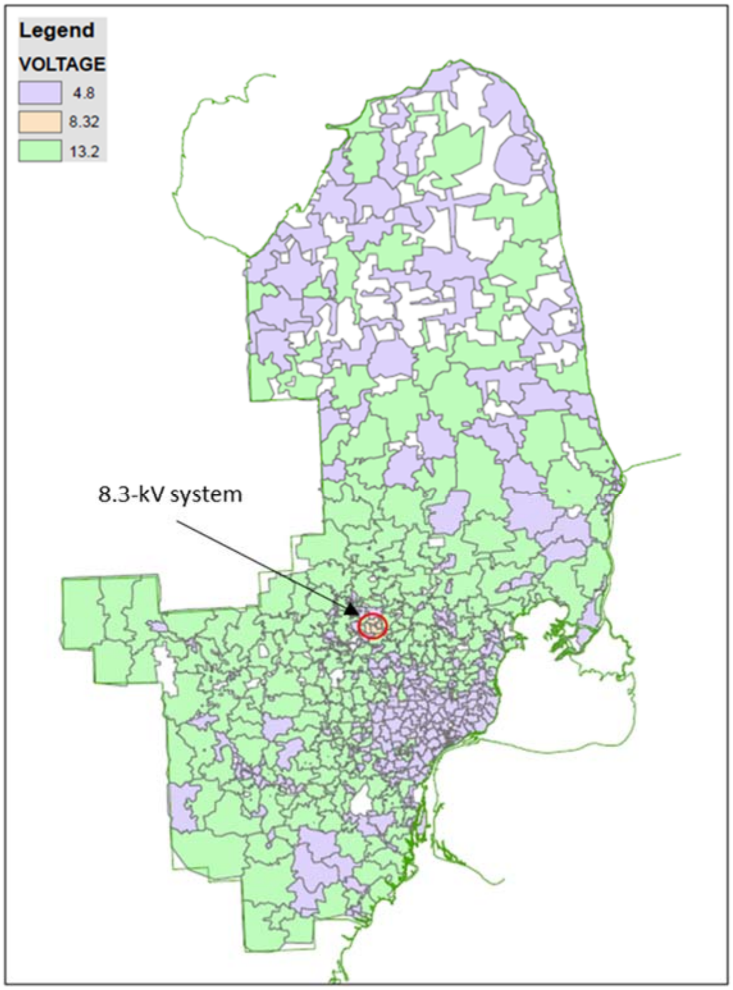


Exhibit 5.5.4 DTEE Distribution System Voltage Map



5.5.2 4.8 kV System Design

The 4.8 kV system is older, less efficient, and associated with more trouble events, as summarized in Exhibits 5.5.1-5.5.3.

Other key characteristics of the 4.8 kV system are:

- The 4.8 kV system is an ungrounded delta configuration, making detection, location and protection of single phase downed wires difficult.

- 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 voltages and/or more outage events for customers.
- The 4.8 kV system is predominately overhead, rear-lot construction, resulting in longer outage restoration or planned work construction time due to bucket truck inaccessibility.
- The 4.8 kV system has low penetration rates of 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 of its wiring must be replaced to accommodate the new technology.
- Most of the 4.8 kV system is constructed with #6 copper, #4 ACSR, and #4 copper conductors, which are weaker in strength compared to current standard wires. Replacing the small wires with larger wires usually requires new cross arms, insulators and poles due to the increased clearances, mechanical loading and tension.
- The 4.8 kV system has lower capacity and more significant voltage drop than the 13.2 kV system.

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. The conversion and consolidation of the 4.8 kV system will require substantial investments and take 20-30 years or more depending on many factors that cannot be predicted today. Therefore, other measures are being developed as intermediate solutions to address risk, reliability and cost considerations.

Most of the near-term 4.8 kV conversion and consolidation is driven by system capacity needs and DTEE’s commitment to not expanding the aging 4.8 kV system. These projects are expected to bring multi-faceted benefits on load relief, risk reduction, reliability improvements, technology modernization and cost reduction. Exhibit 5.5.5 summarizes the programs specific to the 4.8 kV system.

Exhibit 5.5.5 Programs to Address 4.8 kV System

Program	Scope of Work	Drivers	Cost Estimate ($ million)
4.8 kV Conversion and Consolidation	• Convert and consolidate two to three 4.8 kV substations and their respective 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)	• Replace aging infrastructures (oldest part of the DTE system) • Reduce operation and maintenance costs by decreasing equipment volume and trouble volume • Increase SCADA penetration and enhance grid technology to Improve circuit and substation level reliability • Prepare the grid for increased DER penetration	[To be provided in the final report]
Secondary and Service Improvement Program	• Remove banked secondary and reduce quantity of wires • Replace service drops	• Reduce trouble volume related to rear-lot banked secondary and services • Improve reliability and power quality for small pockets of customers or single customers • Reduce wire down events	[To be provided in the final report]
4.8 kV Circuit Rebuild	• Underground primary, secondary and services • Move primary from rear lot to front lot	• Aggressively reduce trouble volume related to rear-lot banked secondary and services • Improve reliability and power quality for small pockets of customers or single customers • Reduce wire down events • Improve truck accessibility and operational efficiency	[To be provided in the final report]

4.8 kV Conversion and Consolidation Program consists of multiple projects, most of which are triggered by strong area load growth and system capacity needs. While the scope of work generally refers to the entire project, the cost estimate captures the total remaining cost to execute projects that are ongoing. Exhibit 5.5.6 provides further details on each of the projects. Exhibits 5.5.7 and 5.5.8 provide maps to illustrate the 4.8 kV conversion and consolidation activities in the City of Detroit.

Exhibit 5.5.6 4.8 kV Conversion and Consolidation Projects

Program	Community	Drivers	Scope of Work	Cost Estimate ($ million)
Cortland / Oakman / Linwood Consolidation	Detroit	• Reduce operation and maintenance costs 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	[To be provided in the final report]
Hilton Substation and Circuit Conversion Phase One	Ferndale Hazel Park	• Provide load relief to Ferndale area • Replace aging, at risk infrastructures • Reduce operation and maintenance costs • 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 4 new 13.2 kV circuits	[To be provided in the final report]
Downtown City of Detroit Infrastructure Modernization (Downtown CODI)	Detroit	• Provide sufficient capacity to serve fast growing Detroit core downtown areas • Replace aging, at risk infrastructures • Reduce operation and maintenance costs by decommissioning eight 4.8 kV substations • Improve reliability and power quality	• 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 Brooklyn 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	[To be provided in the final report]

Program	Community	Drivers	Scope of Work	Cost Estimate ($ million)
Belle Isle Substation and Circuit Conversion	Detroit	• Replace aging, at risk infrastructures • Reduce trouble and maintenance costs • 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	[To be provided in the final report]
I-94 Substation and Circuit Conversion	Detroit	• Replace aging, at risk infrastructures • Reduce trouble and maintenance costs • Provide capacity to emerging business 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	[To be provided in the final report]
Herman Kiefer Substation and Circuit Conversion	Detroit	• Replace aging, at risk infrastructures • Reduce trouble and maintenance costs • Provide capacity to emerging business	• 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	[To be provided in the final report]
Cody Upgrade and South Lyon Decommission	South Lyon	• 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 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 and decommission South Lyon	[To be provided in the final report]

Program	Community	Drivers	Scope of Work	Cost Estimate ($ million)
Argo / Buckler Load Transfer	Ann Arbor	• Driven by load relief • Increase jumpering capability	See Section 5.1.3	
Elba Decommission and Circuit conversion	Elba Twp	• Driven by load relief • Replace aging infrastructure • Eliminate 40 kV tap that has a history of poor reliability performance	See Section 5.1.3	
White Lake Decommission and Circuit Conversion	White Lake	• Driven by load relief • Replace aging infrastructure • Allows for jumpering (existing 4.8 kV is islanded – surrounded by 13.2 kV)	See Section 5.1.3	
Almont Relief and Circuit Conversion	Almont Twp	• Driven by load relief • Replace aging infrastructure • Increase jumpering capability • Improve circuit voltage	See Section 5.1.3	
Bunert Decommission and Circuit Conversion	Warren Roseville	• Driven by load relief • Replace aging infrastructure • Improve reliability with 120 kV feed to substation • Eliminate 4.8 kV	See Section 5.1.3	
Reno Decommission and Circuit Conversion	Freedom / Bridgewater	• Driven by load relief • Replace aging infrastructure • Increase jumpering capability	See Section 5.1.3	
Lapeer Expansion and Circuit Conversion	Lapeer	• Driven by load relief • Replace aging infrastructure • Increase jumpering capability	See Section 5.1.3	

Exhibit 5.5.7 Detroit 4.8 kV Conversion and Consolidation Map

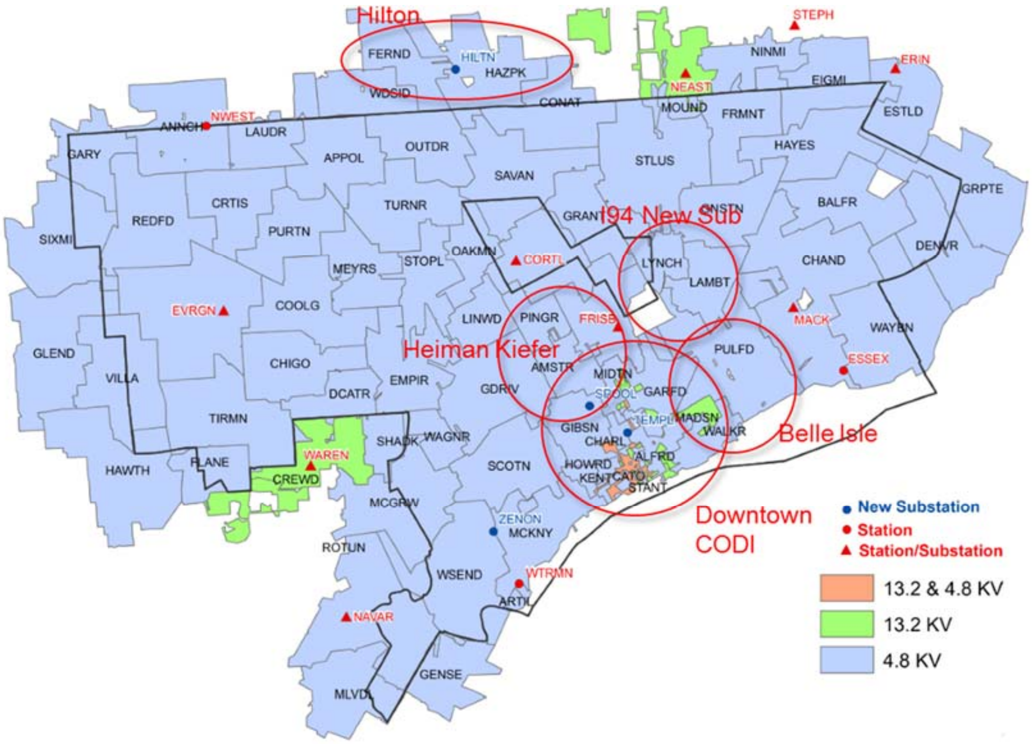
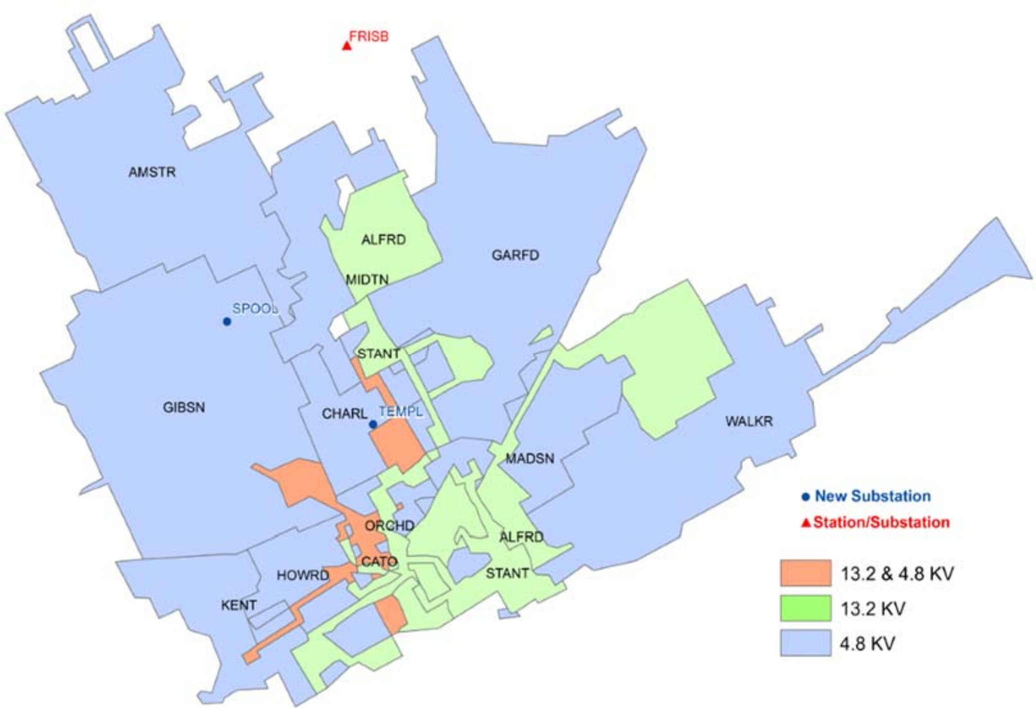


Exhibit 5.5.8 Downtown Detroit Substation Areas (Downtown CODI)



Secondary and Service Improvement Program aims at removing, consolidating and upgrading the secondary system to reduce trouble volume related to rear-lot banked secondary system and service drops, and improve reliability and power quality for small pockets of customers or single customers.

4.8 kV Circuit Rebuild is a pilot project to assess the cost / benefits of various options of undergrounding primary, secondary and services in the rear lots and front lots of the 4.8 kV circuits. These pilots are designed to help DTEE further understand the costs, easement / right of way, technical and economic feasibility of various circuit undergrounding and relocating options. DTEE will work collaboratively with local communities on the pilot projects.

Summarizing all the programs above, DTEE projects the annual capital spend to address 4.8 kV system in Exhibit 5.5.9.

Exhibit 5.5.9 Capital Spend to Address 4.8kV System

Year	Projected Capital Spend ($ million)
2018	[To be provided in the final report]
2019	[To be provided in the final report]
2020	[To be provided in the final report]
2021	[To be provided in the final report]
2022	[To be provided in the final report]

5.5.4 8.3 kV System

DTEE's 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 a 8.3kV substation level 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.

In addition, crews must be trained to operate and maintain the 8.3 kV system. This adds 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 is to build a new 13.2 kV substation in the Pontiac area and convert 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 3 Stockwell underground circuits will be left on the 8.3 kV system, but upgraded with submersible vault equipment as discussed in Section 4.18. Exhibit

5.5.10 illustrates the geographic locations of the substations under discussion. Exhibit 5.5.11 provides a summary of the project.

Exhibit 5.5.10 Potential Stranded 8.3 kV Load in Pontiac

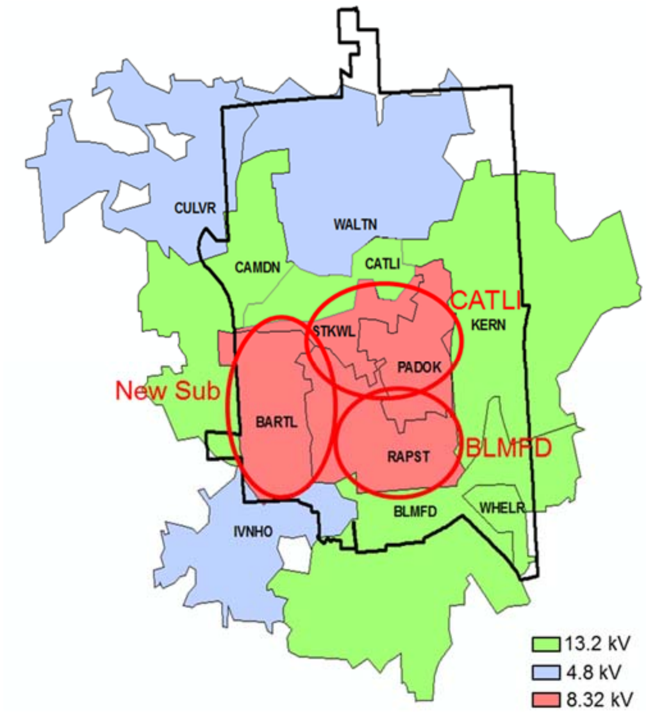


Exhibit 5.5.11 Pontiac 8.3 kV Overhead Conversion Capital Spend

Year	Projected Capital Spend ($ million)
2018	[To be provided in the final report]
2019	[To be provided in the final report]
2020	[To be provided in the final report]
2021	[To be provided in the final report]
2022	[To be provided in the final report]

5.6 Reactive Trouble and Storm Costs

5.6.1 Context

As DTEE's electric distribution system continues to age, reactive work related to trouble events is placing an unprecedented demand on costs and resources. Existing data show the electric distribution system requires more than 214,000 truck rolls every year, with approximately two-thirds of the truck rolls driven by non-outage events. Typical non-outage events include low voltage, flickering lights, hazards (e.g., sagging wires, defective lightning arrestors), and downed 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 ($000)

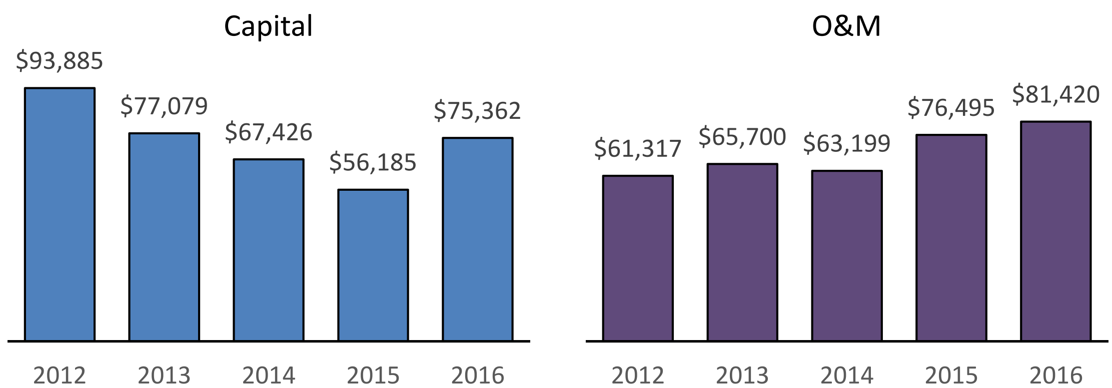
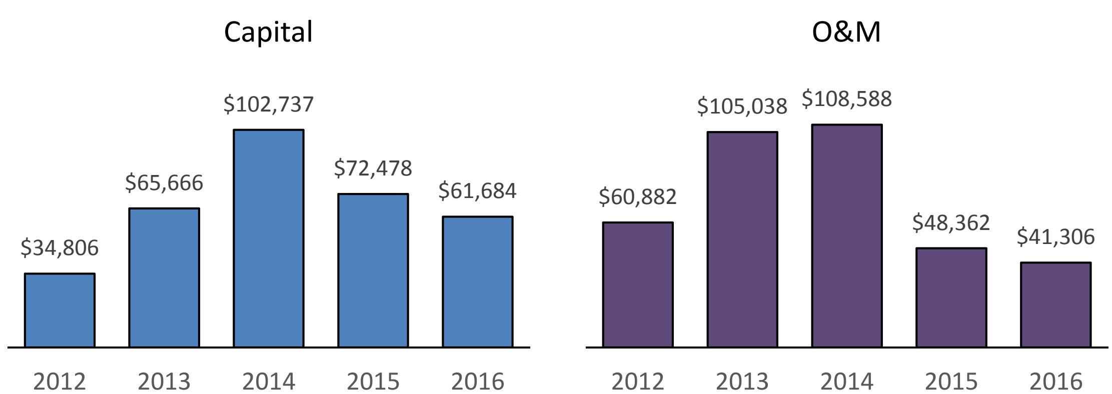


Exhibit 5.6.2 Storm Event Cost ($000)



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

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. Efforts are underway to identify potential truck roll and cost reduction measures. Capital replacement programs, tree trimming, reliability programs targeting root causes of outage events, secondary and service improvement program, the 4.8kV circuit rebuild pilot and 4.8 kV system conversion and consolidation are expected to replace aging infrastructure and reduce trouble volume, leading to cost reduction in both daily operation and maintenance and trouble / storm events. Grid technology programs will also help improve operational efficiency, increase productivity and further 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, to some extent, help offset O&M cost increases that are driven by continued system aging and inflation.

5.6.3 Storm Insurance Options

DTEE has not had storm insurance for the past ten years. The policies DTEE wrote prior to that resulted in numerous full limit losses to the insurers. The insurance premiums became so expensive that DTEE stopped coverage. DTEE is re-evaluating storm damage insurance options and will provide an update to the MPSC as further progress is made.

6 Distribution Maintenance Plan

6.1 Tree Trimming

Trees and tree-related events are responsible for more than two-thirds of time DTEE customers are without power and account for approximately one-third of the interruption events. Preventing tree outages will significantly reduce SAIDI and DTEE's reactive expenses.

Due to the increasing tree growth rates and tree density, line clearance specifications have evolved. The latest evolution occurred in late 2014 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 are as follows:

- Dividing circuits into zones based on the number of customers affected by an outage
- Differentiating the 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

Circuits trimmed per the ETTP had an average reduction of approximately 50 percent in the number of tree-related customer interruptions per year and an average reduction of approximately 75 percent in the number of tree-related outage minutes per year (relative to the average performance over the five-year period prior to trimming). This is significantly better performance than the prior tree trimming practice, which yielded reductions of approximately 15 percent and 40 percent respectively.

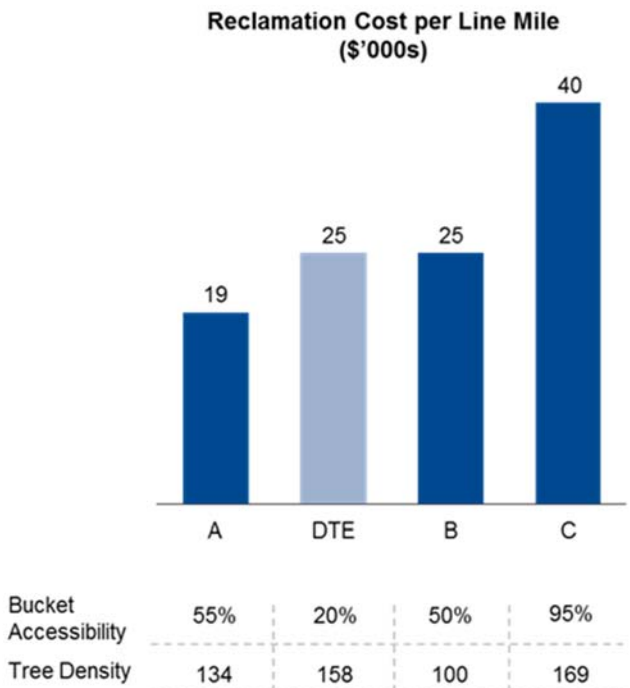
Based on benchmarking, DTEE has identified eight key attributes that define the quality of utility tree trimming programs. Exhibit 6.1.1 provides a description of eight attributes and how DTE's current practices are compared to industry best practices.

Exhibit 6.1.1 DTEE Tree Trimming Program Assessment

#	Program Attribute	Description of Best-Operated	DTE 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; current run rate = 8.5 years based on funding • Focused on reclamation
2	Herbicide Use	• Cut-stump treatment for removals • Foliar spray in rural areas • Basal bark treatment where feasible	• Comprehensive herbicide program under development in 2017
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 months • Clearion work management system is currently being rolled out – will significantly shorten cycle times between program phases
5	Work Management	• Fully digital system from work assignment through billing / invoicing	• On track to be best operated in 2017 via Clearion work management system rollout
6	Contract Structure	• Time & Expense contract with incentives contract for easement reclamation with a transition to fixed-price for maintenance work	• Time & Expense with incentives fully in place with one contractor; being established for the remaining three contractors in 2017
7	Resourcing	• Outsourced planners (typically sole sourced) during reclamation • In-house auditing • Crew to arborist ratio = 6-10:1	• Outsourced planners • Outsourced auditing • Crew to arborist ratio ≈40:1
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

Particularly with respect to cost-per-mile, DTEE's program benchmarks well when the comparison considers work scope, system configuration and tree density (Exhibit 6.1.2). Work scope is the most important of these factors, and it can be separated into two broad categories: reclamation work and maintenance work.

Exhibit 6.1.2 DTEE Tree Trimming Cost Benchmarking



Reclamation work is intended to significantly improve the vegetation conditions on rights-of-way, and typically involves a high percentage of tree removals and removal of overhanging branches. DTEE's current tree trimming program consists of reclamation on circuit backbones.

Maintenance work is defined as maintaining the condition of rights-of-way after reclamation has occurred. Maintenance work typically involves a lower percentage of tree removals and removal of overhanging branches. Prior to 2014, DTEE's program consisted entirely of maintenance work.

Based on this benchmarking work, DTEE is making a number of 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 incorporate target pricing with incentives on productivity improvements
- Conducting a full system assessment on tree density to optimize the plan in the future
- Identifying a balanced resource plan to support tree trimming targets
- Implementing a herbicide program to control vegetation growth and reduce long-term costs

DTEE's tree trimming five-year plan is listed in Exhibit 6.1.3.

Exhibit 6.1.3 DTEE Tree Trimming Five-Year Plan

Year	Projected Spend ($ million)	Projected Line Miles
2018	[To be provided in the final report]	[To be provided in the final report]
2019	[To be provided in the final report]	[To be provided in the final report]
2020	[To be provided in the final report]	[To be provided in the final report]
2021	[To be provided in the final report]	[To be provided in the final report]
2022	[To be provided in the final report]	[To be provided in the final report]

6.2 Preventive Maintenance (PM) Program

Preventive Maintenance (PM) is performed to achieve a twofold purpose: 1) maximize the total life expectancy of the equipment at minimum lifecycle cost while maintaining an expected level of reliability and safety, and 2) acquire timely asset performance and condition data to support trend data analysis and identify potential issues.

An effective PM program is critical in managing asset condition, 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 lack of proper maintenance and equipment failing pre-maturely during services.

The PM program was developed by DTEE Engineering and is derived from our Maintenance Policies, which set the inspection scope and intervals based on:

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

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 analysis of inspection results and equipment failures
- Using Substation Predictive Maintenance (SPdM) data to drive inspection timeline instead of time-based inspections, to be aligned with Condition Based Maintenance principal and achieve high cost efficiency
- Reducing maintenance activities by using new technology (e.g., smart relays)
- Coordinating inspection intervals on different equipment to reduce the need of multiple shutdowns

Furthermore, DTEE is developing Condition Based Maintenance plans to maximize maintenance efficiency efforts. By evaluating certain monitoring data available on some assets, engineers can prioritize equipment on the maintenance schedule and possibly defer some equipment to the next inspection cycle. One successful example is the prioritization of transformer maintenance through dissolved gas analysis and infrared thermal imaging inspection. This data is then used as an early predictor of transformer failures and drives 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 perform as designed, it is 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 breaker replacement, relay betterment 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 PM programs inspect the equipment listed in Exhibit 6.2.1. Efforts are underway to continue assessing the maintenance policies and addressing any PM backlog.

Exhibit 6.2.1 DTE Distribution Operations Preventive Maintenance Program

Category	Asset	General Inspection Cycles (Years)
Substation	Breakers (Cycle depends on voltage, type, application, number of operations, etc.)	3/10/12
	120kV Disconnects	10
	Buses	10
	Substation Regulators	10
	Single Tap Substations	10
	Network Banks	5
	Network Bank Structures	10
	13.2kV Enclosed Capacitor Banks	1
	Relay Periodic (Cycle depends on type and application)	5/7/10
	Substation Predictive Maintenance Inspections (SPdM)	3
	Battery Inspections	1
	Dissolved Gas Analysis of Transformers & Regulators	1
Distribution System	40kV Pole Top Switch	8
	OH Distribution SCADA Reclosers and Pole Top Switches (Cycle depends on types of devices and type of control)	4/8
	Primary Switch Cabinet (Cycle depends on type and location)	5/10/15
	Manhole	10
	Tower Climbing	10
	DTEE Equipment in High Rise Structure	20
	OH Capacitor & Regulator Control	1
	OH Distribution Device (SCADA) Battery	4
	Voltage Control Periodic	1

6.3 Preventive Animal Interference

DTEE takes measures to minimize animal interference. Animal interference accounts for less than one percent of the minutes interrupted per year on average. All new substations are designed and built with animal protection. In existing substations, where multiple animal interference events are found, 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 found.

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 conferences and survey planning meetings. This participation allows DTEE to speak informally with peer utilities to gain additional insights that don't always come through in the raw data.

Various criteria are used to determine the best peer set for DTEE 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 raw data.

Once the data is compiled and metrics are created, DTEE analyzes the metrics to identify any gaps in performance. These gaps are then researched in greater detail, often with site visits to other utilities that benchmark well in the specific metric of concern. 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 plan is approved and implemented, progress is monitored to verify that the program is delivering the intended results.

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 importance its people play in maintaining the electric grid and works to proactively manage its changing workforce needs through its rigorous workforce planning process. Exhibit 7.2.1 illustrates DTE's overall workforce planning process and Exhibit 7.2.2 provides the details on how the overall process translates into detailed analysis and recommendations.

Exhibit 7.2.1 DTE's Strategic Workforce Planning

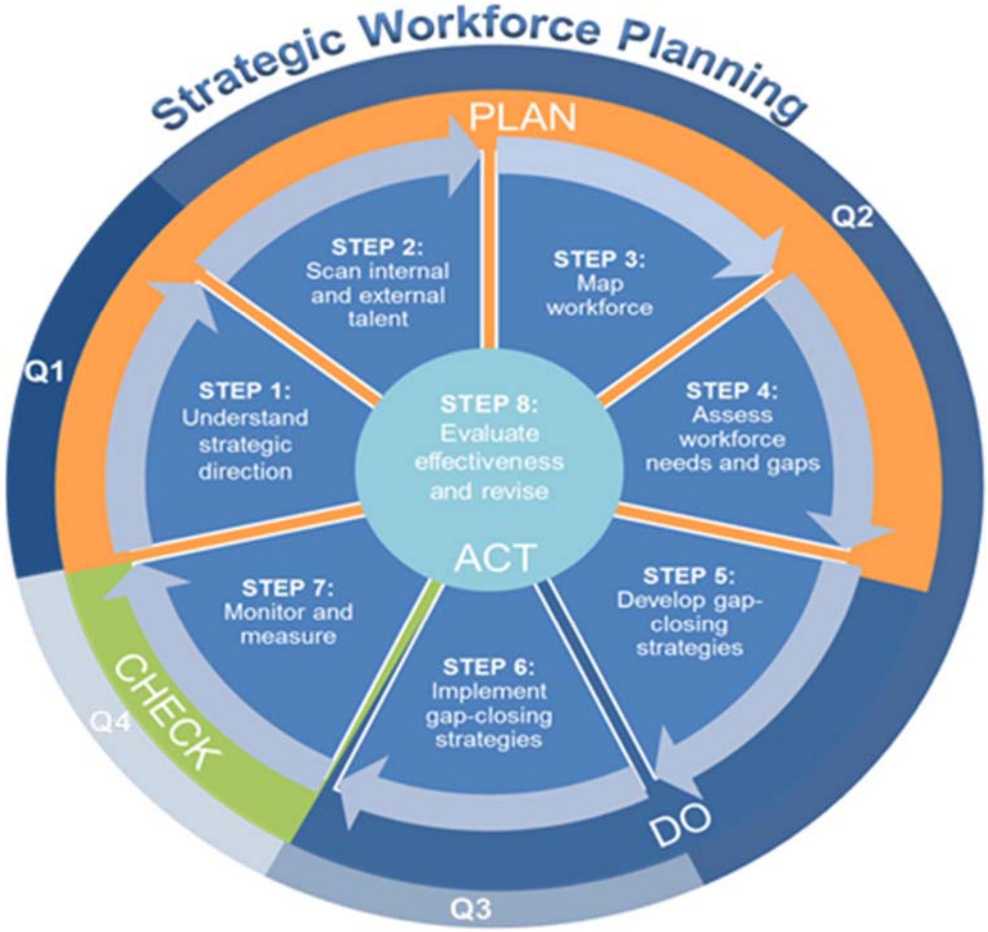
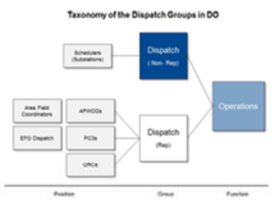


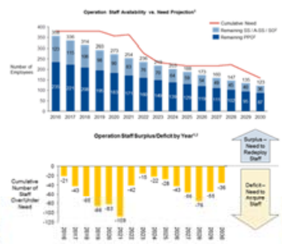
Exhibit 7.2.2 Strategic Workforce Planning Detailed Process

Develop Position Taxonomy



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

Develop Workforce Need and Availability Profiles



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

Determine Workshop Needs

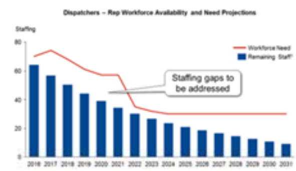
Workshop

Monitor and Backfill as Needed

Attrite with No Backfill

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

Conduct Workshops



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

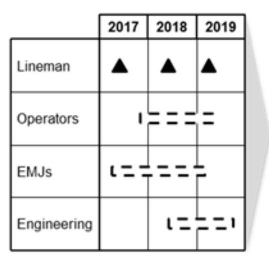
Conduct Recommendation Follow Up

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

Review Recommendation Feasibility

- The DO leadership team will review the recommendations
- Determinations will be made on whether components are consistent with the overall labor strategy

Conduct an Integrated Review of Recommendations



- Recommendations will be reviewed across groups to determine dependencies and connection points
- DO will establish a "baseline" approach

Develop Approach for Engaging the Union

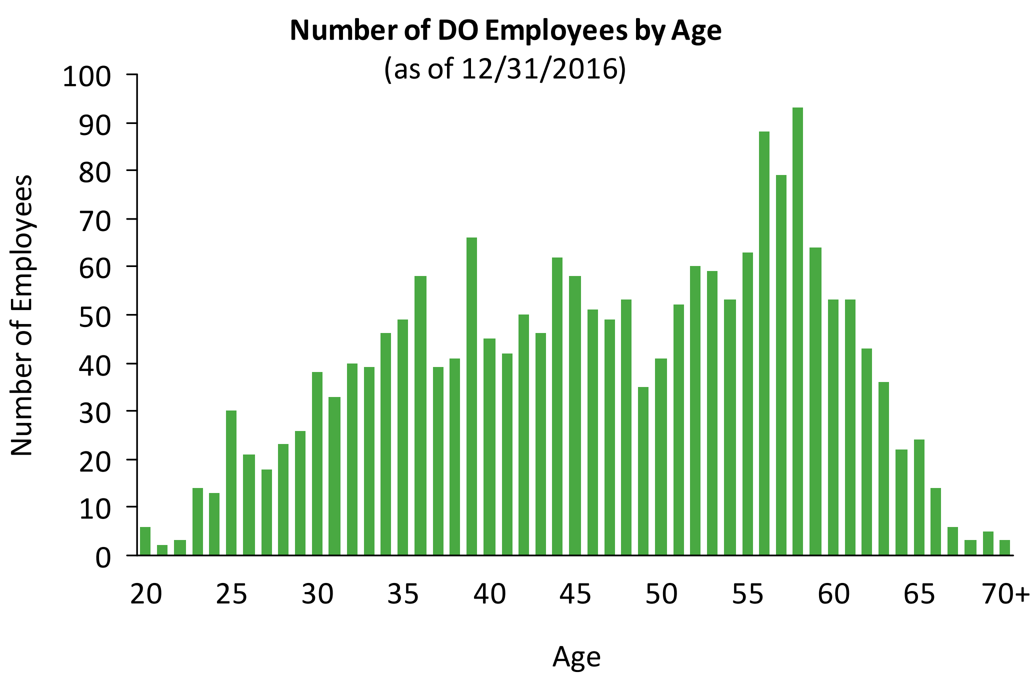
- With the "baseline" approach, DO leadership will determine when and how they will engage with union leadership

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

1. Understanding the drivers of attrition, which allows projection of attrition levels for different employee groups
2. 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
3. Identifying talent pipelines for each employee group and the lead time it takes to recruit, hire and train those employees
4. Understanding the impact of productivity initiatives
5. 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 (DO) is retirement. DTEE's workforce is aging, and an uptick 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 groups that 50 percent or more of the workforce will leave or retire 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 Linemen Workforce Gaps (2017-2031)

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 fill the required workforce needs in a cost-effective way and allow 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 of our skilled trades, there is a significant apprenticeship period required before employees can be fully productive members of the team. For other roles, there is significant competition for talent within the area and at a national level, 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 we look to further modernize our 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 eliminate the wiring and are comprised of fiber optic computer networks, interoperable data models and logical programming. With these changes, the need for employees with strong analytical and technical backgrounds will continue to grow.

Additionally, part of constructing 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 allow us to 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, and are also a function of historical improvement rates and projections for specific technology 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 and 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.

As these initiatives are combined, they allow DTEE to put together a fully integrated workforce plan. This plan is monitored and adjusted as strategic objectives change. Having these plans in place will allow DTEE to be proactive in how it addresses its future talent needs and will ensure we have the people we need to continue serving our customers.

7.3 Capital Plan and Capital Project Approval Process

[To be provided in the final report]

7.4 Distribution Design Standards

DTEE maintains a comprehensive set of Distribution Design Standards (DDS) that are the basis for the electrical system design. These standards have evolved with years of experiences in operating DTEE's distribution system. They have also incorporated industry best practices gained from DTEE's involvements in 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, or as dictated by developments in the industry, asset and system performance or 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 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 (DDO), which address individual topics within the DDS. In addition, there are Job Aides to supplement the DDO. The Job Aides contain step-by-step instructions and any additional information useful for the planners or engineers.

The DDO dictates the size of equipment to be used. The size of 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.

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

7.5 Replacement Unit and Spare Part 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.

<u>Replacement Units</u>

For the generic replacement units, inventory is typically controlled through automatic reordering when a specified inventory level is reached. The re-order 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 inventory based on known new projects, planned replacements, and any unplanned replacements based on historic failure rates and equipment condition assessment.

Some major equipment, such as switchgear, is highly customized depending on the substation and circuit configuration. 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 replacements 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 operation depending on the extent of the failure.

Compounding the complexity of spare parts inventory is the existence of many different manufacturing models and ages of equipment. There are nearly 2,500 distinct spare parts for substation breakers alone. 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.

In contrast, when spare parts for a specific make, model and age of equipment become expensive or impossible to obtain from manufacturers, it typically results in recommendation for replacement for that specific type of equipment.

8 Performance Metrics

8.1 Internal Metrics

DTEE's key distribution internal metrics are illustrated in Exhibits 8.1 – 8.8. DTEE's distribution internal metrics were developed and tracked to understand two key questions: 1) how DTEE has been executing the distribution investment and maintenance plan, and 2) how DTEE's distribution investment and maintenance work affects the system reliability performance.

Exhibit 8.1.1 All Weather SAIDI (minutes)

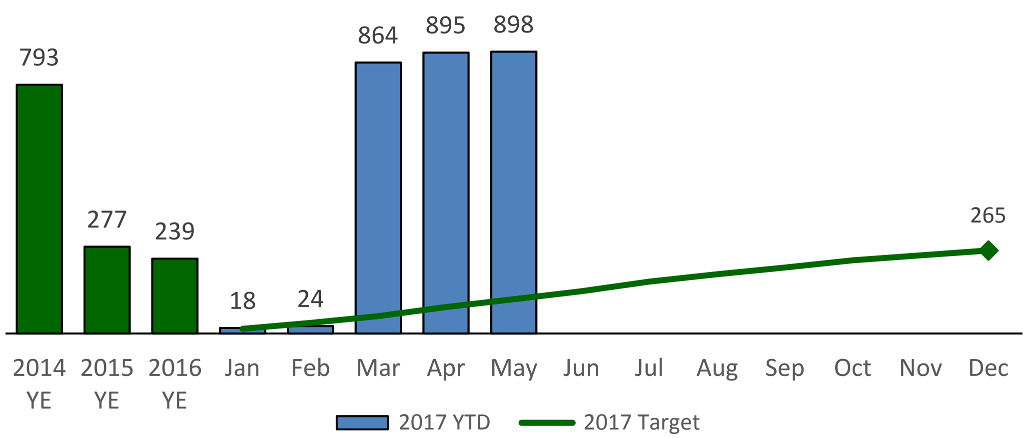


Exhibit 8.1.2 All Weather SAIDI (minutes) – Excluding March 8 Storm

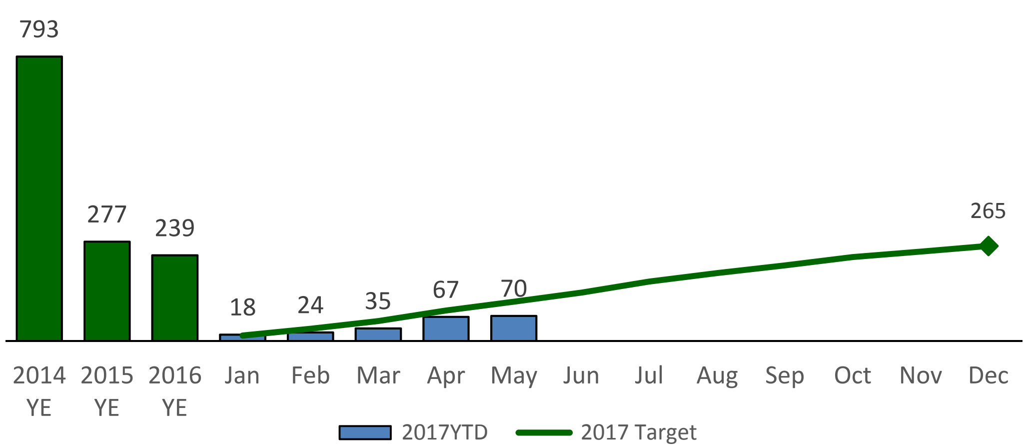


Exhibit 8.1.3 Blue Sky CAIDI (minutes)

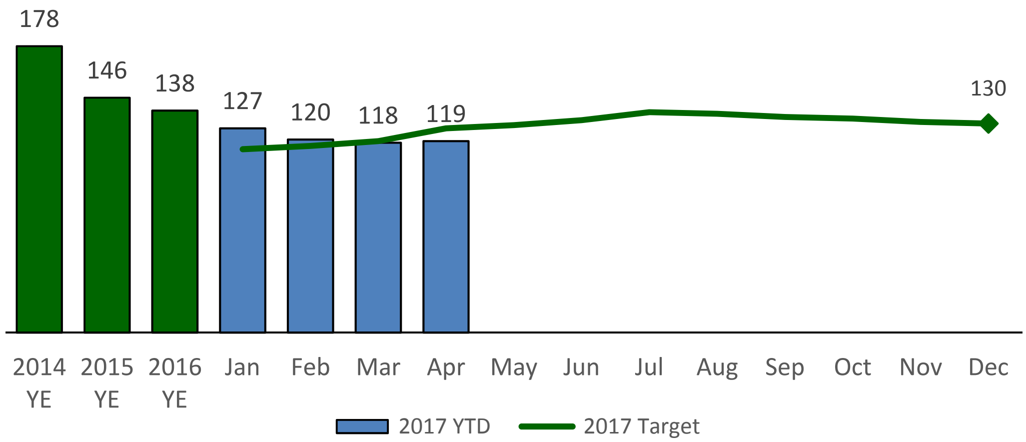
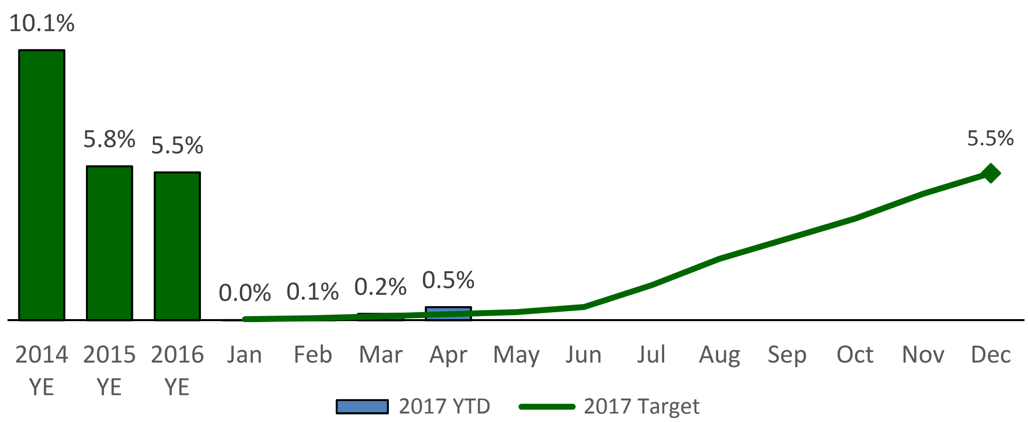


Exhibit 8.1.4 CEMI4 Percent of Customers



Adherence to capital investment plan metric is an equally-weighted index that tracks adherence across the following capital investment programs: 1) circuit improvements – system resiliency, circuit renewal and CEMI programs, 2) asset capital replacement programs, and 3) pole and pole top maintenance program.

Exhibit 8.1.5 Adherence to Capital Investment Plan (Index)

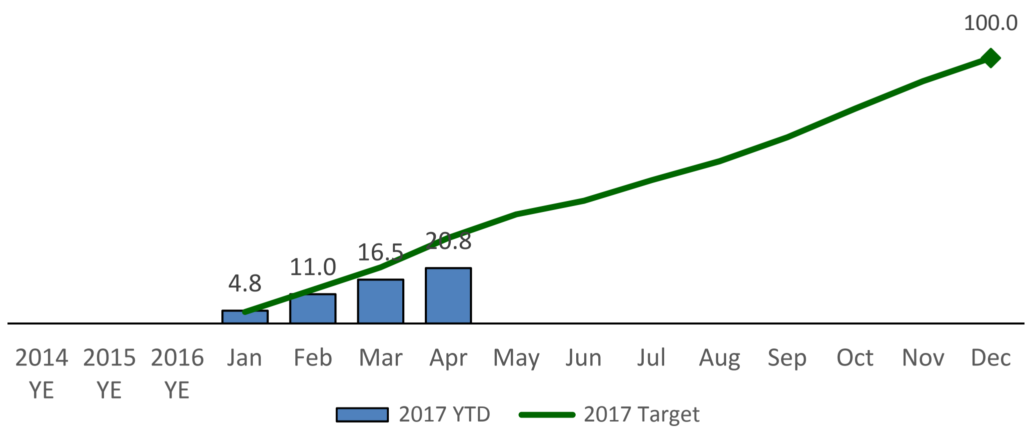


Exhibit 8.1.6 Tree Trimming Miles Completed

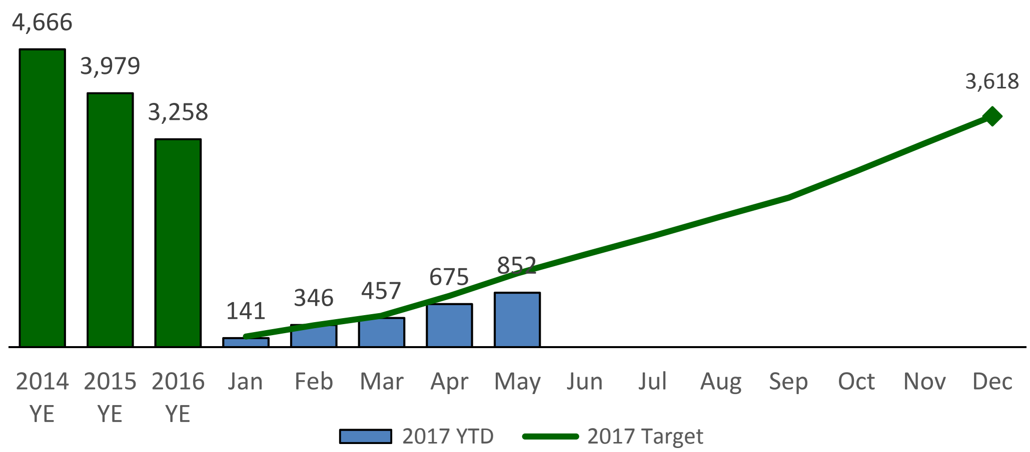
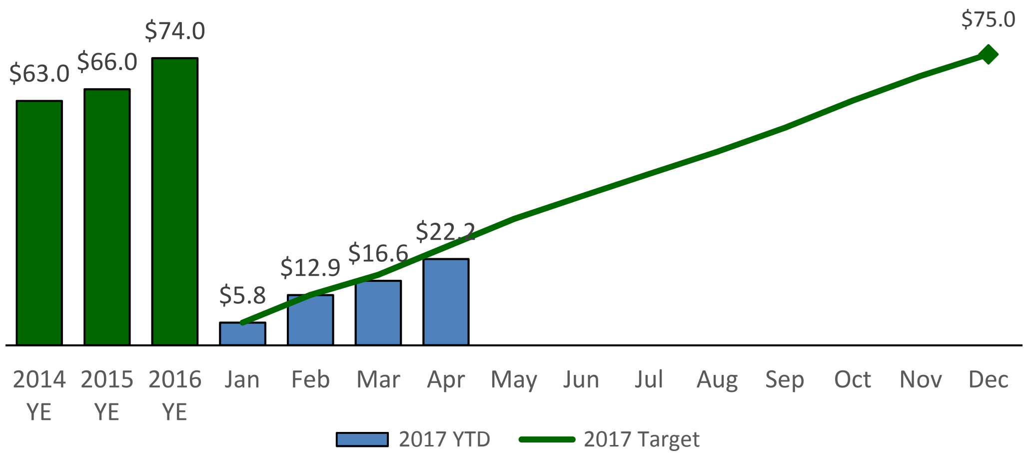
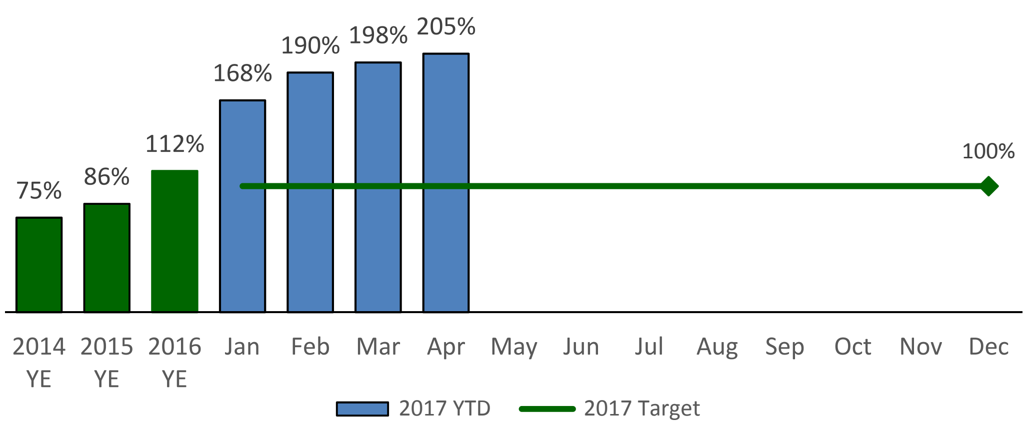


Exhibit 8.1.7 Tree Trimming Program Spend ($ millions)



Critical Preventive Maintenance (PM) Compliance metric tracks percentage of critical PM work orders completed as opposed to total critical PM work orders scheduled to be completed in the same period. The over-compliance on the PM targets is to address the critical PM backlog.

Exhibit 8.1.8 Critical PM Compliance (%)



8.2 Customer Satisfaction Benchmark

DTEE strives to provide safe, reliable and affordable electricity to our customers and ensure superior customer satisfaction. By executing various investment and maintenance programs to reducing risk, improve reliability and managing costs, the distribution investment and maintenance plan is aimed at achieving the best-in-class customer satisfaction as the ultimate goal.

DTE's ongoing efforts to continuously improve our products, programs and processes, with a stellar customer experience, have resulted in significant improvements in customer satisfaction since 2007. DTE measures customer satisfaction with our utility businesses 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. We rank second in J.D. Power customer satisfaction scores for both gas and electric residential customers in the Midwest. Our goal is to be number one and maintain that position.

9 Potential Cost Recovery Mechanisms

[To be provided in the final report]

Appendix I Integrated Models for DTEE's Distribution Investments

DTEE has developed a series of interconnected models to guide our investment decisions. These models allow DTEE to look at how our investment decisions impact risk reduction, reliability improvement and cost reduction (both O&M and reactive capital). The relative impact of each investment decision can then be weighed against the others to determine how to most efficiently deploy our capital resources. The modeling framework, as well as major model components, are described below.

Capital Reliability Model

The Capital Reliability model was created to project how our strategic capital investments would impact our system reliability and the amount of reactive capital needed to address trouble / storm events in the DTEE system. The model is comprised of many different equipment capital replacement models that are then interconnected together to allow us to see how changes to our investment budget impact reliability and reactive capital. The model was created to provide insight into the main drivers of our system reliability and, as such, models outage events that cause the majority of the system SAIDI minutes in great detail. Other events with little or no SAIDI impacts (e.g., house service issues) are modeled at a less granular level. This model is still relatively new (less than two years old) and is continuously being updated as new data is obtained or assumptions are improved.

Component models within the Capital Reliability Model include:

- Breaker Replacement Model
- Switchgear Replacement Model
- Substation Transformer Replacement Model
- Relay Replacement Model
- Substation Disconnect Replacement Model
- Pole Replacement Model
- 40kV Automatic Pole Top Switch Replacement Model

- Faulty Fuse Cutout Replacement Model
- Recloser Replacement Model
- Distribution Pole Top Switch Replacement Model
- System Cable Replacement Model
- URD Replacement Model
- System Resiliency Program Model
- Circuit Renewal Program Model
- CEMI Customer Reduction Model
- Secondary Program Model
- 4.8kV Conversion Model
- Downtown City of Detroit Infrastructure Modernization (CODI) Model
- SCADA Monitoring Rollout Model
- Ground Detection Program Model

Each sub-model is unique in its construction but typically shares the following traits:

- 15-year annual proactive capital spend profile (variable input)
- Current Population of DTE Equipment – age, model (if applicable), condition of asset
- Equipment Replacement Cost – labor and material, often also calculating the difference in cost by planned (proactive) replacement and trouble (reactive) replacement
- Equipment Failure Curves – curves have been constructed from historical DTE failure data where possible. When DTE failure data was insufficient other industry partners were consulted.
- 15-Year Impact Projections – impacts are projected on reactive failure events, reactive failure cost, proactive replacements, outage minutes, and customers impacted

Tree Trim Model

The Tree Trim Model forecasts the 15-year tree trim cost (both proactive and reactive cost), the annual tree outage and non-outage event reduction, and the associated reliability and cost benefits from the event reduction. Additionally, the model outputs the tree trim contractor workforce requirement needed to execute the program at a given level of work. The model outputs feed into the Capital Reliability Model and the O&M Cost Model (discussed below) to help complete our reliability and cost forecast.

Model inputs include: tree trim cost per line mile, initial benefit expected of enhanced tree trimming, benefit deterioration rates in years post trimming, and on Right of Way (ROW) vs off ROW tree events. These inputs have been obtained from DTE data, industry benchmarking, and industry experts. As we obtain more data from our enhanced tree trim program, we will continue to refine the model to increase the accuracy of our input assumptions.

O&M Cost Model

The O&M Cost Model projects the O&M budget over the next 15 years based on inputs from the Capital Reliability Model, Tree Trim Model, and Workforce Model (discussed below). To the extent possible, the model uses a bottom-up approach and segments cost buckets into units of work, and uses the change in units over time to project the change in budget. For trouble and storm costs, the O&M model uses reactive event projections from the Capital Reliability Model to determine future trouble and storm spend. Non-event driven work, such as preventive maintenance (PMs) Activities, are projected using amount of equipment on the distribution system. As an example, breaker PM expenses drop as DTEE is able to replace or eliminate breakers. Some harder to model items, like required employee training, are simply projected with an inflation adder.

Workforce Model

The Workforce Model projects DTEE Distribution Operation's annual employee headcount demand and employee attrition over 15 years.

Attrition - Leveraging employee history, DTEE has created expected attrition curves (probability of an employee leaving Distribution Operations at a given age) for Union and Non-Union employees. These curves are used by the model to predict annual attrition of existing employees and future hires.

Demand – the existing employee population is segmented into 53 separate job groups by work function. For each function, the work demand drivers were identified (e.g., linemen work is primarily driven by trouble / storm work, preventive maintenance work, and overhead construction work) and then mapped to outputs from other models based on events, capital spend, or O&M spend. This allows the headcount demand to fluctuate based on inputs received from the other models. The demand projection for each job group accounts for all work, including work expected to be completed by a contractor.

Using the demand and attrition information for each job group enables us to determine the projected "headcount gap" proactively and address it by hiring additional employees, improving productivity, and/or leveraging contractors.

Substation Risk Model

The Substation Risk Model uses substation equipment health, substation loading, and substation stranded load (defined below) to create a risk score for distribution substation.

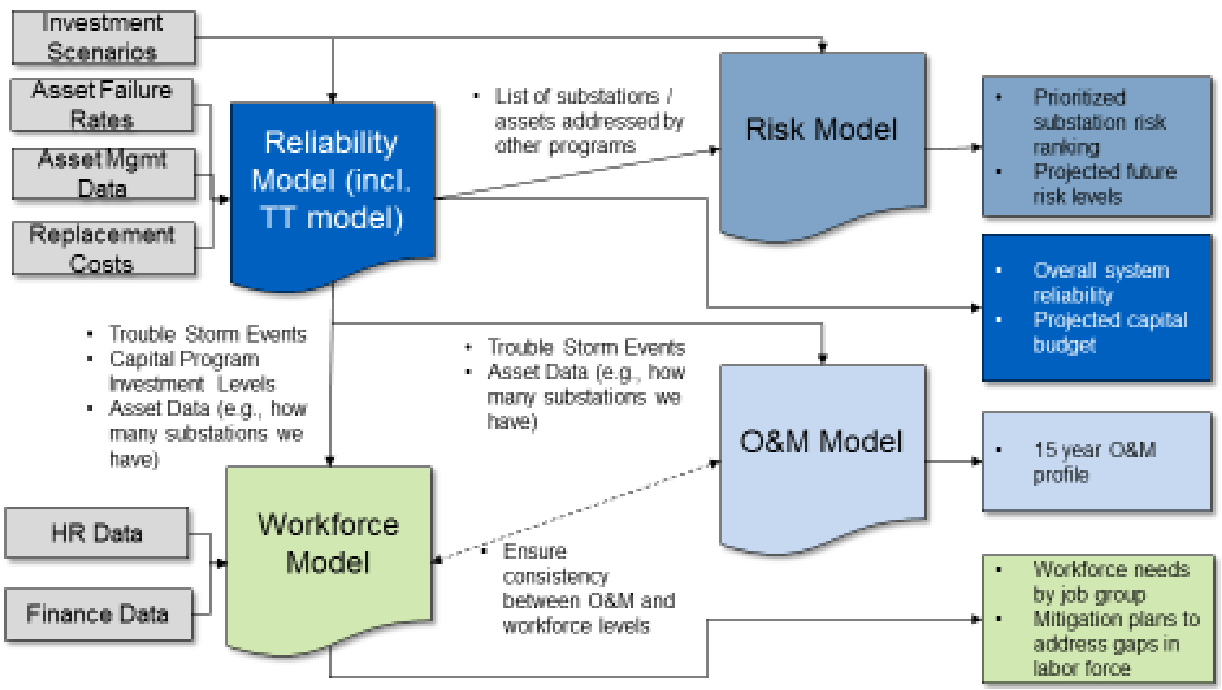
Equipment Health – Major substation equipment (switchgear, transformers, breakers, system cable) is scored based on condition, age, and the number of customers impacted if these pieces of equipment were to fail.

Substation Loading – Substations with high loading and high load growth are considered for an increased risk.

Stranded Load – Any amount of load that cannot be served by adjacent substations in the event of a complete loss of an entire substation is quantified as stranded load. Substations with stranded load are at risk of extended outages in the event of a complete substation failure.

Substations with the highest outage risk scores are considered the most at risk and are prioritized for projects in capital budget. High risk substations may be addressed by other programs (4.8kV Conversion, Load Relief). The Capital Reliability Model provides forecasted substation and equipment replacements to the risk model over a 15-year time horizon, allowing the risk model to provide a projection of our substation risk profile.

Exhibit A-1 DTEE's Distribution Investment Model Framework



Appendix II Historical 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 (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 (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 indicative of the actual customer's experience on a circuit. All else being equal, a circuit with relatively more customers will have a larger impact on the system-based indices than will a circuit with fewer customers; the circuit-based indices will be the same for both circuits. See the following illustration.

Illustration

Circuit A serves 500 customers, each experiences 2 outages, each lasting 120 minutes

Circuit B serves 2,000 customers, each experiences 2 outages, each lasting 120 minutes

Total system serves 2 million customers

	Circuit Basis		System Basis	
	SAIFI	SAIDI (min)	SAIFI	SAIDI (min)
Circuit A	2.0	240	0.005	0.06
Circuit B	2.0	240	0.002	0.240

Exhibit A-2 Circuit SAIFI Distribution – System Basis

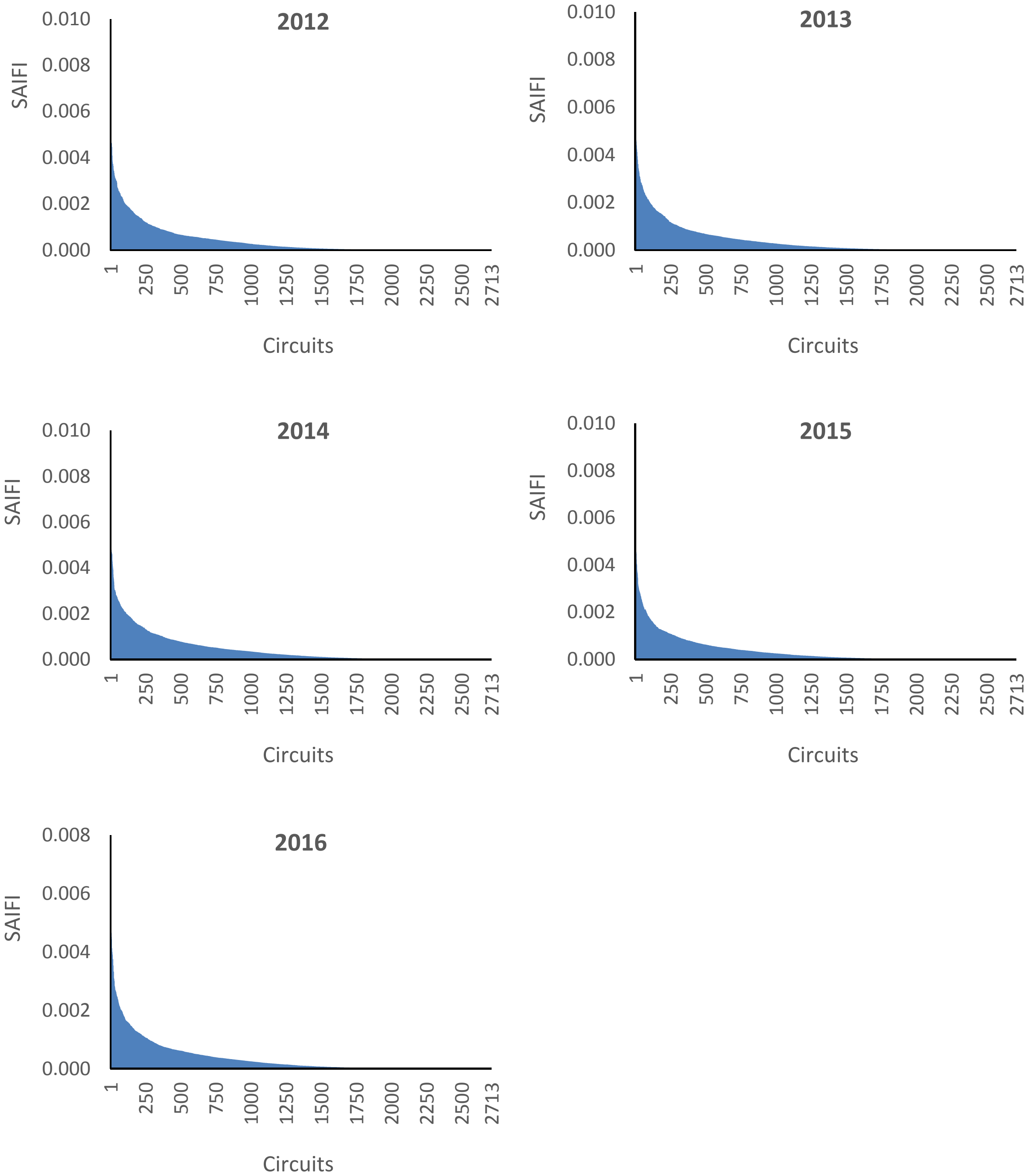


Exhibit A-3 Circuit SAIFI Distribution – Circuit Basis

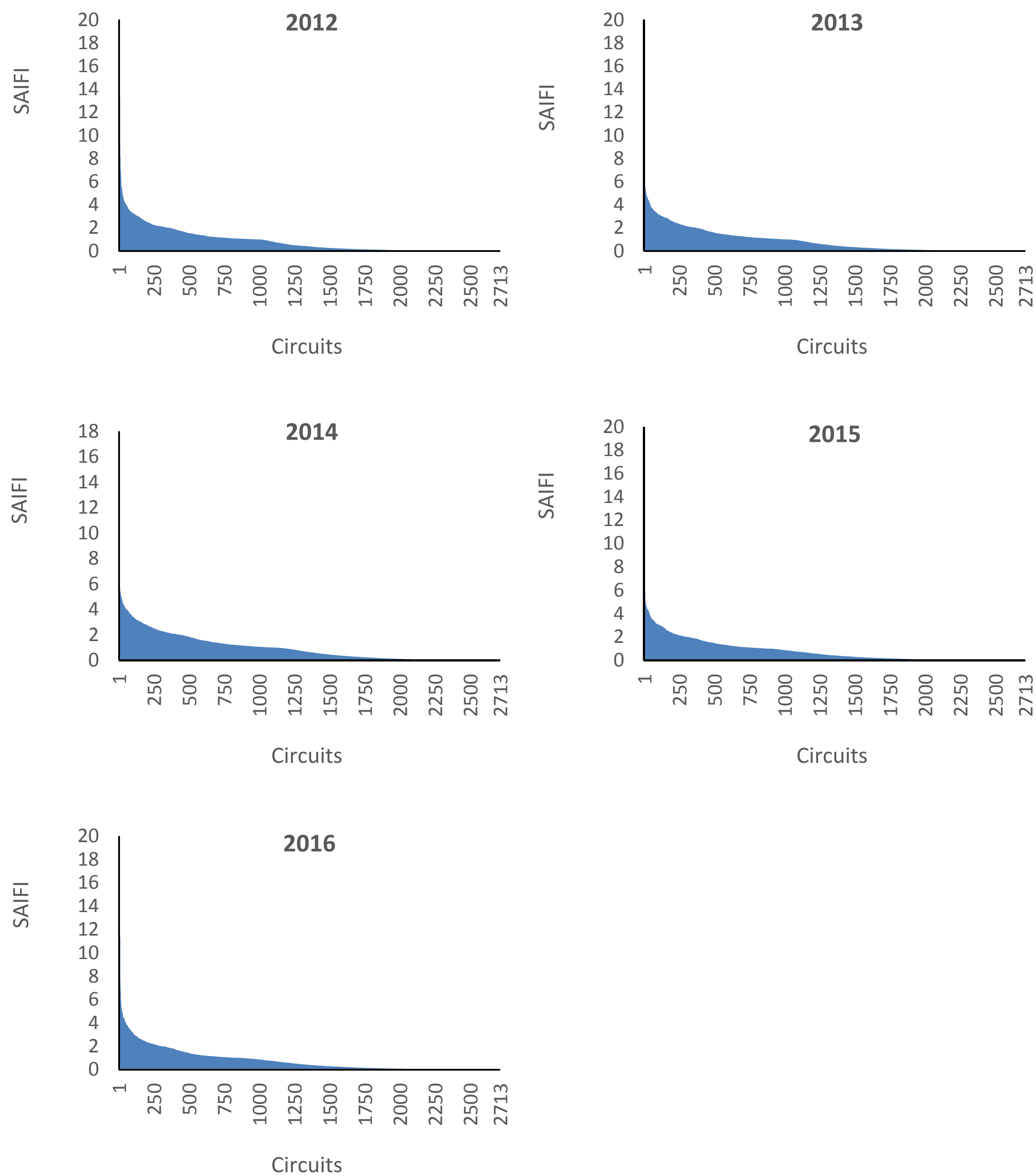


Exhibit A-4 Circuit SAIDI Distribution – System Basis

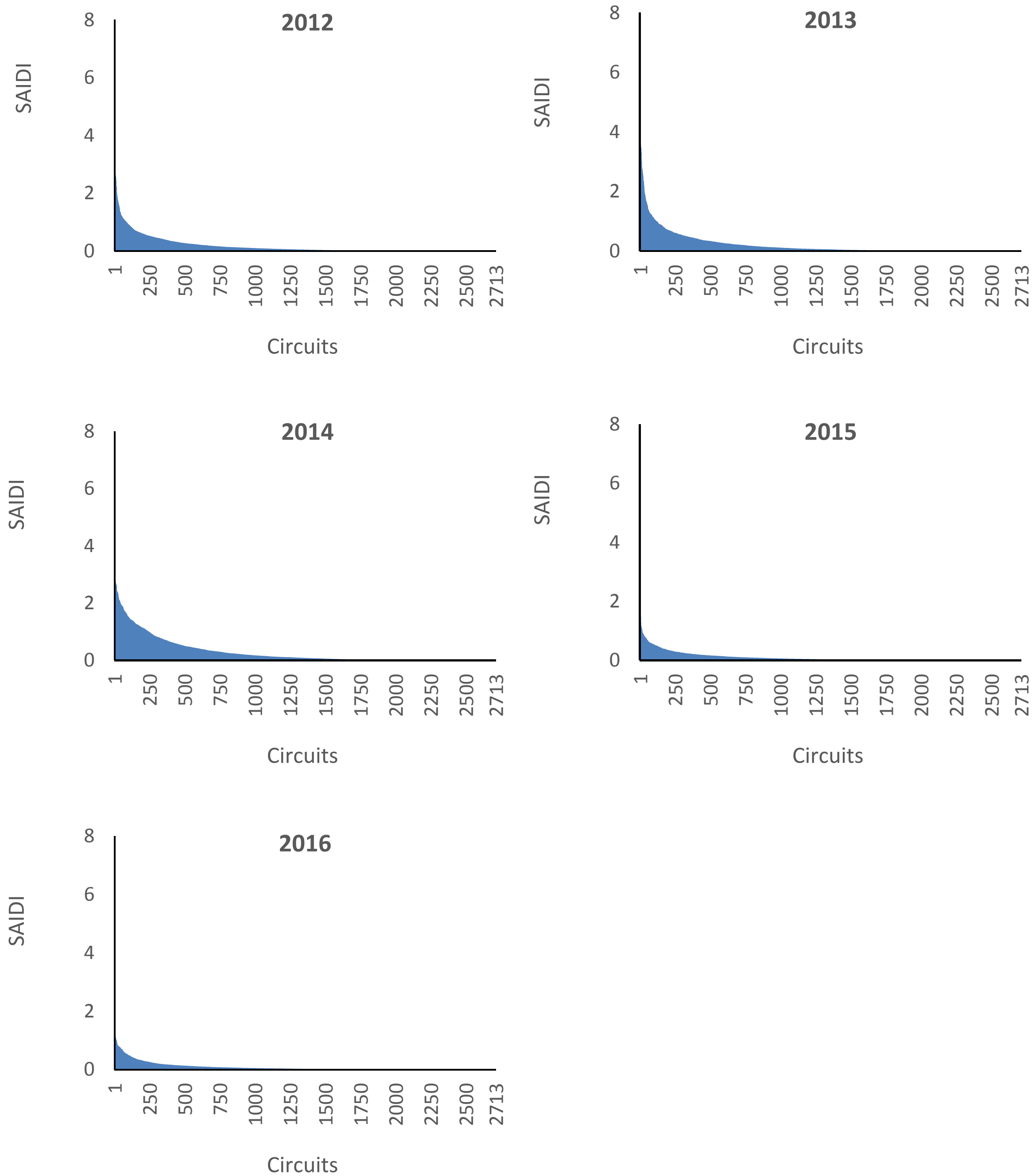
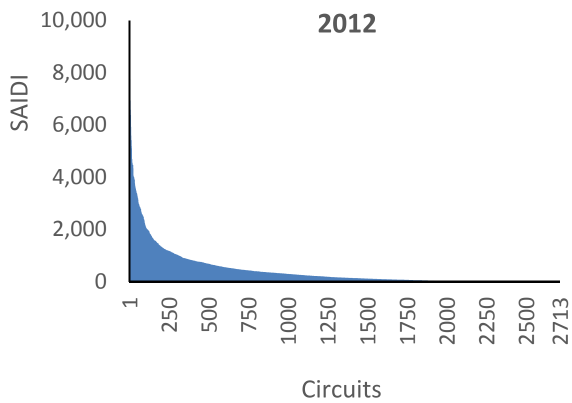
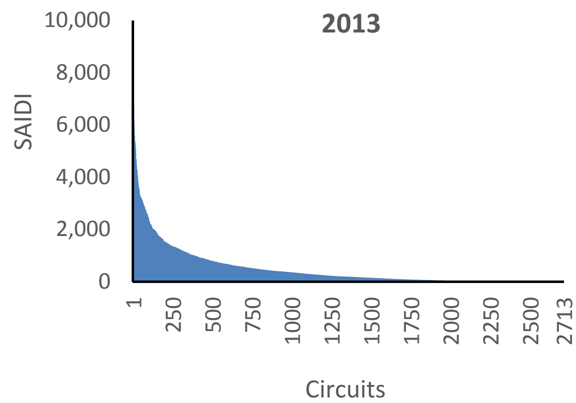
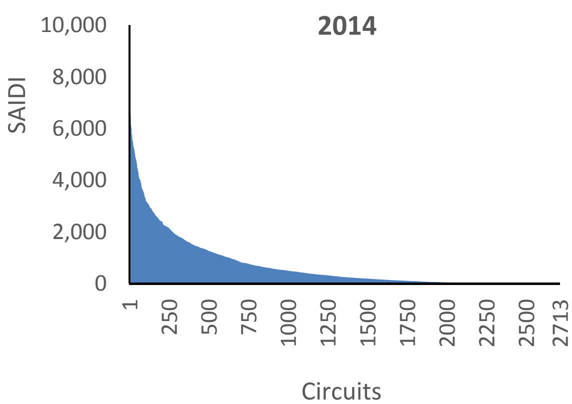
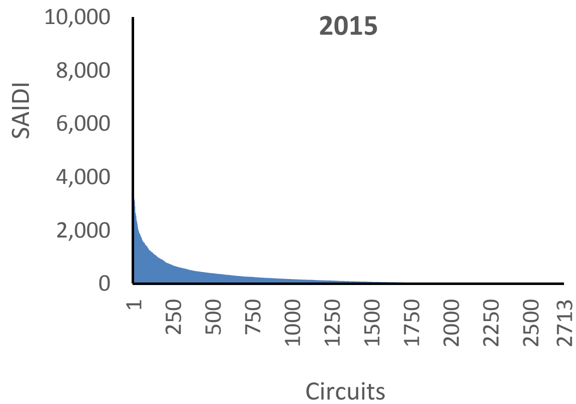


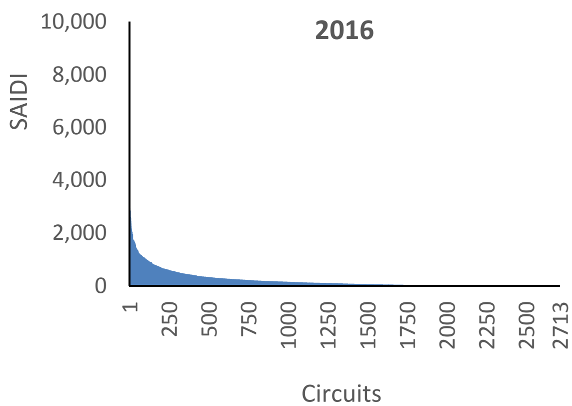
Exhibit A-5 Circuit SAIDI Distribution – Circuit Basis











Appendix III Historical Storm Events

Exhibit A-6 Storm Event and Restoration Duration History

Storm #	Wind	Lightning	Rain	Ice/Snow	Heat	Other	Storm Start and Restoration Duration in Hours		Customers Affected	Capital $000	O&M $000
2012001	W		R				01/01/12 12:10	31.3	19,979	N/A	N/A
2012002	W		R				03/02/12 21:00	67.5	105,018	N/A	N/A
2012003	W	L	R				04/16/12 07:00	67.0	93,761	N/A	N/A
2012004	W						04/23/12 10:00	35.5	32,300	N/A	N/A
2012005	W						05/28/12 23:00	42.0	35,334	N/A	N/A
2012006	W	L	R				06/02/12 15:00	51.3	37,737	N/A	N/A
2012007	W						06/21/12 05:00	48.5	43,550	N/A	N/A
2012008	W	L	R		H		07/03/12 06:00	216	366,846	N/A	N/A
2012009	W	L	R		H		07/26/12 01:00	76.0	52,404	N/A	N/A
2012010	W	L	R				10/13/12 17:00	78.5	52,610	N/A	N/A
2012011	W		R				10/28/12 17:00	141.5	124,470	N/A	N/A
2012012	W		R			Cold	12/20/12 06:00	71.5	36,997	N/A	N/A
2013001	W					Cold	01/20/13 00:00	90.0	107,485	N/A	N/A
2013002			R	I S			01/27/13 22:00	38.0	45,850	N/A	N/A
2013003	W			I S		Cold	02/26/13 16:00	66.0	50,245	N/A	N/A
2013004	W	L	R				04/18/13 13:00	62.5	91,286	N/A	N/A
2013005	W	L	R				05/22/13 15:00	32.0	31,793	N/A	N/A
2013006	W	L	R				05/30/13 12:00	54.0	36,807	N/A	N/A
2013007	W	L	R				06/17/13 16:00	48.0	25,365	N/A	N/A
2013008	W	L	R				06/26/13 17:00	98.0	99,951	N/A	N/A
2013009	W	L	R				07/08/13 14:00	75.5	53,130	N/A	N/A
2013010	W	L	R		H		07/15/13 17:00	95.0	60,391	N/A	N/A
2013011	W	L	R		H		07/19/13 16:00	103.0	153,265	N/A	N/A

Storm #	Wind	Lightning	Rain	Ice/Snow	Heat	Other	Storm Start and Restoration Duration in Hours		Customers Affected	Capital $000	O&M $000
2013012	W	L	R				08/30/13 21:00	52.0	24,525	N/A	N/A
2013013	W	L	R				09/11/13 16:00	91.0	107,279	N/A	N/A
2013014	W		R				10/31/13 07:30	62.5	51,825	N/A	N/A
2013015	W	L	R				11/17/13 07:00	158.5	305,424	N/A	N/A
2013016			R	I S		Cold	12/21/13 18:00	192.3	128,408	N/A	N/A
2014001	W		R	S			02/21/14 07:30	37.5	33,693	$3,109	$4,370
2014002	W						04/10/14 12:00	19.5	15,500	$330	$450
2014003	W	L	R				04/12/14 19:00	108.5	162,561	$10,385	$17,828
2014004	W	L	R				04/28/14 23:30	47.0	28,411	$2,381	$4,089
2014005	W	L	R				05/13/14 14:00	30.5	19,079	$2,233	$3,661
2014006	W						06/03/14 07:30	38.0	18,323	$1,922	$3,463
2014007	W	L	R		H		06/17/14 07:30	104.0	127,571	$7,237	$12,126
2014008	W	L	R				07/01/14 02:30	69.0	105,189	$7,713	$13,161
2014009	W	L	R				07/08/14 07:30	46.0	25,394	$2,747	$4,557
2014010	W	L	R				07/27/14 16:00	101.0	158,528	$12,395	$22,031
2014011			R				08/11/14 15:30	59.0	42,612	$3,101	$6,382
2014012	W	L	R				08/19/14 17:00	47.0	27,662	$1,788	$4,175
2014013	W	L	R				08/26/14 15:30	80.5	120,041	$8,616	$16,511
2014014	W	L	R				09/01/14 16:00	44.5	19,355	$2,127	$4,333
2014015	W	L	R		H		09/05/14 15:30	172.0	374,284	$26,350	$54,083
2014016	W	L	R				09/20/14 19:00	52.5	28,657	$1,663	$4,019
2014017	W		R				10/03/14 07:30	38.0	17,182	$2,275	$5,919
2014018	W						10/31/14 15:30	53.0	45,245	$3,823	$8,830
2014019	W						11/24/14 12:00	89.5	151,801	$8,393	$21,336
2015001	W		R	I S			03/03/15 11:00	40.5	34,691	$1,716	$5,175
2015002	W		R				03/25/15 06:30	32.5	16,920	$1,275	$3,218
2015003	W		R				04/10/15 12:00	27.0	35,744	$2,029	$5,406

Storm #	Wind	Lightning	Rain	Ice/Snow	Heat	Other	Storm Start and Restoration Duration in Hours		Customers Affected	Capital $000	O&M $000
2015004	W		R				05/25/15 11:00	80.0	52,812	$2,462	$5,985
2015005	W	L	R				05/30/15 11:00	55.0	38,966	$2,434	$6,202
2015006						Salt	03/01/15 10:00	27.0	62,736	$3,311	$7,904
2015007	W	L	R				06/22/15 15:00	61.5	131,086	$7,148	$17,460
2015008	W		R				06/27/15 05:30	89.0	95,860	$5,340	$13,097
2015009							08/02/15 14:00	82.0	25,299	$1,481	$3,901
2015010	W	L	R		H		08/14/15 18:00	50.0	20,289	$1,491	$3,549
2015011	W	L	R				08/19/15 15:00	49.0	55,261	$3,025	$7,496
2015012	W	L	R		H		09/03/15 11:00	58.0	17,283	$1,590	$3,898
2015013		L	R				09/19/15 00:00	50.5	26,703	$806	$2,203
2015014	W	L	R				10/23/15 02:00	67.5	34,636	$1,921	$3,769
2015015	W		R				10/28/15 02:00	50.5	30,333	$2,052	$4,920
2015016	W		R				10/02/15 09:00	56.0	39,208	$2,127	$5,153
2015017							11/06/15 06:00	51.5	48,371	$818	$2,531
2015018	W						11/12/15 06:30	47.0	32,118	$4,383	$9,929
2015019	W		R				11/18/15 14:30	49.0	72,496	$704	$2,359
2015020			R	S			11/21/15 14:00	75.0	18,972	$2,250	$6,683
2015021	W		R				12/23/15 16:00	49.5	45,696	$1,898	$5,761
2015022	W		R	I S			12/28/15 08:00	60.5	50,997	$4,047	$10,407
2016001	W			S			01/10/16 05:30	39.0	42,871	$1,696	$4,506
2016002	W						02/19/16 12:00	77.5	112,419	$766	$2,058
2016003	W		R	I S		Cold	02/24/16 07:30	53.5	26,590	$454	$1,763
2016004	W		R	I S		Cold	02/28/16 19:00	36.5	20,052	$3,747	$10,973
2016005			R				03/13/16 10:00	35.0	20,519	$2,493	$6,281
2016006	W		R				03/16/16 07:30	75.5	54,601	$2,864	$6,446
2016007	W		R				06/04/16 12:00	71.0	41,376	$4,266	$11,198
2016008	W				H		06/11/16 12:00	35.0	33,444	$3,106	$7,320

Storm #	Wind	Lightning	Rain	Ice/Snow	Heat	Other	Storm Start and Restoration Duration in Hours		Customers Affected	Capital $000	O&M $000
2016009	W				H		06/19/16 14:00	56.0	46,495	$3,072	$7,351
2016010	W	L	R		H		07/08/16 00:00	91.0	100,228	$2,030	$4,765
2016011	W	L	R		H		07/12/16 16:00	76.0	54,799	$2,365	$5,334
2016012	W				H		07/17/16 15:00	50.0	26,933	$2,242	$4,632
2016013	W	L	R		H		07/21/16 12:00	59.5	36,313	$2,881	$6,961
2016014	W	L	R				07/29/16 14:00	57.5	23,158	$2,062	$4,422
2016015		L	R				08/12/16 15:00	59.5	43,902	$1,317	$2,813
2016016	W		R				08/16/16 00:00	37.0	28,692	$3,773	$7,385
2016017	W	L	R		H		09/07/16 13:00	32.0	24,553	$3,109	$4,370
2016018	W	L	R				09/10/16 04:00	44.5	17,312	$330	$450
2016019	W	L	R				09/29/16 05:00	58.0	32,104	$10,385	$17,828
2016020	W	L	R				11/18/16 19:00	80.0	57,216	$2,381	$4,089
2016021	W		R				11/28/16 20:00	33.5	52,256	$2,233	$3,661
2016022	W						12/26/16 16:00	30.5	33,644	$1,922	$3,463
2017001	W						01/10/17 14:00	50.0	71,192	$7,237	$12,126
2017002	W						02/28/17 23:00	45.5	39,192		
2017003	W						03/08/17 08:00	202.0	754,046		
2017004	W			S			03/18/17 06:30	37.0	26,735		
2017005	W						04/06/17 07:30	106.0	81,258		
2017006	W						05/17/17 13:00	80.0			

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
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
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

DDS Section 70	Voltage
DDO Number	**Topic**
DDO-0070-005	Power Factor
DDO-0070-006	Harmonics
DDO-0070-007	Subtransmission Power Service

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

DDS Section 90	Loading
DDO Number	**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	13.2kV Emergency Circuit Loading
DDO-0090-007	4.8 kV Normal Circuit Loading
DDO-0090-008	4.8kV Emergency Circuit Loading
DDO-0090-009	13.2kV Load Loss
DDO-0090-010	13.2 kV Single Phase URD Loading
DDO-0090-011	13.2 kV Three Phase URD Loading
DDO-0090-012	Redundancy

DDS Section 100	System Automation
DDO Number	**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	Urban Networks
DDO Number	**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

DDS Section 110 DDO Number	Urban Networks Topic
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
CRISP	Cybersecurity Risk Information Sharing Program
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	Gas-filled paper lead – refers to the type of insulation on an underground cable
GIS	Geographical Information 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 infrastructures
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
Meggar testing	Procedure to measure electrical insulation resistance
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	Operations 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 on an underground cable
PM	Preventative maintenance – routine scheduled maintenance based on time or number of operations
Primary	Any part of the electrical system energized at 4.8 kV, 8.3 kV, or 13.2 kV
PTM	Pole Top Maintenance (Section 4.7)

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 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 part 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 Faults	A fault occurring internal to the transformer which may seriously damage the insulation of the transformer and causes a break down in 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 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 cable