OLSON, BZDOK & HOWARD

May 19, 2022

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-Filing

RE: MPSC Case No. U-20836

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Direct Testimony of Robert G. Ozar P.E. on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan;

Exhibits MEC-14 through MEC-35; and

Proof of Service.

Sincerely,

Digitally signed by Tracy Jane Andrews
DN: cn=Tracy Jane Andrews, email=tjandrews@envlaw.com, c=US
Date: 2022.05.19 17:02:56 -04'00'

Tracy Jane Andrews
tjandrews@envlaw.com

xc: Parties to Case No. U-20836

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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 electricity and for miscellaneous accounting authority.	U-20836 ALJ Sharon Feldman

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TESTIMONY OF ROBERT G. OZAR P.E.

ON BEHALF OF

MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, AND
CITIZENS UTILITY BOARD OF MICHIGAN

May 19, 2022

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DIRECT TESTIMONY OF ROBERT G. OZAR P.E. FOR MNSC
CASE NO. U-20836

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Robert G. Ozar. I am a Senior Consultant at 5 Lakes Energy LLC, a Michigan limited liability corporation, located at Suite 710, 115 W Allegan Street, Lansing, Michigan 48933.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council ("MEC"), Natural Resources Defense Council ("NRDC"), Sierra Club ("SC"), and the Citizens Utility Board of Michigan ("CUB").

Q. Please summarize your work experience in the field of utility regulation.

A. I have worked in the area of energy policy and utility regulation for over forty years. I began employment with the Michigan Public Service Commission in 1979, retiring in 2019. I began my employment with 5 Lakes Energy LLC in 2020.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan (CUB), collectively referred to as "MNSC."

Q. Please summarize your experience in the field of utility regulation.

A. I have worked in the area of energy policy and utility regulation for over forty years. I began employment with the Michigan Public Service Commission in 1979, retiring in 2019. I began my employment with 5 Lakes Energy LLC in 2020.

During my tenure with the Michigan Public Service Commission, I testified as an expert witness in a multitude of contested regulatory proceedings, in both the gas and electric industries. I supported the Commission in its role advising the Michigan Legislature regarding energy related bills, and participated in legislative committees, providing technical input regarding draft energy legislation. I was Chair of the Energy Efficiency Workgroup, providing input to the Michigan integrated resource plan called: "The 21st Century Energy Plan". I was a lead Staff in the Michigan Electric Vehicle Preparedness Task Force. I initiated and led the MPSC Smart Grid Collaborative. I also led the Michigan Energy Optimization Collaborative, overseeing the development of the framework for implementing energy efficiency programs for all Michigan Utilities, including development of the technical resource manual (TRM) called: "The Michigan Energy Savings Database." I was lead technical advisor for the MPSC Incentive Ratemaking Workgroup and a contributing author of the MPSC report to the legislature. I was a lead technical advisor to the MPSC's stakeholder workgroup charged to study a cost based distributed generation tariff. I was the author of the 2016 white paper, "A Reasoned Analysis for a New Distributed Generation Paradigm the Inflow & Outflow Mechanism A Cost of Service Based Approach." I was a principal author of the 2018 study: "Report on the MPSC Staff Study to Develop a Cost of Service-Based Distributed Generation Program Tariff."

During my final decade with the MPSC Staff, I served as Manager of various Staff sections, supervising both engineering and other technical staff. I was Manager of the Electric Operations Section, having responsibility for electric reliability issues, resource adequacy, renewable energy, smart grid, electric meters, and advanced electric technologies, including plug-in electric vehicles and battery storage. I subsequently served as Manager of the Energy Efficiency Section, overseeing the implementation and enforcement of the Energy Optimization Program requirements of PA 295, emerging demand response issues, and revenue decoupling issues. Finally, I ended my tenure at the MPSC as Assistant Director of the Electric Resources Division, retiring in December 2019. My resume is provided as Exhibit MEC-14. My work experience is summarized in my resume, provided as Exhibit MEC-14.

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. Yes. I have previously testified before the Michigan Public Service Commission (Commission) in a multitude of cases over a forty-plus year period.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit MEC-14:	Resume of Robert G. Ozar
Exhibit MEC-15:	Contribution in Aid of Construction Workgroup Report, Jan. 15, 2022
Exhibit MEC-16:	Texas DFA Project Papers
Exhibit MEC-17:	DFA Manual, Tutorials, FAQs
Exhibit MEC-18:	White Paper Incipient Conditions on Electric Power Circuits
Exhibit MEC-19:	MNSCDE-2.12 with 2.12-01 Equipment Outage Contribution
Exhibit MEC-20:	MNSCDE-4.4a-h

Exhibit MEC-21:	MNSCDE-4.4i with 4.4i-01 2022-2023 4.8kV Projected Investments
Exhibit MEC-22:	MNSCDE-4.6c with 4.6c-01 2020 Hardened Effectiveness Analysis
Exhibit MEC-23:	MNSCDE-6.1ai, -9.8ci, -9.8cii with 9.8c-01 2022 Pole and PTMM Circuits
Exhibit MEC-24:	MNSCDE-6.1c and -6.1d
Exhibit MEC-25:	MNSCDE-9.1b with 9.1b-01 Pole Top Hardware Patrol Items
Exhibit MEC-26:	MNSCDE-9.2a
Exhibit MEC-27:	MNSCDE-9.3 and -9.5a-f
Exhibit MEC-28:	MNSCDE-9.5b (Public Version)
Exhibit MEC-28C:	MNSCDE-9.5b with 9.5b-03 Redacted Contract (CONF)
Exhibit MEC-29:	MNSCDE-9.5f with excerpt from 9.5f-05 Tree Invoice
Exhibit MEC-30:	MNSCDE-9.15 with excerpts from 9.15-01 and -02
Exhibit MEC-31:	MNSCDE-9.19a-e
Exhibit MEC-32:	MNSCDE-9.25a with excerpts from 9.25a-01, -02, and -03
Exhibit MEC-33:	MNSCDE-9.28b with 9.28-01 Bench Marking Notes
Exhibit MEC-34:	MNSCDE-9.30 with 9.30-01 Equipment Related Outages
Exhibit MEC-35:	MNSCDE-9.37ax

II. RECOMMENDATION SUMMARY

Q. Please summarize your recommendations?

A. I offer the following recommendations:

(1) The Commission should reject the Company's proposal to more than double the capital expenditures in the 4.8kV Hardening and Pole and Pole Top Maintenance and Modernization (Pole/PTMM) programs, relative to approved annual spending in U-20561.[1] The proposed 2023 test year funding for these programs is $114.31 million (Hardening) and $87.735 million (Pole/PTMM). DTE Electric has not demonstrated that its proposed spending <u>increases</u> are economically efficient. The Commission should cap the approved level of capital investment for these two programs during the bridge and projected test year at the actual spending level for 2021 ($66.246 million for 4.8kV Hardening and $33.444 for Pole/PTMM). I further recommend that the Commission direct DTE to support the effectiveness of increasing distribution capital spending in these programs, and to develop a plan to decrease its pole and pole top inspection cycle.

(2) The Commission should recognize the extensive *overcapitalization* in the Company's distribution capital programs, particularly the 4.8kV Hardening and Pole/PTMM programs.

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[1] In Case No. U-20561, DTE Electric proposed to spend $66.000 million for 4.8kV Hardening and $32.333 million for the "Pole and Pole Top Hardware" programs in the test year ending 4/30/2021. Case No. U-20561, Ex A-12, Sch B5.4, p. 7, lines 11, 12. However, the Commission disallowed 20% of the Strategic Capital spending proposal due to a concern about possible underspending. Case No. U-20561, May 8, 2020, Order, pp. 88-91. Strategic Capital includes resilience and hardening programs, including the 4.8kV Hardening and the Pole and Pole Top Hardware programs. My interpretation of the order is that the Commission was only limiting the amount of projected Strategic spend that would be included in setting rates but was not capping the Company's actual spend below what was being requested. The Company's actual spending in 2021 was consistent with their proposed level in U-20561 and should be approved.

This is the result of unreasonable and inappropriate capitalization of operating expenses associated with the programs. The Commission should order the Company to submit in its next rate case detailed information related to, in particular, inspections and tree trimming associated with strategic distribution programs, especially the Hardening and Pole/PTMM programs. This is necessary to allow the Commission and stakeholders to assess whether tree trimming and inspections are assigned to the appropriate Uniform System of Accounts (USOA) plant or operating expense account, and the appropriate allocation between installation and removal.

(3) The Commission should reject the proposed expanded bridge and test year spending for Strategic Undergrounding Pilots, as the projected $54,300,000 costs are <u>substantially</u> out of line with the intended learnings. In its place, the Commission should approve up to $1 million to support development of the foundational assessment, including a lifecycle study, to support undergrounding.

(4) The Commission should direct the Company to undertake a new pilot to explore the reliability benefits of new machine-learning based instantaneous distribution system monitoring technologies.

(5) The Commission should direct the Company to undertake a new pilot to test the reliability benefits of modifying its tree trimming program goal from a uniform five-year cycle period to a program goal that accommodates multiple cycle lengths. Variable cycles would recognize higher tree/conductor contact risk associated with high tree-density circuits.

(6) With respect to contribution in aid of construction (CIAC) reform, that the Commission direct the Staff to continue its workgroup to explore mitigation of cross-class subsidies while retaining the current allowances provided to customers.

(7) The Commission should direct the Company to develop a plan to survey its customers experiencing outages with respect to their willingness to pay higher bills for reliability improvements and direct the Commission Staff to commence a new workgroup to create a new and up-to-date Michigan-based tool to estimate the economic value to customers of reliability improvements.

III. DISTRIBUTION CAPITAL PROGRAMS

Q. What are the drivers of increasing distribution capital program spending in this case?

A. While DTE Electric proposes numerous increases in distribution capital spending, the programs that account for most of the increase are Strategic Capital Programs, where DTE Electric proposes to increase test year spending from $308 million in 2020 to $798 million (test year), an increase of $490 million (150%).[2] Within Strategic Capital, the main drivers of spending increases between 2020 and the test year are the Resilience and Hardening programs, with 4.8kV Hardening (from $55 million in 2020 to $114 million in the test year) and Pole/PTMM (from $36 million in 2020 to $87 million in the test year), and the Redesign and Modernization programs, with substation rebuilds and 4.8kV substation conversions collectively contributing to most of test year spending in that category.

[2] Ex A-12, Sch B5.4, line 22.

Q. Before addressing DTE's specific proposals, regarding the replacement or retirement of aging distribution assets, is there a foundational basis for evaluating proposed distribution capital spending?

A. Yes. In my opinion, asset replacements should be based on the two core principles "*replacement upon failure*" (including incipient[3] failure) and "*replacement upon imminent*[4] *failure*" with respect to preemptive replacement.

With these core principles driving distribution asset replacements, it should be expected that the preponderance of asset replacements would be those having experienced actual failure, whether or not related to storm damages. To a much lesser degree, pre-emptive replacements may be needed of assets that have not yet failed, but giving signs of immediate occurrence of failure, *e.g.*, imminent failure.

Q. You have used the term "pre-emptive" in reference to distribution asset replacements, but DTE uses the term "proactive" in this context.[5] Can you explain the difference?

A. Yes. What I describe as "preemptive" replacement is with reference to imminent failure. It is a replacement of an existing distribution asset to preempt actual failure in the immediate future. However, the Company's replacement policy is more expansive, going well beyond

[3] Incipient – means beginning to come into being or to become apparent, Webster Dictionary.

[4] Imminent – means certain and very near, The Word Counter.

[5] See, *e.g.*, Pfeuffer Direct, p. 78 (describing Pole/PTMM program as "proactively" replacing equipment before unexpected failures occur); p. 118 (pilot to "proactively" replace overhead services with underground services).

preempting imminent failure. DTE refers to its replacement approach as "proactive" replacement.[6]

The difference between *proactive* replacement and *preemptive* replacement is highly relevant, as this difference is a core factor driving up distribution system capital program costs, in my opinion. A striking example of proactive replacement is the replacing of all wooden crossarms with fiberglass crossarms in a circuit, as in DTE's 4.8kV Hardening program. Just because a crossarm is constructed of wood does not mean it is at risk of imminent failure. The proactive replacement of wooden crossarms has a multiplying effect on asset replacements in light of the fact that all the pole top equipment attached to the cross arm is then replaced.[7] Another example is that old ceramic insulators are replaced with polymer insulators. Although polymer insulators may have greater durability characteristics over ceramic insulators, ceramic insulators do not have a design defect on the basis of being made of ceramic material, nor are they at risk of imminent failure just because they are old. Ceramic fuse cutouts are also replaced with polymer cutouts, and so on. The consequence is that capex can swell with the implementation of "proactive" replacement policy.

Q. Does DTE's "proactive" replacement policy impact the level of lower-cost distribution system repairs as opposed to outright replacements?

A. Yes. It should be noted that Ms. Pfeuffer, indicated that DTE has revised its emergent replacement policy to require replacement rather than perform available lower-cost repairs

[6] See Ex A-23, Sch M1, Section 8, including Exhibit 8.2 (proactive replacement programs).

[7] Ex MEC-20 (MNSCDE-4.4b).

if damaged equipment does not meet its current standards.[8] I asked in discovery if DTE repairs damaged equipment in its Hardening and Pole/PTMM programs, and the utility responded that it does not make repairs, only replacements.[9] It may be presumed that this no-repair approach is a fundamental attribute of the overall "proactive" replacement policy.

Q. Should the level of proactive replacements associated with this rate request be a matter of significant concern for the Commission?

A. Yes. As rate base regulation creates an inherent bias toward capitalized investment, it would be in the public interest, in my opinion, that substantial "proactive" replacements of assets require a substantial demonstration of cost effectiveness, much more so than a traditional maintenance policy of replacement upon failure or imminent failure and repairing damaged assets if repairs are cost effective. This higher standard is necessary to avoid potentially unreasonable early retirement of historical investments (albeit aging) that could result in a loss of the inherent value paid for by customers, as those are sunk costs.

Q. Are there any other perspectives that may bear on the Commission's evaluation of distribution asset replacements proposed in this proceeding?

A. Yes. The staggering level of preemptive replacement being proposed in this rate proceeding raises the issue of whether the utility is in a state of crisis with respect to its distribution system. One explanation for the proposal to massively accelerate replacements could be viewed as reflecting a crisis with respect to the distribution system's state of health. That raises further questions about how the utility's management in past years got the Company

[8] Pfeuffer Direct, p. 26.

[9] Ex MEC-26 (MNSCDE-9.2a).

into its current predicament. The Commission should consider what would cause a company to fail to maintain its system over an extended period of time such that its core assets are at substantial risk of looming failure. Management failures should certainly not be remediated at the expense of ratepayers.

An alternative explanation for the massive expansion in replacements is that the Company views the Commission's concerns regarding historically poor reliability as an opportunity (*i.e.*, opportunity to grow rate base). The serious misallocations of operating expenses to capital associated with distribution replacements (which I illustrate below) may be an indication of such a bias toward capitalization. It also raises the question of whether the massive expansion in distribution asset replacements may also have an element of gold plating. Information asymmetry associated with the regulatory process may not provide for clear resolution of these issues. Nonetheless, in light of the sheer magnitude of the distribution capital request, and the disproportionate increase in asset replacement programs (Hardening and Pole/PTMM), the Commission should consider these possibilities in setting the level of proof to be put forward by the Company to supportits proposed massive growth in "proactive" distribution replacements in the bridge and projected test year.

Q. How do these principles apply to DTE's proposed capital replacements in this case?

A. In my opinion, the leap in planned distribution asset replacements for the two core programs, 4.8 kV Hardening and Pole/PTMM, cannot reasonably be attributed to a commensurate leap (more than double) in imminent failures commencing in 2022. In light of the sheer magnitude of the requested increase in capital expenditures, it must be assumed that the Company is heavily relying upon its "proactive" expansion of costly distribution system replacements to pump accelerated improvements in reliability indices (SAIDI, SAIFI etc.). Unfortunately, the cost effectiveness of the Company's expansion of capital replacements (far beyond what it requested in its prior rate cases) as a core means to improve SAIDI and SAIFI is not a slam dunk proposition for these two programs, as I discuss in the next sections.

Q. Do your concerns regarding preemptive distribution system replacements have implications regarding its 13.2 kV conversions?

A. Yes. The question of 4.8 kV hardening versus conversion to 13.2kV was addressed in prior DTE rate cases, U-20162 and U-20561, where the Commission approved the launch of hardening and cost recovery of program expenses. This was done in the context of much smaller investments over the 2018 through 2020 timeframe, as discussed below. As noted above, in this case, conversions are a major driver of bridge and test year distribution system capital spending. Due to issue complexity, wide scope of Company proposals, and the limited timeframe in this case, I have not evaluated the efficacy or rationales supporting Company's proposed conversion planning and investments. My failure to address those issues should not be interpreted as support or acquiescence to the Company's proposed approached to or investment in 4.8kV to 13.2kV conversion.

Q. Would any of your recommendations related to distribution system investments in this case have implications for plans and spending related to conversions to 13.2kV?

A. Absolutely. A more robust analysis of hardening, particularly reliability benefits and costs associated with non-tree-trimming components of hardening, may inform the investment in conversion. If hardening beyond trimming proves cost effective, it may influence the conversion roll-out, given the lower cost of hardening relative to conversion. Conversely, over-aggressive hardening may delay conversions that would otherwise be prudent. It is critical to have an accurate understanding of the cost effectiveness of hardening to make informed planning. The level spending for hardening and conversions collectively is unprecedented in magnitude and scope.

It should also be investigated whether increasing tree trimming, beyond what DTE has proposed, including a more refined long-term variable cycle approach (discussed below), would support modifications to the conversion plan. Additional value for conversion planning may be obtained as a result of new instantaneous monitoring such as DFA technology to better flag incipient failures, and from a transition towards a 5-year Pole/PTMM program inspection cycle that is merged with the enhanced tree trimming program (ETTP).

Collectively, once implemented, my recommendations below, in particular improved analysis of hardening effectiveness, may support modified 4.8kV hardening with a slightly accelerated conversion to 13.2kV as the least-risk and no regrets approach, especially in light of the greater urgency of climate change policy today vis-à-vis 2018, when DTE first introduced its Hardening program. Whatever spending the Commission approves for conversion in this case should reserve the opportunity for modifications and refinements going forward, based on the recommendations I make below.

Q. What should the Commission's priorities be in evaluating DTE's distribution system investment proposals in this case?

A. As my colleague Douglas Jester testifies, DTE has relatively poor distribution system reliability and high and accelerating residential rates driven by distribution system costs. Faced with these facts, the Commission should focus on ensuring that DTE's expenditures on the distribution system are cost-effective and well supported.

A. 4.8KV HARDENING PROGRAM

Q. Please describe the Company's 4.8kV Hardening program.

A. DTE developed this program as an interim way to improve safety and reliability for the 4.8kV system in Detroit until the Company is able to eventually convert these circuits to 13.2kV.[10] The Company started the program in 2018, and "hardened" about 637 miles in Detroit between 2018 and 2021.[11] The Company proposes to substantially increase the annual miles "hardened" starting in 2022, and continuing at an increased rate through 2027, to address over 2,000 line-miles in Detroit.[12] The Company will evaluate applying the program to parts of the 4.8kV system in other parts of its service territory, which includes a total of 11,444 miles of overhead 4.8kV lines.[13]

[10] Pfeuffer Direct, pp. 67-68; Ex A-23, Sch M1, Section 9.3.4 (p. 242 of 568).

[11] Pfeuffer Direct, p. 71, Fig. 13.

[12] Pfeuffer Direct, p. 74.

[13] Pfeuffer Direct, pp. 13, Table 4; *id.* at p. 68.

Q. Has the Commission previously considered the 4.8kV Hardening program?

A. Yes. The Commission approved the Hardening program in DTE's two previous rate cases, Case Nos. U-20162 and U-20561. In the U-20162 Order, the Commission rejected arguments that hardening did not go far enough to address reliability and safety concerns in Detroit and that conversion was warranted, stating as follows:

> The ALJ agreed with DTE Electric that the 4.8 kV hardening proposal is economically efficient and that a more complete conversion of the system to 13.2 kV would be expensive and provide limited economic benefit …. The Commission adopts the findings and recommendations of the ALJ.[14]

In U-20561, the Commission reaffirmed that determination.[15]

Q. Do the Commission's prior decisions mean that the Commission has determined that the 4.8kV Hardening program is reasonable and prudent?

A. Although Ms. Pfeuffer suggests the Commission's prior orders determined hardening is a cost-effective way to address concerns with the 4.8kV system,[16] I believe the orders are limited to the record, arguments, and spending proposed in U-20162 and U-20561, respectively. The Commission's statement in U-20162, which it adopted in U-20561, regarding economic efficiency was in the context of comparing hardening 4.8kV lines to converting circuits from 4.8 kV to 13.2 kV in the City of Detroit, based on estimated costs and benefits of the two programs, noting that conversion provided minimal reliability benefits over hardening. I do not believe it is reasonable to interpret the Commission's prior orders to include preapproval of limitless expansion of capital replacement spending

[14] Case No. U-20162, May 2, 2019, Order, pp. 31-33.

[15] Case No. U-20561, May 8, 2020, Order, p. 110.

[16] Pfeuffer Direct, pp. 71-72.

beyond 2020. DTE bears the burden of proof to support its spending requests proposed in this instant proceeding, and did not carry its burden in this matter, in my opinion. In addition, the Commission noted DTE's argument that hardening would cost an estimated $600 million, versus conversion for an estimated $4.2 billion, and hardening would produce about 80% of the benefits of conversion.[17] It does not appear that the Commission previously compared the Hardening program to *less* costly opportunities to address concerns with the 4.8kV system, only to *more* costly alternatives.

Q. What are the goals of the 4.8kV Hardening program?

A. According to Ms. Pfeuffer, the program is intended to increase safety by reducing wire downs and increase reliability by reducing the frequency of outages.[18] These are consistent with the concerns related to the 4.8kV system raised by Soulardarity and recognized by the Commission in U-20162 -- *i.e.*, the need to reduce outages and improve safety associated with the 4.8kV system.[19] According to the Company's 2021 Distribution Grid Plan, the 4.8kV system "has the highest volume of trouble events" due to age, and "[t]hose problems are exacerbated by the abandoned and overgrown alleys in the city of Detroit."[20] While DTE claims that it "continues to work to maintain the electric grid across the entire service territory in a cost-effective manner," there are many areas where "general maintenance practices are no longer sufficient."[21]

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[17] Case No. U-20162, May 2, 2019, Order, p. 32.

[18] Pfeuffer Direct, pp. 68.

[19] Case No. U-20162, May 2, 2019, Order, p. 33.

[20] Ex A-23, Sch M1, Sec. 9.3.1 (p. 241 of 568).

[21] *Id.* at pp. 241-243.

Q. **Please describe the Company's approach to 4.8kV Hardening since the Commission order in U-20561.**

A. Since the Commission's 2020 Order in U-20561, DTE has decided to significantly increase its investment in 4.8kV Hardening, as reflected in the instant case:[22]

2018	2019	2020	2021 Projected	2022 Projected	2023 Projected
$40 million	$58 million	$55 million	$68 million	$116 million	$114 million

Starting in 2022, DTE plans to increase the number of line miles hardened by 79% (from 195 in 2021 to 350 in 2022), and continue hardening at that pace through at least 2025.[23]

Q. **Since DTE has not yet trimmed and inspected the circuits that will be included in the 2022 and 2023 4.8kV Hardening program, how did DTE determine the projected investments for 2022 and 2023 Hardening?**

A. DTE subject matter experts estimated the costs by reviewing historic expenditures and comparing those to projected scope of work.[24]

[22] Ex A-12, Sch B5.4, p. 8, line 9 (2020 to 2023 costs); Case No. U-20561, Ex A-12, Sch B5.4, p. 12 (2018 actual costs, 2019 projected costs).

[23] Pfeuffer Direct, p. 71, Fig. 13.

[24] See MNSCDE-9.38e. See Ex MEC-21 (MNSCDE-4.41i-01 2022-2023 4.8kV Projected Investments) for detailed projected costs.

Q. What work does DTE perform under the 4.8kV Hardening program?

A. Ms. Pfeuffer identifies the program scope in her testimony.[25] In response to discovery, Ms. Pfeuffer described the order of work: first, the line is tree trimmed; second, the poles and pole tops are inspected; third, construction (replace wooden cross arms with fiberglass cross arms, remove PLD arc and distribution wire, remove abandoned service wire, additional work identified in the field) is performed.[26]

DTE further explained that an entire circuit is trimmed as part of this program – circuits in the Hardening program are not part of the Company's Enhanced Tree Trimming program.[27] Tree trimming is projected to be about 20% to 24% of the Hardening program spending.[28]

Then the whole circuit is inspected to DTE's pole inspection and pole top inspection standards.[29] All wooden crossarms are replaced with fiberglass crossarms, without regard

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[25] Pfeuffer Direct, p. 68.

[26] Ex MEC-20 (MNSCDE-4.4h).

[27] See MNSCDE-9.10 ("**Question:** Were any circuits included in the Hardening or Pole and PTMM program for 2018-2021 excluded/deferred from a previously or currently established tree-trimming scheduled for that period? Please explain. **Answer:** The Pole and PTMM program follows the tree trimming schedule and does not defer tree trimming's schedule. 4.8kV Hardening circuits are tree trimmed as part of the program scope and all hardened circuits are excluded from scheduled tree trim until they are eligible for tree trim again under the tree trim five-year cycle.").

[28] Ex MEC-21 (MNSCDE-4.4i with 4.4i-01 2022-2023 4.8kV Projected Investments). In 2022, Tree Trim is projected to be about 20% of program costs ($23,644/582/$118,914,246). In 2023, Tree Trim is projected to be about 24% of program costs ($26,699,999/$113,086,502).

[29] Ex MEC-27 (MNSC 9.3, 9.5a-f).

to condition, and new pole top equipment is installed.[30] DTE aims to trim and inspect in one year, and complete construction the following year.[31]

Q. What evidence has DTE provided to support the effectiveness of the 4.8kV Hardening program, in terms of increasing safety and reliability?

A. Ms. Pfeuffer discussed an assessment the Company undertook to quantify the effectiveness of the Hardening program. The study looked at a 3-year historic average for reliability and wire downs on a control group and a treatment group (*i.e.*, circuits to be hardened). The study compared the reliability and wire down data for both groups during the 3-year historical period and for the year after hardening. According to Ms. Pfeuffer, the control group was not hardened or trimmed over this (5-year) period. The three-year historical period was 2017, 2018, and 2019.[32] The hardening period was 2020, and the one-year-after period was 2021.[33] According to Ms. Pfeuffer, the analysis suggests hardening improved all-weather SAIFI performance, SAIDI excluding major event day performance, and wire downs, compared to non-hardened circuits. DTE included this study in its 2021 Grid Distribution Plan,[34] and referred to it in its filing with the Commission in U-21122.[35] It is apparently the Company's core analytical study of Hardening program effectiveness.

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[30] Ex MEC-20 (MNSC 4.4a, b); Ex MEC-26 (MNSCDE-9.2aiii1).

[31] Ex MEC-31 (MNSCDE-9.19a).

[32] Ex MEC-22 (MNSCDE-4.6c _ 2020 Hardened Effectiveness Analysis), note 1.

[33] Pfeuffer Direct, pp. 72-74, Figs. 14-17; Ex MEC-22 (MNSCDE-4.6c with 4.6c-01 2020 Hardened Effectiveness Analysis), note 1.

[34] Ex A-23, Sch M1, Exhibits 9.3.3.1, 9.3.3.2, 9.3.3.3 (pages 345-246 of 568).

[35] See Case No. U-21122, DTE Electric, Oct. 1, 2021, DTE Electric Company's 2021 Storm Report, pp. 13-14.

Q. Does DTE's assessment of the effectiveness of the Hardening program support the Company's proposal to substantially increase Hardening program spending starting in 2022?

A. No. As discussed below, DTE's study is flawed because it fails to correlate the performance improvements with "hardening." DTE has demonstrated that historically trees cause two-thirds of outage minutes, and tree trimming is the most cost-effective way to improve system reliability.[36] Line clearing is the first step in hardening. The Company has not demonstrated that the non-line-clearing component of "hardening" (*i.e.*, asset replacement, particularly cross arms), as opposed to the line clearing program component, caused identified benefits.

Q. Can you address the specific flaws in DTE's support of its Hardening program, beginning with the fundamental issue of comingling asset replacement and tree trimming data?

A. Yes. Figures 14 through 16[37] succinctly frame DTE's analysis of the effectiveness of its Hardening program, and thus its core justification of the program. DTE compared 4.8 kV Hardened circuits with the control group, delineating SAIFI, SAIDI and wire downs over the five-year period. DTE compared data for the treatment and control group for the 3-year

[36] Hartwick Direct, pp. 19-20, 26-27; Case No. U-20221, DTE Electric, Oct. 1, 2021, Storm Report, pp. 7-9 (addressing trees as lead factor causing two-thirds of historic outage minutes, and documenting benefits of trimming program); Ex A-23, Sch M1, Exhibit 7.2.3.1 (identifying trees/wind as leading cause of outages), Section 10 (discussing tree trimming program).

[37] Pfeuffer Direct, pp. 73-74.

period prior to hardening (the historical period), and for the 1st year after hardening (the test period); thus, the study effectively encompasses a five-year period (2017-2021).

Because the treatment group of circuits comingled asset replacement with tree trimming, it is impossible to discern to what extent the improvement in the 1-year-after data was driven by the extensive tree trimming that had just taken place and to what extent improvement was driven by asset replacements. In order to determine whether Hardening is economically efficient, a clear differentiation of the two is necessary to find the appropriate balance between more aggressive tree trimming cycles and more aggressive preemptive asset replacement. On the record in this case, the cost effectiveness of DTE's pre-emptive Hardening program remains substantially unknown.

Q. Is the commingling of line clearing and asset replacement the only flaw in DTE's effectiveness justification for its program expansion?

A. No, there is also a core deficiency with the particular control group selected by DTE. As I previously noted, the Company asserted that control group was comprised of circuits that were not hardened and did not receive tree trimming (during the 5-year study period).[38] With respect to this control group, it is likely that the worsening reliability data captured in the study was substantially driven by the fact that there was no tree trimming for at least

[38] Pfeuffer Direct, p. 72; Ex MEC-22 (MNSCDE-4.6c-01 Hardened Effectiveness Analysis). It should be noted that, although Ms. Pfeuffer's testimony indicates that none of the circuits in the control group had been trimmed during the 3-year historic period, the data provided in MNSCDE-9.37cxi (last time circuits in control group were trimmed) indicates 2 circuits were trimmed in 2019.

5 years. I note that the Company supports its 5-year trimming cycle in part on the basis that trees typically grow approximately 10 feet on average in a 5-year cycle.[39]

I reviewed detailed data provided by the Company in response to discovery regarding the last time the circuits in the control group were trimmed.[40] Of the 55 circuits in the control group for which DTE provided last trim data, 42 had not been trimmed since 2012 or earlier; 8 were last trimmed in 2014; 3 were trimmed in 2015; and 2 were trimmed in 2019. None are scheduled to be trimmed again until 2022 or later. All 28 of the hardened circuits were trimmed in 2019 or later.[41] Comparing reliability differences between the control group circuits, 76% of which had not been trimmed for at least 9 years by the "1-year-after" period, to hardened circuits that had all been trimmed within 2 years of the "1-year-after" period, is demonstrative of the value of trimming and not much else.

Assuming the hardened (treatment group) and control group circuits had comparable performance in the 3-year historic period, it is entirely reasonable to expect worse performance for the control group, compared to the hardened group.

The bottom line with respect to the control group of circuits is that increasing tree growth over such a lengthy time frame, up to 9 years, likely had a dominant impact on the worsening reliability data during the final '1-year-after' period.

[39] Hartwick Direct, p. 27.

[40] See MNSCDE-9.37cxi.

[41] See MNSCDE-9.37bxi.

Q. How does this deficiency impact the validity of the control group selected by DTE?

A. The specific control group selected by DTE is of little apparent value, as it does not create a level playing field to test the cost effectiveness of preemptive equipment replacements. The treatment (hardened) group received a tree trimming either in the year before or year of the hardening, and the control group did not for a substantial period. In effect, DTE's <u>study simultaneously introduced two treatments, thus invalidating the chosen control group, and in consequence, the results of the study</u>. DTE did not investigate any other control groups.[42] As a result, it is impossible to discern whether and to what extent the reliability and safety improvements are a result of the asset replacements.

DTE's control group should have consisted of circuits that received the same level/timing of tree trimming as the hardened treatment group as this is the appropriate alternate investment to cull out the effectiveness of asset replacement and other non-trimming components of the Hardening program.

Q. Did you find other deficiencies in the Company's effectiveness demonstration?

A. Yes. The Company prioritized lines with worse reliability for hardening.[43] As a result, it is reasonable to conclude that clearing these lines would result in greater improvements than

[42] See MNSCDE-4.8c.

[43] MNSCDE-4.8b ("DTE did not select a control group that differed significantly from the group of hardening program circuits. All included circuits, both control and hardened, are 4.8kV circuits located in the City of Detroit. The only difference between the control and the hardened groups was that the control group circuits had not been hardened, and the hardening program group circuits were selected for hardening ("Before") and had been hardened ("After"). **The circuits with worse reliability, higher SAIFI and/or SAIDI, were prioritized for hardening to improve reliability**.") (emphasis added). See also Ex MEC-22 (hardened circuits had notably worse performance "before" hardening than control group).

the control group, which includes circuits with relatively better reliability than the hardened group. The study thus likely distorts the benefits of hardening (or trimming) the worst lines.

Q. Is there a reasonable basis to conclude that line clearing *without* asset replacement may be expected to achieve similar levels of SAIDI, SAIFI, and wire downs improvements as the Company's Hardening program effectiveness demonstration?

A. Yes. The collective impact of factors discussed above – the fact that the Company prioritized hardening lines with the worst performance in the service area, where that poor performance was exacerbated by extensive historic disinvestment in line clearing in this part of the system,[44] makes it likely that intensive line clearing and general maintenance (repairs) along these lines would have achieved similar outcomes. The Company's analyses shows Hardening may be slightly more effective than line clearing alone, but it is impossible to correlate that improvement with construction aspects of Hardening versus the fact that these were notably poor performing and overgrown lines in the first place.

Comparing Ms. Pfeuffer's Figures 14 through 16 with Ms. Hartwick's Tables 6 to 8 shows pretty consistent impacts between Hardening and the Enhanced Tree Trimming Program one year after the work:

[44] Ex A-23, Sch M1, Sec. 9.3.1 (p. 241 of 568).

	Hardening	Tree Trimming
All-Weather SAIFI[45]/ Customer Interruptions[46]	32%	34%
SAIDI Ex-MEDs[47] / Customer Minutes of Interruptions[48]	66%	45%
Wire Downs[49]	28%	18%

It is reasonable to expect that an effective tree trimming program targeting the worst-performing 4.8kV lines would achieve significant reliability and safety improvements, at a lower cost to ratepayers.

Q. What benefits are associated with the Company's proactive replacement of equipment that is systematically replaced in the Hardening program?

A. It is impossible to isolate the benefits. It appears that the Hardening program prioritizes replacing *all* wooden cross-arms with fiberglass cross-arms, and then installing new pole top equipment on the new cross arms.[50] The Company has not demonstrated that wooden cross-arms fail or cause significant outages. To the contrary, Ms. Pfeuffer testified that

[45] Pfeuffer Direct, p. 73, Fig. 14.

[46] Hartwick Direct, p. 17, Table 6.

[47] Pfeuffer Direct, p. 74, Fig. 15.

[48] Pfeuffer Direct, p. 74, Fig. 15.

[49] Pfeuffer Direct, p. 74, Fig. 16; Hartwick Direct, p. 19, Table 8.

[50] Ex MEC-26 (MNSCDE-9.2aiii1, "Under the 4.8kV Hardening program all wood cross arms are replaced. In the Pole and PTMM program only cross arms that are damaged or defective are replaced."); see also MEC-20 (MNSCDE-4.4b) ("The Company does not reinstall existing pole top equipment on new cross arms. Replacement of retirement units are capitalized according to DTEE's standard accounting procedure.").

equipment is identified as the cause of about 25% of system-wide outage events.[51] The data suggests equipment cause 25% of events, but equipment accounts for only about 10% of SAIDI (customer-minute interruptions):[52]

	Customers Interrupted	**Customer-Minutes Interrupted**	**Events**
Equipment	3,042,180	548,470,359	64,143
All outage causes	13,577,873	5,572,383,178	260,154
Equipment %	22%	10%	25%

More specifically, DTE data shows that, of equipment-caused outages, cross arms and pole top equipment are minor contributors:[53]

[51]Pfeuffer Direct, p. 82 ("Overhead equipment related outages account for almost 25% of all events."); Ex MEC-19 (MNSCDE-2.12 with 2.12-01 Equipment Outage Contribution); Ex MEC-34 (MNSCDE-9.30 with 9.30-01 Equipment Related Outages).

[52] Ex MEC-34 (MNSCDE-9.30 with 9.30-01 Equipment Related Outages).

[53] Ex MEC-19 (MNSCDE-2.12 with 2.12-01 Equipment Outage Contribution).

Material Affected	% SAIFI	Material Affected	% SAIDI
Unknown or no data	42.62%	Unknown or no data	43.49%
Conductor or cable	18.62%	Conductor or cable	20.03%
Fuse cutout	9.11%	Fuse cutout	9.04%
Recloser, sectionalizer, or breaker	6.11%	Transformer	5.86%
Transformer	5.76%	Pole or structure	5.22%
Pole or structure	3.97%	Recloser, sectionalizer, or breaker	3.79%
Crossarm or stand off	3.57%	Crossarm or stand off	2.81%
PTS or PSC switch	1.90%	Lightning arrester	2.37%
Disconnect	1.75%	PTS or PSC switch	1.53%
Cable pole, pothead, fanout	1.28%	Cable pole, pothead, fanout	1.26%
Lightning arrester	0.86%	Disconnect	1.13%
Connector sleeve, splice, or joint	0.85%	Insulator pin	0.98%
Regulator or boost	0.83%	Fuse block	0.86%
Fuse block	0.76%	Connector sleeve, splice, or joint	0.71%
Connector bolt on	0.55%	Insulator linepost	0.29%
Insulator pin	0.50%	Connector hot tap	0.22%
Insulator linepost	0.47%	Connector bolt on	0.19%
Connector hot tap	0.37%	Regulator or boost	0.10%
Terminal or pedestal	0.07%	Terminal or pedestal	0.06%
Ground wire, shield wire, or guy wire	0.01%	Ground wire, shield wire, or guy wire	0.03%
Capacitor	0.01%	Capacitor	0.01%
Meter bases	0.01%	Meter bases	0.01%
Meter, relay, or controls	0.00%	Meter, relay, or controls	0.00%
Insulator dead end	0.00%	Insulator dead end	0.00%
OH other	0.00%	OH other	0.00%
Substation other	0.00%	Substation other	0.00%
UG Other	0.00%	UG Other	0.00%

This data shows that most (about 43%) equipment-related outages are of unknown origin (both SAIFI and SAIDI), and 20% (SAIDI) are related to conductors (lines), which are not part of the Hardening program. Other equipment combined causes 37% of equipment related customer-minute interruptions (SAIDI). With about 10% of customer-minute interruptions (SAIDI) caused by all equipment, this means that only 3.7% of customer-minute interruptions (SAIDI) are related to identifiable, non-conductor equipment, including poles, pole top hardware, meters, and everything else.[54] Cross arms are a small fraction of equipment failures (2.81% SAIDI), thus causing only 0.281% of customer-minute interruptions.[55] Absent some demonstration to the contrary, it appears that replacing

[54] 10% equipment outages times 37% identifiable non-cable equipment outages = 3.7%.

[55] 10% equipment outages times 2.81% crossarm or stand off equipment outages = 0.281%.

wooden cross arms with fiberglass cross arms likely produces *de minimus* reliability and safety benefits.

Q. Has DTE provided evidence suggesting that equipment generally, and pole top equipment (particularly cross arms) is a more substantial cause of outages on circuits hardened under the 4.8kV Hardening program than the overall distribution system?

A. No. In discovery, DTE provided outage data from 2015 to 2021 for 20 circuits hardened in 2020.[56] The data suggests that for these hardened circuits, equipment was *less* of a cause of outages, and trees were a *greater* cause of outages, compared to overall systemwide outage causes:[57]

		Customers Interrupted	**Customer-Minutes Interrupted**	**Events**
2020 Hardened circuits: outage causes 2015-2021	Equipment	42,141	6,436,914	2,053
	Trees	*121,142*	*119,827,506*	*2,847*
	All outage causes	224,654	159,875,760	12,056
	Equipment %	19%	4%	17%
	Trees %	*54%*	*75%*	*24%*
5-year system-wide outages	Equipment %	22.4%	9.8%	24.7%
	Trees %	*50.3%*	*73.9%*	*36.7%*

[56] See MNSCDE-9.23bv.

[57] *Id.* System-wide outage cause data from Ex A-23, Sch M1, Exhibits 7.2.3.1, 7.2.3.2, 7.2.3.3.

Q. Has DTE provided information that would enable the Commission to evaluate the cost-effectiveness of hardening, on a circuit level basis?

A. No. In discovery, I asked for the cost per substation area to harden lines in 2020, and DTE was unable to provide cost data.[58] DTE provided projected costs to harden circuits in 2022 and 2023,[59] but that data does not assist in evaluating the effectiveness of prior year investments.

Q. What additional data is needed to establish the economic efficiency and reasonableness of increased spending in preemptive "hardening" replacements?

A. What is needed is both cost and reliability/resilience data of replaced assets on a decoupled basis (from tree trimming) so as to enable the determination of the effective cost of improvements -- $/SAIDI, $/SAIFI, $/wire downs. To be complete, the Company should demonstrate the reasonableness of its proposed increase in Hardening spending by showing the incremental cost of reliability improvement on a decoupled basis. A complete analysis would also incorporate the projected benefits or spending reductions expected from investments in emerging and strategic spending. The Commission should be concerned that the substantial jump in the pace of replacements under the Hardening program in the bridge and projected test year may cause cost inefficiencies in the nature of premature loss-of-service-life of existing assets. But the lack of available data precludes this evaluation.

The upshot is that in light of the material defects in the Company's choice of measuring the effectiveness of its Hardening program, the Commission has no idea of the true level

[58] Ex MEC-35 (MNSCDE-9.37ax), MEC-32 (MNSCDE-9.25a with 9.25a-01, -02, and -03 (excerpts)).

[59] Ex MEC-21 (MNSCDE-4.4i with 4.4i-01 2022-2023 4.8kV Projected Investments).

of reliability improvements emanating from DTE's proposed investments. The failure to separate tree trim reliability improvements from asset replacement/repair improvements appears to be a deliberate decision on the part of the Company, in light of the fact that it views "construction required" tree trimming as an inherent component of program capital spending. I address this below in the overcapitalization section, but note that the Hardening program's tree trim activities may have dual purposes. The primary purpose is no different than the O&M tree trimming program; the secondary purpose may be attributed to clearing for construction activities. The fact that a major portion of the Hardening program's reliability benefits are likely derived from tree trimming (whether line clearing or construction-related) unmasks the flaw in the Company's classification. With respect to Hardening, trimming and inspections are scheduled before the construction plan is crafted, in the year preceding construction. In addition, the so called "construction required" tree trimming necessitates that O&M tree trimming program be deferred for 5 years, identical to circuits trimmed in the O&M program. Finally, it is highly relevant that the third-party contractors who implement the Hardening program tree trimming are contracted via the same RFP and contracts as those who trim for Pole/PTMM, and are thus indifferent as to which "program" the tree trimming they perform is assigned.[60] If trimming for Hardening has a different specification than trimming for the Pole/PTMM program under the O&M Enhanced Tree Trimming program, it is likely a minor difference in reliability benefits.

[60] See Ex MEC-27 (MNSCDE-9.5a).

Q. What is your recommendation regarding how the Commission should address the Company's Hardening program spending proposed in this proceeding?

A. First, I recommend that the Commission disallow the Company's proposed <u>expansion</u> in Harding investment during the bridge and test year periods, and instead maintain the level of annual spending as in 2021.

Second, in order to correct for the material program flaws, and to support the continuing reasonableness of the 2021 historic spend level that I support in this case, I recommend that the Commission require DTE to develop and file, in its next rate case, a new effectiveness analysis of circuits hardened, in other words, those having strategic capital replacements, which provides a clear separation between tree trimming and other construction work, especially distribution asset-replacement, together with the respective costs and reliability impacts (*e.g.* SAIDI, SAIFI, wire downs). *Ex ante* analysis of past spending is a crucial step in evaluating reliability/resilience spending requests, particularly substantial spending increases. The comingling of impacts precludes the Commission in this case from evaluating the requested Hardening spending, particularly the proposed substantial ramp in spending. The disaggregated impact study should include analysis on a circuit and substation basis and be filed in the next DTE general rate proceeding.

B. POLE AND POLE TOP MAINTENANCE AND MODERNIZATION PROGRAM

Q. What is the Pole and Pole Top Maintenance and Modernization (Pole/PTMM) program?

A. The Pole/PTMM program aims to preemptively identify and replace damaged or defective pole and pole top equipment related issues before unexpected failures occur.[61] The program was previously called the Pole Top Maintenance (PTM) program.[62]

Q. Has the Commission previously considered the Pole/PTMM program?

A. Not in its current iteration. The Commission previously approved spending in the PTM program in U-20561 and U-20162, but the program did not draw opposition in testimony and the Commission did not address the details or merits of the program, as it existed at the time of those orders.[63]

Q. Please describe the Company's Pole/PTMM program.

A. The Pole/PTMM program follows line clearing, and starts with a circuit inspection of poles and pole tops.[64] After inspection, DTE aims to replace or reinforce poles that fail inspection within 12-months, and aims to replace pole top hardware within 12 to 24 months after of

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[61] Pfeuffer Direct, p. 78. The program is identified as the Pole and Pole Top Hardware program in Exhibit A-12, Sch. B5.4, page 8, line 10.

[62] *Id.*

[63] See Case No. U-20561, May 8, 2020, Order, pp. 88-91 (reducing distribution system "strategic capital" by 20% due to recent underspending, without discussing PTM program in particular); Case No. U-20162, May 2, 2019, Order, pp. 19-33 (discussing distribution capital, with no specific discussion of PTM program).

[64] See MNSCDE-9.10 (the Pole/PTM program follows the tree trimming schedule).

inspection.[65] DTE contracts for inspection, and uses a combination of contractors and employees for the replacement work.[66]

Q. Please describe Pole/PTMM inspections and replacement work.

A. In discovery, related to the Pole/PTMM program, I requested the Company's Requests for Proposals, typical contracts, sample invoices, and inspection reports. In sum, contractors test poles along a circuit following the Company's Wood Pole Maintenance Specification, and inspect pole top equipment following the Company's Pole Top Maintenance Specification. These specifications require the contractor to test the strength of the pole, assess poles for damage and decay, and identify defects in pole top equipment such as oversagging or missing cross-arm bolts. Following inspection, pole reinforcement and equipment replacements are implemented.

Q. Does the Company conduct repairs (as opposed to replacements) based on the Pole/PTMM inspections?

A. Apparently not. According to DTE, the Pole/PTMM program does not consider "replacement rather than repair;" the Company states that this program (and Hardening) "involve replacements only."[67]

Q. What is the "Modernization" component of the Pole/PTMM program?

A. This is not clear to me. Ms. Pfeuffer states in testimony that the word "modernization" was added to the program title because of "an enhanced specification that replaces old and

[65] See MNSCDE-6.1aiv.

[66] See MNSCDE-9.6.

[67] Ex MEC-26 (MNSCDE-9.2a).

outdated components with components of an enhanced specification."[68] I asked in discovery: "what are the enhanced specifications of old and outdated equipment replaced with the new modernization function of the PTMM program," and the Company responded:[69]

> The Company does not have enhanced specifications of old or outdated equipment. The PTMM program uses enhanced equipment and materials but does not have a "new modernized function".

Q. What enhancements and replacements does DTE include in the Pole/PTMM program?

A. Based on Ms. Pfeuffer's testimony, as well as the Company's Pole Top Specification and pole top inspection reports, DTE replaces defective wooden crossarms with fiberglass crossarms, porcelain equipment (cutouts, disconnect switches) with polymer equipment, and blackburn hot tops, when such equipment is identified in inspections.[70] Enhancements to poles include testing "younger" poles, checking for below-grade decay, reinforcing poles (as opposed to replacement), and DTE has increased the minimum pole class.[71]

However, it appears that the Pole Top Maintenance program was already replacing wooden crossarms with fiberglass cross arms, and porcelain cutouts and insulators with polymer equipment, and had increased the minimum pole class for primary voltage wire in DTE's

[68] Pfeuffer Direct, p. 78.

[69] See MNSCDE-6.1hi.

[70] Pfeuffer Direct, pp. 81-82; Ex MEC-25 (MNSCDE-9.1b-01 Pole Top Maintenance Specification); Ex MEC-30 (excerpts from MNSCDE-9.15-01, -02 inspection reports).

[71] Pfeuffer Direct, p. 81.

pre-"modernization" version of the program.[72] The more rigorous pole testing requirements delineated by Ms. Pfeuffer appears to be the sole program enhancement.

Q. What is the Company's historic and proposed spending in the Pole/PTMM program?

A. The Company has requested that the Commission approve an increase in Pole/PTMM program funding from $ 36.4 million during the 2020 historical year, to $87.7 million in the projected test year ($93.5 million in calendar year 2023).[73] The Company is clearly planning on significantly ramping up spending in this program:[74]

2018	2019	2020	2021	2022 Projected	2023 Projected	2024 Proposed	2024 Proposed
$36 million	$28 million	$36 million	$32 million	$59 million	$94 million	$121 million	$125 million

[72] See Case No. U-20561, Bruzzano Direct, 4 TR 55 ("Does the Company replace failed equipment with identical equipment for the pole and pole top hardware program? A83. No. When the Company replaces these items, it uses equipment that complies with current standards. For example, the minimum pole class for poles with primary voltage wire (4.8kV and 13.2kV) is stronger than previous standards. Also, the Company replaces wood crossarms with fiberglass crossarms, porcelain cutouts with polymer cutouts, and porcelain insulators with polymer clamp-top insulators. Fiberglass crossarms have five times the mechanical strength of their wood counterparts, and polymer equipment has six times the mechanical strength of its porcelain counterparts."). See also U-20262, Bruzzano, page 43, for nearly identical language.

[73] Ex A-12, Sch B5.4, p. 8, line 10.

[74] Case No. U-20561 Ex A-12, Sch B5.4, p. 7 line 12 (2018 historic and 2019 projected investment); MNSCDE-6.1b-01) (2020 and 2021 actual investment)); Ex A-12, Sch B5.4, p. 8, line 10 (2022 and 2023 projected investment); Ex A-23, Sch M1, Exhibit 9.1.1.1 (p. 224 of 568) (2024 and 2025 proposed investment).

Q. Has the Company provided an explanation for why it needs such substantially increased funding in 2022 and 2023?

A. The Company supports its proposal to massively expand the Pole/PTMM program expenditures with three arguments:[75] (1) that it has set a goal of decreasing the inspection cycle time for poles and pole top hardware from the historical three-year average of 10.9 years, to 10.0 years by 2025; (2) that it has changed its pole inspection process, to require pole testing (including below grade) as opposed to visual inspection, for poles 20 years or older, from the previous standard of greater than 40 years old; and (3) with respect to poles that are replaced, that the minimum pole class is increased to provide for higher strength.

Q. Do these three explanations provide sufficient justification for the Commission to more than double the Pole/PTMM program spending?

A. No. In addition, the Company has not supported the effectiveness in improving reliability, nor the cost-effectiveness, of this program to support such a large increase in program spending.

Q. Can you comment on the Company's first justification for increasing the Pole/PTMM program spending – *i.e.*, its goal to decrease inspection cycle time to 10.0 years by 2025, from the historical 10.9 years?

A. Yes. I have four points regarding why I disagree with the Company's argument that its goal to achieve a 10-year inspection cycle by 2025 justifies its proposed substantial expansion in Pole/PTMM program spending. I am labeling them (a) - (d).Point (a): Moving towards a 10-year cycle is not out of line with the Company's historic 10-12 year inspection

[75] Pfeuffer Direct, pp. 79-81.

cycle length, with the notable exception of 2020, which was exceptional for pandemic-related reasons. The Company provided the following look-back at its recent inspection cycles:[76]

- 2017 inspection cycle was approximately 9 years
- 2018 inspection cycle was approximately 11 years
- 2019 inspection cycle was approximately 9 years
- 2020 inspection cycle was approximately 14 years* (*2020 was impacted by COVID and other delays that prevented the Company from inspecting the number of poles planned at the start of the year.)
- 2021 inspection cycle was approximately 11 years
- 2022 inspection cycle expected to be 10-12 years
- 2023 inspection cycle expected to be 10-12 years

Point (b): the Company is proposing to tighten up inspections from a 10-12 year cycle goal to a 10-year cycle goal over a 4-year period (by 2025).[77] Shaving part of a 1-to-2 year improvement off a 10-to-12 year cycle length over the first couple of years of the ramp-up should not require a near-doubling and then near-tripling of cost.

Point (c): inspections constitute a fraction of the annual historic and projected Pole/PTMM costs. While DTE stated in discovery that it "does not have an inspection 'sub-program'," it nevertheless broke out Pole/PTMM inspection spending as follows:[78]

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[76] See MNSCDE-9.4a.

[77] Pfeuffer Direct, p. 80.

[78] See MNSCDE-6.1b ("The Company does not have an inspection "sub-program". The Pole and Pole Top Maintenance and Modernization (PTMM) program is one program and includes all activities associated with inspections, tree trim in the areas to be inspected, pole replacement and reinforcement, and replacing pole top hardware. The investments associated with the Pole and PTMM program are broken out as shown in attachment U-20836 MNSCDE-6.1b-01 Pole and PTMM Program Investments. Note that 2021 projection has been replaced with actuals."); see also 6.1b-01 Pole and PTMM Program Investments.

U-20836 MNSCDE-6.1b-01 PTMM Program Investments		Investment			Bridge Period 22 mos. ending	Test Year 12 mos. ending
Sub-Program	**2020 Actuals**	**2021 Actuals**	**2022 Projected**	**2023 Projected**	**10/31/2022**	**10/31/2023**
Inspections	$110,000	$1,379,000	$5,528,000	$6,016,000	$5,985,667	$5,934,667
Reinforce-ments	$27,000	$121,000	$5,312,000	$5,781,000	$4,547,667	$5,702,833
Line Miles Modernized	$36,227,000	$30,051,000	$48,072,000	$81,703,000	$70,111,000	$76,097,833
Total	$36,364,000	$31,551,000	$58,912,000	$93,500,000	$80,644,333	$87,735,333

Given these costs, it is clear that *inspections* are not driving the cost increases – it is "modernizing" these lines that drives costs.

Point (d): contrary to the Grid Plan, it is not clear that the Company will substantially increase inspections in the future, relative to historic years. In discovery, the Company provided the following table showing circuits and line miles "completed" since 2017:[79]

	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Projection	2023 Projection
# of Circuits	115	138	135	136	112	100	154
Line Miles	786	2,019	1,027	1,496	1,541	1,203	1,643
Inspections (poles)	63,230	84,005	58,100	2,400	25,300	87,606	92,500

This table indicates the Company plans to inspect only about 10% more poles in 2023 than it did in 2018,[80] and address about 376 fewer line-miles in 2023 than in 2018. Yet the Company proposes to invest $58 million more in 2023 ($94 million) than in 2018 ($36 million).

[79] See MNSCDE-9.13.

[80] 8,495 more poles inspected in 2023 than 2018.

In sum, it is doubtful that slowing moving from a 10-12 year to a 10-year inspection cycle justifies the significantly increasing Pole/PTMM investment in the bridge period or projected test year. That means that the primary drivers of projected increased capital spending have to be associated with justification two and three, which relate to the change from visual inspection to physical testing for certain poles, and to the higher pole class standard for replacement poles. Neither of those justifications is compelling.

Q. Why is the Company's second justification for its proposed massive increase in the Pole/PTMM program spending – *i.e.*, the change in the pole inspection process, not compelling?

A. The Company asserts that the change in pole inspection process will result in a greater amount of remediation work. The Company asserts that the purpose of the change in procedure is two-fold: (a) to identify and remediate the "first signs of decay" allowing this to be addressed earlier than the previous 40-year testing standard, and (b) with respect to the requirement to test below-grade, to ascertain decay and remediate if necessary to prevent the spread of decay.[81]

Identifying and containing pole decay implies a focus on cost effective pole maintenance, including potentially increasing pole reinforcements. This approach should be less costly than pole replacement. It may be that this change has the potential to increase both testing and remediation spending on poles, but will not create a need for much in the way of

[81] Pfeuffer Direct, p. 81.

additional program funding[82] Thus, it not logical that identifying decay in pole earlier will lead to massive increases in capital expenditures. To the contrary, the new testing standard should reduce the need for costly replacements.

Q. Why is the Company's third justification for increasing the Pole/PTMM program spending – *i.e.*, replacement of poles to a higher class, not compelling?

A. For several reasons. First, the new standard for pole replacement is an increase in the minimum pole class (for poles with primary wire). Because this change is to the minimum standard, that implies that the new standard will not necessarily affect all poles (with primary wire) needing replacement. Only those poles that currently do not meet the new minimum class will have a replacement of a higher pole class. In other words, the impact of the Company's policy change to the minimum pole class is limited and will not affect all replacements.

Second, only defective or rejected poles are replaced to the higher pole standard, and Ms. Pfeuffer testified that more poles may actually be reinforced rather than replaced.[83] As a result, unless poles are failing and being rejected at a higher-than historic level (which DTE has not demonstrated), and at a rate that exceeds the opportunity for reinforcement as opposed to replacement, there is no reason to expect that the stronger minimum pole class will result in more replacements.

[82] See MNSCDE-6.1b-01 (reproduced on page 38 above) for inspection and reinforcement costs, suggesting that not all reinforcement will be driven by the new testing standard.

[83] Pfeuffer Direct, p. 81.

Third, for that limited pool of poles, it may be that replacement poles may have a higher incremental installed cost than poles replaced in the historical test period. However, a pole replacement consists of both labor and materials, and labor costs associated with installing a pole are not likely to vary substantially with the strength rating of the pole. As a result, it is likely that additional costs of replacement compared to the historical test period are principally related to the incremental cost of materials (*i.e.*, the incremental cost of the higher-class pole). The upshot is that the new minimum pole class specification is unlikely to be a material factor leading to massively expanded Pole/PTMM program spending during the bridge and projected test period.

Fourth, in DTE's prior rate cases, U-20162 and U-20561, DTE witness M.A. Bruzzano testified that the Company was already replacing to the new pole class standard.[84] Thus, there is no actual change in policy in effect during the bridge and projected test period that would cause program costs to spike.

Q. Has the Company provided evidence of a substantial increase in pole and pole top equipment failures starting in the bridge and projected test period to support its requested Pole/PTMM program spending increase?

A. No. DTE has provided no credible evidence demonstrating a sudden and massive increase in imminent failures of the Company's distribution assets. If such a phenomenon actually

[84] See Case No. U-20561, Bruzzano Direct, 4 TR 55 (when Company replaces failed equipment, it applies current standards, and the minimum pole class is stronger than previous standards); Case No. U-20162, Bruzzano Direct, 4 TR 734 (same).

occurred, credible evidence of such a change would be elicited through circuit inspections in the Pole/PTMM program, preceding filing of this rate case.

To the contrary, as discussed above in the Hardening program, the Company's data suggests that about 25% of outages are caused by equipment (including substation, underground, and overhead equipment and hardware), and most of those equipment-related outages are either of unknown cause or are related to conductors (which are not included in the Pole/PTMM program).[85] For the circuits included in Pole/PTMM program in 2020 and 2021, DTE data shows that all equipment *collectively* accounted for a fraction of outages on these lines:[86]

	Customers Interrupted	**Customer-Minutes Interrupted**	**Events**
Equipment	824,618	141,005,679	23,485
All other outage causes	3,825	1,562,177,605	102,308
Equipment %	22%	9%	23%

[85] Ex A-12, Sch M1, Exhibit 7.2.3.1 (p. 126 or 568); see also MNSCDE-9.28a ("Equipment, including pole and pole top hardware equipment, is the second leading cause of outage events and outage minutes, behind tree/wind related outages. Outages caused by equipment may be related to substation, underground, and overhead equipment.").

[86] See MNSCDE-9.34aii-01 (tab ii, outages by cause, 2015 to 2021).

Q. Has the Company inspected the circuits it intends to include in the Pole/PTMM program in 2022 and 2023?

A. Not yet. The Company selected circuits for the 2022 Pole/PTMM program on December 10, 2021 and has not yet selected the circuits for the 2023 Pole/PTMM program.[87] The Company selected circuits for 2022 based on when they were last trimmed and last inspected.[88]

Q. Then how was the Company able to estimate the additional spending required to expand the program?

A. The Company explained in discovery that it follows a top-down[89] approach for the Pole/PTMM program "based on the Company's goal of achieving a 10-12 year inspection cycle, moving to a 10-year inspection cycle by 2025."[90] Since the Company has not yet done the inspections that will support the 2023 capital replacements in the Pole/PTMM program (allowing a bottom-up approach to estimate spending), the spending projection appears premature. While MNSC attempted to discern exactly how the Company calculated its massive Pole/PTMM spending expansion, the Company has so deeply buried the cost components for "line modernization" that it is near impossible to establish the reasonableness of the request.

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[87] See MNSCDE-9.8c, 9.8ciii, 9.8d.

[88] Ex MEC-23 (MNSCDE-6.1ai, 9.8ci, 9.8cii).

[89] Top-down means based on a budget set for the program, see MNSCDE-9.8di.

[90] See MNSCDE-9.8di.

Q. Has the Company evaluated the effectiveness of the Pole/PTMM program, in terms of reliability, wire downs, or other benefits?

A. No. I inquired whether the Company had performed an effectiveness study for this program, analogous to the study it offered in support of the 4.8kV Hardening program (which is highly flawed, as discussed above), but the Company has not performed such a study yet.[91] It would further be necessary to support program costs at the circuit level to assess program cost effectiveness and to justify the substantial test year spending increase.

Q. What is your recommendation regarding how the Commission should address the Company's Pole/PTMM program request in this proceeding?

A. Principally, I recommend that the Commission disallow the Company's proposed expansion of the Pole/PTMM investment and maintain the 2021 actual spending level annually through the bridge and test year periods. I further recommend that the Commission require DTE to support the cost effectiveness – on a circuit level – of the Pole/PTMM program to support any future increase in spending in this program. The Company should support costs associated with enhanced specifications for materials (*i.e.*, stronger poles, upgraded equipment). Additional recommendations related to the Pole/PTMM program are discussed in the overcapitalization section below.

Q. Do you have additional concerns related to the Pole/PTMM program?

A. Yes. The Commission should encourage the Company to lead imminent replacements with an accelerated inspection cycle frequency. The Company undertook benchmarking that

[91] See MNSCDE-9.22.

supported patrolling 20-25% of circuits.[92] This represents a 4-to 5-year inspection cycle. DTE is not yet at a consistent 10-year inspection cycle, and does not anticipate attaining that goal until 2025. As the Company has indicated an intent to eventually move to a 5-year cycle, the Company should establish a ramp-up plan, to achieve a 5-year inspection cycle. That plan should be detailed in the Company's next rate case filing or as part of its next Grid Distribution Plan.

Q. Will a shorter inspection cycle increase costs for ratepayers?

A. Not necessarily. The Company's goal to eventually halve its 10-year inspection cycle, and move to a 5-year cycle, if accomplished, would reasonably require increased spending on *inspections* as the number of circuits inspected annually would double. But inspections are aimed at identifying problems before they lead to failures, and should not necessarily result in massively increasing capital replacements. Even if the Company achieved a 5-year cycle, it has not established that if the time between inspections is halved, the number of assets in a state of imminent failure and in need of replacement would double or increase substantially. On the record in this case, there is a disconnect between DTE's forecasted spike in capital expenditures for the Pole/PTMM program and continued lengthy inspection cycles that have little variation from year to year. Increasing inspections that lead to preemptive *repairs* to avoid capital *replacements* is likely to lead to lower costs for ratepayers.

[92] Ex MEC-33 (MNSCDE-9.28b with 9.28-01 Bench Marking Notes).

C. <u>OVERCAPITALIZATION OF DISTRIBUTION CAPITAL SPENDING</u>

Q. What is overcapitalization?

A. For purposes of this testimony, I define the term "overcapitalization" to mean the improper or unreasonable capitalization of program associated O&M expenses. I also include biased allocation of construction-related expenses between installation and cost-of-removal.

Q Does the regulatory process create an incentive for the Company to capitalize, as opposed to expense, program costs?

A. Yes. Because the approved return on equity (ROE) is applied to rate-base, the Company's earnings growth is directly tied to the expansion of new capital additions. Rate base regulation thus creates an incentive for the utility to capitalize.

Q. Why is there an issue with overcapitalization intrinsic to the Company's proposed Hardening and Pole/PTMM program spending?

A. Based upon my review of the Company's filed case, and the Company's responses to discovery requests, it appears that <u>the Company has designed these programs from the ground up to capitalize.</u> Terminology is an important factor in the capitalization bias. The word "program" is important because this designation provides cover, ostensibly, to bundle operating expenses into the "program," then capitalize them. I demonstrate the significant bias in this policy with two core program expenses: (1) inspections; and (2) tree trimming. In addition, I address the reasonableness of the Company's allocation of tree trimming costs between installation (capital) and removal (expense), which in my opinion is biased toward capitalization over removal.

Q. Was the overcapitalization issue addressed in the Company's last rate case?

A. This issue was not addressed specifically by the Commission in the Company's last rate proceeding U-20651, nor the prior rate proceeding U-20162.

Q. Please describe the Company's approach to inspections and tree trimming in the Hardening and Pole/PTMM program.

A. The Hardening program involves first clearing the whole line, then inspecting the line, then construction.[93] DTE clears the entire circuit.[94] However, DTE does not consider lines in this program to be part of the O&M Enhanced Tree Trimming.[95] The Hardening program follows the same pole and pole top inspection criteria as the Pole/PTMM program. As in subpart A above, the Hardening program involves replacing all crossarms with fiberglass, and removal of wires. DTE claims that it does not engage in "repair" work as part of this program; it engages in "replacement." DTE claims that its line clearing work as part of the Hardening program is to a higher "construction" standard.[96]

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[93] See Ex MEC-20 (MNSCDE-4.4h) (sequence of components: tree trim, testing, construction); see also Ex MEC-31 (MNSCDE-9.19a).

[94] See MSNCDE-9.35a ("Under the 4.8kV Hardening program tree trim is performed along the entire circuit before the inspections and subsequent construction occur to allow crews to have a clear line of site to inspect the entire circuit, remove any arc wire or PLD distribution wire, and perform all construction activities.");

[95] See MNSCDE-9.10 ("4.8kV Hardening circuits are tree trimmed as part of the program scope and all hardened circuits are excluded from scheduled tree trim until they are eligible for tree trim again under the tree trim five-year cycle.")

[96] See MNSCDE-9.35b ("If the whole circuit is not trimmed to the same standards as the company's Enhanced

Tree Trim Program (see SMH-2), explain why not **Answer:** The whole circuit is trimmed to a construction standard, a different standard than the enhanced tree trim program. The construction standard specifically supports the clearances needed for the hardening construction activities.").

The Pole/PTMM program involves both inspections and some tree trimming. The Pole/PTMM program first inspects circuits according to the Company's Pole Maintenance Specification and the Pole Top Specification.[97] After inspection, the Company aims to reinforce or replace poles within 12 months after failed inspection, and replace pole top hardware within between 12 to 24 months after inspection.[98] While the Company trims as needed for construction under the Pole/PTMM program, the lines in this program are selected from the O&M Enhanced Tree Trimming Program, so trimming may be more limited.[99] It is notable, however, that of the 193 circuits to be included in the 2022 Pole/PTMM program, 58 (or 30%) have not been trimmed since at least 2014,[100] suggesting that some portion of the Pole/PTMM program may be invested in circuit-level trimming ahead of inspections.

Q. How much does DTE actually spend on inspections and tree trimming in the Hardening and Pole/PTMM programs?

A. The Company provided total Pole/PTMM inspection expenditures for 2020 through the test period, actuals and projected, which range from <1% in 2020 to 9% in 2022.[101] Tree trimming expenditures for the Pole/PTMM program are not available.

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[97] See MNSCDE-9.14a,-01 (Wood Pole Maintenance Specification); Ex MEC-25 (9.1b-01 Pole Top Hardware Patrol Items: Pole Top Maintenance Specification).

[98] Ex MEC-31 (MNSCDE-9.19a).

[99] See MNSCDE-6.1b, 9.9, 9.10.

[100] See Ex MEC-23 (MNSCDE-9.8c-01).

[101] See MNSCDE-6.1b-01 Pole and PTMM Program Investments (reproduced on page 38 above).

The Company provided projected Hardening tree trim and inspection and reinforcement costs for 2022 and 2023 at the circuit level, with the total provided below:[102]

	Tree Trim	Inspection & Reinforcement	Design	Construction	Total
2022	$23,644,582	$1,617,268	$1,577,519	$92,074,877	$118,914,246
2023	$26,699,999	$1,771,667	$1,594,500	$83,020,336	$113,085,502

Q. Where can direction be found for determining if expenses associated with the Company's Hardening and Pole/PTMM programs are properly operating expenses, or if they can be capitalized in association with asset replacements?

A. The primary source of direction can be found in the FERC Uniform System of Accounts (USOA), which the Michigan Public Service Commission follows.[103] Specific direction can also be made by the Commission in its orders, especially where an interpretation of the USOA is needed.

Q. Based on your definition, what are the different pathways that may result in "overcapitalization"?

A. Referring to my definition above, there are two fundamental pathways: (1) the improper or unreasonable capitalization of program-associated O&M expenses; and (2) allocation of construction-related expenses between installation and cost-of-removal that is biased toward installation over removal. The dual pathways can both be applied to a cost category,

[102] Ex MEC-21 (MNSCDE-4.4i-01 2022-2023 4.8kV Projected Investments).

[103] Mich Admin R. 460.9002.

resulting in compound overcapitalization. Such is the case with circuit-level tree trimming associated with the Company's Hardening program, as I explain below.

Q. How are inspections relevant to the issue of unreasonable or improper capitalization of operating expenses in the Hardening and Pole/PTMM programs?

A. With respect to inspections, and contrary to the Company's cost classification policy, inspections are exclusively operating expenses, having no capital component whatsoever. The USOA is clear and explicit on this matter. Operating Expense Instructions 2 Maintenance A states:

> *The cost of maintenance chargeable to the various operating expense and clearing accounts includes labor, materials, overheads and other expenses incurred in maintenance work. A list of work operations applicable generally to utility plant is included hereunder. Other work operations applicable to specific classes of plant are listed in functional maintenance expense accounts.*

Within Operating Expense Instructions 2 Maintenance is a list of 8 work operations (Items) that shall be charged to operating expenses. Item 2 in that list reads as follows:

> *Inspecting, testing, and reporting on condition of plant specifically to determine the need for repairs, replacements, rearrangements and changes and inspecting and testing the adequacy of repairs which have been made.*

The Company's inspections/testing associated with its Hardening and Pole/PTMM programs clearly fall within the scope of USOA Operating Expense Instructions 2. Maintenance as an operating expense.

Q. Did the Company provide its basis for capitalizing inspection costs in these programs?

A. Yes. In the Company's response to discovery, the Company explained its reasoning for why it considers inspections capital:

> Under the Pole and PTMM program the Company performs inspections at the circuit level and each circuit is considered as a unit of work. Every circuit inspected may contain poles that fail inspection and/or pole top hardware that fails inspections. As such the cost associated with inspecting the circuit is considered capital under the Pole and PTMM program and is unitized against the replaced, reinforced poles and/or replaced pole top hardware of that circuit.[104]

In discovery, the Company explained that: "Inspections done as part of the Pole/PTMM program are part of the capital program cost."[105] It appears that DTE treats inspection costs in the Hardening program as capital, in the same way it treats inspection costs in the Pole/PTMM program.[106]

Q. By performing inspections at a circuit level, under the Hardening and Pole/PTMM programs, is the Company able to avoid the USOA Operating Expense Instructions 2. Maintenance classification of inspections as operating expenses?

A. No. First, I am not aware of any other manner of accounting for distribution circuit inspections delineated in the USOA. Second, circuit level inspections are the only logical and likely cost-effective way to inspect distribution lines. Even if there were another way of structuring an inspection program, the USOA makes no distinction in cost classification based on how a utility packages inspections of individual poles and pole top equipment (i.e., a utility's definition of work unit), or whether or not a utility combines such inspections with the repairs, replacements, rearrangements and changes that are indicated by the inspection/testing activities into a "program". If DTE is examining the condition of distribution assets "to determine the need for repairs, replacements, rearrangements and

[104] Ex MEC-24 (MNSCDE-6.1c) (emphasis added).

[105] Ex MEC-24 (MNSCDE-6.1cii, 6.1d) (emphasis added).

[106] See Ex MEC-31 (MNSCDE-9.19c).

changes" then the costs of doing so are operating expenses, and not capital pursuant to USOA Operating Expense Instructions 2. Maintenance.

Q. How does the USOA treat tree trimming?

A. Tree trimming for the distribution system is addressed in both the Plant and Operating Expense accounts. USOA Account 365, *Distribution Plant: Overhead conductors and devices,* includes "the cost installed of overhead conductors and devices used for distribution purposes," and includes "tree trimming, initial cost including the cost of permits therefor."[107] USOA Account 593, Maintenance of overhead lines (Major only) includes "the cost of labor, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is includible [accounts 364, 365, and 369]. (See operating expense instruction 2.)." This account includes, as part of Item 2, "Work of the following character on overhead conductors and devices: … 9. Trimming trees and clearing brush."[108]

Q. What is the "initial cost" for tree trimming under Account 365?

A. In my opinion, there are two reasonable interpretations of the word "initial" as a qualifier for tree trimming in Account 365. The first interpretation is that <u>all tree trimming subsequent to original construction of a circuit is maintenance</u>, thus an operating expense. If construction related trimming is needed in a future replacement, that cost, not being an "initial" cost, is an operating expense under Account 593.

[107] USOA Account 365, 18 CFR Part 101.

[108] USOA Account 593, 18 CFR Part 101.

A second interpretation is that the word "initial" regarding tree trimming in Account 365 means tree trimming required at the time of the installation of a listed asset (a component of the overhead conductors and devices in Account 365), and thus directly related to the install of that asset. Ongoing tree trimming to maintain that asset would be expensed pursuant to USOA Account 593. Tree trimming associated with the replacement of that asset may be capitalized when an asset is installed subsequent to the original construction of the circuit in question (*i.e.*, part of a unit replacement). I am willing to accept this latter interpretation.

Q. Is DTE's tree trimming for the Hardening and Pole/PTMM programs compatible with either of these two interpretations under USOA Account 365 to capitalize "initial" tree trimming?

A. No. It is hard to fathom that the drafters of the USOA envisioned a utility capitalizing full circuit tree trimming on the basis of a select number of distribution assets that fail subsequent inspections and are then replaced in a reliability program.

Moreover, it appears that the Company is unitizing circuit level and construction tree trimming against replaced poles, reinforced poles and/or replaced pole top crossarms (as it does for inspections).[109] However, the USOA does not provide for the capitalization of tree trimming costs associated with the installation of assets included in Account 364, "Poles Towers, and Fixtures." Account 364 includes guys, brackets, crossarms and braces, insulator pins and suspension bolts, and poles. To the extent the Hardening program is

[109] See MNSCCD-9.26 (Pole/PTMM program). I assume DTE follows the same approach for Hardening.

designed for replacement, it is principally to replace crossarms – not conductors.[110] Pole/PTMM work appears to involve more reactive replacements, but its replacements are likewise focused on "poles and pole top hardware" including poles, crossarms, insulators, guy wires -- not conductors.[111] Only Account 365, Overhead conductors and devices, and not Account 364, provides for the capitalization of "initial" tree trimming costs related to the installation of assets included in the account list. As the Company is not replacing conductor in either the Hardening or Pole/PTMM programs, few if any capital items replaced in these programs would actually qualify for "initial" tree trimming to be capitalized with the install, and certainly not circuit level tree trimming. Unless trees are trimmed to install or replace overhead conductor, I believe circuit-level tree trimming should be expensed, not capitalized.

Q. Is it reasonable for the Company to capitalize tree trimming in the Hardening and Pole/PTMM programs?

A. No. The bottom line is that the Company's designation of circuit-level tree trimming as "construction related tree trimming" is in conflict with the USOA, and USOA is non-supportive of capitalizing such activity. In my opinion, the circuit level tree trimming associated with the Company's Hardening Program (and any circuit level tree trimming associated with the Pole and PTMM program[112]) is a maintenance activity and properly

[110] See Ex MEC-20 (MNSCDE-4.4a, b); Ex MEC-26 (MNSCDE-9.2aiii).

[111] Pfeuffer Direct, p. 78; Ex MEC-26 (MNSCDE-9.2aiii).

[112] See MNSCDE-6.1b (Pole/PTMM includes tree trimming "in the areas to be inspected").

charged to operating expenses. The Company' erroneous argument is in direct conflict with not only the clear language of the USOA, but also any reasonable interpretation of it.

To the extent the Company engages in targeted tree trimming associated with pole and pole top hardware inspections and ultimately repairs/replacements of defective assets, the USOA does not support the capitalization of those costs. The poles and pole top hardware are capitalized under Account 324 (Poles, Towers, and Fixtures), not Account 325 (Overhead Conductors and Devices). Ratepayers should not be on the hook for funding shareholders' return on what are properly operating expenses.

Q. What difference, if any, would it make if the circuit-level tree trimming in the Hardening program actually serves two purposes – line clearing for equipment maintenance and construction clearing for equipment replacement.

A. DTE stated in discovery that line clearing for Hardening is a more rigorous standard to support construction.[113] Circuit-level tree trimming <u>may</u> have a dual maintenance and construction function, if in fact trimming for Hardening is done to a more rigorous standard than that for the regular (ETTP) maintenance.

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[113] See MNSCDE-9.35a ("When a circuit is hardened under this program, is tree trimming conducted along the entire circuit, or is tree trimming limited to areas where construction activities (e.g., replace cross arms) will be conducted? **Answer:** Under the 4.8kV Hardening program tree trim is performed along the entire circuit before the inspections and subsequent construction occur to allow crews to have a clear line of site to inspect the entire circuit, remove any arc wire or PLD distribution wire, and perform all construction activities."); 9.35b ("If the whole circuit is not trimmed to the same standards as the company's Enhanced Tree Trim Program (see SMH-2), explain why not. **Answer:** The whole circuit is trimmed to a construction standard, a different standard than the enhanced tree trim program. The construction standard specifically supports the clearances needed for the hardening construction activities.").

I have some doubt about whether line clearing for construction related to Hardening is practically different than line clearing for maintenance. First, DTE provided typical contracts for Pole/PTMM and Hardening-related work, and the contract does not specify a different specification for construction line clearing.[114] DTE provided a single typical contractor invoice for tree trim for both the Hardening and Pole/PTMM programs.[115]

In addition, the nature of replacement-construction work for Hardening does not appear to be materially different than replacement-construction work for the Pole/PTMM program – both appear to principally involve pole testing and cross-arm replacements.[116] DTE explained that circuits in the Pole/PTMM program are first cleared under the Enhanced Tree Trimming program, before inspection under the Pole/PTMM program.[117] It is dubious that DTE would apply a different tree trimming standard to each program, given similar inspections and replacements under both programs. It would also be inefficient for DTE to first clear Pole/PTMM lines under the O&M Enhanced Tree Trimming standards and then

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[114] Ex MEC-28C (MNSCDE-9.5b and NDA U-20836 MNSCDE-9.5b-03 Redacted Contract) (specifying compliance with Tree Trimming Specifications for Overhead Lines 2020).

[115] Ex MEC-29 (MNSCDE-9.5f with excerpt from 9.5f-05 Tree Trim Invoice).

[116] See Ex MEC-26 (MNSCDE-9.2aiii) ("The Hardening program replaces every wooden cross arm on a circuit with a fiberglass cross arm. For the Pole and PTMM programs, some but not each and every wood crossarm is replaced within a circuit.").

[117] See MNSCDE-9.36a ("Tree trim is required for Pole and PTTM. The Pole and PTMM program follows after the tree trim program, which means that the entire circuit is trimmed prior to Pole and PTMM beginning. It should be noted that only a portion of the cost in tree trim on those circuits is capitalized to support the work of the Pole and PTMM program, the remainder is an O&M expense under the Tree Trim program."); 9.36b (in the Pole/PTMM program, "[t]he whole circuit is trimmed to the same standards as the Company's Enhanced Tree Trim program.").

the next year trim trees again to a higher construction standard for the Pole/PTMM program.

But even if trimming for Hardening were done to a more rigorous standard than the O&M Enhanced Tree Trimming program, that does not support DTE's practice of capitalizing the line clearing expense. At most, only the *incremental* cost of the "construction" standard over the "enhanced" O&M standard may properly be capitalized, if it is associated with Account 365 Overhead conductor and devices. In my opinion, it may be reasonable to interpret the USOA to allow splitting circuit level tree trimming into an operating and a capital component to reflect the dual character of tree trimming as both an operating and a capital expense, but only if the Company demonstrated a more rigorous a standard that could differentiate construction independent of maintenance, from a clearance and cost perspective which it has not done. And in that case, DTE would further need to support the incremental *construction*-related cost and limit capitalized trimming costs accordingly.

Q. Aside from the USOA, are there practical reasons to treat circuit-level tree trimming under Hardening and Pole/PTMM as maintenance rather than capital replacement activities?

A. Yes. Circuit-level tree trimming associated with Hardening and Pole/PTMM is inherently a maintenance activity that needs to be done on a regular and continued basis. The tree trimming that DTE would label "construction-required tree trimming" has no special characteristics and is apparently indistinguishable from trimming done pursuant to the Company's defined O&M tree trimming maintenance program. Tree trimming is tree trimming. If there was a sufficient growth of tree cover that needed to be cleared (enhanced tree trimming) prior to construction, then it must be presumed that there already was in existence a need for proper maintenance. DTE recognizes that part of the necessity of tree trimming for Hardening is lack of historic maintenance:

> Additionally, there has been lack of proper maintenance within the City of Detroit's alleys, which over time have been overgrown and filled with debris, impeding access and making maintenance activities difficult and costly, which the 4.8kV Hardening Program will help address.[118]

The fact that the Company does some construction (replacement) on a circuit that had not been recently or adequately maintained does not create a basis to capitalize the trimming.

In addition, the Company has no obvious impediment to coordinating maintenance tree trimming with inspections and construction activities, as these strategic capital programs are preemptive in nature. As discussed above, tree trimming, by DTE's own account, is a primary cause of outages and is likely a significant portion of the reliability benefit of the Company's strategic programs.

It is notable that after DTE undertakes circuit-level trimming for Hardening, those circuits are no longer eligible for O&M Enhanced Tree Trimming Program, and instead "start over" the 5-year trim cycle.[119] This supports tree trimming constitutes maintenance work, and the cost thereof must be charged to operating expenses.

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[118] Ex A-23, Sch M4, p. 30 of 101.

[119] See MNSCDE-9.10 ("The Pole and PTMM program follows the tree trimming schedule and does not defer tree trimming's schedule. 4.8kV Hardening circuits are tree trimmed as part of the program scope and all hardened circuits are excluded from scheduled tree trim until they are eligible for tree trim again under the tree trim five-year cycle.").

In sum, the tree trimming component of distribution strategic capital programs is directly connected with the tree trimming maintenance program, and provides substantial non-construction related value (*i.e.*, maintenance life), beyond the need for clear construction access.

Q. Regarding the second overcapitalization pathway that you previously described – the allocation of costs between installation and removal, what is the Commission's regulatory authority in overseeing installation/removal factors used to allocate capital costs?

A. The Commission has broad legal jurisdiction over the utility ratemaking under MCL 460.6a, and to make regulations for the conduct of utility business under MCL 460.55. Interpreting and applying the USOA to DTE practices is comfortably within that authority. Thus, the Company's chosen allocation factors must be subject to regulatory approval, as it directly impacts the level of retail rates.

Q. Are all Hardening and Pole/PTMM program costs capitalized by the Company as 80% installation and 20% cost-of-removal?

A. In discovery, the Company confirmed that it applies the 80/20 allocator to all Pole/PTMM program costs, including inspections, tree trimming, overheads, and direct labor and materials. [120] Hardening tree trim costs, overheads, crossarm replacements, and likely other costs, are also allocated 80% install and 20% removal.[121]

Q. Did you request the Company provide its basis for the 80%/20% allocation between installation and removal of program costs?

A. Yes. The Company's response was simply that it was determined by its subject matter experts.[122] Because the Company would not explain or divulge its basis, I surmise it was calculated with reference to an estimated average of the relative level of direct expenditures for installation in comparison to that for removal, noting that the cost of installation likely includes the cost of the physical replacement asset, and the cost of removal does not.

Q. Is the use of direct costs of installation relative to direct cost of removal an appropriate method to allocate construction required tree trimming between the installation activity (capital) and the removal activity (cost of removal)?

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[120] See MNSCDE-6.1cii (Pole/PTMM inspections are part of the capital program cost); 6.1e (Pole/PTMM tree trim costs are allocated 80% install and 20% removal); 6.1f (Pole/PTMM overheads and crew costs are allocated 80% install and 20% removal); 9.27a (Pole/PTMM inspections, overheads, crew costs allocated 80% install and 20% removal); 9.27c ("With respect to the Pole and PTMM program all expenditures are allocated 80/20 install/removal.").

[121] See MEC-20 (MNSDCDE-4.4f) (Hardening tree trim costs), 9.7e (Hardening overheads), 9.20d (Hardening wooden crossarm replacements).

[122] See MNSCDE-9.25b (related to Base and Strategic capital programs in Ex A-12, Sch B5.4, p. 1, "[p]lease indicate if any cost categories are allocated to the programs on a basis other than 80% install and 20% removal, and what that allocation factor is. **Answer:** For Programs the Company has not performed this analysis. Projects (including new business, relocation projects and emergent work) include multiple assets and work requests that have different installation and removal ratios. For Projects, the Company will not know the exact allocation until the projects are completed."); 9.27a ("What is the basis for the 80/20 install/removal split for inspections, overheads, and crew costs? **Answer:** The Company's subject matter experts reviewed and investigated the work actually performed historically under the Pole and PTMM program and determined that the 80% install and 20% removal allocation for the assets worked on was the appropriate ratio.").

A. Not in my opinion. The fact that circuit tree trimming precedes inspection means that the final construction plan for a circuit (including costs) is unknown at the time of the tree trimming. The costs of an unknown construction work plan cannot be determinative of the allocation of the "construction required" tree trimming expenses. Irrespective of the sequential order of trimming and inspections, the cost for clearing a circuit to the Company's construction standards (*e.g.*, enhanced tree trimming standard) does not depend on the cost of the replacement asset nor on the labor needed to install it, nor the labor cost to remove the existing asset.

Whether or not my surmised approach is the full or partial basis of the Company's subject matter experts, though, is immaterial. With respect to incremental <u>construction-related</u> tree trimming costs, I cannot see justification for anything other than a simple 50/50 allocation between the cost-of-removal (charged to accumulated depreciation) and the cost of installation of the replacement component (capitalized). This follows from the fact that any construction-related tree trimming must precede both removal and replacement activities, and there is no rational basis to favor one over the other with respect to the need for line clearance.

Q. What action do you recommend the Commission take in this case to address the concerns you have discussed, related to overcapitalization of inspection and trimming in distribution capital strategic spending programs?

A. The Commission should recognize the extensive overcapitalization in the Company's distribution capital programs, particularly the 4.8kV Hardening and Pole/PTMM programs, and order the Company to submit in its next rate case detailed information related to, in particular, inspections and tree trimming associated with these strategic distribution programs. This is necessary to allow the Commission and stakeholders to assess whether tree trimming and inspections are assigned to the appropriate USOA plant or operating expense account, and the appropriate allocation between installation and removal.

Q. Do you have any concerns with transparency of distribution capital expenditures?

A. Yes. It is exceptionally difficult to follow the money trail with respect to how much DTE is actually spending on distribution reliability improvements associated with the Hardening and Pole/PTMM programs. This is partly because associated operating expenses and cost-of-removal components are deeply buried in other exhibits, rendering the line items in the Company's fundamental summary document (Exhibit A-12) an incomplete reflection of the true cost of program activities. For example, MNSC attempted to no avail, to obtain data corresponding to Exhibit A-12, showing any non-capital components (tree trimming, inspections, labor, materials, overhead, installation and repairs) for distribution "capital" programs.[123] Compounding the transparency problem, evaluation of the prudency of spending on individual program activities (such as pole replacement versus pole reinforcement) is similarly stymied by the lack of transparency.

Q. What do you recommend the Commission do to improve transparency related to capitalization of inspection and tree trimming costs associated with the Hardening and Pole/PTMM programs?

[123] Ex MEC-32 (MNSCDE-9.25a with 9.25a-01, -02, and -03 excerpts – DO Summary & B5.4 Resilience Tabs).

A. The Commission should require the Company to provide clarification regarding exactly how the Company treats maintenance-related expenses (especially inspections and tree trimming) when these activities are commingled into a distribution capital program.

D. STRATEGIC UNDERGROUNDING PILOTS

Q. What is your recommendation regarding the Company's proposed expansion of undergrounding piloting and requested funding?

A. I recommend that the Commission not approve the proposed expansion of the Strategic and Service Undergrounding Pilot, at a projected cost of approximately $54.3 million during the 2022 through 2023 bridge and projected test-year periods.[124] In its place, I recommend the Commission approve up to $1 million to support assessments of lifecycle costs of underground and overhead systems and other opportunities, to support the foundation for any future more cost-effective future undergrounding pilot.

Q. What does the Company propose with respect to its Strategic Undergrounding Pilots in this case?

A. The Company proposes to complete its ongoing Appoline pilot, which it began in 2018 to underground overhead lines and is going.[125] In addition, the Company proposes to expand its undergrounding pilot work to include undergrounding existing services and laterals.[126]

Q. What is the basis for your recommendation to not approve the proposed bridge and test year funding for Strategic and Service Undergrounding pilots?

[124] See Ex A-12, Sch B5.4, p. 10, line 87.

[125] Pfeuffer Direct, pp. 114, 118.

[126] Pfeuffer Direct, p. 118.

A. The requested level of bridge and test year spend on these pilots has not been demonstrated to be in the public interest. The core associated learnings asserted by DTE Electric relate to ascertaining costs and benefits. Such learnings, although germane, are not commensurate with the proposed costs of the pilots. The proposed spending for these pilots is astronomically expensive. The proposed expenditures during the bridge and projected test year ($54.3 million) are approximately equal to historical expenditures for the entire Detroit 4.8kV Hardening program in 2020 ($55.2 million).

Further dimming the prudency of the proposed spending are the piloting results presented to date. Based on those results, it is unlikely that undergrounding will be cost effective. The Company asserts a cost of $3,000,000 per mile for its backlot pilot. Even with anticipated future reductions in cost per mile, the exceptionally high cost needed to underground overhead lines are unlikely to be offset by commensurate benefits on a lifecycle basis. The Company has apparently acknowledged this issue, and is now proposing new pilots to underground a lateral (Fairmont DC 1593) as well as potentially other lateral and service lines.[127]

In addition, the Company asserts that the strategic undergrounding of laterals proposed in the pilot, despite it not being as cost effective as undergrounding of services, will prepare such areas for future voltage conversion. The Company has not provided any rational basis for premature replacement of existing distribution assets in anticipation of future conversions. The fact that the Company has not done circuit-level load-analysis for future

[127] Pfeuffer Direct, pp. 118-20.

transportation and building electrification[128] (also a defect in establishing the appropriate timing of circuit conversions), exacerbates the unreasonable basis of voltage conversion as support for undergrounding.

Q. Are there any other issues with the proposed undergrounding pilots?

A. Yes. The requested funding, in part, will be used to implement a new pilot to "proactively replace overhead services with underground services."[129] The Company asserts a two-fold basis for the service undergrounding pilot: (1) customer interest, and (2) challenges with overhead lines. Both the proposed service undergrounding pilot itself and the proactive replacement goal of the proposed pilot are unsupported, uneconomical, and unwarranted. The Company asserts that they already require "any new, relocated, or upgraded services to be placed underground."[130] Regarding customer interest in undergrounding services, Rule 460.56 (Replacement of Existing Overhead Lines) already grants customers the right to request their overhead service be converted to underground at a fair cost specified by law.[131] Thus, a new service undergrounding pilot is unnecessary to serve "customer

[128] See MNSCDE-4.1a.

[129] Pfeuffer Direct, p. 118.

[130] *Id.*

[131] Mich Admin R 460.516, Replacement of existing overhead lines. Rule 6. (1) Existing overhead residential, commercial and industrial electric distribution and service lines anywhere in the state shall be replaced with underground facilities at the option of the affected customer or customers. (2) Before construction is started, the customer shall be required to pay the utility the depreciated cost (net cost) of the existing overhead facilities plus the cost of removal less the salvage value thereof and, also, make a contribution in aid of construction in an amount equal to the estimated difference in cost between new underground and new overhead facilities including, but not limited to, the costs of breaking and repairing streets, walks, parking lots and driveways, and of repairing lawns and replacing grass, shrubs and flowers.

interest." The new pilot appears to be a workaround to Rule 6, with ratepayers subsidizing undergrounding service lines.

An additional issue is that the proposed new pilot's goal of "proactive" replacement of overhead services runs afoul of the principle of *replacement upon failure* or *replacement upon imminent failure*. Overhead service line "challenges" (*i.e.*, susceptibility to storm related damages) do not fall into the category of *replacement upon failure* or *replacement upon imminent failure*. The stated goal of addressing overhead service line challenges is a clear example of potentially costly capital spending brought about by early retirement of distribution assets in pursuant of unproven reliability gains.

Q. Has DTE demonstrated that, on a lifecycle basis, undergrounding of laterals and services is cost effective?

A. Not yet.[132] Other entities that have considered this have reached the conclusion that undergrounding is not cost effective on a life-cycle basis.[133] The high initial upfront cost of undergrounding is obvious. There are also risks associated with undergrounding, as a result of maintaining and repairing these lines. The Company's cable replacement program in this case, where the Company proposes to spend $84 million in the bridge and test year, is a good example of the high costs associated with such risks.[134]

[132] See Ex A-23, Sch M1,Appx V, Pilot Information, Front Lot URD – FRMNT1593 Pilot Design, item 2 ("Evaluation of the pilot will include comparing down wires, reliability and emergent costs on the circuit before and after construction is complete, as well as completing an overall assessment of the total lifecycle cost of an underground lateral against an overhead lateral.").

[133] Case No. U-21122, Oct 21, 2021, Comments by Paul Alvarez and Dennis Stephens, Wired Group, on behalf of ABATE, pp. 28-30 (addressing cost-effectiveness of undergrounding).

[134] Pfeuffer Direct, pp. 82-87; Ex A-12, Sch B5.4, p. 8, line 11.

Q. How do you recommend the Company should proceed with respect to its undergrounding pilots?

A. In light of the difficulties the Company acknowledges it is facing, the Company should bring the Appoline pilot to a close with as minimal additional expense as possible. The Company should at least pause or cancel the Fairmont and any other planned new undergrounding pilots, at least until it has completed and presented to the Commission a full lifecyle cost analysis of undergrounding.

Q. What additional undergrounding-related analysis be addressed prior to the Company filing its next rate request?

A. Several issues merit further exploration as they bear on additional piloting work that may be approved in the future. First, the Company should draw upon its considerable data resources to analyze new, relocated or upgraded services (which must be undergrounded) as a proxy an undergrounding pilot, in order to better understand and quantify cost effectiveness and overhead service line challenges.

Second, it would be fair to assume that customer interest in potential undergrounding is related to storm related challenges. I recommend that the Company develop a new program to partner with customers on addressing tree contact issues affecting customer overhead service lines via uniquely crafted enhanced tree trimming along the service line.

Third, I recommend that the Commission approve a comprehensive study of lifecycle costs of both overhead and underground distribution systems across DTE's service territory. Such study is a core requirement in evaluating the potential economics of undergrounding, and in combination with work done on its existing undergrounding pilot, should provide the Commission with a basis for a go/no-go decision to approve additional piloting funding.

Fourth, the Company should explore cost efficiencies related to the timing of undergrounding work. It may be possible in certain cases that undergrounding would be more cost effective if done in coordination with water, sewer, and street work, rather than on standalone basis. I recommend that DTE explore the feasibility of coordination and provide its insights along a lifecycle cost study.

Fifth, as undergrounding existing overhead lines has been a longstanding issue of common interest across the country, it behooves the Company to attempt to procure outside funding to support piloting. The Company should demonstrate a good faith effort to obtain outside funding.

Sixth, the Company should aggressively continue its benchmarking efforts and cooperative learnings garnered from other utilities who may be considering or have begun to implement undergrounding pilots.

To this end, I recommend that the Commission approve a reasonable level of funding toward completion of these preliminary objectives in the 2023 projected test year. A funding level of no more than $1,000,000 for these efforts is reasonable in my opinion.

Q. Do you have any further recommendations with respect to potential future expanded spending on **undergrounding pilots?**

A. Yes. I suggest that the Company not propose new undergrounding pilot until the initiatives I described above are complete, and in particular a workable cost/benefit analysis that demonstrates with a reasonable level of confidence that undergrounding existing overhead lines may cost effectively provide reliability benefits on a lifecycle basis. Should the preliminary work outlined above satisfy the Commission, then I recommend that the Company work closely with Staff and stakeholders to develop a reformulated pilot for a future rate proceeding.

IV. DISTRIBUTION PILOTS

Q. Are there any initiatives that DTE Electric should implement that have the potential to improve reliability without (or with minimal) additions to the Company's strategic capital spending?

A. Yes. My reading of the Company's filing reveals that the Company is under intense pressure to replace its aging distribution assets as a fundamental, but unfortunately costly, means to improve grid reliability. The massive ramp in distribution capital spending proposed for the bridge and projected test year appears to be a direct manifestation of that pressure. It is obvious that the more tools available to the Company to improve reliability, the better, as this may lessen its both its urgency to replace, and thus, rate of replacement of existing distribution assets associated with circuits having poor reliability. I recommend two initiatives, which, in my view, are of particular importance: (1) pilot an instantaneous distribution system monitoring system as a key supplement to the Company's field-inspections; and (2) develop and implement a pilot to test the potential reliability improvements associated with converting its O&M Enhanced Tree Trimming program (upon achievement of its surge goals) from a uniform cycle length of 5 years[135] to a variable cycle length based on priority-binning of circuits within each service region.

A. <u>CONTINUOUS DISTRIBUTION SYSTEM MONITORING</u>

Q. Please summarize your recommendation for a new pilot to test the effectiveness of an instantaneous distribution system monitoring system?

A. I recommend that DTE institute a new pilot to gage the cost effectiveness of instantaneous distribution system monitoring such as the Distribution Fault Anticipation (DFA) system developed by Texas A&M University and the Electric Power Research Institute (EPRI). Instantaneous monitoring of incipient failures offers multiple potential benefits. It may reduce inefficiencies related to multi-year asset surveys (*e.g.*, the Company's 10-year inspection cycle goal for its Pole /PTMM program). It may also reduce the Company's pressure to replace aged distribution infrastructure that may retain serviceable life when multi-year field inspections (10-year cycle) are the primary means of monitoring asset health. Most importantly, an instantaneous monitoring system (*e.g.*, DFA) would strengthen DTE's ability to address <u>incipient</u> failures, something that appears to be a weak link in DTE's distribution system repertoire.

[135] Case No. U-21122, March 3, 2022, Order, p. 21 ("The goal of the ETTP is to trim and/or remove trees to maintain circuit clearance for a five-year cycle of growth.").

Q. Should system monitoring be a key attribute of grid modernization?

A. Yes, absolutely. For example, the Company has established five key categories of investments that are essential to grid modernization, one of them being "observability."[136] I agree that observability is essential. The Company accurately notes that: "[e]nhancing observational capabilities and translating observations into situational awareness and intelligence to help customers will be increasingly needed …."[137]

Q. What is the value of adding a continuous distribution monitoring system to the Company's toolbox?

A. A continuous distribution system monitoring system is harmonious with the Company's goal to enhance observational capabilities. The Company's current monitoring actions clearly constitute important reliability tools, and incipient adverse conditions that may result in a fault can be identified at the time of such monitoring.[138] However, because distribution system monitoring occurs on a scheduled basis, with significant time periods in between asset evaluations, it has an obvious inherent limitation. Scheduled monitoring is incapable of flagging incipient adverse conditions that occur in the interim between monitoring. Decreasing the timespan between scheduled monitoring (such as the Company's long-term goal with respect to its Pole/PTMM program[139]), under this paradigm, could improve asset evaluation but cannot eliminate this limitation. Moreover,

[136] "A modern distribution grid needs observational visibility … The Company has made significant progress in boosting sensing coverage throughout its distribution system through investments in substation monitoring, line sensing, AMI, and the new ESOC." Pfeuffer Direct, p. 52.

[137] Pfeuffer Direct, p. 52.

[138] Ex MEC-18 (Incipient Conditions on Electric Power Circuits).

[139] Pfeuffer Direct, p. 80 (noting "goal of achieving a five-year pole top hardware inspection cycle).

continuous monitoring using field crews under the current monitoring paradigm would be unreasonably costly. An advanced continuous distribution monitoring system mitigates this limitation because it uses technology to monitor the distribution system instantaneously.[140]

Q. Would traditional line sensors provide the same functionality as the advanced continuous asset monitoring systems you have been discussing?

A. No. The primary purpose of traditional line sensors is to optimize the determination of fault locations. They are strategically located to divide circuits into zones for this purpose. Line sensors are used for locating faults after the fact, not to anticipate adverse conditions that may result in a future fault or system failure. The fault location, isolation, and service restoration (FLISR) function associated with Distribution Management Systems[141] automates outage restoration but does not incorporate the ability to anticipate future faults or system failures.

Q. Do you have an example of available continuous monitoring technology?

A. Yes. Researchers at Texas A&M University have developed a continuous distribution monitoring technology that utilizes machine learning, called *Distribution Fault Anticipation* (DFA) technology.[142] This DFA technology was funded by the Electric Power Research Institute (EPRI), and the researchers worked with EPRI and the industry for 20 years to implement real-time monitoring on more than 100 distribution circuits. The basic concept of DFA technology is that software embedded in DFA system reports identify

[140] Ex MEC-18 (Incipient Conditions on Electric Power Circuits); Ex MEC-16 (DFA Presentation).

[141] See Direct Testimony of M. Elliot Andahazy, p. 6.

[142] Ex MEC-16 (DFA Presentation & Texas Case Studies).

events that may persist for weeks ahead of an event, but which conventional technology ignores.[143]

Several Texas electric utilities participated in the Texas Powerline-Caused Wildfire Mitigation project to test and document the potential reliability and safety benefits of DFA technology.[144] Notably, as reported in the utility case studies, participating utilities tested DFA technology to identify issues along various types of distribution circuits, equipment and substations, and involved conditions influenced by weather (wind and moisture). For example, DFA provided early notice of substation switch arcing for Mid-South Synergy Electric Cooperative.[145] Before complaints or existing systems indicated a problem, DFA technology detected which circuit switch was carrying most of the circuit load, and a patrol at the substation immediately identified the offending switch. Because the switch was located on the substation buswork, failure may have caused an outage for the entire substation, and may have even caused a fire. Another example is the Pickwick Electric Cooperative, where DFA noticed repeated severe restrikes and was able to identify the affected capacitator bank that was the source of the issue.[146] When crews arrived, they found the bank had a switch with partial loss of vacuum, and they were able to repair the issue and avoid multiple potential problems, including catastrophic switch failure.

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143 *Id.* at p. 5 (DFA Presentation).

144 *Id.* at p. 6, 20-22.

145 *Id.* at p. 28.

146 *Id.* at p. 29.

A notable example of a larger urban utility that has integrated DFA into its monitoring repertoire is Austin Energy, which is a vertically integrated municipal utility with over 11,000 miles of distribution lines, and whose service area the City of Austin and surrounding areas.[147] Austin Energy initiated a DFA pilot project in 2016 to improve predictive fault analysis, with the aim of anticipating issues associated with voltage/current waveforms, fault location, downed conductors, conductor-slap, equipment arcing and explosions, and trees and vegetation. While DFA has been used to identify faults with the aim or reducing wildfires caused by power lines, the primary original purpose of DFA is improving reliability of distribution circuits by detecting and identifying incipient failure before failure.[148]

This is a state-of-the-art technology that has the potential to detect adverse conditions, including as follows:

- Detect and repair a substantial number of routine outages, without customer calls.
- Detect and locate tree branch hanging on line and causing intermittent faults.
- Detect and locate intact tree intermittently pushing conductors together
- Detect and locate broken insulator that resulted in conductor lying on and heavily charring a wooden crossarm.
- Detect and locate catastrophically failed lightning arrester.

[147] *Id.* at p. 20 (noting Austin Energy participation); *see also* https://www.energy.gov/sites/prod/files/2020/10/f79/EAC_October_BigDataSession2_Kelly.pdf, last visited May 17, 2022.

[148] Ex MEC-15, p. 20.

- Detect and locate arc-tracked capacitor fuse barrel.
- Detect and locate multiple problems involving capacitor banks.[149]

It is notable that this technology not only has the potential to identify a fault before an outage event occurs, but it has the potential to identify "upstream" conditions that may cause "downstream" events. As a result, where traditional corrective action may address the manifest cause of an event (*e.g.*, broken conductor), DFA technology has the ability to detect underlying conditions and provide proactive repairs.

Further details about DFA technology are in Exhibit MEC-17, which contains the DFA technology manual, Frequently Asked Questions about DFA, and DFA tutorials.[150]

Q. Are proactive replacements or repairs advantageous to waiting for an actual failure?

A. Absolutely. The Company's entire Infrastructure Resilience and Hardening program is based on the principle of proactive replacements. What the program is missing, in my opinion, is further refinement in replacement/repair strategies that continuous anticipation monitoring technologies may offer over sole dependence upon field inspections having long timelines between inspections, and thus potential cost reductions in those programs, and the mitigation of outages made available by implementation of continuous distribution asset monitoring technologies.

[149] *Id.* at 6.

[150] See also *Mid-South DFA presentation at 2019 Annual Membership Meeting* (July 8, 2019), available at https://www.youtube.com/watch?v=nrb42Hmvh0g, last checked June 22, 2021; KETK, *Tool Developed in Texas to predict power failures now being tasted in California to prevent wildfire* (Dec. 17, 2019), available at https://www.youtube.com/watch?v=7nG1vjuWdps, last checked June 22, 2021.

Q. **What are your recommendations with respect to continuous distribution system monitoring?**

A. State-of-the-art continuous distribution monitoring technologies have potential to enhance the Company's ability to make proactive replacements or repairs, to improve reliability, improve safety, reduce costs, and to improve distribution asset replacement strategies. The Company proposes significant investments in Infrastructure Resilience and Hardening projects in particular, both in recent rate cases and in this case, and that trend is likely be repeated in future rate case distribution system capital spending requests. As a result, it befits the Company and its ratepayers to integrate a concerted fault investigation into its repertoire of technology investments, and to fully investigate their potential application to the Company's distribution system.

I recommend that the Commission direct the Company to undertake a comprehensive investigation into available continuous distribution monitoring technologies and file a report on such investigations, within six months after the final order in this docket. This report should include, among others the Company may identify, the DFA technology, provide a thorough cost and benefit analysis, and include at least one pilot project proposal to test integration of this technology. It is critically important to begin immediately to investment and implement continuous monitoring to identify incipient conditions, particularly considering the magnitude of year-over-year increases the Company is requesting for asset replacements and the potential to further improve asset replacement strategies and thus control escalating costs.

B. PILOT TO TEST TREE TRIMMING AT MULTIPLE CYCLE LENGTHS

Q. Is the Company's goal to bring to completion its tree trimming surge program, and move to a uniform 5-year cycle, the end-game with respect to tree trimming?

A. Not in my opinion. As tree trimming is proven to be one of the most effective means of enhancing grid reliability and resilience,[151] continued improvements to this activity may have considerable strategic value. To continue innovation and improvement, I recommend that the Company pilot an augmentation to the Enhanced Tree Trimming program that would shift the program goal from a uniform cycle length of 5 years[152] to instead develop unique cycle-lengths by bucket, based on tree intensity and other parameters. The goal would be to bin circuits with the highest priority to enhanced trimming cycles of less than 5 years.

Q. Is the concept of binning circuits into a multiple tree trimming cycle lengths novel?

A. Not at all. Variable cycle-periods are inherent to the Company's surge initiative, as this is the only way to accelerate transition (*i.e.*, to surge) from the previous long-cycle trim period to its goal of a shorter 5-year cycle period. The process of accelerating the pace of transition means that the time period since the last trim will vary among circuits trimmed pursuant to the surge. The Company asserts that any subsequent trimming of a circuit that has been surge trimmed will be *on-cycle*, with a uniform 5-year cycle period going forward for all

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151 Case No. U-21122, Oct. 1, 2021, Order, p. 21 ("DTE Electric states that trees are a leading factor in reliability performance and, historically, have been responsible for two-thirds of the outage minutes and half of overall outages."); Hartwick Direct, p. 26 ("As discussed in the Company's Distribution Grid Plan (U-20147), tree interference remains the leading driver of customer outages.").

152 Case No. U-21122, Oct. 1, 2021, Order, p. 21 ("The goal of the ETTP is to trim and/or remove trees to maintain circuit clearance for a five-year cycle of growth."); Hartwick Direct, p. 31. ("The Company trims and removes trees to maintain circuit clearance for one five-year cycle worth of growth …").

circuits.[153] As a result, the temporary existence of multiple cycle periods is really a product of the Company's reactive maneuvers to bring circuits on-cycle, and thus transition to the uniform 5-year trim cycle set by the Company.

Q. Once the surge program goals are achieved, does it make sense for the Company's permanent tree trimming program to proactively provide for multiple trimming cycles?

A. Yes. Proactive use of multiple trimming cycles (as opposed to the uniform 5-year goal) could allow the Company to set an optimal cycle length for high-risk circuits based on circuit tree density,[154] as opposed to a one-size-fits-all period between tree trimming. Thus, in my opinion, the binning of select circuits into optimal cycle periods could yield a strengthened connection between the risk of tree-related outages and cycle period, driving further economic improvement in reliability for the program.

Q. Are there other core factors besides tree density that impact the risk of tree related outages on distribution circuits?

A. Yes. In addition to tree density, tree growth rate is a fundamental factor in setting the time interval between tree trimming. The Company appropriately recognized the relationship between tree growth and the time interval between trimming in setting its long-term cycle-goal at five-years. Unfortunately, though, by framing the program on the basis of a <u>system-wide tree contact standard,</u> the Company has left some nickels on the table, so to speak.

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[153] Hartwick Direct, p. 30 ("Circuits already trimmed as part of the ETTP will be maintained on a five-year cycle while also addressing the backlog of circuits that have yet to be trimmed …").

[154] In addition to tree density, the Company may identify additional key reliability and/or cost factors to reasonable bin circuits with similar characteristics together.

Multiple trimming cycles (rather than a system-wide uniform cycle) may allow the Company to further extract reliability benefits from its tree trimming program, and to do so economically.

Q. Are there additional reasons why a uniform cycle length may be limiting with respect to extracting maximum reliability benefits from the tree trimming program?

A. Yes. The Company's choice of a uniform 5-year trimming cycle is comparable to a system-wide standard of no more than 10% to 15% tree to conductor contact.[155] Because the tree-contact standard is based on a system-wide perspective, it is an average over all circuits. The Company asserts that it has circuits that range from less than 10 trees per mile to circuits with more than 1,000 trees per mile,[156] a greater than <u>100-fold range</u> in tree density. Circuits with more trees per mile than average will have more potential points of contact at five-years post trim, some significantly more than average, under the standard. The latter are circuits that logically could be assigned a shorter trim cycle, and by doing so, reduce the points of contact that may result in tree related events in the interim between trim cycles. For example, a 10-mile circuit with 1,000 trees per mile would be at risk of 1,000 to 1,500 points of contact in the 5th year after trimming. Whereas a 10-mile circuit with 10 trees per mile would be at risk of only 10 to 15 points of contact in the 5th year after trimming. It is logical to conclude that a circuit with a risk factor of 1,500 points of tree contact should have a shorter tree trimming cycle than the circuit at risk of only 15 points

[155] Hartwick Direct, p. 28.

[156] *Id.* at 8.

of contact, resulting in an improvement in grid reliability, which is the goal of the tree trimming program.

Because the cost to trim increases with longer trim cycles (due to continued tree growth), the shorter period between trimming high tree-density circuits may result in lower trimming costs, thus offsetting the increased cost of more frequent circuit trimming. The degree of offset may be explored in a pilot.

Q. Could the institution of multiple tree-trimming cycle-lengths provide an opportunity for the Company to attain an even shorter system-wide cycle-length than 5.0 years?

A. Yes. The 5-year cycle goal is certainly not an endgame. Figure 1, "Distribution Utility Vegetation Management Benchmark," in Ms. Hartwick's testimony (page 29) denotes both goals and actual tree trimming cycles lengths achieved, with the median cycle length of each category at 4.0 years and 1.7 years respectively.

Q. If tree trimming for selected high tree-density distribution circuits was on a cycle shorter than 5 years, would you expect that the line clearing standard would need to be changed from the Company's enhanced clearing standard?

A. No. I would expect that circuits binned into shorter trimming cycles would be trimmed to the same clearance standards that the Company has set for its 5-year cycle goal,[157] otherwise the benefits of the shorter trim cycle on high tree density circuits may be lost.

[157] Hartwick Direct, p. 31 ("The Company trims and removes trees to maintain circuit clearance for one five-year cycle worth of growth, which, on average, necessitates ten feet of clearance to the outermost conductor. The required clearance is species-specific.").

Q. Would the pilot, if successful, result in a major change to the Company's tree trimming program?

A. No. I would consider this to be a refinement to the program, not a wholesale change. None-the-less, I believe it may be worthwhile to explore the concept in the context of a pilot. Assuming successful implementation of a pilot, the variable cycle-length based on the binning of circuits could be instituted once the Company completes its surge program by achieving its goal of meeting a at least a 5-year cycle for all circuits (tentatively 2024 pursuant to Ms. Hartwick's testimony[158]). I am recommending that the Company initiate the pilot as soon as possible.

Q. Should the Company file a report detailing the results of the variable cycle length pilot?

A. Yes. I recommend that upon conclusion of the pilot, the Company file a report in an appropriate public docket (*e.g.*, U-20147, or in this case) detailing the results of the pilot, including both reliability improvements and cost savings achieved by the pilot.

V. CONTRIBUTION IN AID OF CONSTRUCTION (CIAC) REFORM

Q. How are Contributions in aid of construction (CIAC) currently handled?

A. Current policy (which is proposed to be continued by the Company) necessitates that the "free" allowance toward new customer line extensions be based on a multiple of estimated annual revenues from customers. That dollar amount sets a cap. For residential customers, the algorithm translates into a 600 ft maximum allowance (based on historical cost/ft). As

[158] Hartwick Direct, p. 30 ("The Company is targeting to achieve a five-year cycle, and complete the Surge program, by the end of 2024.").

the "free" allowances are being contributed by the utility, they constitute a net addition to rate base (equal to the total installed cost of line extensions less the customer contributions-in-aid-of-construction (CIAC)). The revenue requirements associated with such net rate-base are allocated to the various rate classes pursuant to a Cost-of-Service Study (COSS).

Q. Has the MNSC asserted in prior DTE Electric and Consumers Energy rate cases that there is a cross-class subsidy associated with the current policy?

A. Yes. The issue was presented as two-fold in that it relates to the formulation of allowances based on projected future revenues (and need for updating of cost data), and secondly with relation to the allocation of costs and revenues in the COSS.

Witnesses for MNSC asserted that under the current CIAC policy, there is a cross-class subsidy created for three reasons: (1) the company's contributions toward line extensions are based on formulas that incorporate projected revenues from both distribution and power supply components of rates; (2) the projected revenues of large customer rate-classes are generally more heavily composed of power supply revenues than those of small customer rate-classes; and (3) the revenue requirements associated with the utility's line-extension contribution (*i.e.*, the free allowances) are allocated to the various rate classes as distribution revenue requirements pursuant to a COSS, and thus heavily allocated to small-customer classes (such as secondary general service and residential customers).

This dichotomy between how line extension allowances are quantified and how they are recovered in rates create a likely cross-class subsidy.[159] To correct for this issue, MNSC

[159] See Case No. U-20561, Jester Direct, 9 TR 3816-18.

witnesses proposed in DTE's last rate case that the formulas for quantifying the free allowance should be exclusively based on the fixed cost portion of distribution revenues, and that there should be a uniform payback period for all rate classes based upon the reciprocal of the economic carrying cost of the total electric distribution capital investment (electric distribution rate base divided by the capital portion of distribution revenue requirement).[160]

Q. What are you recommending related to CIAC reform in this proceeding?

A. MNSC witnesses' previously recommended approach is technically correct. But changing the existing structure for new line extensions has drawn strong objections that are manifest in Staff's January 2022 workgroup report,[161] I therefore recommend an alternative approach be explored in context of a continuation of the Staff CIAC workgroup) that maintains the existing CIAC allowances (recognition of both distribution and power supply revenues), but ameliorates the cross-class subsidy issue.

Q. Please explain the alternate cost allocation approach that you recommend be considered in a continuation of the Staff CIAC workgroup.

A. The overall concept is quite simple. The revenue requirements associated with the utility's contribution toward line extensions (net rate base) are split in two: (a) the revenue requirements of line extension allowances that are attributed to projected distribution revenue (pursuant to the existing CIAC formulas) should continue to be allocated as in current policy (assigned to distribution revenue requirements and recovered in distribution

[160] Case No. U-20561, Jester Direct, 9 TR 3819-21.

[161] Ex MEC-15 (CIAC Workgroup Report).

charges); and (b) the revenue requirements of line-extension allowances attributed to projected power-supply revenues (capacity and energy) should be assigned to power-supply revenue requirements, and recovered in power supply charges (note that allowances vary pursuant to the CIAC table for customers with load greater than 1000 kW). Under this approach, new customers will see the identical free allowances toward line extensions as under the current policy, but rates will more accurately reflect the line-extension allowances available for each respective rate class. In addition, if the above change is made, it may be appropriate to consider whether the current approach for assigning revenues from customer contributions should be amended to more fairly allocate such revenues to the classes from which they were derived (CIAC deposits are currently assigned to working capital and allocated by revenue[162]).

Should the Commission agree that this CIAC cost assignment approach, or modifications of it, may have merit, I recommend that the Commission direct its Staff to continue the CIAC workgroup, holding additional meetings to explore this concept and work out details with the Company, stakeholders and other interested regulated electric utilities, then provide an additional report.

[162] Ex MEC-15 (Contribution in Aid of Construction Workgroup Report, Case No. U-20697, Jan. 15, 2022) ("In electric cost of service studies customer deposits for line extension are part of working capital and allocated to customers on revenue. For example, if CIAC policy reform arises from this report that would increase residential customer deposits then the corresponding revenue requirement reduction would be spread to all customers and not just the residential class.").

VI. VALUE OF RELIABILITY STUDY

Q. Why are new tools needed to evaluate the economic value of electric distribution investments, and in particular DTE's proposed investments?

A. The primary focus of electric rate cases has shifted to new investments, new technologies, and substantial replacement of aging distribution assets. As a consequence, the swelling cost of these investments has become the main driver of electric utility rate increases. However, a profound incongruity exists in that utilities, including DTE, resort to a severely long-in-the-tooth approach to quantifying the value of reliability/resilience investments and evaluating the economic efficiency of modernization investments. Here I am referring to the Lawrence Berkeley National Lab (LBNL) Interruption Cost Estimator (ICE). DTE explicitly references use of this calculator (Exhibit A-23, Schedule M8).[163] In addition to the fact that the survey data incorporated in the calculator is old, it is not Michigan specific. In light of the unprecedented expansion in DTE's distribution investments, and in particular, replacements of aging distribution assets, it is apparent that a new approach to evaluating the economic efficiency and public interest is needed.

Q. Putting aside for the moment, the out-of-date and non-Michigan characteristics of the LBNL ICE calculator, is such tool of any real value in evaluating DTE's massive growth in distribution reliability investments.

A. If the ICE calculator was based on current Michigan specific data, the tool may have value in evaluating the gross level of the Company's distribution investment. However, customer-surveys regarding *willingness to pay* for outage reductions cannot be used to

[163] Pfeuffer Direct, pp. 62-63.

justify cost effectiveness of reliability investments, nor the prudency of the rate of replacement of aging infrastructure, which are core issues in this rate proceeding.

A simple analogy illustrates the shortcomings of *willingness to pay* information. If you were to walk into a car dealership, the first question asked by the salesperson is likely: "How much are you intending to spend, or what is your budget?" The salesperson likely has vehicle options that meet your *willingness to pay*, but you have no assurance that you are getting the best deal (*i.e.*, cost effectiveness), without comparison shopping.

In this proceeding, the Company offers reliability investments that presumably meet (*i.e.*, are below) customers' willingness to pay (pursuant to the ICE calculator) of $9.8 to $13.2 billion on a net present value basis.[164] However, as I discussed above, the Company's support for its massive ramp in Hardening and Pole/PTMM programs remains deficient. The ICE calculator is of no practical value in remediating this shortcoming, as it is incapable of resolving the issue of whether the proposed investments are a cost-effective implementation strategy to achieve improved reliability.

Q. What is your recommendation regarding the measurement of customers' willingness to pay for reliability improvements?

A. In light of the unprecedented increase in reliability and modernization investments being proposed by Michigan regulated electric utilities, I recommend that the Commission initiate a new Staff-led workgroup to develop useful methods to accurately measure customers' willingness to pay. Establishing an accurate measurement of willingness to pay,

[164] Pfeuffer Direct, p. 59.

from the customer perspective, may have value in estimating a reasonable cap on future reliability investments. This is the logical next step to the Commission's prior workgroup initiatives. Staff's distribution workgroup did explore benefit/cost analysis associated with distribution investments but did not advance an up-to-date and Michigan-specific replacement for the LBNL ICE calculator, which needs to be done.

In conjunction with the above recommendation, I recommend that the Commission direct the Company to develop a plan to survey its customers who have experienced outages to ascertain the extent that they are willing to pay for reliability improvements. This will provide needed data for future development of a Michigan-specific interruption cost analysis.

Q. Does that complete your testimony?

A. Yes.

Robert G. Ozar P.E.

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- 5 Lakes Energy: Senior Consultant
- MPSC: Assistant Director, Electric Reliability Division

WORK EXPERIENCE

5 Lakes Energy **March 2020 – May 2022**
Professional Accomplishments

- Expert witness in multiple MPSC hearings with respect electric distribution infrastructure, cost analysis, rate design, and regulatory theory
- Modeling and analysis of energy storage and solar PV using the HOMER Grid for the Michigan Energy Storage Roadmap

Michigan Public Service Commission **Nov 1979 – Dec 2019**
Natural Gas Regulatory Accomplishments

- Created Quartile Exponential Smoothing Strategy for gas distribution utility hedging during periods of high market volatility
- Created Contingency Factor regulatory process for setting Gas Cost Recovery Factors
- Performed energy market analysis and projections of natural gas supply/demand/prices
- Review of gas transmission infrastructure projects requested by regulated gas utilities
- Developed residential, commercial and industrial sales forecasts and weather normalization methods for use in gas utility general rate-case proceedings
- Testified in numerous contested case proceedings on issues related to natural gas engineering, economics, and regulatory theory, policy and practice

Energy Efficiency Accomplishments

- Chair of the Energy Efficiency Workgroup in the Capacity Needs Forum for development of a statewide Integrated Resource Plan
- Created, led and managed the Michigan Energy Efficiency Workgroup
- Created the first Energy Optimization Program Incentive-Mechanism for meeting and exceeding performance targets set by Michigan statute

- Led the development of the Michigan Deemed Savings Database, used to set uniform achieved savings levels for Michigan utilities
- Led the regulatory review of Energy Optimization Plans and annual financial reconciliations for Michigan utilities
- Wrote the Request for Proposal (RFP) for the creation of *Michigan Saves*, a statewide program for financing energy efficiency improvements by Michigan utility customers

Electric Industry Accomplishments

- Chief lead for MPSC staff in the Michigan Electric Vehicle Preparedness Taskforce
- Created and led the Michigan Smart Grid Collaborative facilitating the introduction of electric utility infrastructure and regulatory structure for review and approval of capital expenditures. Led Staff review of utility requests for rate approval of advanced metering infrastructure (AMI)
- Created the request for proposal (RFP) for a $5 million electric vehicle study of the potential impact of market growth of plug-in EV's on electric utility distribution systems and electric generation systems in Michigan, and the need for active management by utilities of EV charging by utility customers
- Created the concept of using a twenty-year levelized cost of renewable energy programs which was codified in PA 295
- Author of the Inflow/Outflow pricing model adopted by the MPSC as a cost based regulatory structure to replace Net Energy Metering (NEM) in Michigan

Depreciation Engineering

- Wrote a MATLAB model for review of life curves and remaining life of utility assets for use by the MPSC Staff

EDUCATION

Michigan State University, East Lansing, MI **2001**
Master's in Chemical Engineering

Michigan State University, East Lansing, MI **1979**
BS in Chemical Engineering, with Honors

- Recipient of the Schlumberger Scholarship in Chemical Engineering
- Inducted into the national engineering honor societies Tau Beta Pi, and Omega Chi Epsilon

TEACHING

Mr. Ozar has spoken as an energy expert at energy industry conferences having both national and international audiences. He has regularly taught at the Michigan State University Institute of Public Utilities (IPU) Fundamentals, Intermediate and Advanced Regulatory Studies Program.

Michigan Public Service Commission

Contribution in Aid of Construction Workgroup Report

MPSC Case No. U-20697

January 15, 2022

Dan Scripps, Chair
Tremaine Phillips, Commissioner
Katherine Peretick, Commissioner

LARA
LICENSING AND REGULATORY AFFAIRS

Contents

Executive Summary

On December 17, 2020 the Michigan Public Service Commission (MPSC) directed MPSC Staff (Staff) to convene a workgroup to address the Contribution in Aid of Construction (CIAC) policy of Consumers Energy Company (Consumers).[1] This direction was in response to the MEC Coalition's[2] analysis of and recommendations for CIAC policies in Consumers' general rate case.[3] According to the MEC Coalition, Consumers' existing CIAC policy predated unbundled ratemaking and created subsidies between customer classes. Rather than require Consumers to implement the MEC Coalition's recommendations in the Company's next rate case, the Commission ordered Staff to "establish a framework for participation and a conference schedule; and, in collaboration with participants, a list of topics, issues, and objectives to be addressed and achieved." Following the conclusion of the workgroup, Staff was required to file a report "detailing its findings and recommendations regarding any recommended changes to the Commission's CIAC policies that can be considered in future rate case." This report will present the CIAC workgroup's activities including a summary of its three conferences, an overview of the discussions held during those conferences, and the joint recommendations of the workgroup.

This report is organized as follows:

1. Introduction to the Commission's recent orders on CIAC policy
2. Overview of the workgroup's meetings
3. Details of MEC Coalition's analysis and proposal for CIAC policies
4. Discussion topics explored by the workgroup and ongoing issues with CIAC policies
5. Recommendations

The key findings of this report are: CIAC policy is a complex issue that directly affects new and existing utility customers, the workgroup was unable to reach consensus on which revenues to use in setting CIAC policy, the workgroup sees benefit in continuing to meet for further discussion on more specific CIAC topics, and CIAC reform should only take place in general rate cases**.** Staff is grateful for the generous participation of all workgroup members.

[1] December 17, 2020 Order in MPSC Case No. U-20697, p 330-331.
[2] The MEC Coalition is made up of the Natural Resources Defense Council, Sierra Club, and Citizens Utility Board.
[3] MPSC Case No. U-20697.

Introduction

CIAC policies are those that require a customer requesting a new connection to an electric distribution utility's system to pay a refundable deposit for a portion of the costs associated with the new connection or line extension. Should other new customers attach to the system extension partially paid for by the original customer's deposit, that original customer will receive a refund as prescribed in the utility's tariff.

Typically, a general service customer requesting a line extension for less than 1,000 kW of load must pay the difference between the cost of the connection and the expected total revenue generated by the customer over a period of time, such as 2 years. Commercial and industrial (C&I) customers over 1,000 kW are afforded an allowance set by a standard table, which varies by the number of full service contract years, including for customers without a full service contract.

A deposit by residential customers is usually required for extensions beyond an initial allowance (e.g., 600 feet) at a flat cost per foot of additional distribution extension. The deposit may be offset by a refund if additional customers attach to the original customer's extension at a later date. The allowances, length of revenue generation offset, price per foot of extension, deposit refund conditions, and special considerations for underground extensions are codified in the utility's CIAC tariff. New customers create new costs for their connection, but they also create new revenue for the utility to offset costs beyond the connection project timeline. These CIAC policies are intended to balance the cost associated with new customer connections between those individual customers and the existing rate base at large, while allowing an affordable way for customers to join the system.

Distribution line extensions requiring CIAC via customer deposits are not to be confused with the service line extension to the customer's building. Service lines begin at the nearest utility pole and terminate at the Customer's meter. Every customer requires a service line whereas a customer may not require a distribution line extension (i.e., zero foot extension) if there is already a utility pole near enough for connection.

Consumers filed a general rate case in February 2020. The MEC Coalition intervened in the case and proposed changes to existing CIAC policy to be included in the utility's following rate case. Consumers recommended that any changes to CIAC policy should be withheld until a future case or proceeding due to the complexity of the issues at stake. The Commission agreed with the administrative law judge's opinion that a workgroup should be convened to discuss such issues but did not agree that updated CIAC tariffs should be included in Consumers' next rate case.

The Commission directed Staff to convene the CIAC workgroup in 2021 to consider updates to CIAC policies. Staff was required to provide notice of the workgroup, create a framework for participation, and create a list of topics, issues, and objectives in collaboration with workgroup participants. This report, as ordered by the Commission, provides the input of the parties and recommendations of the workgroup's effort for use in future rate cases.

Prior to the Consumers case, for which the CIAC workgroup was created, the MEC Coalition made a substantially similar proposal in DTE Electric Company's (DTE's) general rate case. The Commission's final order in the DTE case was issued on May 8, 2020[4] and differed from its later order in the Consumers case by directing DTE in its next case to: "(1) provide supplementary, substantial, and specific support of the current CIAC model, (2) demonstrate that the current CIAC model is cost-of-service based, (3) provide evidence specifically showing how the overall revenues from new customer connections help offset other customer costs, and (4) provide details regarding how new customer connections drive upgrades to the system that may benefit other customers."[5] While the Commission ordered a different approach for the two largest electric utilities in the state, Staff invited and received participation by both companies in the CIAC workgroup formed from the Consumers case order.

The MEC Coalition presented analysis which examined the payback periods for new customer attachments and compared those periods between customer class in both the Consumers and DTE cases, assuming that only distribution plant revenues should be considered in the payback period calculation. In both cases the MEC Coalition asserted that residential customers generated additional revenue to offset their line extension costs faster than larger general service customers, implying a subsidy was taking place under existing CIAC policies. To correct for the alleged subsidy, the MEC Coalition proposed to standardize the payback period for line extensions across customer classes. In the DTE case, the Commission found the MEC Coalition's proposal to be unsupported but requested that DTE provide evidence to support its existing CIAC policy. In the Consumers case, the Commission demurred that the issues were complex and required additional study.

Neither utility was required to adjust tariffs or propose new CIAC policy in subsequent cases. However, it is clear that the Commission is interested in further study of CIAC policy issues as evidenced by the request for support in DTE's case and the creation of the workgroup in Consumers' case. This report provides details on the MEC Coalition's analysis and proposal as well as the discussion and findings of the CIAC workgroup for the Commission's consideration in following cases. Because the workgroup was created in response to the MEC Coalition's proposal in the Consumers case this report will focus at times on the particulars of that utility, but the discussion and some recommendations may still apply to DTE and other utilities' CIAC policies.

The analysis and discussion presented in this report does not bind any of the participating parties to a particular CIAC policy recommendation unless expressed otherwise in a formal

[4] The final order in the DTE case was issued between the filing of the Consumers case and the MEC Coalition's similar proposal in the Consumers case.
[5] [May 8, 2020 Order in MPSC Case No. U-20561, p 98](#).

proceeding before the Commission. While the process was instructive for the workgroup members, it should not constrain any future proposals for any reason.

Workgroup Meetings

Staff notified parties to the Consumers case of the formation of the CIAC workgroup and held meetings on August 24, September 21, and October 15, 2021. The Association of Businesses Advocating Tariff Equity (ABATE), Consumers, DTE, the MEC Coalition, and Staff all participated in the workgroup meetings. While the workgroup was created in response to the Commission order in the Consumers case, DTE was invited to and participated in the meetings in anticipation of CIAC issues being addressed in its next rate case.

The first meeting included a presentation by 5 Lakes Energy on behalf of the MEC Coalition to review its CIAC analysis and proposal made in the 2020 Consumers case with an update to the model with data from Consumers current on-going general rate case[6]. Further details of the MEC Coalition's presentation will be addressed in the next section of this report. Staff led an open-ended discussion following the MEC Coalition's presentation and debuted a list of topics, issues, and objectives to the workgroup. As a result of the workgroup's discussion, Consumers agreed to present a review of its CIAC policy at the next meeting. Staff explained its intention for the workgroup's ultimate report to the Commission and the format for future workgroup meetings.

The second meeting consisted of separate presentations by DTE and Consumers regarding each utility's CIAC policy along with examples of how a customer would engage with the utility during the line extension process. The presentations generally supported the utilities' current CIAC policies. Following the presentations, another free-flowing discussion ensued which expanded on issues brought up in the first meeting and from the utilities' presentations.

Staff reserved the third meeting of the workgroup to present its draft report and discuss initial recommendations. The workgroup discussed lingering issues from the previous meetings and narrowed the scope for its recommendations to the Commission. Following the third meeting Staff continued to develop the workgroup's report and recommendations and engaged with stakeholders on the report's contents throughout the early winter of 2021.

MEC Analysis and Proposal

In direct testimony on behalf of the MEC Coalition in the 2020 Consumers general rate case Robert Ozar of 5 Lakes Energy sponsored and discussed the CIAC analysis and proposal that

[6] MPSC Case No. U-20987.

spurred the CIAC workgroup's efforts in 2021.[7] Mr. Ozar reproduced his analysis for the CIAC workgroup using updated data from the current Consumers rate case. His analysis relies on the idea that Consumers' current CIAC policy predates unbundled rate making (i.e., the division of rates between power supply and delivery to accommodate customer choice in energy provider). When the utility was vertically integrated, a customer's total revenue could be assumed to offset all costs associated with being served by the utility's generation, transmission, and distribution systems. For this reason, the CIAC policy for general service customers provides an allowance for three times the customer's expected *total* annual revenue.[8] The MEC Coalition argued that since the advent of unbundled electric service, the actual offset to extension cost made by the customer is to the distribution capital revenue requirement. According to the MEC Coalition, applying an allowance of a new customer's total revenue over three years for what the MEC Coalition argues is only a distribution capital investment thus creates a mismatch. Further, according to the MEC Coalition, only a portion of total distribution revenue can be said to apply to the distribution capital revenue requirement. In other words, they claim that only a portion of a customer's total bill going forward will end up contributing to the new connection to the distribution system.

The MEC Coalition opined that the aforementioned balancing act of CIAC policy – between the additional costs a new customer creates versus their continued contribution to the distribution system—no longer holds under Mr. Ozar's analysis. Because only a part of the customer's total revenue over 3 years will pay for the utility's upfront contribution toward the new line extension under their assumption, it thus takes longer for the customer to "pay it off" through base rates than the tariff assumes. Fundamentally, the MEC Coalition argued that it takes much longer for this to occur for a general service customer than it does for a residential customer because the power supply revenues from general service customers are a larger percentage of total revenues. In order to quantify the purported difference in payback periods among customer classes, Mr. Ozar calculated how long it would take a customer in each class to repay the Company's CIAC allowance using only the portion of revenue associated with distribution capital. The CIAC allowances for some rates had to be calculated differently because of the different CIAC policies offered to residential and general service customers (e.g., 600 foot allowance for residential overhead lines versus 3 years of total revenue for general service.) Mr. Ozar found that when applying only the distribution capital portion of customer revenue to the appropriate allowances, it took 4.9 years for an overhead-line-serviced residential customer to pay back their allowance and between 26.9 and 140.2 years for a General Primary Demand (GPD) customer, voltage level 3 and 1 respectively. This is because a relatively smaller portion of GPD customers' overall bills is revenue associated with distribution capital. Based on this analysis, Mr. Ozar concluded that

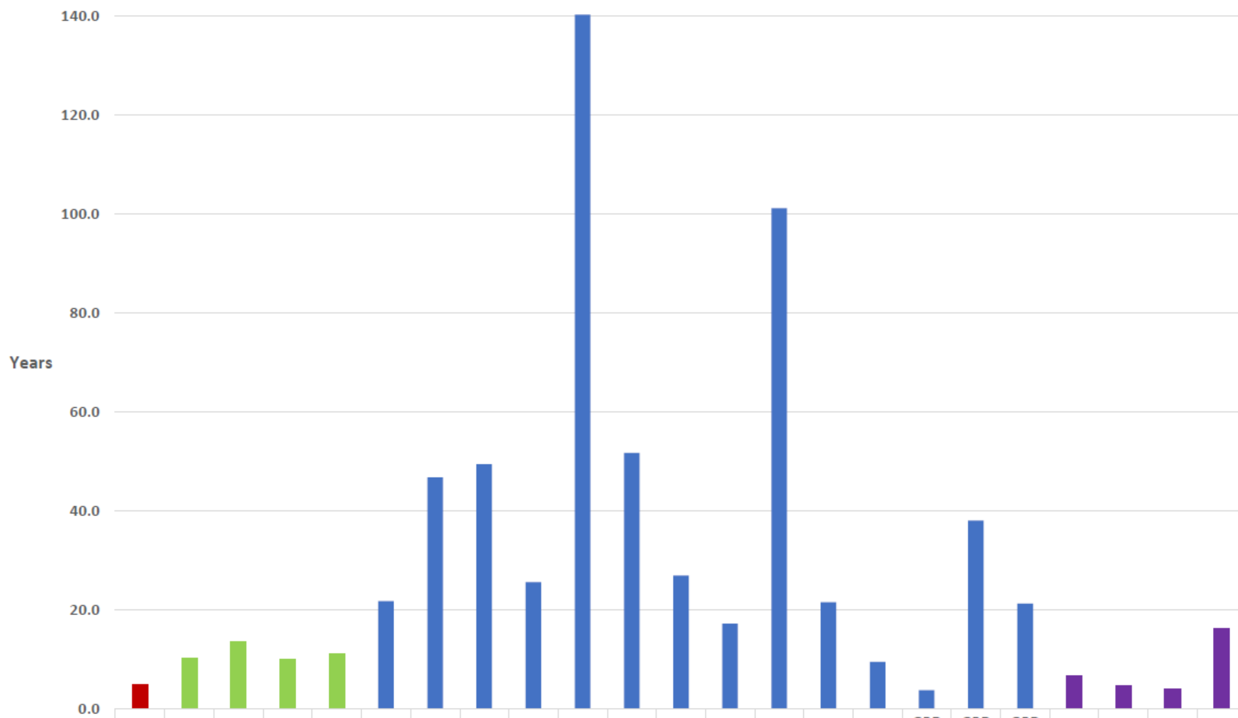
[7] For an in depth explanation of the MEC Coalition's analysis see Mr. Ozar's testimony in Case U-20697.

[8] The tariff provides adjustments for differences between expected and actual revenues and refunds for additional customers connecting to the new service extension. See Sheet No. C-27.00 in the Consumers rate book for details.

Consumers current CIAC policy creates a subsidy between customer classes, because general service customers are allowed such a long time to achieve parity with the rest of customers contributing to distribution rate base compared to residential customers, who do so much more quickly, since a larger portion of their overall bills is associate with distribution capital costs.

Figure 1

Payback Times for Distribution Systems Additions Under Current CIAC Rule



	RS	GS	GSD	GS GEI	GSD GEI	GP	GPTU Vit 1	GPTU Vit 2	GPTU Vit 3	GPD Vit 1	GPD Vit 2	GPD Vit 3	GP GEI	EIP Vit 1	EIP Vit 2	EIP Vit 3	GPD GEI Vit 1	GPD GEI Vit 2	GPD GEI Vit 3	GML	GUL	GU-XL	GU
Series1	4.9	10.2	13.6	9.9	11.1	21.7	46.7	49.3	25.5	140.2	51.6	26.9	17.2	101.1	21.5	9.4	3.7	37.9	21.2	6.5	4.6	4.1	16.2

MEC Coalition Presentation to CIAC Workgroup 9/24/2021

To remedy the alleged disparity among classes, Mr. Ozar calculated a uniform payback period for line extensions by taking the reciprocal of the economic carrying cost of total electric distribution capital investment, or the electric distribution rate base divided by the capital portion of distribution revenue requirement (i.e., total distribution capital divided by total annual revenues associated with paying for that capital). This resulted in a system-wide average of 7.42 years, or the time it takes for distribution revenue alone to pay for distribution capital costs. In order to apply this uniform payback period to each rate schedule individually, Mr. Ozar then multiplied the 7.42 years times the capital-related portion of each distribution rate. This is akin to creating any other type of rate, where required revenue is divided by sales to reach a $/kWh rate, but in this case the required revenue is the capital-related portion of distribution revenue, which is then multiplied by 7.42. Thus, an individual customer would receive an allowance of the newly calculated credit rate times their estimated annual energy usage.

Figure 2

MEC Coalition CIAC Reform-Utility Contribution

Rate Schedule	Credit $/kwh
RS	0.40710
GS	0.33805
GSD	0.20860
GS GEI	0.34951
GSD GEI	0.26817
GP	0.11019
GPTU Vit 1	0.03847
GPTU Vit 2	0.03790
GPTU Vit 3	0.08567
GPD Vit 1	0.00850
GPD Vit 2	0.03358
GPD Vit 3	0.07995
GP GEI	0.14731
EIP Vit 1	0.01240
EIP Vit 2	0.06460
EIP Vit 3	0.19592
GPD GEI Vit 1	0.02319
GPD GEI Vit 2	0.05996
GPD GEI Vit 3	0.11450
GML	0.40225
GUL	1.31620
GU-XL	3.04535
GU	0.13424

Applied to estimated annual usage (kWh)

While the rates differ for every customer type, they are all based on the same 7.42 years Mr. Ozar believes it takes for all customers' collective distribution revenues to pay off distribution capital. Alternatively, a footage allowance could be calculated using the MEC Coalition's proposal by multiplying the per kWh residential allowance by the class average sales per customer then divided by an updated cost-per-foot of line extension (See Appendix A for MEC Coalition's complete presentation.)

Under this scheme, Mr. Ozar calculated that the average residential customer's allowance would be reduced from $4,250 to $3,157, and general service customers would also see a decrease in CIAC allowance. The ultimate beneficiaries would be the existing Consumers customers who, after CIAC reform, would pay less through base rates to cover the cost to extend service to new customers. It may be counterintuitive to see the residential allowance decrease when attempting to resolve the alleged subsidy between residential and general service customers, however, the reduction in CIAC allowance, under the uniform payback approach is larger for general service customers. That is because the solution also affects the alleged subsidy between existing customers currently paying base rates and the new customers receiving a line extension.

The MEC Coalition's analysis can be affected by a number of assumptions, chiefly, 1) the assumption that only distribution capital-related revenues should be recognized in the analysis, and 2) the cost per foot of residential distribution line extension. The analysis in the Consumers rate case relied on the $3.5 per foot cost for additional line extension beyond the 600 foot allowance for residential customers as the actual cost for distribution investment in line extension. In the workgroup presentation, Mr. Ozar accounted for this assumption by providing a chart showing how different costs per foot of line extensions affects the residential allowance. The greater the cost per foot of extension the less footage would be included in the allowance. The primary cause of reduction in length of residential extension allowance is related to the out-of-date per foot cost in the tariff. As will be discussed, parties disagree on the validity of the assumption that only distribution capital-related revenues should be recognized.

The CIAC policy reform proposed by the MEC Coalition would be included as a table in Consumers' line extension tariff and be updated in general rate case proceedings with newly approved cost data.

Discussion

The MEC Coalition's analysis and proposal spurred a great deal of discussion among the workgroup members. Utility, Staff, MEC, and ABATE experts engaged in debate on the assumptions, outcomes, and merits of the work presented by the MEC Coalition as well as purpose and nature of CIAC policy in general. This section of the report represents the continuation of the analysis of CIAC policy and will provide the Commission with further investigation into the ideas and implications raised by the workgroup. The final section of this report will be the synthesis of that investigation via the workgroup's recommendations.

How much power supply revenue should be included in deposits, or should only distribution capital be used to determine the deposit amount?

Perhaps the most discussed topic of the workgroup meetings was on whether it is appropriate to consider only distribution capital investment and revenues in the MEC Coalition's analysis. On its face, it seems reasonable to conclude that a line extension only affects the cost of the distribution system, since the line extensions are physical infrastructure installed to deliver electricity to the new connections. However, the new load connected to the utility's distribution system still needs to receive power from somewhere. While the new customer necessarily requires more wires to join the system, they are also providing additional revenue for power supply, if they are a full service customer. This incremental revenue may be more difficult to discern. During the workgroup discussion, it was clear that some parties believe that a portion of power supply revenue could be attributed to offsetting the line extension, since the utility receives incremental revenue from supply as well. Like in so many other facets of utility regulation that "some portion" can be difficult to define.

ABATE argued that when considering the policy in the context of whether a customer chooses to locate in the territory or not, the incremental margin of revenues over fixed costs, inclusive of both supply and delivery, will benefit all customers, as it will contribute to virtually any rate base item on which the utility receives a return.

DTE presented its current CIAC policy to the workgroup during the second meeting. The tariff for this policy provides a standard allowance table for customers requesting a line extension with a load greater than 1,000 kW. This table offers different allowances for customers choosing full service contracts and no full service contracts, with full service contract customer allowances varying by the number of years on such contracts. Customers requesting a line extension without a full service contract receive a smaller allowance because they will not produce power supply revenues to offset any marginal increase in power supply cost. This solution neatly addresses the issue about whether total revenue or only distribution revenue should be considered in CIAC policy because it treats the two services differently. Arguments can still be made about how much power supply revenue is reasonably necessary to offset the increase in costs related to the customer's new load. However, it is assumed by some that non-power-supply customers would not contribute to any marginal power supply costs; so they should not receive an allowance for that missing revenue. In theory, this method could be applied to residential customers as well, because they too can participate in customer choice of power supply. However, practically speaking, distinguishing between full service and choice customers is unhelpful because of the enrollment cap in customer choice. What DTE's CIAC tariff does is explicitly consider that for power supply customers some costs associated with line extension is related to power supply.

The question remains: if power supply revenue should be considered to offset incremental power supply costs for new load, then how much? Consumers' general service CIAC policy lies on one end of the spectrum where total power supply revenue for three years is implicitly assumed fully available to pay for the incremental increase in distribution cost (i.e., the distribution line extension). The MEC Coalition's CIAC reform policy is situated at the opposite end of that spectrum where the utility's contribution toward the line extension is made only through recognition of the customer's future distribution revenue and there is no assumed offset for power supply. This issue begs another question: how much incremental pressure does one customer's newly connected load put on power supply? If the utility has sufficient capacity in its power supply to accommodate the single source of new load, then the pressure (i.e., added cost) is zero. If that single customer's new load happens to be at the margin that requires the utility to expand its power supply, then the pressure, and thus cost, is significant.[9] As is often the case with issues of marginal power supply, the costs can be said to be zero until they aren't. Depending on the specific circumstances of the issue sometimes an analyst will rely on some form of market prices to determine marginal power supply costs or perhaps assume the most common method a utility may use to increase its power supply to meet new load (e.g., 75% of cost of new entry.)

In summary, ABATE, Consumers, and DTE all agreed that power supply revenue should be included in the offset for CIAC for full service customers. MEC advocated for its proposal to only rely on distribution capital-related revenue to determine line extension deposits, as discussed in the third section of this report. DTE made a further distinction that power supply fuel revenues should not be included in full-service revenues for the purpose of CIAC. Staff did not take a position on changes to CIAC policy in either the recent Consumers or DTE cases wherein MEC made its reform proposals and remains skeptical on this specific issue of what revenues to include in line extension deposits. The workgroup did not arrive at a consensus on this topic, but its contemplation led to the other issues discussed herein.

[9] This is the same inter-generational equity issue that has existed for decades for rates in general. Some might ask, "Why should legacy customers have to pay for new facilities (generation or delivery), if they've already paid for facilities sufficient to meet their needs?". But that is not how traditional rate setting works; rates have been set treating customers of all durations the same for decades.

Updating current line extension cost per foot

The actual cost per foot of line extension and how it differs from the tariff was raised several times during workgroup discussion. The Consumers tariff still shows a cost per additional foot of line extension beyond the 600 foot allowance for residential customer of $3.50. In contrast, DTE's residential line extension tariff charges $6.50 per foot beyond 600. Consumers did not contend that $3.50 was the actual current cost per foot for additional overhead distribution line. It was clear that the figure used in the tariff was many years old but Consumers was willing to explore reexamining the excess line extension charge for residential customer deposits. According to Consumers, 25-30% of complaints to the MPSC are about costs being too high for new construction.

To further complicate things it would be difficult to determine an exact per foot cost for line extension that would be applicable to all projects. For example, one line extension project could require more utility poles than another project of equal length. In this case the project with more poles would have a higher cost per foot for the extension. This also begs the question: if actual costs per foot of line extension is higher than the tariff, then should the cost for additional foot of extension be increased or should the allowance for footage be decreased? One could also consider the $3.50 per foot of additional line extension as a "charge" rather than the utility's direct cost being passed through to the customer. Should this be the case then that "charge" would still need to be linked to a cost, or net-cost, in some fashion in order to keep rates cost-based. Upon further investigation, the Commission could determine that the charge per additional foot of line extension should be made up of the combination of actual cost of the physical infrastructure being built less some amount representative of the benefit of additional load. Taking it one step further, should a line extension allowance and/or charge consider whether the new customer is a distributed generation customer? This is all to say that while it may be tempting to include an actual cost estimate per foot for extending service, there are other ways to incorporate the actual costs into CIAC allowances and charges. Updating the cost per foot in the tariff could also create a higher barrier for new customers to attach to the distribution system. Discouraging new load on the system through more onerous CIAC policy will negatively impact existing customers as well, assuming the new load contributes revenues above variable costs and thereby provides a contribution to fixed costs, enjoyed by all other customers. If one considers the role of the new customer after they have provided incremental revenues sufficient to cover their CIAC credit amount, then all future revenue from the customer can be said to help offset the rates of all other customers. When allocating costs and designing rates, the more customers and load available over which to spread those costs relieves the burden on the individual customer. Any utility would prefer to sell more of its product to more customers, and in the long-run existing customers benefit from load growth, so long as the cost of that growth is lower than the long-run benefits.

It could be beneficial to match actual costs of line extension more closely with CIAC charges over the standard allowance, but it must be weighed against the benefit to existing customers. As shown in Mr. Ozar's analysis the cost of the line extension could have a direct impact on the allowance for residential customers.

Whether or not the Commission approves a change to the residential line extension cost per foot in the utilities' tariffs, the allowance for C&I customers need not be changed. There is no specific cost per foot of line extension printed in the tariff for these customers. Instead, the allowance is dependent on the customer's revenue, with contractual assurance that the revenue target is actually met. For example, for C&I customers with load greater than 1,000 kW, the customer's CIAC allowance is set based on a standard allowance table, as shown below from DTE's rate book[10]:

Figure 3

DTE Electric CIAC Standard Allowance Table

Rate Schedule	Full Service Contract Term, Years					No Full Service Contract
	1	2	3	4	5	
D11, D10, D3	$*120* / kW	$*230* / kW	$*330* / kW	$*430* / kW	$*520*/ kW	$*95* / kW
D6.2	$*120* / kW	$*230* / kW	$*335* / kW	$*435* / kW	$*525*/ kW	$*95* / kW
D8, R1.1, R1.2, D3.3	$*90* / kW	$*170*/ kW	$*245* / kW	$*320* / kW	$*385*/ kW	$*95* / kW
R10	$*40* / kW	$*75* / kW	$*110*/ kW	$*145* / kW	$*175* / kW	$*95* / kW
D4	$*245* / kW	$*480* / kW	$*695* / kW	$*895* kW	$*1,085* / kW	$*95* / kW

Section C6.2(4)(a), Sheet No. C-30.00, based on anticipated average maximum demand

For these larger customer extensions current CIAC policy fixes the allowance based on full service contract year terms and charges the customer with the total cost of the extension beyond that allowance. This is contrasted by residential CIAC policy which sets prices and the allowance based on footage alone. For residential customer footage is a proxy for total line extension cost for rather than passing the actual cost through to the customer less an allowance like for C&I customers. The shortcoming of CIAC policy for residential compared to C&I customers is that the actual cost (i.e., total cost less allowance) of the line extension is not specifically borne by the customer. Therefore, updating the per foot line extension cost for residential customers may bring customer classes closer to parity in CIAC policy.

[10] Consumers has a similar table in section C1.4 (Sheet No. C-4.00) of its rate book, but allowances are calculated on anticipated energy rather than demand.

Determining footage allowance

Similar to the discussion on updating the cost for additional line extension footage in the tariff is how to set the free footage allowance. Both Consumers and DTE offer residential customers the first 600 feet of line extension free of charge. It came to light through discussion with the workgroup that this figure is not based on any specific calculation, but that most new individual customers fall below that threshold. In theory, if the typical customer requires 600 or fewer feet of line extension, and they only require about 4 years of distribution revenue to repay that allowance, that customer will quickly join the pool of customers contributing revenues above incremental costs. If another customer requires a longer line extension, then it stands that they will take longer for them to provide revenues above incremental costs. More data would be necessary to determine how much more costly it is to extend service to customer beyond 600 feet, and whether that cost increases linearly.

Determining the appropriate footage allowance could also run afoul of a basic tenet of electric rate design: calculating rates based on the cost of serving the *average* customer. If 600 feet were found to be the amount of line extension under which most new customers fell, then it ignores the amount of distribution line needed to serve the average customer. If the average customer only required a 200 foot extension, then at what length beyond that average is it appropriate to begin charging customers a deposit? Again, more analysis is necessary to confirm or evaluate this question, and particularly analysis showing whether or not the cost of a line extension increases linearly, or by some more complex function. This complex function could include the problem of how many utility poles are necessary for any given distance of line extension. For example, the cost per foot may be flat up until the next pole is required, at which point the flat cost ratchets up.

Customer deposits for line extensions can also be viewed as a transfer of risk from the utility to the customer requesting an attachment. A customer requiring a short extension of the distribution system is relatively low-risk to add compared to a similar customer much further away. If it is riskier to extend the system beyond 600 feet because costs increase beyond that distance or there are greater hazards in construction, then requiring a deposit would offset that risk.

During the second workgroup meeting, Staff posited a potential solution to updating costs and line extension footage allowances. Using a minimum system study, an analyst could determine the minimum amount of distribution line necessary to reach any customer on a utility's system. [That analysis differs from the traditional "minimum system study," which considers the zero load cost of connecting customers to the system.] That minimum would then be the standard allowance in footage or cost, with all excess cost to be recovered through the customer's deposit. The problem with this hypothesis is that the length of distribution system needed to attach the nearest customer could be zero. Such an analysis would require a number of assumptions, which would themselves inspire further debate. Another method suggested by Staff would be to calculate system-wide average or customer class average of distribution line footage per customer. That average could then be used as the CIAC allowance, with all excess extension costs to be included in the deposit.

While Consumers believes that the currently approved residential footage allowance of 600 feet is ideal, because it represents the average line extension necessary for residential customers (not including zero foot extensions) and adjusting the residential footage allowance could significantly impact the cost to customers for attachment to Consumers' system, the company is still open to exploring the topic further. Likewise, DTE is open to exploring the topic further.

Like with any theoretical cost allocation question, a trade off must be considered between burdening the existing customer, the new customer, the average customer, the outlier customer, and the vulnerable customer. Determining the charge for additional line extension and the standard allowance for the extension must also consider this trade off.

Effects of changing CIAC policy on revenue requirement

Beyond its effect on individual customers requesting a line extension, CIAC policy also affects the utility's revenue requirement. Changing CIAC policy such that it requires larger customer deposits, as the MEC Coalition's proposal would, reduces the utility's capital spending and thus its revenue requirement. If the new customer or load continues to be a going concern that contributes to the utility's revenue longer than the time it takes to recoup the initial outlay for line extension, then both the utility's shareholders and customers come out ahead. Shareholders will enjoy the return on increased capital spending and the customer base will enjoy another member to which costs can be spread. One potential pitfall of CIAC policy occurs when the customer at the end of the new line extension discontinues their service before their revenue can fully offset the extension costs. Requiring a customer deposit alleviates this concern somewhat.

It would also be difficult to determine if and when a line extension becomes no longer used and useful because at any time a new customer could come along and take advantage of the line extension. Again, this issue requires a delicate balancing act on the part of CIAC policy: how does the Commission balance the need of new connections to the system with those already connected? Extending distribution infrastructure without attachable customers would be a waste for current ratepayers, but the argument can be made that *eventually* there will be more customers to attach. Though the reasonableness of that argument must be evaluated carefully.

Further, the impact on revenue requirement from changes in CIAC policy for one customer class may affect all classes. In electric cost of service studies customer deposits for line extension are part of working capital and allocated to customers on revenue. For example, if CIAC policy reform arises from this report that would increase residential customer deposits then the corresponding revenue requirement reduction would be spread to all customers and not just the residential class.

The impact of CIAC policy on a utility's revenue requirement can be substantial. According to its workgroup presentation Consumers spends about $14M to connect new residential customers per year. Overall spending on new business, including line extension, can make up a significant portion of any utility's rate case request, and adjusting something as innocuous as the CIAC policy can eventually flow through rate case models and have a material impact on rates. This fact supports the workgroup's recommendation that the Commission consider implementing changes to CIAC policy only in general rate case proceedings, where the effects of those changes can be observed directly. A standalone proceeding or workgroup such as the one creating this report can provide insight to future Commission decisions, but any actual change in CIAC policy or tariffs should occur as part of a comprehensive rate proceeding.

Extraordinary facilities exemption

In the meeting, ABATE indicated that large customers for whom significant investments are made to connect them, are subject to minimum charges that help ensure that they provide revenues sufficient to cover the costs. Although they may exist to help ensure payment for extraordinary distribution costs, such minimum charges are based on demand charges that include power supply costs. ABATE suggests that this linkage between distribution connection costs and supply revenues further supports the position that both supply and delivery revenues should be considered, rather than just delivery revenues, as proposed by the MEC Coalition.

ABATE also notes the distinction between customers who pay minimum charges and those who do not in terms of reduced risk of stranded investment costs associated with distribution connections. Thus, the existence of minimum charges has an interplay with connection costs that should be recognized in the analysis, rather than just a simple payback period analysis that does not capture the risk difference.

Consumers supports ABATE's views on the extraordinary facilities exemption and recommends that if the Commission approves an alteration of residential line extension cost per foot that the allowance for C&I customers remains unchanged.

Line extension as an economic development tool

Line extension policies can be an important tool in the economic development package. Great care should be taken in considering policies that will detrimentally impact the state and local communities' ability to attract large customers.

Equity issues

The specifics of the MEC Coalition's proposal may suffer from equity issues. As described in the previous section of this report, the proposal would create a table of $/kWh allowance rates to be applied to the customer's projected energy use. For example, using data from the current Consumers electric case the MEC's Coalition's proposal results in an allowance credit rate of $0.40710 per kWh for residential customers. If a customer had an estimated monthly usage of 1,000 kWh, or 12,000 kWh annually, the customer would receive an allowance of $4,885 toward their line extension and be required to pay the excess as a refundable deposit. The flat per kWh allowance credit means that a customer using half the energy of the 1,000 kWh per month customer would also receive half as much in line extension allowance, or $2,442. A customer with a larger house or an electric vehicle would therefore be awarded a larger allowance than a customer with on-site solar generation or extensive energy efficiency investments. Any action that would drive down the customers annual energy usage would directly reduce their CIAC allowance. It seems unfair for a low-income or senior customer with relatively low annual energy consumption, for example, to receive a smaller CIAC allowance, however the higher energy use customer would still contribute more of their new revenue to offset the line extension investment. That being the case, if both the low-use and high-use customers remain in service for long enough to fully pay in for their line extension, then both can be said to be successfully entered into paying base rates; but the initial outlay for the customers remains different. A rural customer may be more likely to require a longer line extension than their urban counterpart even if they both generate the same revenue for the utility. While the urban and rural customer would have the same CIAC allowance they would face very different costs to connect to the distribution system.

Another equity issue discussed by the workgroup pertains to larger general service customers on demand rates. The MEC Coalition's proposal creates per kWh based allowance rates. The bulk of the revenue generated from Consumers general primary demand rates comes from, as the name implies, demand charges. Because the MEC Coalition's proposal relies on distribution revenues it should have noted that Rate GPD's distribution charges are only demand or customer charges and not energy billed rates. The mismatch between the MEC Coalition's proposal and existing rates for demand-billed customers can and should be easily fixable by simply using demand as the billing determinant rather than energy to calculate a demand-based allowance rate. This is already the case in DTE's tariff for large customer line extension allowances, which are all per kW credits.

Finally, any CIAC policy, existing or proposed, should consider equity in access to electric service. If electricity is requisite to living a healthy and safe life in modern society, then all who desire the service should be equally allowed reasonable and fair access.

Recommendations

Based on the discussion throughout the three workgroup meetings and condensed and presented in this report, the workgroup offers several recommendations to the Commission for considering CIAC policy. These recommendations are made on behalf of the workgroup as a whole and not just certain individual parties therein. While some recommendations may seem overall generalized it is because they come from a general group of stakeholders. That is also to say that recommendations made by any of the authors of this report in future cases or proceedings before the Commission are likely to be at odds and will require continued thoughtful consideration by the Commission.

Further consider updating the cost per foot of line extension presented in tariffs.

The workgroup discussed the origin of existing cost per foot of additional line extension beyond the 600 foot allowance and agreed that whatever data were used to create it are likely obsolete. Updating the tariff with an actual, approved cost-based charge for line extension would give confidence to customers that their refundable deposit is rooted in the actual investment made by the utility. Per the discussion in the previous section of this report, the footage allowance for line extension may also need to be readjusted in light of a different additional footage charge.

Only change CIAC policy in general rate cases and not standalone proceedings.

As explained in the discussion section of this report CIAC policy can be very influential on revenue requirement, rates, and on individual customers engaging with their utility. Line extension tariffs can even expand beyond the scope of the Commission's authority to set rates, because a CIAC policy that is too lacking or too generous to a customer can influence whether or not a new house is built, or a new business launched. The effect of CIAC policy can be observed as it flows through the financial model, cost of service study, and finally the rate design when made in a rate case. Because of the wide reaching effects of CIAC policy on the rate making process and potentially on economic development, any adjustment proposed to and approved by the Commission should only be done in the context of a general rate case proceeding.

Continue CIAC workgroup meetings to further develop known issues and gather data for further analysis. Stakeholders may use the discussion and data to make proposals in future cases.

Outside of a contested rate proceeding stakeholders would be able to further discuss CIAC policy and generate novel approaches to creating equitable and fair line extension allowances. The Commission may require utilities to answer audit request from the workgroup members to gather the data needed to support alternative CIAC policy approaches. Future CIAC workgroup meetings could narrow the scope of analysis to residential line extension CIAC policy, for example, or to how CIAC policy impacts economic development.

Conclusion

The CIAC Workgroup members worked prodigiously through the fall of 2021 to hold open and honest discussions on CIAC policy reform. These discussions furthered the group's understanding of CIAC policy as well as allowed workgroup members the opportunity to share their unique and diverse perspectives on the issues at hand. Continuing the conversation into 2022 will allow the workgroup to focus deliberations and encourage a robust record on CIAC in future rate case proceedings. The workgroup is pleased to present this report to the Commission for consideration.

Appendix

Contribution in Aid of Construction (CIAC) Reform

5lakes energy

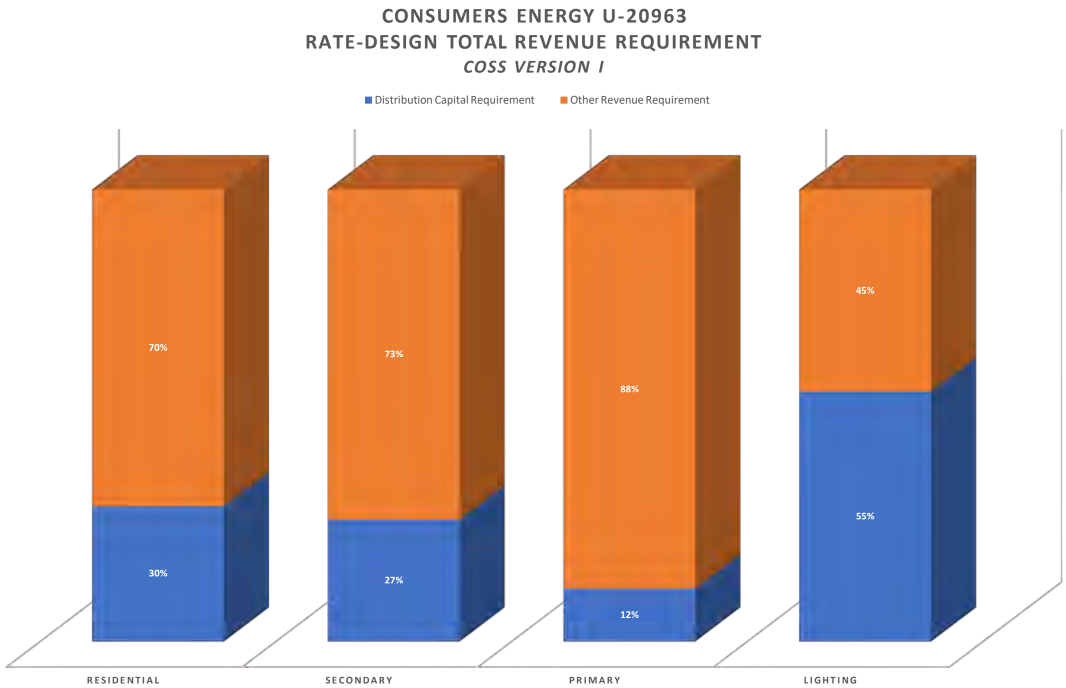
Robert G. Ozar PE
Senior Consultant, 5 Lakes Energy
September 24, 2021

Current Electric CIAC Policies are Inappropriate

Current CIAC methodology predates unbundled rate making

Utility contribution to line extensions is based on both distribution and production revenues

Only the capital related portion of distribution revenues is relevant to determining utility contributions, as line extensions are classified as distribution plant



Calculation of Payback Period for Company Contribution (Under Existing Rules)

- $Payback\ (yrs) = \frac{\$\ Contribution\ by\ Company}{Estimated\ Capital\ Related\ Distribution\ Revenue/yr}$

- $Payback\ (yrs) = \frac{(Distribution + Powersupply)\left(\frac{\$}{kWh}\right) x C\left(\frac{kWh}{}\right) x 3Yrs}{\left[\frac{Capital\ Related\ Distribution\ Revenue}{Distribution\ Revenue}\right] x \left[\frac{Distribution\ Revenue}{Total\ Revenue}\right] x\ (Distribution + Powersupply)\left(\frac{\$}{kWh}\right) x C\left(\frac{kWh}{Yr}\right)}$

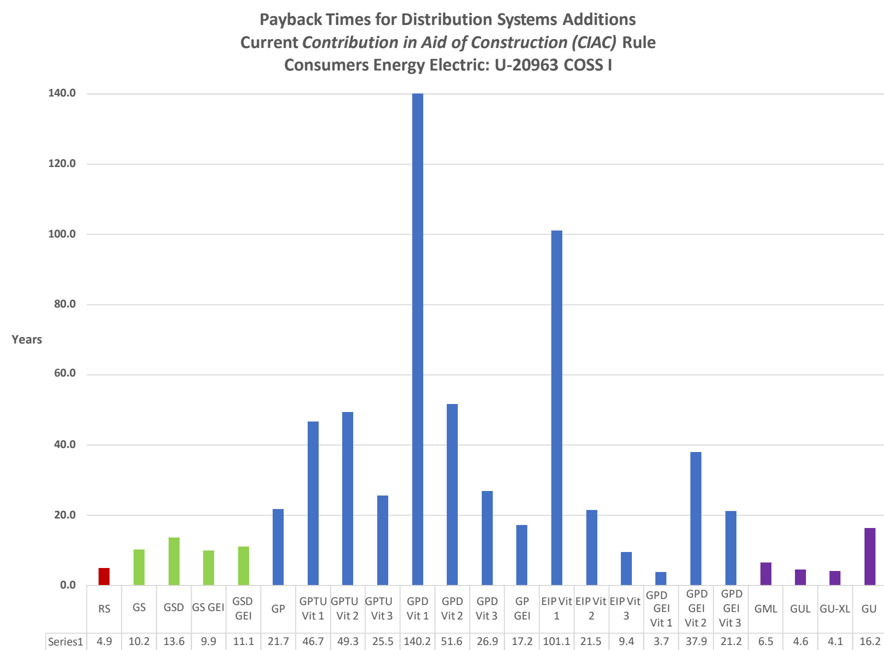
- $Payback\ (yrs) = \frac{3\ yrs}{\left[\frac{Capital\ Related\ Distribution\ Revenue}{Distribution\ Revenue}\right] x \left[\frac{Distribution\ Revenue}{Total\ Revenue}\right]}$

**Consumers Energy CIAC: 3xAnnual Revenue*

Payback Times for Distribution System Additions
Based on Consumers Energy Proposed Production and Distribution Revenues U-20963 COSS Version I
And Current *Contribution In Aid of Construction* Formula (3 times Annual Revenue)

Rate Schedule	Full Service Sales MWh	Distribution Sales MWh	Production Revenue (thousands)	Distribution Revenue (thousands)	Production Revenue per kWh	Distribution Revenue per kWh	Prod. + Dist. Revenue per kWh	% Distribution	Payback Years w/Distribution Revenue	Capital % of Distribution	Payback years w/Distribution Capital Revenue	% Distribution Capital
RS (Overhead Line)	12,621,349	12,621,349	1,334,015	971,991	0.1057	0.0770	0.1827	42%	3.52	71%	**4.9**	**30%**
RS (Underground Line)	12,621,349	12,621,349	1,334,015	971,991	0.1057	0.0770	0.1827	42%	7.12	71%	**10.0**	**30%**
GS	3,750,286	3,758,814	349,084	231,547	0.0931	0.0616	0.1547	40%	7.5	74%	**10.2**	**29%**
GSD	2,985,974	3,106,807	266,187	118,096	0.0891	0.0380	0.1272	30%	10.0	74%	**13.6**	**22%**
GS GEI	89,373	103,955	8,130	6,621	0.0910	0.0637	0.1547	41%	7.3	74%	**9.9**	**30%**
GSD GEI	139,134	199,503	11,795	9,749	0.0848	0.0489	0.1336	37%	8.2	74%	**11.1**	**27%**
GP	740,549	781,557	65,712	14,485	0.0887	0.0185	0.1073	17%	17.4	80%	**21.7**	**14%**
GPTU Vit 1	429,373	429,373	31,832	2,778	0.0741	0.0065	0.0806	8%	37.4	80%	**46.7**	**6%**
GPTU Vit 2	920,450	920,450	71,402	5,867	0.0776	0.0064	0.0839	8%	39.5	80%	**49.3**	**6%**
GPTU Vit 3	3,617,577	3,617,577	302,471	52,129	0.0836	0.0144	0.0980	15%	20.4	80%	**25.5**	**12%**
GPD Vit 1	1,028,117	2,088,960	53,574	2,988	0.0521	0.0014	0.0535	3%	112.3	80%	**140.2**	**2%**
GPD Vit 2	1,096,753	2,316,280	79,178	13,082	0.0722	0.0056	0.0778	7%	41.3	80%	**51.6**	**6%**
GPD Vit 3	2,041,798	2,867,360	169,649	38,560	0.0831	0.0134	0.0965	14%	21.5	80%	**26.9**	**11%**
GP GEI	90,489	124,414	8,039	3,083	0.0888	0.0248	0.1136	22%	13.8	80%	**17.2**	**17%**
EIP Vit 1	383,669	383,669	20,787	800	0.0542	0.0021	0.0563	4%	80.9	80%	**101.1**	**3%**
EIP Vit 2	64,327	64,327	3,303	699	0.0513	0.0109	0.0622	17%	17.2	80%	**21.5**	**14%**
EIP Vit 3	9,389	9,389	469	309	0.0499	0.0330	0.0829	40%	7.5	80%	**9.4**	**32%**
GPD GEI Vit 1	-	2,504	(0)	10	0.0000	0.0039	0.0039	100%	3.0	80%	**3.7**	**80%**
GPD GEI Vit 2	17,941	86,329	1,652	871	0.0921	0.0101	0.1021	10%	30.4	80%	**37.9**	**8%**
GPD GEI Vit 3	81,110	223,052	7,269	4,296	0.0896	0.0193	0.1089	18%	17.0	80%	**21.2**	**14%**
GML	13,118	13,118	672	876	0.0512	0.0668	0.1180	57%	5.3	81%	**6.5**	**46%**
GUL	62,386	62,386	3,153	13,632	0.0505	0.2185	0.2691	81%	3.7	81%	**4.6**	**66%**
GU-XL	19,268	19,268	939	9,742	0.0487	0.5056	0.5543	91%	3.3	81%	**4.1**	**74%**
GU	100,655	100,655	7,599	2,243	0.0755	0.0223	0.0978	23%	13.2	81%	**16.2**	**18%**

Sources: Exhibit A-16, Schedule F1, pages 2-3 (Excel Version)

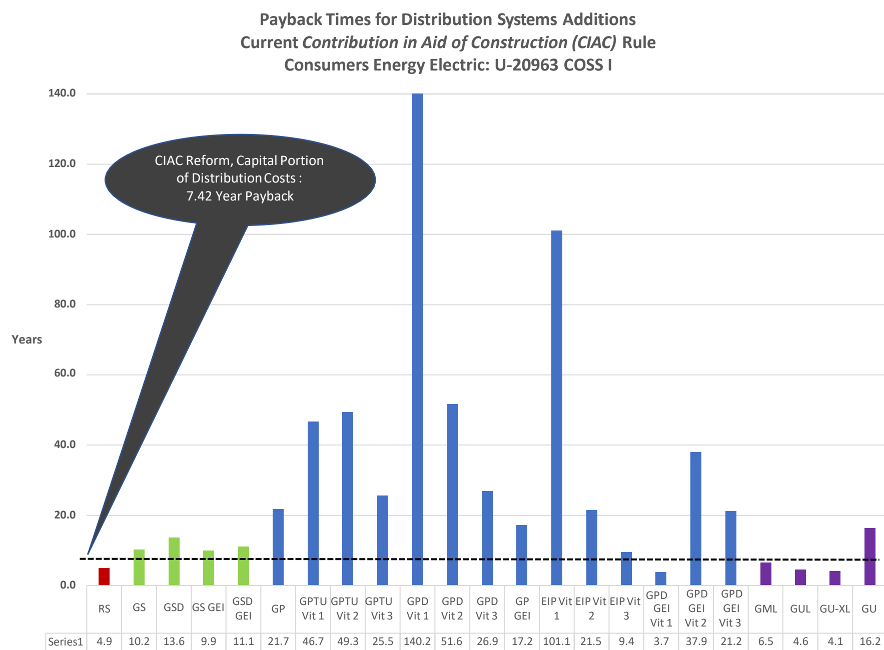


The Same Payback Should be Set for Customers Under all Rate Classes

- The correct **uniform** payback-period is the reciprocal of the *economic carrying cost* of total electric distribution capital investments:
- $Payback = \frac{1}{Economic\ Carrying\ Cost} = \frac{1}{\left[\frac{Lifecycle\ Average\ Revenue\ Requirement}{Undepreciated\ Balance\ of\ Investment}\right]}$

- $Payback \approx \frac{Electric\ Distribution\ Ratebase}{Capital\ Portion\ of\ Distribution\ Revenue\ Requirement}$

- $Payback = \frac{\$8{,}145{,}807{,}000}{\$1{,}505{,}709{,}000/yr} = \boxed{7.42\ yrs}$ (CE U-20963 COSS version I)



	RS	GS	GSD	GS GEI	GSD GEI	GP	GPTU Vit 1	GPTU Vit 2	GPTU Vit 3	GPD Vit 1	GPD Vit 2	GPD Vit 3	GP GEI	EIP Vit 1	EIP Vit 2	EIP Vit 3	GPD GEI Vit 1	GPD GEI Vit 2	GPD GEI Vit 3	GML	GUL	GU-XL	GU
Series1	4.9	10.2	13.6	9.9	11.1	21.7	46.7	49.3	25.5	140.2	51.6	26.9	17.2	101.1	21.5	9.4	3.7	37.9	21.2	6.5	4.6	4.1	16.2

Uniform Payback Under CIAC Reform

Consumers Energy example (based on its U-20963 COSS Version I):

Free allowance = 7.42 times the capital-related portion of electric distribution rate design revenue ($/kWh), for the appropriate rate class), times the end-user's estimated kWh sales.

Would replace current standard of 3 times estimated total annual revenue.

The Capital-Related Portion of Electric Distribution Rate Design Revenue

Rate Schedule	Full Service Sales MWh	Distribution Sales MWh	Production Revenue (thousands)	Distribution Revenue (thousands)	Production Revenue per kWh	Distribution Revenue per kWh	Prod. + Dist. Revenue per kWh	% Distribution	Capital % of Distribution	Capital Portion Distribution Rev. $/kWh
RS	12,621,349	12,621,349	1,334,015	971,991	0.1057	0.0770	0.1827	42%	71%	**$ 0.0548**
GS	3,750,286	3,758,814	349,084	231,547	0.0931	0.0616	0.1547	40%	74%	**$ 0.0455**
GSD	2,985,974	3,106,807	266,187	118,096	0.0891	0.0380	0.1272	30%	74%	**$ 0.0281**
GS GEI	89,373	103,955	8,130	6,621	0.0910	0.0637	0.1547	41%	74%	**$ 0.0471**
GSD GEI	139,134	199,503	11,795	9,749	0.0848	0.0489	0.1336	37%	74%	**$ 0.0361**
GP	740,549	781,557	65,712	14,485	0.0887	0.0185	0.1073	17%	80%	**$ 0.0148**
GPTU Vit 1	429,373	429,373	31,832	2,778	0.0741	0.0065	0.0806	8%	80%	**$ 0.0052**
GPTU Vit 2	920,450	920,450	71,402	5,867	0.0776	0.0064	0.0839	8%	80%	**$ 0.0051**
GPTU Vit 3	3,617,577	3,617,577	302,471	52,129	0.0836	0.0144	0.0980	15%	80%	**$ 0.0115**
GPD Vit 1	1,028,117	2,088,960	53,574	2,988	0.0521	0.0014	0.0535	3%	80%	**$ 0.0011**
GPD Vit 2	1,096,753	2,316,280	79,178	13,082	0.0722	0.0056	0.0778	7%	80%	**$ 0.0045**
GPD Vit 3	2,041,798	2,867,360	169,649	38,560	0.0831	0.0134	0.0965	14%	80%	**$ 0.0108**
GP GEI	90,489	124,414	8,039	3,083	0.0888	0.0248	0.1136	22%	80%	**$ 0.0198**
EIP Vit 1	383,669	383,669	20,787	800	0.0542	0.0021	0.0563	4%	80%	**$ 0.0017**
EIP Vit 2	64,327	64,327	3,303	699	0.0513	0.0109	0.0622	17%	80%	**$ 0.0087**
EIP Vit 3	9,389	9,389	469	309	0.0499	0.0330	0.0829	40%	80%	**$ 0.0264**
GPD GEI Vit 1	-	2,504	(0)	10	0.0000	0.0039	0.0039	100%	80%	**$ 0.0031**
GPD GEI Vit 2	17,941	86,329	1,652	871	0.0921	0.0101	0.1021	10%	80%	**$ 0.0081**
GPD GEI Vit 3	81,110	223,052	7,269	4,296	0.0896	0.0193	0.1089	18%	80%	**$ 0.0154**
GML	13,118	13,118	672	876	0.0512	0.0668	0.1180	57%	81%	**$ 0.0542**
GUL	62,386	62,386	3,153	13,632	0.0505	0.2185	0.2691	81%	81%	**$ 0.1773**
GU-XL	19,268	19,268	939	9,742	0.0487	0.5056	0.5543	91%	81%	**$ 0.4102**
GU	100,655	100,655	7,599	2,243	0.0755	0.0223	0.0978	23%	81%	**$ 0.0181**

Based on Consumers Energy Proposed Production and Distribution Revenues U-20963 COSS Version I

CIAC Reform – Utility Contribution - Based on End User's Estimated Annual (kWh)

7.42 times the capital-related portion of electric distribution rate design revenue ($/kWh)

Rate Schedule	Credit $/kwh
RS	0.40710
GS	0.33805
GSD	0.20860
GS GEI	0.34951
GSD GEI	0.26817
GP	0.11019
GPTU Vit 1	0.03847
GPTU Vit 2	0.03790
GPTU Vit 3	0.08567
GPD Vit 1	0.00850
GPD Vit 2	0.03358
GPD Vit 3	0.07995
GP GEI	0.14731
EIP Vit 1	0.01240
EIP Vit 2	0.06460
EIP Vit 3	0.19592
GPD GEI Vit 1	0.02319
GPD GEI Vit 2	0.05996
GPD GEI Vit 3	0.11450
GML	0.40225
GUL	1.31620
GU-XL	3.04535
GU	0.13424

Applied to estimated annual usage (kWh)

Based on Consumers Energy Proposed Production and Distribution Revenues U-20963 COSS Version I

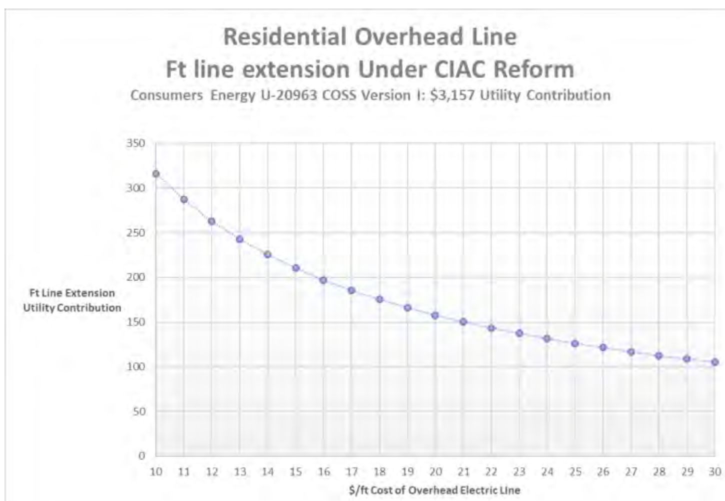
Residential CIAC Overhead Electric Line

Consumers Energy current CIAC rule allows for 1st 600 ft to be covered at the utility expense.

Under CIAC reform, length of "free" extension would depend on cost/ft.

	Current Framework		CIAC REFORM
	Total Revenue	Distribution Revenue	Capital Portion Revenue
Residential kWh/yr	7,754	7,754	7,754
Rate $/kWh	0.1827	0.0770	0.0548
Revenue $/yr	1417	597	425
Payback Period	3		7.42
$ Company Contribution	**$ 4,250**		**$ 3,157**

35% TOO HIGH



Conclusions & Recommendations

1) Payback associated with utility contribution-in-aid-of-construction should be **uniform** across all rate classes.
2) The uniform payback (*x Yrs.)* should be based on the **reciprocal of the economic carrying cost of electric distribution capital investment**.
3) The **capital portion** of distribution revenue requirements (%) should be calculated for each customer class (residential, secondary, primary, lighting).
4) The capital portion of the rate-design distribution-revenue ($/kWh) is calculated as product of (3) and the rate design distribution revenue ($/kWh) for full service + ROA sales.
5) Free allowance ($/ kWh of estimated annual usage, for each rate class) is calculated as the product of (4) and the uniform payback period (*2).*
6) The per kWh allowance for each rate class (5) should be reflected in a **schedule**, updated in each general rate proceeding. The per kWh allowance is applied to the end-user's estimated annual usage (kWh)
7) With respect residential **overhead line-extensions**, the maximum # of feet allowed at the utility's expense should be fixed in each rate case, based upon the per kWh residential allowance reflected in (6) times the class average sales per customer (from the COSS) divided by the current cost per foot also set in each rate case.

DFA Technology Detects Circuit Device Failures – Experience of Mid-South Synergy

Presented by Carl L. Benner

72nd Annual Conference for Protective Relay Engineers
Texas A&M University, College Station, Texas
March 25-28, 2019

Accompanying paper authored by
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Paper in substantially similar form was first presented to CIGRE Grid of the Future Conference, Reston, Virginia, October 2018.

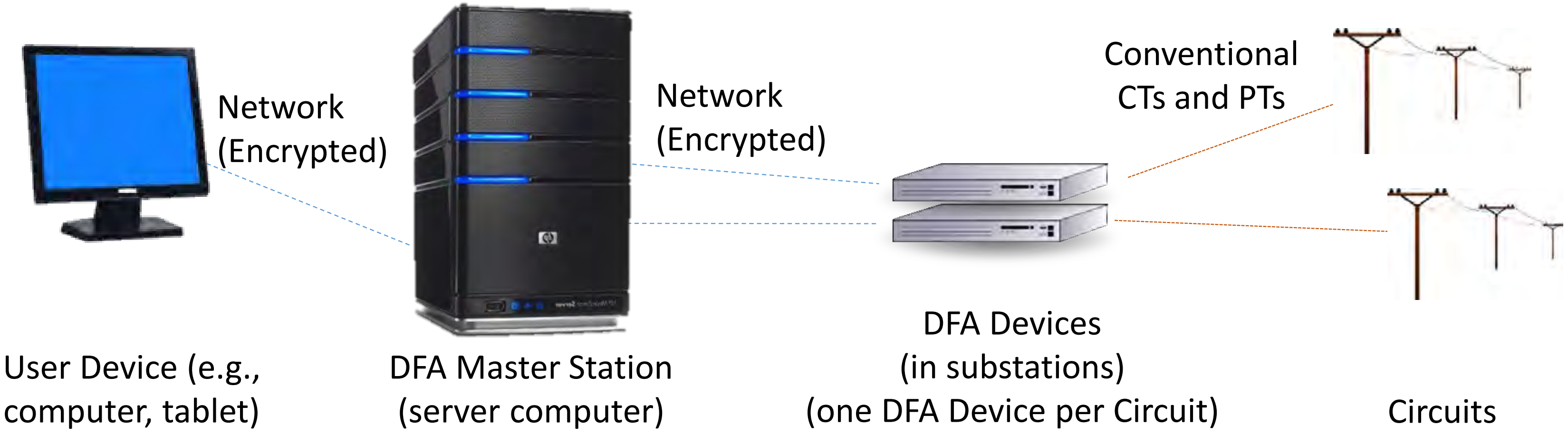
Takeaways

- Electrical signals contain much information about line health.
- But conventional technologies waste most of it.
- Proper use enables:
    - Improved Reliability – fewer interruptions, outages, …
    - Improved Safety – fewer hazards to personnel and public, reduced fire risk, …
- Three examples in this presentation:
    - Each affected reliability. Each affected safety.
    - None were actionable from conventional technologies, AMI, smart grid, etc.
    - All data comes from conventional CTs and PTs at the substation. Communications with line devices (e.g., reclosers) is not required.

Data System for Examples in This Presentation

- Texas A&M Engineering, working with EPRI and industry for two decades, has implemented a real-time monitoring system to detect line issues.
- The technology, known as Distribution Fault Anticipation (DFA), is installed on more than 100 distribution circuits.
- Substation-based DFA devices analyze waveform events and send reports to a central master station server in real-time. Circuit owners and Texas A&M access those reports via secure, browser-based login.
- Mid-South initially installed DFA on 10 circuits, added 10 more in 2018, and is adding 10 more in 2019.
- Important: Sensing data comes from conventional, substation-installed CTs and PTs, without distributed sensing or communications with reclosers or other line devices.

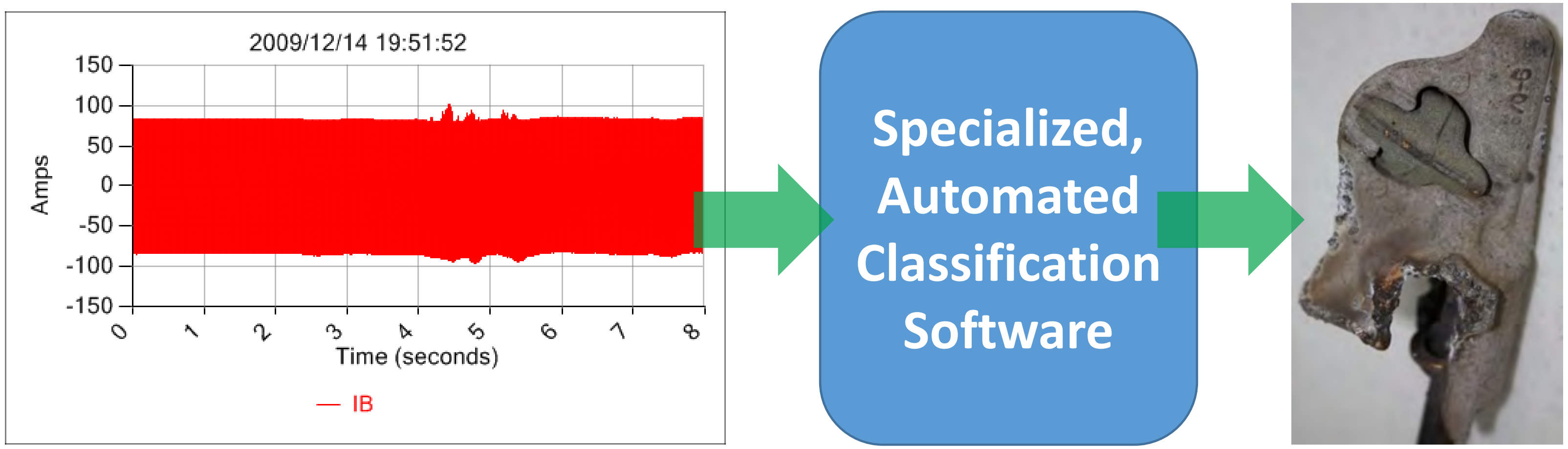
Data System for Examples



Waveform analysis software runs automatically in each substation-installed DFA device, which then sends reports to the DFA Master Station for access by personnel. The Master Station deploys improved waveform analysis software as it becomes available.

Basic Concept – Waveforms Reveal Problems

- Graph shows line current during “normal” operations.
- Conventional technologies waste (ignore) this information entirely.
- Software embedded in the DFA system reports this event as a failing clamp (which can persist for weeks, degrade service, even burn down a line).



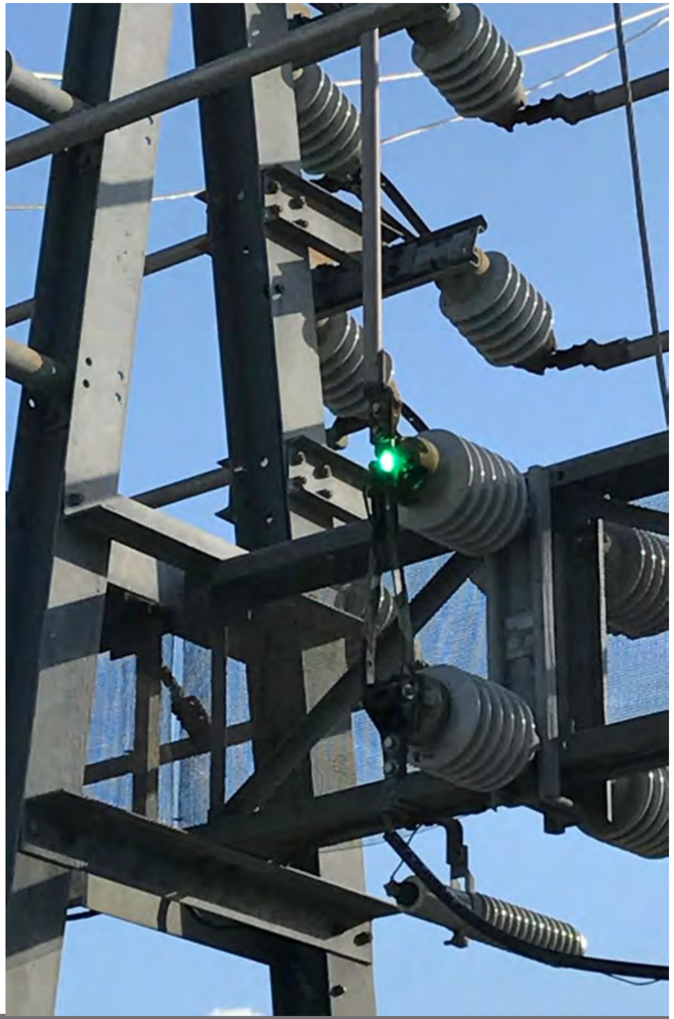
Texas Powerline-Caused Wildfire Mitigation Project

- DFA was the basis for the Texas Powerline-Caused Wildfire Mitigation project, 2014-2017.
- Mid-South and five other Texas utilities installed DFA on 50+ circuits and worked with Texas A&M to document how DFA enabled them to correct many issues. A partial list:
  - Detect and repair a substantial number of routine outages, without customer calls.
  - Detect and locate tree branch hanging on line and causing intermittent faults.
  - Detect and locate intact tree intermittently pushing conductors together.
  - Detect and locate broken insulator that resulted in conductor lying on and heavily charring a wooden crossarm.
  - Detect and locate catastrophically failed lightning arrester.
  - Detect and locate arc-tracked capacitor fuse barrel.
  - Detect and locate multiple problems involving capacitor banks.

Example 1

Failing Sub Switch (Series Arcing)

- Rural 25 kV distribution substation
- Three circuits, hundreds of customers
- Blade switch on substation metalwork
- Incipient failure
  - “Hot spot” visible in photograph
  - No customer calls
  - No indication from SCADA
  - No indication from smart meters, even when pinged after being alerted to the switch problem by the DFA monitoring system

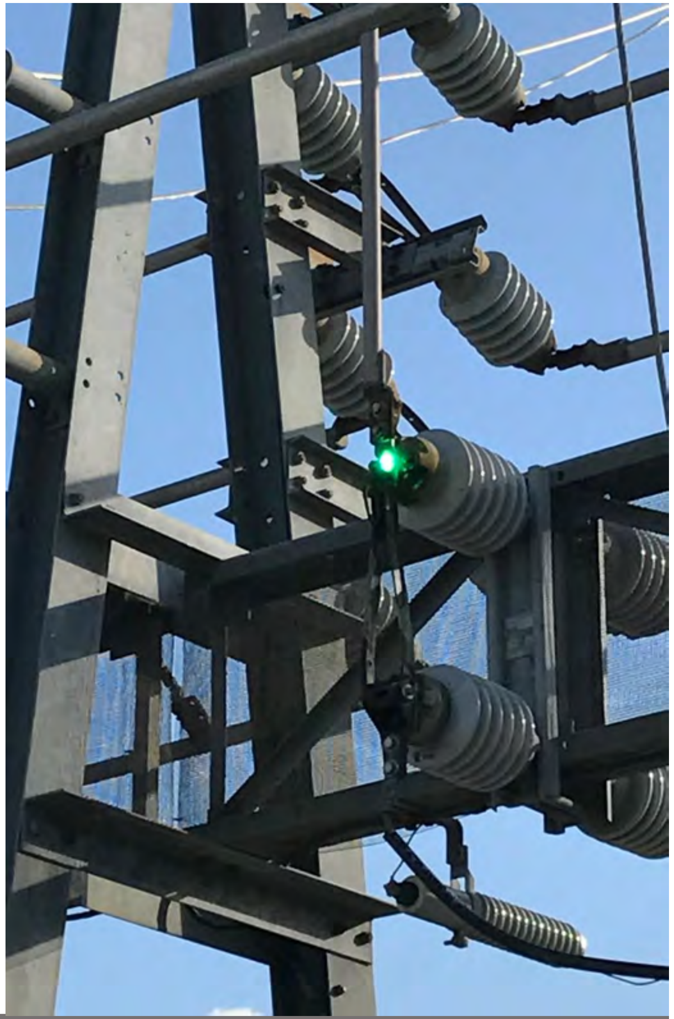


A Momentary Aside

Brief Tutorial on Series Arcing

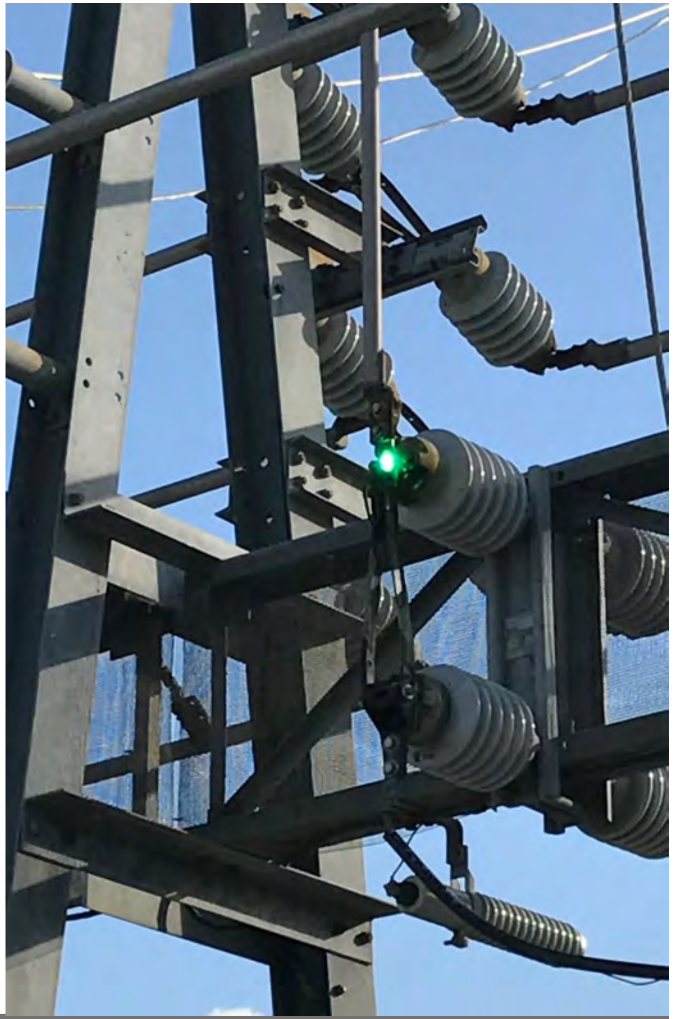
<u>Arcing – two distinct types</u>

- Shunt arcing: <u>unintended</u> current flow, usually phase-to-ground/neutral or phase-to-phase.
- Series arcing: "hot spot" resulting from failing contacts; interferes with <u>intended</u> current flow.



A Momentary Aside (cont'd)

Brief Tutorial on Series Arcing



Series Arcing – Some Characteristics

- Is poorly understood scientifically
- Affects load-carrying devices – clamps, switches, etc.
- Can exist for minutes to weeks prior to notice
- Tends to be highly intermittent - Can "flare up" for minutes and then go quiescent for days
- Causes vague symptoms, making it hard to diagnose
  - Flickering lights
  - Blown fuses (but replacement fuse may hold for a while)
  - Momentary operations, with successful auto-reclose
- Conventional location techniques (current magnitude or impedance) not applicable

A Momentary Aside (cont'd)

Miscellaneous Examples of Series Arcing

Eroded hotline clamp

Conductor burn-through at clamp

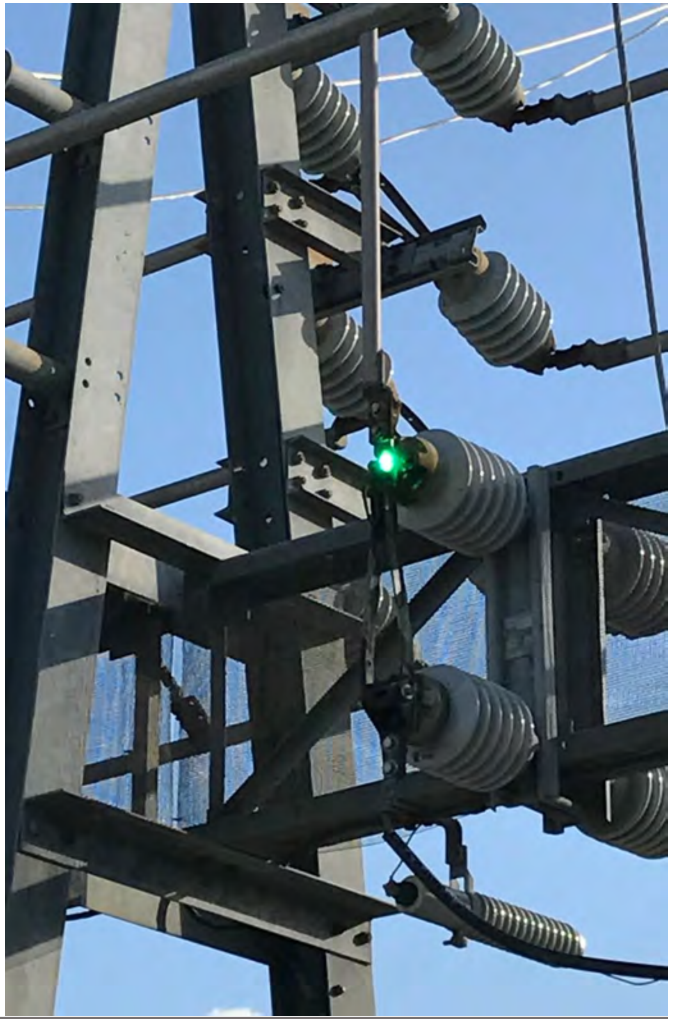
Sizzling substation blade switch

Example 1 (resumed)

Failing Sub Switch (Series Arcing)

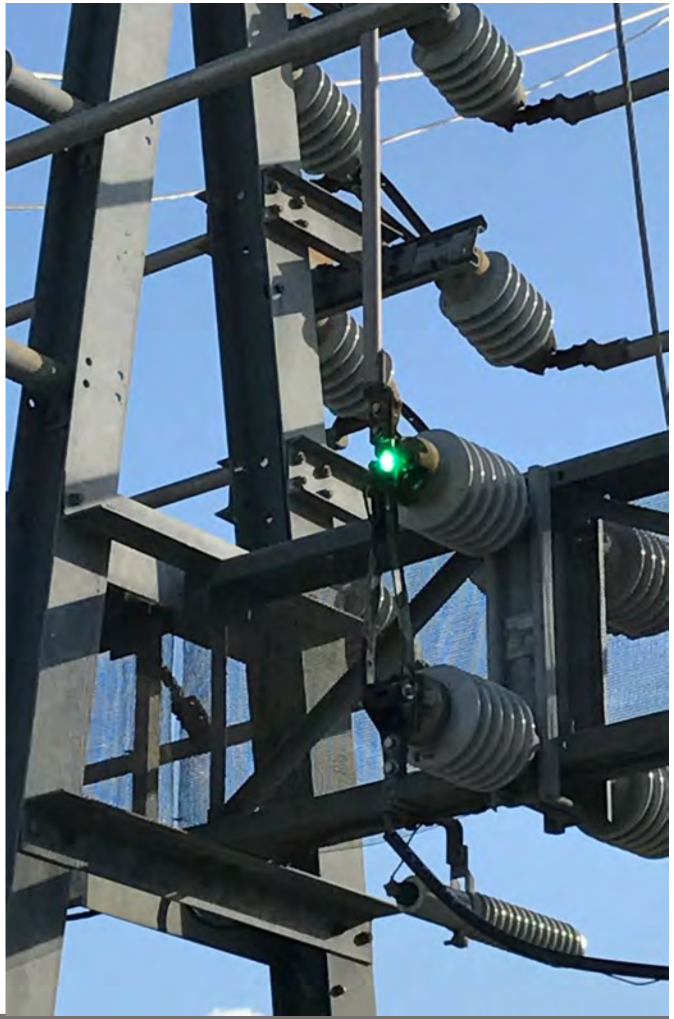
<u>Chronology for This Example</u>

- Received DFA notification mid-day Saturday.
- Checked SCADA (nothing), pinged meters (nothing).
- DFA software, based on waveforms, estimated that the failing device was carrying most of the circuit's load, so line crews patrolled near the sub.
- Lineman heard buzzing upon arrival at substation.
- Location took 1.5 hours (in rural environment).
- Utility called in repair crews (Saturday night).



Example 1 (cont'd)

Failing Sub Switch (Series Arcing)



Reliability impact

- Avoided prolonged outage to at least one circuit, possibly three circuits (100's of customers).

Safety impact

- Avoided catastrophic switch failure and potentially a substation fire (crew safety, public safety).
- Crews made repairs without time pressure inherent to large outage (crew safety).

Example 2

Fault-Induced Conductor Slap

- Fault-induced conductor slap (FICS) tends to occur repeatedly in specific spans.
- Each episode causes a momentary interruption and possibly an outage, typically of a full circuit.
- Each episode emits particles that can start a fire.
- Each episode causes progressive conductor damage, which can break a line.
- Months can elapse between episodes.
- FICS seldom is recognized or diagnosed correctly.

(See paper for full discussion of the FICS phenomenon.)

Example 2 (cont'd)

Fault-Induced Conductor Slap

Specific Example

- A tree far from the substation caused a fault.
- A mid-point recloser locked out to clear the fault.
- But FICS induced a second fault, miles closer to the substation, causing the substation breaker to lock out the circuit.
- DFA software reported this as FICS and provided fault current amplitude to guide location.
- Mid-South found arced conductor damage ("bright spots"), with burned grass beneath.

Example 2 (cont'd)

Fault-Induced Conductor Slap

- Without remediation, FICS occurs repeatedly in susceptible spans.
- Remediation is simple but occurs only if the FICS is recognized, which seldom happens.

Reliability impact

- Avoided future whole-circuit interruptions and outages.

Safety impact

- Consider the same span experiencing FICS again on a "red flag" (high fire risk) day!

Example 3

Charred Wooden Crossarm

The Circuit

- Long, rural 25 kV distribution line
- Next to pine forest with dry underbrush

The Condition

- A phase conductor broke free from its insulator and lay on the wooden crossarm.
- This contact caused significant charring along bottom of crossarm (see photo).
  (Note: Problem had been corrected at the time the photo was taken.)

Example 3 (cont'd)

Charred Wooden Crossarm

- Condition caused two flashovers, about a day apart. Each trip/closed a mid-point recloser.
- DFA software reported each fault sequence of events (based on substation waveforms, without communications to recloser).
- Mid-South personnel noted the two similar events, a day apart, during fair weather, and investigated.
- Guided by their circuit model and DFA fault magnitude, a line crew readily located the problem (six spans from the prediction).

Example 3 (cont'd)

Charred Wooden Crossarm

Reliability impact

- Avoided additional interruptions to significant portion of circuit.
- Avoided long outage (broken line and/or crossarm).

Safety impact

- Avoided poletop fire or fallen, burning crossarm.
- Avoided possible downed conductor (fire hazard, crew safety, public safety).

Takeaways

- Electrical signals contain much information about line health.
- But conventional technologies waste most of it.
- Proper use enables:
  - Improved Reliability – fewer interruptions, outages, …
  - Improved Safety – fewer hazards to personnel and public, reduced fire risk, …
- Three examples in this presentation:
  - Each affected reliability. Each affected safety.
  - None were actionable from conventional technologies, AMI, smart grid, etc.
  - All data comes from conventional CTs and PTs at the substation. Communications with line devices (e.g., reclosers) is not required.

Texas Power Line Caused Wildfire Mitigation Project

Project Description – Findings – Recommendations
March 2018

Introduction

In a three-year study period through 2011, Texas experienced more than 4,000 wildfires caused by power line events, as documented by the Texas A&M Forest Service. Many of these fires were minor, but others resulted in the loss of human life, disruption of lives and commerce, and hundreds of millions of dollars in property damage. This mirrors the occurrence of catastrophic fires in several other states.

In response to this statewide problem, the Texas legislature authorized three million dollars to support a four-year investigation of how power lines cause wildfires and what could be done to mitigate or prevent these catastrophic events. The project vision statement was as follows: To reduce wildfire risks and losses in Texas, using state-developed technologies to mitigate wildfires caused by power lines.

Enabling technology – Distribution Fault Anticipation (DFA)

Prior to the wildfire mitigation project, researchers at Texas A&M University, led by Dr. B. Don Russell and Mr. Carl Benner, had developed advanced diagnostic and monitoring technology for electric power distribution circuits. In a fifteen-year study, Texas A&M conducted the longest longitudinal study of naturally occurring power line failures. More than 1,000 circuit-years of high-fidelity electrical failure signatures of failing devices, apparatus, and abnormal power line events were recorded. This created the largest database in existence of failure signatures and enabled development of detection algorithms to characterize a wide variety of failures of line equipment. Designated Distribution Fault Anticipation, the system uses advanced waveform analytics and artificial intelligence to detect distribution circuit device failures and abnormal electrical events and report them to utility personnel for action.

The primary original purpose of DFA technology was to improve the reliability of distribution circuits, by detecting and identifying incipient failures of devices, before catastrophic failure. This enables condition-based maintenance, whereby operators can find and fix problems before an outage and often before a single customer calls. It was soon discovered that DFA technology had the capability of finding failing devices and power line problems in their early stages, before they became competent ignition mechanisms for wildfires. It was this concept that initiated the four-year statewide study with the aim of validating the use of DFA technology to reduce wildfire risk.

The Project

The following utilities, some in the highest risk wildfire areas, agreed to cooperate in this statewide study.

Austin Energy
Concho Valley Electric Coop
Pedernales Electric Coop
Bluebonnet Electric Coop
Mid-South Synergy
Sam Houston Electric Coop
United Cooperative Services

More than 50 circuits were instrumented with DFA technology for continuous, multi-year monitoring. During the project study period, numerous failing devices and abnormal line events were detected, recorded, and analyzed. Initially, the purpose was to document that failing devices and events, such as conductor slap and vegetation intrusion, could be reliably detected and located before a wildfire was ignited. By the end of the project, utility personnel had learned to use the technology to find and fix many problems that pose high wildfire risk but also that adversely affected circuit reliability. This showed that circuit reliability and resilience could be improved using DFA technology, with the additional benefits of improving safety and reducing wildfire risk.

Project Findings

Over the course of the four-year project, DFA technology was proven to detect, diagnose and/or identify numerous failure mechanisms and apparatus misoperations that were competent ignition mechanisms. Recall, for a wildfire to ignite, sustain itself, and grow, numerous conditions must exist, including dry fuels, low humidity, high winds, etc. DFA technology can detect failing devices such as arcing hotline clamps which, under the right circumstances and conditions, can most certainly be competent ignition mechanisms for wildfires. Further, whether a fire occurs or not, a failing clamp represents a potential customer outage and may cause a downed energized conductor and create a public safety hazard.

During the course of the project, utility participants used DFA technology to identify various failure mechanisms, including the following.

Broken insulator	Conductor clash
Contact by vegetation	Lightning arrester failure
Clamp failure	Switch failure
Equipment arc tracking	Capacitor bank internal failure

Individually and collectively, the above failure mechanisms demonstrate all of the following primary fire ignition mechanisms from power delivery apparatus and lines; namely:

1. Burning embers from vegetation
2. Molten or combusting metal particles expelled during faults
3. Downed conductors, including high-impedance arcing faults
4. Burning insulating fluids expelled from transformers, capacitors, reclosers, etc.

Major Findings

The following findings are important to fully understand the power line ignition mechanisms for wildfires.

1. Conductor clash, including fault-induced conductor clash, is more common than conventionally understood. Each event represents the potential for ignition and also progressively weakens conductors, increasing the likelihood of future broken conductors.
2. Vegetation-induced faults often occur multiple times, spread over periods of days.
3. A single root cause may cause multiple faults, spread over weeks or months, without an outage.

4. Many failing devices manifest early stage detectable signatures long before catastrophic failure that would cause a fire or an outage.
5. Incipient failures of clamps and connectors often develop over weeks and ultimately can result in broken conductors on the ground, an obvious ignition mechanism.

The above mechanisms can be detected by DFA technology, often with sufficient lead time to find and fix failures before wildfire ignition. This was documented extensively during the course of the Texas wildfire mitigation project.

Recommendations

1. DFA technology can detect the incipient stage of numerous power line failure mechanisms that can cause wildfire ignition, outages, explosions, and other hazards.
2. The use of DFA technology by utilities would allow for continual, automated distribution circuit health assessment, which would improve the reliability and safety of electricity delivery.
3. DFA technology would allow utility operators to determine the cause of outages and reduce the duration of outages by targeting repair crews to specific root causes.
4. Since many failing devices develop over weeks or months, DFA technology can facilitate early cause identification and enable repairs before "red flag" wildfire ignition conditions exist.
5. DFA technology can immediately identify potential ignition events on distribution circuits on "red flag" days, when any fault or arcing event has a high probability of fire ignition, enabling more rapid response to fires.

Conclusion

The Texas wildfire mitigation project definitively demonstrated that many wildfires can be prevented by continually monitoring distribution circuits to keep those circuits healthy. Operators can identify and fix failures in their early, incipient stages. Many wildfires can be prevented in months when conditions are optimal for ignition, by detecting and correcting problems in advance.

DFA technology is a unique, transformational tool for utilities which will improve reliability, increase safety, and enable wildfire risk reduction, by providing advanced diagnostics and situational awareness for operators.

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Compendium of Selected Case Studies
Related to the Texas Power Line-Caused Wildfire Mitigation Project

Mid-South Synergy Uses DFA Technology to Diagnose Fault-Induced Conductor Slap

Dr. Comfort Manyame, Sr. Mgr., Research and Technical Strategy
Robert E. Taylor, Engineering Specialist
Mid-South Synergy Electric Cooperative

Carl L. Benner, Research Associate Professor
Dr. B. Don Russell, Distinguished Professor
Texas A&M Engineering

June 2017

Distribution Fault Anticipation (DFA) technology helped Mid-South Synergy Electric Cooperative (MSEC) diagnose a complex fault event that included a difficult-to-diagnose condition known as fault-induced conductor slap (FICS). Absent remediation, FICS tends to recur. Each instance causes sparks that can ignite a fire. Repetitive instances progressively damage conductors, which can cause them to break and fall, endangering the public. Remediation of FICS typically is straightforward, if the utility is aware that it is occurring. DFA provided MSEC's only notice that FICS had occurred.

MSEC is one of seven utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration supported by the Texas legislature. As part of that effort, MSEC has instrumented ten circuits, primarily long, rural circuits, with DFA technology. Each is fitted with a single, substation-installed DFA device, which detects faults, failures, and other events along the circuit's length and reports them to a central master station server computer for access by personnel. MSEC has used DFA to diagnose multiple types of diverse issues on their circuits.

Fault-induced conductor slap, or FICS, is a complex phenomenon that occurs when an initial fault on a circuit causes line conductors to swing together and create a second fault. The second fault occurs closer to the substation and often results in a more widespread outage. FICS is an onerous problem, both because its complex nature makes it difficult to diagnose, and because, absent proper diagnosis and remediation, it tends to recur. Individual episodes may occur months or even years apart, making it difficult for personnel to recognize that a problem that occurred today is the same as the one that occurred six months ago.

The subject event was even more complex than conventional FICS. On 11 June 2017, a balloon string contacted a 25 kV circuit, causing a fault. An automatic circuit recloser (ACR) upstream of the fault locked out, as would be expected, but a second ACR and even the substation circuit breaker locked out, too.

MSEC's field crew found a burned jumper in the section of line between the first ACR and the second. They concluded that the passage of fault current from the first fault caused the jumper to fail, resulting in the second fault and tripping the second ACR. They also initially concluded that the complexity of the sequence of events had "fooled" the substation protection and caused it to trip.

DFA recorded the current and voltage signals of the full sequence. The DFA On-Line Waveform Classification Engine software analyzed those signals and reported probable FICS. Prompted by the DFA report, MSEC used their circuit model software to determine that the fault currents that caused the substation circuit breaker to trip were too large to have resulted from the balloon fault or from the jumper fault. Using model-based location predictions, they then patrolled a targeted area of the circuit and found conductors with the "bright spots," or arc pitting, typical of slapping conductors. On site, they spoke with a member of the public, who reported seeing the conductors slapping and causing a shower of sparks, further confirming the FICS. Notably the FICS was more than five circuit miles from the initial, balloon-induced fault.

Remediating the subject span was possible only because DFA made MSEC aware of the FICS. Left uncorrected, the span likely would have caused additional outages, in addition to the dangers associated with fire ignition and public safety.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software, known as the On-Line Waveform Classification Engine, to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the system-wide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance. No technology can detect all problems, but DFA provides a quantum step forward in the detection and diagnosis of many failures and incipient failures.

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Texas-based Power Solutions, LLC.

Headquartered in Navasota, Texas, Mid-South Synergy serves 22,500 members and 30,000 meters in a service territory covering parts of six counties in Central Texas. Mid-South has installed DFA technology on ten distribution circuits as part of its participation in the Texas Power Line-Caused Wildfire Mitigation project.

Pedernales Uses DFA Technology to Reduce Vegetation Wildfire Risk and Increase Reliability

Robert A. Peterson, P.E.
Director, Control Center and Emergency Preparedness
Pedernales Electric Cooperative

Carl L. Benner, P.E.
Research Associate Professor
Texas A&M Engineering

April 2016

Pedernales Electric Cooperative (PEC) improved reliability and reduced wildfire risk by detecting, locating, and clearing vegetation contacting a rural, overhead distribution line near Blanco, Texas. Distribution Fault Anticipation (DFA) technology enabled this by detecting early warning signs of the vegetation intrusion. Conventional technologies did not notify PEC of this condition. Rather PEC's only notification came from DFA.

PEC is one of six utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration effort supported by the Texas legislature. As part of that effort, PEC has instrumented ten distribution circuits, primarily long, rural circuits, with DFA technology. PEC has instrumented each of these circuits with a single, substation-installed DFA device, which detects and warns of faults, failures, and other events along the length of the circuit.

Latent power line conditions, such as vegetation intrusion and certain apparatus failures, can cause recurring fault events. Many such conditions are affected by weather conditions, such as wind and moisture, and therefore cause fault events only intermittently. These conditions are difficult to detect and locate with conventional technologies.

Like most utility companies, PEC applies automatic circuit reclosers at multiple locations on long circuits. Such a recloser attempts to clear temporary faults by tripping a section of line, waiting a few seconds, and then reclosing to restore service to customers. This momentary interruption clears most faults successfully, without causing a lengthy outage or requiring unnecessary patrols by line crews.

In the early morning hours of 06 March 2016, a fault caused a single momentary trip/close operation of a recloser on one of PEC's DFA-monitored circuits. Some 30 minutes later, the fault recurred and again caused a single trip/close operation. Eight hours later, the fault occurred a third time, once again causing a single trip/close operation. No customers experienced a sustained outage, no customers called to complain of the momentary "blinks," and no conventional technology notified PEC of a problem requiring investigation.

DFA detects and characterizes fault events. In addition, each time it detects a fault event, it calculates multiple parameters about that fault event, compares those parameters to those from recent fault events on the same circuit, and, if it detects multiple similar fault events, generates a special "recurrent fault" report. In the subject case, DFA detected that the three momentary trip/close operations likely resulted from the same fault condition, alerted PEC to this fact, and provided information PEC could use to locate the problem.

The circuit in question is a long rural circuit with 153 miles of primary line conductor. Upon receiving the DFA report indicating a recurrent fault, PEC utilized DFA-generated fault parameters, PEC's electronic circuit model, and "blink counts" from PEC's AMI (automated metering infrastructure) system to direct a search to a small portion of that long circuit. A PEC crew patrolled the indicated area and efficiently found and removed the cause of the recurrent fault: a tree branch on the overhead line. By responding in a timely way, the line conductors avoided damage and possible burn-down. In addition this preemptive action avoided possible future faults and interruptions to customers and removed the source of a possible future fire ignition.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device continuously monitors circuit currents and voltages, with high-fidelity, via conventional CTs and PTs. DFA devices use embedded, proprietary signal processing to characterize electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the fleet of DFA devices on circuits across the power system. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance.

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Power Solutions, Inc.

Serving more than 270,000 customers in a service territory covering 8,100 square miles in the Texas Hill Country, Pedernales Electric Cooperative is the largest electric cooperative in the United States. Pedernales has installed DFA technology on ten distribution circuits as part of its participation in the Texas Power Line-Caused Wildfire Mitigation project.

Sam Houston EC Uses DFA Technology to Detect and Locate Failed Arrester

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May 2016

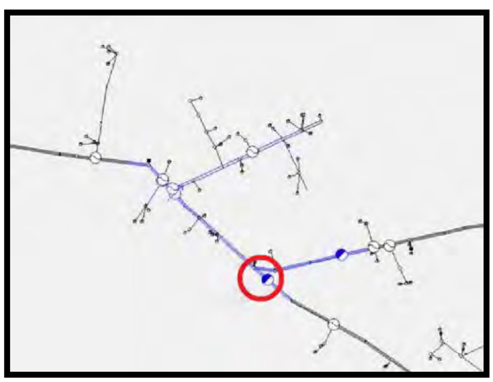
Sam Houston Electric Cooperative recently used Distribution Fault Anticipation (DFA) technology to detect and efficiently locate a failed lightning arrester, enabling its replacement. Failed arresters can reduce a line's surge suppression capability, affect service reliability, cause future short circuits, and create a risk of wildfire ignition. The Cooperative learned of the failure only from DFA, not from any conventional technology.

Sam Houston EC is one of six utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration effort supported by the Texas legislature. As part of that effort, Sam Houston is instrumenting ten distribution circuits, primarily long, rural circuits, with DFA technology. DFA instrumentation of a circuit consists of a single, substation-installed DFA device, which detects and warns of faults, failures, and other events along the length of the circuit.

During a storm on 30 March 2016, one of Sam Houston EC's DFA-instrumented circuits experienced a short-circuit fault. The Cooperative's conventional circuit protection properly detected the fault, tripped the circuit, and then reclosed two seconds later to restore service. Like most utility companies, Sam Houston utilizes automatic circuit reclosing to clear most faults without sustained outages for their customers.

Conventional systems detected and cleared the subject fault and notified the Co-op's dispatch center that the event had occurred, but indicated nothing more serious than a temporary fault. Temporary faults are common during storms and often require no utility follow-up, so system operators ordinarily would have had no reason to take action based on this fault and reclose. DFA recorded the electrical signature of the fault and the response of the protection system, but it also enabled diagnosis of the likely cause of the fault: a failed lightning arrester.

Knowing of arrester failures is important because a failing arrester can expel superheated fragments capable of igniting combustibles. A failed arrester also can leave detached pole-top components energized and free to swing and contact other pole-top apparatus, resulting in future faults and potential ignition events.



DFA technology enabled detection and efficient location of a failed arrester not detected by conventional systems.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the systemwide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance.

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Power Solutions, Inc.

The circuit in question is a long, rural circuit with multiple branches and 120 total miles of primary line. Upon receiving DFA-based notification that the likely cause of the fault was catastrophic failure of a lightning arrester, the Co-op used DFA-generated parameters, along with their electronic circuit model to predict the location of the failed arrester. A Sam Houston EC crew was dispatched with instructions to target a specific portion of the circuit, looking for a failed arrester, which they found with minimal time and effort. Absent DFA-based notification, there would have been no compelling reason to investigate the temporary fault, and consequently the failed arrester would have remained undiscovered.

Headquartered in Livingston, Texas, Sam Houston Electric Cooperative serves more than 71,000 consumers in ten counties. Sam Houston is installing DFA technology on ten distribution lines in conjunction with the Texas Power Line-Caused Wildfire Mitigation project.

Mid-South Synergy Uses DFA Technology to Avoid Outage and Reduce Wildfire Risk

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February 2017

Mid-South Synergy Electric Cooperative (MSEC) avoided a significant outage and reduced other risks, including potential wildfire ignition, by using Distribution Fault Anticipation (DFA) technology to discover a detached conductor lying directly on a wooden crossarm. Conventional technologies did not alert MSEC to the problem.

MSEC is one of seven utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration supported by the Texas legislature. As part of that effort, MSEC has instrumented ten circuits, primarily long, rural circuits, with DFA technology. Each is fitted with a single, substation-installed DFA device, which detects faults, failures, and other events along the circuit's length and automatically reports them to a central master station server computer for access by personnel.

Latent power line conditions can cause recurring faults. Some such conditions are influenced by weather conditions, such as wind and moisture, and cause faults only intermittently. Such conditions are difficult to discover with conventional technologies and can exist for days or weeks without notice.

Like most utility companies, MSEC applies automatic circuit reclosers at multiple locations along long circuits. A recloser clears temporary faults by tripping a section of line, waiting a few seconds, and then reclosing to restore service. These momentary interruptions successfully clear most faults and minimize customer outages and unnecessary patrols.

On 15 January 2017, a fault on one of MSEC's DFA-instrumented circuits caused a single momentary trip/close operation of a recloser. A similar fault occurred the next day. No members experienced outages or reported "blinks," and no conventional technology alerted MSEC of a problem requiring attention.

While reviewing events on the central DFA master station, MSEC personnel noted the two events and observed that they appeared unusual and similar to each other. The circuit is a long, rural line with 109 miles of exposure. MSEC used DFA-provided fault parameters, in conjunction with their existing circuit model software and remote polling of line devices, to dispatch a line crew to patrol a specific portion of the circuit. There the crew identified the cause of the problem, a line conductor displaced from its normal position on an insulator and lying on its wooden crossarm. As shown in the photograph above, the crossarm had substantial charring.

An outage at this location would have interrupted 138 members, all of whom would have been out of service for the full time needed to dispatch crews, locate the problem, and make repairs. Other potential consequences would have included a burned off cross arm, a broken conductor, and multiple mechanisms capable of igniting a fire. Key to avoiding the consequences was the DFA-enabled ability for MSEC personnel to learn of the problem, which in turn enabled them to investigate and make proactive repairs.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the system-wide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance. No technology can detect all problems, but DFA provides a quantum step forward in the detection and diagnosis of many failures and incipient failures.

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Texas-based Power Solutions, LLC.

Headquartered in Navasota, Texas, Mid-South Synergy serves 22,500 members and 30,000 meters in a service territory covering parts of six counties in Central Texas. Mid-South has installed DFA technology on ten distribution circuits as part of its participation in the Texas Power Line-Caused Wildfire Mitigation project.

Mid-South Synergy Uses DFA Technology to Avoid Substation Switch Failure

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May 2018

DFA technology provided Mid-South Synergy Electric Cooperative's (MSEC's) only notice of early stage substation switch arcing. MSEC averted potentially catastrophic failure by initiating emergency repairs within two hours of learning of the issue from DFA.

MSEC is one of seven utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration supported by the Texas legislature. Over the past three years, MSEC has used DFA to detect a variety of issues, including: conductor slap; a phase conductor charring a wooden crossarm; capacitor problems; failing switches; and other issues. MSEC initially installed DFA on ten circuits, primarily long, rural circuits, and currently is adding DFA to ten more. Each circuit has a single, substation-installed DFA device, which detects faults, failures, and other events along the circuit's length and reports them to a central master station server computer for access by personnel.

DFA detected the failing switch based on specialized software that monitors line currents and voltages continuously and automatically recognizes signal patterns indicative of switch failure. MSEC received the DFA report late on a Saturday afternoon and responded immediately.

MSEC did not know immediately which of the circuit's multiple switches was the culprit. MSEC had no active member complaints, and none of their other systems indicated a problem. MSEC operators used their AMI (advanced metering infrastructure) system to ping meters on the affected phase, based on the thought that meters downstream of the arcing switch might report something unusual, but that was not the case. DFA estimated that the offending switch was carrying most of the circuit's load, and MSEC used that information to direct patrols near or in the substation. Upon arriving at the unmanned, rural substation, the responding lineman distinctly heard "sizzling" and knew that he had found the arcing switch. Despite the remote location of the substation, MSEC located the arcing switch within two hours of their first notice.

MSEC found the switch on a Saturday evening. Because of the serious nature of the issue, they initiated corrective action immediately. Catastrophic failure of the switch would have caused an outage for at least one circuit. Because the switch was located on the substation buswork, its catastrophic failure could have caused an outage for the entire substation. In the extreme, it could have caused a substation fire, particularly if a high-current fault on the circuit precipitated the switch's final failure.

Replacement was timely, because MSEC's service territory experienced thunderstorms each of the next two days, and those storms caused multiple faults on the circuit. Had the weak switch still been in service, the added stress of carrying fault current and other system transients likely would have caused its catastrophic failure. The substation has three circuits, all three of which needed to be switched to alternative sources of supply while the switch was replaced. Early warning enabled all load to be switched to alternative sources without outage and without the time pressure that would occur had the switch failed and caused an outage to one or more circuits.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software, known as the On-Line Waveform Classification Engine, to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the system-wide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance. No technology can detect all problems, but DFA provides a quantum step forward in the detection and diagnosis of many failures and incipient failures.

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Texas-based Power Solutions, LLC.

Headquartered in Navasota, Texas, Mid-South Synergy serves 23,000 members and 30,000 meters in a service territory covering parts of six counties in Central Texas. Mid-South initially installed DFA technology on ten distribution circuits and currently is installing DFA on ten more.

Pickwick Electric Cooperative Uses DFA to Avoid PQ Problems and Catastrophic Switch Failure

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March 2017

Pickwick Electric Cooperative (PEC) used Distribution Fault Anticipation (DFA) technology to perform condition-based maintenance on a capacitor bank with a failing vacuum switch, thereby avoiding power quality problems and potentially catastrophic switch failure. No conventional technology, including a remote communications system PEC uses to manage their capacitor banks, alerted PEC to the problem.

Like many utility companies, PEC applies switched and fixed capacitor banks on its distribution circuits. PEC's remote capacitor communications capabilities enable them to detect problems such as blown phase fuses. Such systems cannot, however, detect latent or incipient problems such as switch bounce or symptoms of partial loss of vacuum in a switch.

On 17 February 2017, the DFA device on one of PEC's circuits detected a three-phase capacitor bank switching off and, more importantly, detected that one of the bank's switches had experienced severe restrike during the operation. Restrike is a phenomenon that occurs when switch contacts open and interrupt the flow of current, but immediately thereafter fail to withstand the voltage across them and consequently allow unintended current to flow, typically for a very short period of time.

The subject capacitor bank is programmed to open and close daily. For several days following the severe restrike, the bank switched normally, with no indication of restrike. Then on 22 and 23 February, DFA again detected and reported severe restrike.

PEC readily identified which of the circuit's capacitor banks was experiencing the restrike, by comparing the DFA-reported kvar bank size to the nominal size of the banks known by PEC to be on the subject circuit. They further confirmed the identification of the specific bank by comparing DFA-reported switching times with times reported by the bank's controller via SCADA.

Based on the notice of severe restrike and identification of the affected bank, PEC visited the bank on the afternoon of 23 February. They found that the bank had a switch with partial loss of vacuum. They opened the bank's fuses to isolate the bank, pending full repair. This prevented multiple possible problems, including power quality events for PEC's members and potentially catastrophic failure of the switch itself. DFA provided the only notice that PEC had that any problem existed.

PEC is one of more than 150 local power companies that buy bulk power from the Tennessee Valley Authority (TVA). Both PEC and TVA were key participants in the long-term development of DFA technology. The latent switch problem described herein is one of multiple problems and latent failures that PEC has detected, diagnosed, and corrected using DFA technology. It is PEC's experience that DFA provides them with a level of awareness of their circuits that they do not get from their conventional technologies, and that better awareness enables improved operations and better service to their members.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the system-wide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance. No technology can detect all problems, but DFA provides a quantum step forward in the detection and diagnosis of many failures and incipient failures.

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Texas-based Power Solutions, LLC.

Headquartered in Selmer, Tennessee, Pickwick Electric Cooperative operates 2427 miles of distribution and serves 20,555 members in a service territory covering parts of five counties in Tennessee and Mississippi. Pickwick has been a key, long-term participant in the development of DFA technology.

Tree Limb Burns Down Line, Causes Outage

DFA Technology Could Have Prevented Damage, Outage

John Bowers, Pickwick Electric Cooperative
Carl L. Benner and Dr. B. Don Russell, Texas A&M University
Ashok Sundaram, Electric Power Research Institute

At 6:57 AM on the morning of November 2, 2004, an overcurrent fault tripped a three-phase pole-top recloser on a feeder at Pickwick Electric Cooperative's North Adamsville substation. The recloser closed back in normally and the fault did not persist. As a customer of TVA, Pickwick participates in the Distribution Fault Anticipation (DFA) project that EPRI is sponsoring at Texas A&M University. A DFA Prototype at North Adamsville substation recorded this fault and others discussed in this article.

Faults like this are not uncommon, and there did not appear to be anything out of the ordinary. An hour later, however, there was another fault, with the same characteristics. This time, the recloser tripped and reclosed twice, but again, did not lock out. Figure 1 shows the RMS phase current the DFA measured at the substation during this second episode.

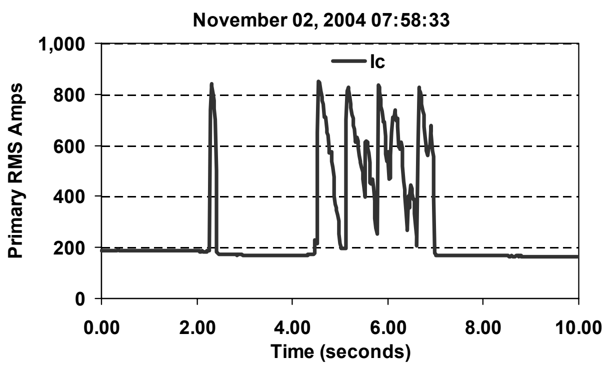

Figure 1. Second fault tripped recloser twice but did not lock out.

All was quiet for the next 16 hours. Then, shortly after midnight, another similar fault occurred. Over the next six hours, the fault recurred multiple times, tripping the recloser 11 more times. However, the faults were not close enough together in time to allow the recloser to lock out and isolate the problem. Then, at 6:19 AM, the fault became more persistent and locked out the recloser, during the episode illustrated in Figure 2. By this time, the recloser had tripped 17 times! The following list tabulates the individual interruptions:

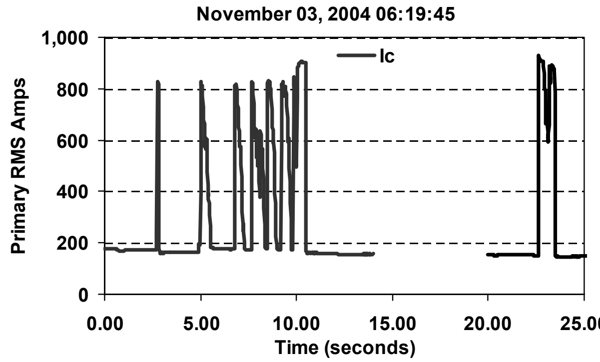

Figure 2. Final instance of fault locked out recloser.

Date	Time	Trips
11/02/2004	06:57:47	1
	07:58:33	2
11/03/2004	00:09:06	1
	00:16:48	1
	00:40:38	1
	00:40:53	1
	01:10:51	1
	01:12:37	1
	01:15:30	1
	03:24:47	1
	04:19:39	1
	04:30:36	1
	05:51:01	1
	06:19:45	3
	Total	17

The ensuing outage resulted in customer lights-out calls. Investigation revealed a broken tree limb that had burned down a span of line. 140 customers were without service for 62 minutes while the crew repaired the line.

The line was of standard single-phase construction, without crossarms. The phase conductor was mounted on pole-top insulators. The neutral conductor was mounted on standoffs several feet down the sides of the poles.

The crew found that a fork in the broken tree limb had hung on the phase conductor. The limb pulled the phase conductor down to within about two feet of the neutral conductor. The fork was in continuous contact with the phase conductor. Casual contact with the neutral occurred a few feet farther along the limb, causing the intermittent faults.

Figure 3. Tree limb tripped recloser 17 times and burned line down.

Figure 3 shows the offending tree limb. There is evidence of burning along about three feet of the limb's length. This would be consistent with the fork (left side of upper picture) hanging from the phase conductor and another position on the limb contacting the under-hung neutral conductor.

The DFA recorded each fault as it happened. The DFA currently is a research project and is not integrated into normal operations at Pickwick. Because a pole-top recloser operated, instead of the substation breaker, Pickwick had no indication of a problem until the lights-out calls that followed the burn-down.

If real-time DFA technology had been available to operations personnel, Pickwick would have dispatched a crew around 1:00 AM on November 3. Using information from the DFA, Pickwick personnel believe that they would have located the source of the problem within a few hours. They would have had time to take remedial action and could have avoided the burn down and the outage.

Bluebonnet Electric Uses DFA Technology to Detect Arrester Failure and Accelerate Response

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July 2016

Bluebonnet Electric Cooperative (BEC) recently used Distribution Fault Anticipation (DFA) technology to detect and locate a failed lightning arrester and initiate response by a line crew before receiving conventional notification of the failure. DFA enabled BEC to respond to this event sooner and with better diagnostic information.

BEC is one of six utility companies participating in the Texas Power Line-Caused Wildfire Mitigation project, a field demonstration effort supported by the Texas legislature. As part of that effort, BEC has instrumented fourteen distribution circuits with DFA technology. Instrumenting a circuit with DFA technology consists of installing a substation-based DFA device, which detects and warns of faults, failures, and other events along the length of the circuit.

During fair weather on the afternoon of 4 July 2016, a DFA-instrumented circuit experienced a short-circuit fault. BEC's conventional circuit protection properly detected and isolated the fault, blowing a fuse and interrupting service to a single member. Relying solely on conventional systems, BEC would have been unaware of this issue until a member reported an outage, which in this case did not happen for a full hour. As an aside, this was the only outage on this circuit for this entire day.

Electrical recordings by the substation-based DFA detected the fault and enabled determination that the likely cause was failure of a lightning arrester. BEC was otherwise unaware of the fault. The circuit in question is a long, rural circuit with more than 160 miles of total overhead line. The BEC control center used circuit model software to estimate the likely location of the fault and dispatch a line crew, informing the crew that the most likely cause was a failed arrester. The crew was en route when the dispatch control center received a "lights out" call from the affected member. Upon arrival on the scene, BEC's crew confirmed a blown fuse and failed arrester and effected appropriate repairs.

DFA technology enabled detection and identification of a failed arrester, thereby improving response.

BEC's proactive use of information from the DFA system enabled faster response and a shorter outage. In addition to the early notification, it generally is beneficial to know the likely cause of an outage, because identification of the cause of an outage sometimes can be quite challenging and time-consuming for the responding crew.

Beyond improving reliability, earlier awareness of failures and better diagnostic information about them can, in some cases, help mitigate fire hazards. The failure of a lightning arrester, for example, often draws an electrical arc in the air and expels superheated fragments that fall to the ground. Conventional technologies may not enable utility companies to detect failures and outages in a timely way, much less know details about their underlying causes. Although no technology will ever prevent all failures and risks, DFA technology appears to be able to provide quicker notification and better information, enabling an improved response.

DFA technology enables a utility to manage its power distribution system better, by providing awareness of line conditions and events not detected by conventional technologies. Each substation-installed DFA device monitors circuit currents and voltages continuously, via conventional CTs and PTs. DFA devices use embedded pattern-matching software to characterize and report electrical events, including events not detected by conventional means. DFA devices report line events to a master station server, which provides access to reports from the systemwide fleet of DFA devices. DFA reports conventional faults and also events that have not yet caused faults or affected customers. Awareness of adverse events and conditions enables preemptive action, directed repairs, and condition-based maintenance. No technology can eliminate all failures, but DFA provides a step forward in detecting and diagnosing many failures .

DFA technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, Inc. and is offered commercially by Power Solutions, Inc.

Headquartered in Bastrop, Texas, Bluebonnet Electric Cooperative serves more than 85,000 consumers in central Texas. Bluebonnet has instrumented fourteen distribution lines with DFA technology, in conjunction with the Texas Power Line-Caused Wildfire Mitigation project.

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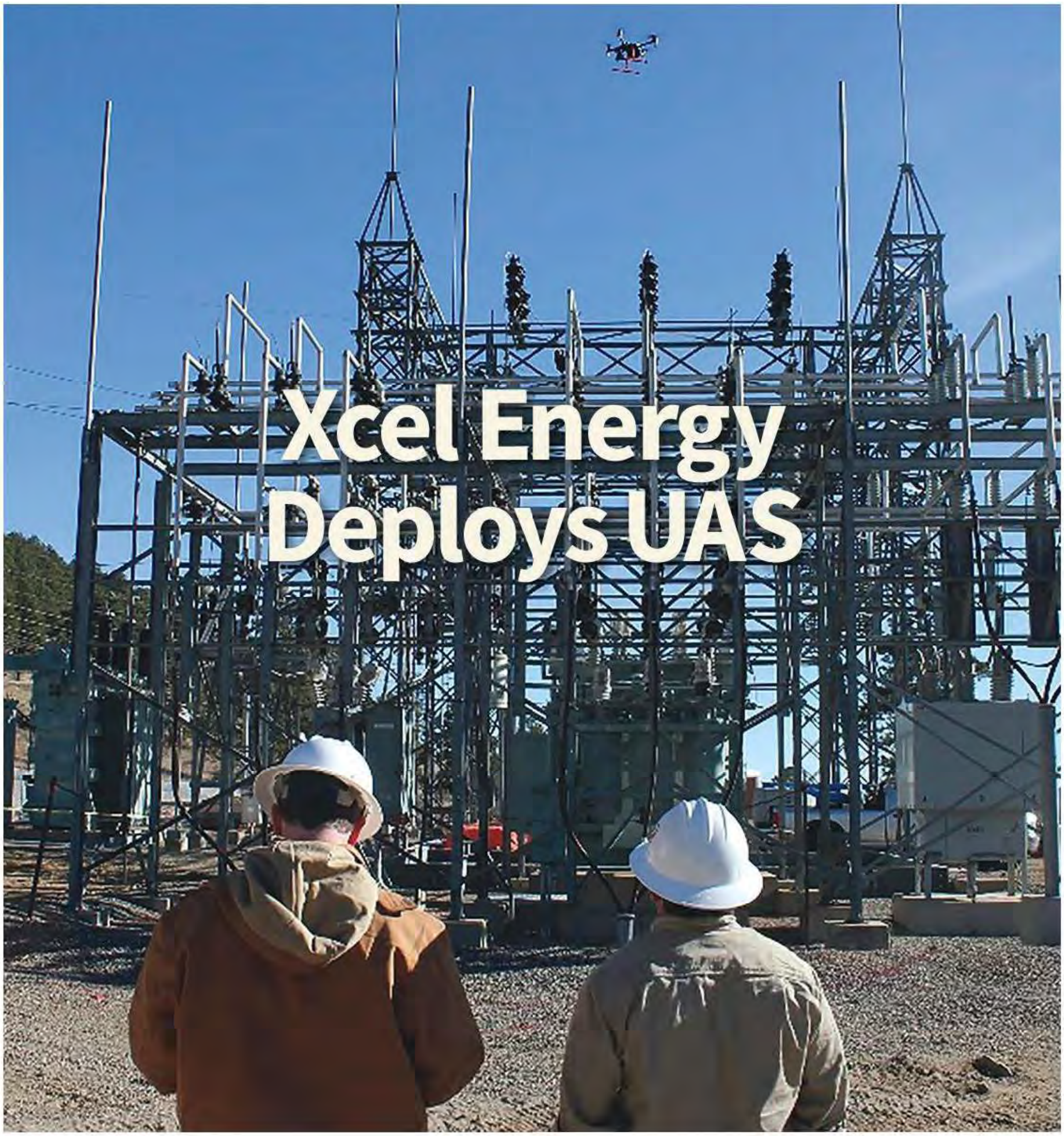


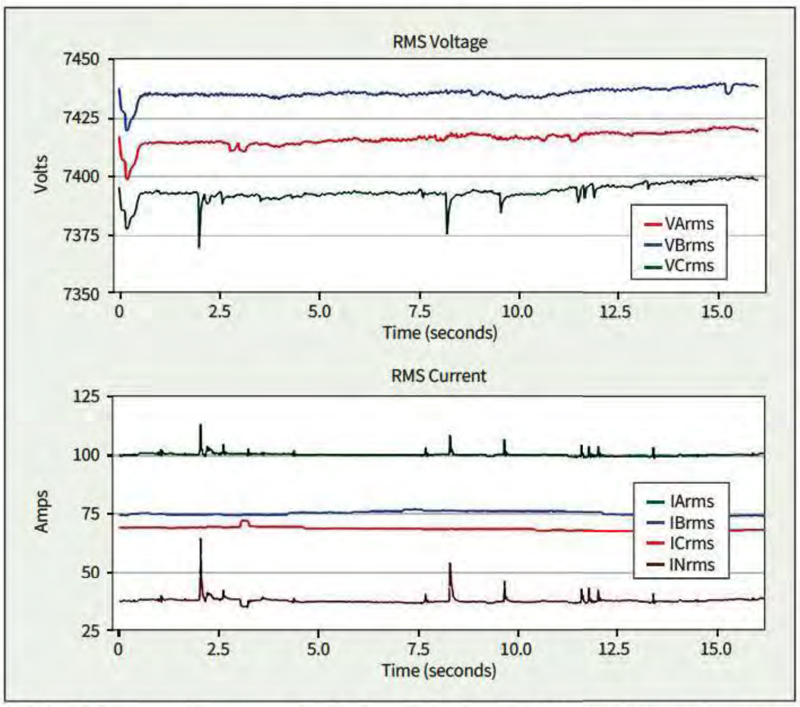
Fault Anticipation Improves Operations

Pedernales is improving the reliability and safety of its distribution system and reducing wildfire risk.

By **Robert A. Peterson**, Pedernales Electric Cooperative, and **Carl L. Benner** and **B. Don Russell**, Texas A&M University

Distribution utilities operate miles and miles of lines to serve large service territories. Knowing what is happening on those lines presents a real challenge. Pedernales Electric Cooperative and other utilities are improving the reliability and safety of their electric power distribution systems, using technology developed by Texas A&M University's College of Engineering. Known as distribution fault anticipation (DFA), the technology helps utilities to manage their systems better by giving them more awareness of what is happening on them.

Pedernales first began testing DFA in 2015, as part of a demonstration project known as the Texas Power Line-Caused Wildfire Mitigation project, supported by the Texas state legislature. As one of seven Texas utilities to participate in the project, Pedernales installed DFA monitoring on 11 distribution circuits. Pedernales and the other participants have used DFA to detect multiple line issues that otherwise could have started fires. Enhanced situational awareness increases crew efficiency and enables corrective actions that inherently improve service quality as well as reliability. Based on successful trials, Pedernales and several other utility companies have begun expanding their deployments of DFA, integrating DFA into their work flows and making DFA information available in their control centers.

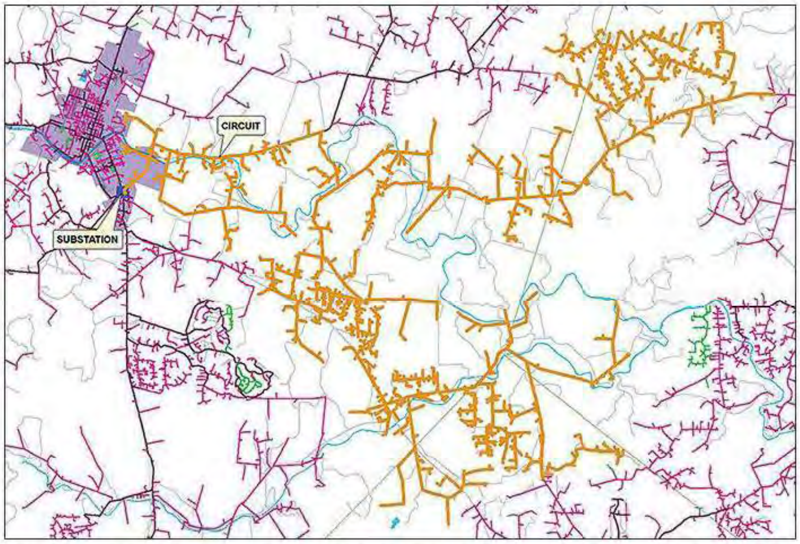


Incipient failures sometimes cause electrical manifestations that DFA reports hours, days or even weeks prior to catastrophic failure. Detection and reporting require specialized pattern-recognition algorithms and sensitive-data triggering relays that other conventional systems do not have.

Awareness Is Key

Knowing about a problem is the first step to correcting it. Pedernales uses 22,000 miles (35,400 km) of primarily overhead distribution lines to serve 300,000 meters across a service territory of 8100 sq miles (20,100 sq km). Unlike transmission lines — which generally run point to point or, perhaps, have a tee or two — distribution circuits have complex topologies with many branches and countless components. Distribution utilities cannot know the current condition of every component. A utility often learns of outages and other problems from customer reports.

Supervisory control and data acquisition (SCADA) and other conventional technologies provide notification of gross events, such as when a high current fault trips a substation circuit breaker. Smart meters can provide additional information, such as blink counts and targeted pings. DFA research and field demonstration programs have shown incipient



Distribution circuits have complex topologies and span wide geographic areas. Pedernales and other utilities use DFA to learn of events and then use DFA-reported parameters synergistically with other tools to track them down.

failures of line components sometimes cause low-amplitude electrical changes, measurable from substation sensors; however, SCADA and smart meters are not designed to detect these changes and, thus, cannot alert the utility to such problems.

Electric service is fundamental to modern society, but despite prudent construction standards and operational procedures, electrical events can cause fires. DFA technology provides awareness of some line conditions capable of starting fires, and awareness enables action. The Texas legislature supported a field demonstration project to document how utilities can use Texas A&M Engineering's DFA technology to reduce wildfire-ignition risk.

Participants installed DFA on select circuits and worked with Texas A&M Engineering to become familiar with the technology. The utilities were charged with documenting examples of DFA-detected events of which they otherwise would have been unaware, paying special attention to events with ignition potential.

Branch on a Line

An early success at Pedernales involved a detached tree branch that hung on a remote single-phase tap on a long rural circuit. The 12.5-kV circuit has more than 150 miles (240 km) of circuit conductor and serves more than 1000 meters.

Most faults result from temporary conditions and can be

The Distribution Fault Anticipation System

Texas A&M University's College of Engineering has been developing distribution fault anticipation (DFA) technology since the late 1990s. Initially funded largely by the Electric Power Research Institute (EPRI), DFA research pursued the fundamental premise that line events, including incipient failures, cause measurable changes in line currents and voltages. Sensitively triggered, high-capacity, high-fidelity waveform recorders were installed in substations to monitor line currents and voltages of 70 distribution circuits during routine operations. These and subsequent installations have provided the largest extant database of high-fidelity waveforms from non-staged faults and other circuit events, with more than 1000 circuit-years of data. Study of that database enabled researchers to identify characteristics of many line events and implement algorithms to recognize and report them.

The state of Texas and other entities have provided substantial support to the development of DFA technology. DFA originally was an acronym for distribution fault anticipation, but the evolving development of the DFA technology resulted in its providing functionality that goes well beyond anticipation of faults. Power Solutions, LLC provides DFA technology commercially, under license from EPRI.

DFA technology is applied with a fleet of DFA monitoring devices and a central DFA master station. Each DFA device is installed in a 19-inch rack in a substation, monitors a single distribution circuit via conventional current transformers and potential transformers, and connects to a DFA master station at a central location through secure internet.

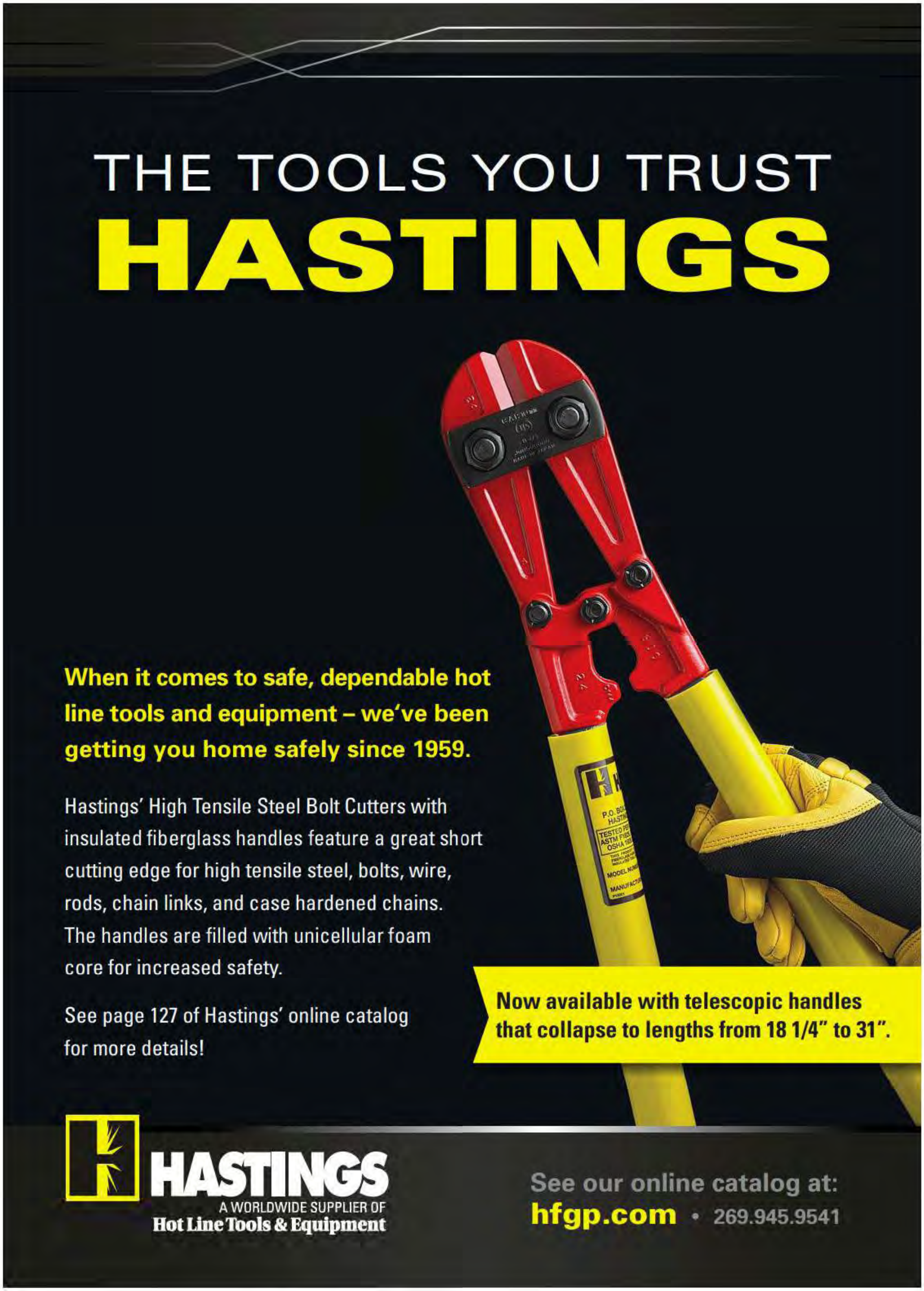
The DFA master station is a server computer with custom DFA software. It retrieves reports from the fleet of DFA devices and makes the reports available to users through a secure, password-protected website. The secret-sauce software that analyzes electrical waveforms to characterize line events resides in each circuit's DFA device. The system architecture is intended to make the system scalable because the centralized master station does not have to perform complex pattern-recognition computations. As algorithms are improved over time, the master station pushes new software to the fleet of devices.

cleared by momentary trip-and-close operations, with no action needed by the utility. However, certain incipient failure conditions also cause momentary interruptions, which temporarily clear the faults but do not heal the underlying conditions. DFA field installations have documented numerous instances in which line conditions cause recurrent faults. Sometimes the faults are separated by minutes or hours, sometimes by days or weeks. Each fault episode is cleared by a momentary trip-and-close operation, but additional faults continue until the underlying condition is corrected, or until it evolves into a permanent fault and perhaps causes damage to facilities.

In the subject case, the tree branch caused multiple faults over a period of several hours during a storm. Each fault was cleared by a trip/close of a hydraulic recloser, with no operation of the substation breaker. Pedernales received no customer calls and ordinarily would have taken no action. By recording and analyzing substation-measured current-transformer and potential-transformer waveforms for this circuit, DFA software characterized each fault. Because DFA maintains a fault history and compares each new fault to that history, when it detects multiple instances of what appear to be the same fault, it reports a recurrent fault cluster. In the subject case, DFA reported the branch-caused faults in this way, resulting in an investigation by Pedernales.

Like many distribution circuits, the subject circuit has many branches. Such a topology means predicting location based

Branches on lines can cause repeated faults and momentary interruptions, degrading service quality and representing risk of ignition. Multiple participants in the Texas Power Line-Caused Wildfire Mitigation project have used DFA to detect and correct such conditions.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solely on fault current amplitude can result in multiple possible locations, resulting in inefficient patrols. Small fault currents generally result in more possible locations than large fault currents. Knowing which recloser is responding to the faults can focus patrols, but many reclosers are unmonitored, so the identity of the recloser must be inferred rather than determined directly by interrogating the recloser.

In the subject case, the recurrent faults drew a mere 300 A, so current-based prediction resulted in a significant number of potential locations. DFA reported each trip and close involved a single-phase recloser that temporarily interrupted approximately 15% of the affected phase's load. After using this information to eliminate some of the circuit's reclosers from consideration, Pedernales used its automated meter reading system to get blink counts from meters downstream of the suspected recloser and was able to confirm which recloser had been operating. Knowing this enabled a targeted patrol to locate the branch hanging on the line.

Without DFA, Pedernales likely would not have known about the problem. Once identified and located, correcting the problem was simple — remove the branch. The targeted patrol minimized crew time, and conductor damage was minimal. Had the branch remained undiscovered, it likely would have caused additional blinks and damaged the conductor. The branch on the line could have ignited, fallen free to the ground and started a fire. A more likely scenario would be progressive conductor damage, eventually dropping the conductor to the ground and potentially igniting a fire in that way.

Texas A&M Engineering has documented other recurrent faults, left uncorrected, that burned down lines or destroyed line equipment, causing lengthy outages; causes have included vegetation and damaged equipment. One that was very similar to the subject event involved a detached branch that eventually burned the line down. Despite more than a dozen trip-and-close operations from this branch, the utility in that case received no customer calls until the burned-down line caused a sustained outage.

Capacitor Management

With a fleet of more 530 capacitor banks to help maintain voltage and reactive power support, Pedernales has used DFA to detect and respond to multiple capacitor issues. Annual maintenance of banks detects failures such as blown fuses, but the annual nature of the cycle means a blown fuse can persist for months before being discovered. Other capacitor problems, such as internal arcing or partial loss of vacuum in a switch, need more timely response. In addition to multiple routine capacitor issues, DFA enabled Pedernales to correct a problem in which the close and open contacts for one phase of a bank had their leads swapped, causing the phase to come on when it was supposed to go off and vice versa. The utility has seen substantial value in using DFA for better oversight of its fleet of capacitor banks.

Unusual Events

DFA has made Pedernales aware of

Wherever utilities face a challenge, we are there.

Think of Marmon Utility as a family of solution providers and risk-reducers for utilities across the country and around the world. The common attribute among our customers is their reliance on us for a seamless product-service continuum that combines (and coordinates) engineering, project design, delivery, installation, training, testing, monitoring and more capabilities than one ad can describe. Look into Marmon Utility, and see how reliability goes to work.

MOLDED PRODUCTS

Hendrix Molded Products, known for high density polyethylene insulators, invented by Bill Hendrix in 1961. Today Molded Products include designs for different line/pole configurations that utilities confront in the field.

AERIAL CABLE SYSTEMS

Hendrix Aerial Cable Systems, proven to harden distribution circuits, reduce outages, minimize environmental impact, protect wildlife, and preserve utility operational and financial performance.

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Hendrix medium voltage and Kerite medium/high voltage and specialty cable, engineered to the highest standards of reliability and served by experienced teams who facilitate every stage ofthe project, from design to testing and monitoring.

Hendrix kerite

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Maximizing Use of DFA Technology

Pedernales Electric Cooperative synergistically uses other tools to get the most benefit from distribution fault anticipation (DFA) and plans to use these more as it deploys DFA more broadly. The circuit model software can help to predict fault locations based on measured fault current amplitude. Its AMR system enables daily blink counts to determine which of a circuit's multiple reclosers is operating in response to recurrent faults. The AMR system also enables pings of selected meters to confirm suspected outages. AMR system constraints generally make it infeasible to ping on a circuit-wide basis. However, pinging a small number of meters — preselected based on DFA and circuit model information — can provide timely, useful information for problem resolution.

As an example of synergistic use, consider a scenario in which DFA reports a recurrent fault-causing intermittent momentary trip-and-close operations of an unmonitored recloser on a long circuit with multiple reclosers. DFA parameters can be used to infer which recloser likely is operating. AMR blink counts can be used to confirm the recloser. Circuit model software, using DFA-provided fault amplitude, can be used to predict location. Patrols then can be targeted beyond the recloser that is operating and further targeted by the prediction based on fault current amplitude. In such a case, DFA provides the most important element — awareness of the problem — then the multiple tools are used together to locate and enable repairs.

line events that are unusual but not recognized. One such event caused 23 single-phase current pulses, each 50 A to 100 A in magnitude, over a period of 13 seconds. The pulses were at regular time intervals, making the utility almost certain some sort of mechanical control was involved. The pulses were too large for a motor start or other individual load. Each pulse caused a voltage dip but lasted only about a cycle and, as measured from the substation, dipped the voltage by no more than 3.5%.

The cause of the pulses was not determined, and the event has not recurred. Still, knowing of such events has value. Customers sometimes report power problems about which the utility has no knowledge. Such problems can be difficult to diagnose. Investigations consume significant manpower and do not always lead to resolution. Having more information, from a sensitive continuous monitoring system such as DFA, can help the investigation. Similarly, when investigating customer problems, sometimes knowing the circuit is not experiencing events can have value and avoid wasting manpower looking for problems in places they do not exist.

Shared Experiences

A user group facilitated by Texas A&M Engineering has enabled Pedernales and other project participants to share their own experiences and gain from the experiences of others. Together, the group has documented a wide array of events:

- Detection and location of a broken insulator that resulted in a conductor heavily charring a wood crossarm
- Detection and location of arcing internal to a capacitor
- Detection, location and repair of multiple routine outages, without customer calls
- Detection and location of an intact tree intermittently pushing conductors together
- Detection and location of catastrophically failed lightning arresters
- Detection and location of an arc-tracked capacitor fuse barrel
- Detection and location of multiple instances of fault-induced conductor slap.

Most of these events represent the potential for ignition, given the right atmospheric conditions and available fuel loads. For each, the key DFA benefit was that it informed the utility that the problem existed.

Moving Forward

Distribution circuits have complex topologies, consisting of long lines and large numbers of components, spread over a large area. Situational awareness for such circuits is challenging. No technology detects all events, but Texas A&M Engineering's DFA has shown the ability to inform utilities of many events of which they otherwise were unaware. Pedernales and other utilities are using Texas A&M Engineering's DFA technology to improve situational awareness, thereby reducing fire ignition risk, making crews more efficient and improving the reliability and quality of electric service delivery. Based on successful trials, Pedernales and several other utility companies have begun expanding their deployments of DFA, integrating DFA into their work flows, and making DFA information available in their control centers. TDW

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Carl L. Benner (carl.benner@tamu.edu) is a research associate professor in Texas A&M University's electrical and computer engineering department. He is an IEEE Fellow and holds BSEE and MSEE degrees from Texas A&M. Benner is a registered professional engineer in the state of Texas, and is a member of IEEE Power & Energy Society, the Industry Applications Society and CIGRE.

B. Don Russell (bdrussell@tamu.edu) is a distinguished professor in Texas A&M University's electrical and computer engineering department and director of the power system automation laboratory. He is past president of the IEEE Power & Energy Society and an IEEE Fellow. He is a registered professional engineer in the state of Texas and vice president of the CIGRE U.S. national committee.

For more information:

Pedernales Electric Cooperative | www.pec.coop
Power Solutions, LLC | www.powersolutionsllc.us
Texas A&M Engineering | engineering.tamu.edu

DFA Technology System Manual

Power Solutions LLC, a Texas Limited Liability Company

Table of Contents

Power Solutions LLC
A Texas Limited Liability Company

1 Glossary of Terms

The following definitions apply to all parts of the DFA Technology System Manual. These definitions apply without regard to capitalization.

DFA Technology – Distribution Fault Anticipation technology.

DFA Technology System – A hardware and software system for the practice of DFA Technology and consisting of a DFA Master Station and a fleet of one or more DFA Devices. Where this document refers simply to "DFA," that means the DFA Technology System, except where context clearly indicates a different meaning.

DFA Master Station – DFA Master Station Hardware, loaded with DFA Master Station Software and acting as a fundamental component of the DFA Technology System, as more fully described in chapter 3, "Components of the DFA Technology System."

DFA Master Station Software – Proprietary, DFA Technology System-specific software, provided by Power Solutions, necessary for the DFA Master Station to perform its intended function, and not including operating system software or any other third-party software.

DFA Master Station Hardware – An appropriately specified computer or system of computers, not proprietary to Power Solutions, on which DFA Master Station Software is installed and used. DFA Master Station Hardware may consist of a single computer or of multiple computers configured to operate as a functional unit.

DFA Master Station Service – A fee-based service that provides the functionality of a DFA Master Station, as more fully described in chapter 3, "Components of the DFA Technology System."

DFA Device – A platform, provided by Power Solutions and consisting of DFA Device Hardware and DFA Device Software, acting as a fundamental component of the DFA Technology System, as more fully described in chapter 3, "Components of the DFA Technology System"; may be marketed under names such as DFA-Plus Device.

DFA Device Software – Proprietary, DFA Technology System-specific software, provided by Power Solutions, embedded in and running on DFA Device Hardware. DFA Device Software is available only as an integral component of DFA Devices, not as standalone software.

DFA Device Hardware – Hardware of proprietary design, to provide the sensing, computing, communications, and other requirements for running DFA Device Software; does not include power supplies, wiring, communications equipment, or other apparatus, except as embedded in and integral to the DFA Device Hardware itself.

DFA Software – Propriety software that is an integral part of the operation of the DFA Technology System and consisting of DFA Device Software, DFA Master Station Software, or both, as implied by context.

DFA Website – A browser-based website that provides each Customer with password-protected access to DFA Data from that Customer's fleet of DFA Devices and other functions.

DFA Fleet Management – A function of the DFA Technology System, whereby a DFA Master Station provides oversight and management functions for a fleet of DFA Devices.

Distribution Circuit or simply Circuit – A three-phase electrical circuit, operating at distribution voltage (i.e., from 1 kV to 35 kV), for conducting electricity from a distribution substation to electric loads; also known as a feeder or a line.

Distribution Company, or DISCO – An electric power distribution company or an entity performing power delivery functions typically ascribed to an electric power distribution company.

DFA Data – Electrical current and voltage waveform data, digitized by DFA Devices, and reports generated by DFA Software acting on that waveform data.

Customer – An end user of the DFA Technology System; typically, a Distribution Company; excludes agents and resellers.

DFA Analysis Service – A fee-based service under which Power Solutions assists the Customer in the interpretation and use of DFA Data, on a case-by-case basis, upon request by Customer, as more fully described in chapter 4, "DFA Analysis Service."

Power Solutions – Power Solutions LLC, a Texas limited liability company.

2 Principle of Operation, Intended Use and Limitations

This chapter on "Principle of Operation, Intended Use and Limitations" uses terms as defined in the accompanying "Glossary of Terms."

The fundamental principle underlying the operation of the DFA Technology System (or simply "DFA") is the fact that electrical events occurring on a Circuit affect the currents and voltages of that Circuit, and therefore that the behavior of those currents and voltages represents events on the Circuit. The starting of a motor, the switching of a capacitor bank, and the occurrence of a short-circuit fault are examples of events that affect a Circuit's currents and voltages. Each DFA Device senses current and voltage waveforms, detects and records anomalies in those waveforms, and uses proprietary software to analyze those recorded waveforms to infer Circuit events, as further described in chapter 3, "Components of the DFA Technology System."

The intended use of DFA is to provide improved awareness, or visibility, of Circuit events. DFA is most effective when used in concert with other data and information sources available to trained utility operators and engineers. DFA does not replace all functions of other data sources but rather complements them. No device or system, including DFA, will report all Circuit events and or do so without error.

DFA is considerably more sensitive than conventional systems, such as SCADA or protection devices, but physics dictates practical limits to sensitivity. The amplitude and other characteristics of waveform variations resulting from a given Circuit event depend on the nature of the event and on external factors, such as weather. There are inherent tradeoffs between sensitive detection and avoidance of false alarms. Based on industry input, DFA biases toward minimizing false alarms.

The Customer should make all decisions regarding how or whether to act based upon all available information, from DFA and other sources, and upon the Customer's inherently superior knowledge of its own Circuits. It is not expected that either the Customer or Power Solutions will ever review, investigate, or act upon all data from the DFA Technology System. Power Solutions will use commercially reasonable best efforts to respond to Customer requests for DFA Analysis Service within the timeliness and other parameters outlined in the chapter of this manual that describes that service.

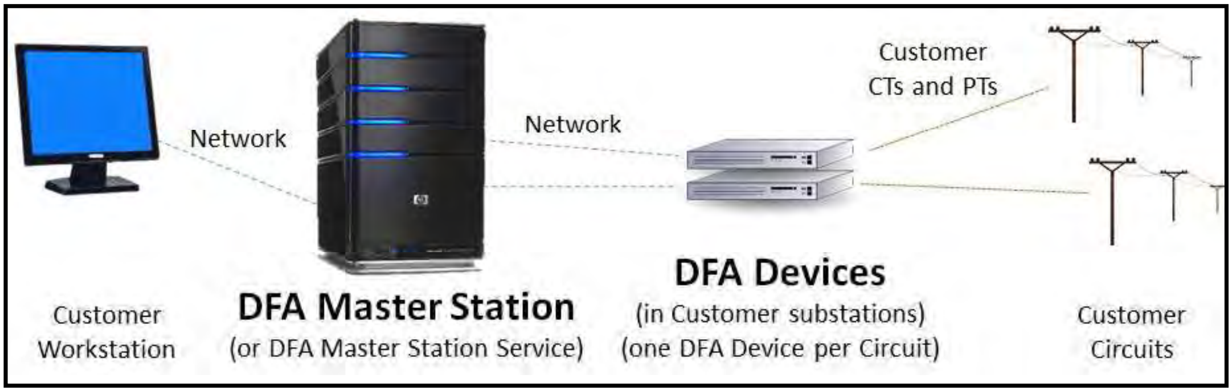
3 Components of the DFA Technology System

This chapter on "Components of the DFA Technology System" uses terms as defined in the accompanying "Glossary of Terms."

The DFA Technology System consists of two fundamental components, DFA Devices and a DFA Master Station, both of which are necessary to the basic use of the DFA Technology System.

Issues related to cybersecurity safeguards are discussed in chapter 8, "DFA Cybersecurity and Software Updates and Maintenance."

The following high-level schematic illustrates the relationship between the basic components. The Customer is fully responsible for all items other than the DFA Master Station and DFA Devices. A properly functioning network connection between each DFA Device and the DFA Master Station is necessary for operation of the DFA Technology System.



High-Level Schematic of the DFA Technology System

3.1 DFA Devices

DFA Devices monitor electrical waveforms, detect anomalies, and generate reports by using proprietary DFA Device Software to process those waveform anomalies and thereby infer Circuit events. Each DFA Device is intended to perform this function for a single Circuit. Inputs to each DFA Device are the secondary leads of a Circuit's conventional, three-phase current and potential transformers (CTs and PTs). Non-traditional current and voltage sensors have characteristic that make them inherently unsuitable as inputs to sensitive applications such as DFA. DFA Device Software operates on DFA Device Hardware and is not intended for use except in the context of DFA Device Hardware.

Each DFA Device communicates with and sends DFA Data to a DFA Master Station via conventional TCP/IP communications over Internet/intranet network service, which is provided by the Customer. Protocols such as SCADA, DNP, or IEC61850 are not suitable. Each DFA Device has a finite capacity of semi-permanent data storage for DFA Data and other information necessary to the function of the DFA Device. Housekeeping functions in the DFA Device Software manage available storage, including deletion of DFA Data, without warning or notice, as needed to maintain sufficient free space for ongoing operation of the DFA Device.

3.2 DFA Master Station and DFA Master Station Service

The DFA Master Station performs a variety of functions, including the following:

1. It retrieves DFA Data from the Customer's fleet of DFA Devices and retains that data in accordance with chapter 9, "DFA Data Backup and Retention."
2. It provides the DFA Website, which provides the Customer with secure, browser-based, password-protected access to the Customer's DFA Data.
3. It provides DFA Fleet Management functions for the Customer's fleet of DFA Devices. DFA Fleet Management relies upon a properly functioning, Customer-provided network connection between each of the Customer's DFA Devices and the DFA Master Station. DFA Fleet Management functions include:
    a. Enabling the Customer to monitor the health of its fleet of DFA Devices, including detection of various problems with the DFA Devices themselves and with network connections from the DFA Devices to the DFA Master Station. For example, a lack of communications between a DFA Device and the DFA Master Station for an extended period of time may indicate a problem with network service or with the DFA Device itself.
    b. Deploying updated DFA Device Software to each DFA Device in the fleet, as such updates become available.

Where Power Solutions provides the Customer with DFA Master Station Service, it provides Power Solutions personnel with access similar to the access it provides to Customer personnel.

The above is not represented as a comprehensive list or as containing all details about DFA Master Station functions, but rather provides the highlights of the function of the DFA Master Station.

The Customer has two options for obtaining DFA Master Station functionality, as described below. The difference is primarily one of ownership and operation of the DFA Master Station, rather than one of functionality.

3.2.1 Customer-owned DFA Master Station

Under this option, the Customer purchases, configures, owns, operates, and maintains its own DFA Master Station Hardware and loads it with proprietary DFA Master Station Software provided by Power Solutions. As a variant of this option, the Customer may enter into an agreement with Power Solutions under which Power Solutions purchases, pre-configures, and delivers to the Customer a "turn-key" DFA Master Station. In either event, the Customer owns the DFA Master Station Hardware, and Power Solutions' responsibility for the DFA Hardware is limited to the provisions of chapter 6, "Statement of Limited Warranty and Limitations of Remedies."

PSLLC intends to offer Customer-owned DFA Master Station at some point in the future but currently does not do so.

3.2.2 DFA Master Station Service

Under this option, the Customer does not own or operate a DFA Master Station. Instead Power Solutions provides equivalent DFA Master Station functionality to the Customer as a fee-based service, known as DFA Master Station Service. Power Solutions may accomplish this by owning and operating a physical DFA Master Station at its own facilities or through the use of an owned or leased collocated server (for example, Rackspace) or a cloud-based service (for example, Amazon Web Services), which are collectively referred to herein as "Cloud Hosting Providers." Power Solutions maintains multiple Customers' DFA Data on the same DFA Master Station. Each Customer accesses only its own DFA Data, via the DFA Website. Power Solutions has access to all Customers' DFA Data, subject to terms more fully described in "Privacy and Consent to Use Data Policy."

In the event that Power Solutions, in the future, stops providing DFA Master Station Service, Power Solutions will offer to provide DFA Master Station Software to Customer under then-prevailing commercial terms and pricing.

4 DFA Analysis Service

This chapter on "DFA Analysis Service" uses terms as defined in the accompanying "Glossary of Terms."

DFA Analysis Service is a fee-based service under which Power Solutions helps the Customer analyze and understand the Customer's DFA Data and related Circuit events more fully than possible than with the propriety, automated DFA Technology software alone.

The Customer initiates requests for DFA Analysis Service on a case-by-case basis. A typical request might involve a Customer's receiving a DFA-generated report of a Circuit event and requesting assistance to interpret it. Another typical request might involve a Customer's experiencing trouble, of unknown cause, and requesting assistance in the use of DFA Data to help diagnose the issue.

DFA Analysis Service typically consists of a dialogue between Power Solutions personnel and Customer personnel and generally occurs telephonically or via electronic mail (email). DFA Analysis Service normally is provided during normal business hours at Power Solutions offices in Texas.

Optimal understanding of Circuit events requires the Customer's inherently superior knowledge of its own Circuits, practices, and events. For example, the Customer may know of special loads on a particular Circuit, or of actions field crews have taken. As another example, the Customer's outage logs or other internal records may contain information concerning trouble calls. The efficiency and effectiveness of DFA Analysis Service depends on the Customer's timely provision of accurate, relevant information.

In the course of providing DFA Analysis Service, discussions often arise regarding courses of action that the Customer might take. Power Solutions may suggest possible options to the Customer, but all decisions related to whether and how to act are the Customer's responsibility and are to be based on the Customer's use of sound operations and engineering judgement, experience, and superior knowledge of its own Circuits, priorities, and prevailing conditions.

Effective provision of DFA Analysis Service requires that Power Solutions have full, direct access to Customer's DFA Data. If Power Solutions provides DFA Master Station Service to the Customer, the required access is inherently available. If the Customer owns its own DFA Master Station, Power Solutions strongly recommends that the Customer provide Power Solutions direct access to that DFA Master Station. Lack of full access substantially impedes the provision of DFA Analysis Service.

As a practical matter, it should be recognized that:

1. It is not feasible for either Customer personnel or Power Solutions personnel to review or act upon all DFA Data.
2. Not all cases that are reviewed will lead to correct conclusions or outcomes.
3. The Customer's active engagement and timely provision of information is key to achieving optimal benefits from DFA Analysis Service.

5 Customer Responsibilities

This chapter on "Customer Responsibilities" uses terms as defined in the accompanying "Glossary of Terms," and outlines some of the basic responsibilities inherently borne by the Customer.

The Customer is responsible for all aspects of installation and commissioning DFA Devices in a suitable environment, and for provision, installation, and proper wiring of conventional CTs and PTs, battery-backed unit power, and Internet service to each DFA Device.

The Customer is responsible for assigning properly trained personnel to review DFA Data on a regular basis. Customer personnel who will use the DFA Technology System should read and understand all pertinent documentation and understand the operation of the DFA Technology System prior to use.

The Customer is responsible for making all decisions regarding how or whether to act on DFA Data. This remains true in the event that Power Solutions provides DFA Analysis Service and/or discusses possible actions with Customer personnel.

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6 Statement of Limited Warranty and Limitations of Remedies

This "Statement of Limited Warranty and Limitations of Remedies" uses terms as defined in the accompanying "Glossary of Terms."

Subject to the accompanying "Customer Responsibilities," Power Solutions makes the following "Limited Warranty":

1. Hardware.

   a. DFA Device Hardware. Power Solutions expressly warrants that all DFA Device Hardware will be delivered free from defects in material and workmanship.

   b. DFA Master Station Hardware. Power Solutions makes no warranty as to DFA Master Station Hardware. As defined in the "Glossary of Terms" and described in more detail in chapter 3, "Components of the DFA Technology System," DFA Master Station Hardware is not proprietary to Power Solutions and is not customarily provided by Power Solutions. In the event that Power Solutions purchases third-party computer hardware and configures it as DFA Master Station Hardware for turn-key delivery to Customer, Power Solutions will "pass through" to the Customer warranties of the manufacturer(s) of said third-party computer hardware, to the extent that Power Solutions has the right to do so ("Pass-Through Warranty").

2. Software.

   a. DFA Device Software. Power Solutions expressly warrants that all DFA Device Software will operate substantially in accordance with chapter 2, "Principle of Operation, Intended Use and Limitations" and any instructions or manuals that exist or may exist in the future.

   b. DFA Master Station Software. Power Solutions expressly warrants that all DFA Master Station Software will operate substantially in accordance with chapter 2, "Principle of Operation, Intended Use and Limitations" and any instructions or manuals that exist or may exist in the future.

3. DFA Master Station Service. In the event that the Customer opts for the DFA Master Station Service (see sub-section 3.2.2 in chapter 3, "Components of the DFA Technology System"), except for the limited warranty of the DFA Master Station Software (stated above), Power Solutions makes no warranty regarding the services provided by any Cloud Hosting Provider. By way of example and not limitation, Power Solutions makes no warranty regarding: (i) the temporary or total loss of Internet access, (ii) the partial or total loss of DFA Data hosted by Power Solutions or by a Cloud Hosting Provider, and or (iii) the partial or total breach of the Customer's privacy.

Duration of the Limited Warranty. The Limited Warranty shall apply for a limited period that will terminate on the earlier of: (i) eighteen (18) months from the delivery of the shipment; or (ii) twelve (12) months from the date the product is installed for use. The limited period shall be extended upon the purchase of an extended warranty period.

Voiding of Limited Warranty. The Limited Warranty shall be voided upon the occurrence of any of the following events: (i) damage to the products resulting from improper storage; (ii) damage to the products caused by misuse, disasters (fire, flood, etc.), or tampering; and (iii) damage to the products resulting from repairs performed by service providers not approved by Power Solutions.

Exclusions from the Limited Warranty. The Limited Warranty shall not apply to (i) any add-on devices and or products; (ii) the design of any system prepared by any service provider or reseller; or (iii) the installation of any system by any service provider or reseller.

Disclaimer of Warranty and Limitations of Remedies. THE LIMITED WARRANTIES SET FORTH HEREIN ARE IN LIEU OF ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, WHICH ARE HEREBY DISCLAIMED AND EXCLUDED BY POWER SOLUTIONS, INCLUDING WITHOUT LIMITATION, ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR USE. BY WAY OF EXAMPLE AND NOT LIMITATION, EXCEPT AS SPECIFICALLY SET FORTH HEREIN, POWER SOLUTIONS MAKES NO WARRANTY AND SHALL NOT BE LIABLE FOR (I) THE MECHANICAL BREAKDOWN OF ANY COMPONENT OF THE DFA TECHNOLOGY SYSTEM, (II) MALFUNCTION OF ANY SOFTWARE COMPONENT OF THE DFA TECHNOLOGY SYSTEM, (III) TEMPORARY OR TOTAL LOSS OF INTERNET ACCESS AT ANY LEVEL, (IV) THE PARTIAL OR TOTAL LOSS OF DFA DATA HOSTED BY DFA MASTER STATION OR DFA MASTER STATION SERVICE AND/OR (V) THE PARTIAL OR TOTAL BREACH OF THE CUSTOMER'S PRIVACY REGARDING THE DFA DATA.

THE SOLE AND EXCLUSIVE REMEDIES FOR BREACH OF ANY AND ALL WARRANTIES AND THE SOLE REMEDIES FOR POWER SOLUTIONS' LIABILITY OF ANY KIND (INCLUDING LIABILITY FOR NEGLIGENCE) WITH RESPECT TO THE PRODUCT SHALL BE LIMITED TO EITHER REPAIR OR REPLACEMENT OF A DEFECTIVE ITEM OF PRODUCT AT THE SOLE OPTION OF POWER SOLUTIONS. IN NO EVENT SHALL POWER SOLUTIONS' LIABILITY FOR DAMAGES AND OR INJURIES INCLUDE LOST PROFITS AND ANY SPECIAL, INDIRECT, INCIDENTAL, OR CONSEQUENTIAL LOSSES OR DAMAGES, EVEN IF THE SELLER SHALL HAVE BEEN ADVISED OF THE POSSIBILITY OF SUCH POTENTIAL LOSS OR DAMAGE.

IF ANY PRODUCT DOES NOT CONFORM TO THIS LIMITED WARRANTY, THE CUSTOMER SHALL NOTIFY THE SELLER OF SUCH FAILURE, OBTAIN A RETURN MERCHANDISE AUTHORIZATION ("RMA"), AND SHIP IT TO POWER SOLUTIONS, AT AN ADDRESS, IN TEXAS, DESIGNATED BY SELLER, AT THE CUSTOMER'S EXPENSE. THE RMA MAY BE OBTAINED BY EMAIL FROM SELLER. AT ITS SOLE OPTION, POWER SOLUTIONS MAY REPAIR AND REPLACE THE DEFECTIVE PART, THEN RETURN IT TO THE CUSTOMER AT POWER SOLUTIONS' EXPENSE. ANY PRODUCT REPAIR OR REPLACEMENT SHALL BE COVERED BY THIS WARRANTY FOR THE LONGER OF ONE (1) YEAR FROM THE DATE OF REPAIR OR THE REMAINDER OF THE ORIGINAL WARRANTY PERIOD.

IF POWER SOLUTIONS FAILS TO REPLACE OR REPAIR AS AFORESAID, OR REACH A RESOLUTION ACCEPTABLE TO THE CUSTOMER, THEN POWER SOLUTIONS' ENTIRE LIABILITY SHALL NOT EXCEED THE ENTIRE AMOUNT PAID TO POWER SOLUTIONS BY CUSTOMER FOR THE PRODUCT IN

QUESTION, AND AS STATED ABOVE, IN NO EVENT SHALL POWER SOLUTIONS' LIABILITY OF ANY KIND INCLUDE ANY SPECIAL, INDIRECT, INCIDENTAL, OR CONSEQUENTIAL LOSSES OR DAMAGES, EVEN IF THE SELLER SHALL HAVE BEEN ADVISED OF THE POSSIBILITY OF SUCH POTENTIAL LOSS OR DAMAGE.

7 Privacy and Consent to Use Data Policy

This "Privacy and Consent to Use Data Policy" uses terms as defined in the accompanying "Glossary of Terms."

Power Solutions recognizes and respects its Customers' right to privacy. By purchasing, installing, accessing or using the DFA Master Station Service, Customer expressly consents to Power Solutions' collection, processing and use of the Customer's data according to this "Privacy and Consent to Use Data Policy." Power Solutions may share the Customer's data, as defined below, with its subsidiaries and affiliates, solely as described herein.

Through the remainder of this "Privacy and Consent to Use Data Policy," second person pronouns ("you," "your," and so on) mean the Customer and first-person pronouns ("we," "our," "us," and so on) mean Power Solutions.

WHAT IS THE SCOPE OF YOUR CONSENT TO OUR USE OF YOUR DATA?

The scope of your consent includes our collecting your DFA Data, analyzing it, and using it today and in the future for product improvements (for-profit commercialization), industry research and publications, and provision of DFA Analysis Service to you, as set forth in this "Privacy and Consent to Use Data Policy."

WHAT DATA DO WE COLLECT?

If you neither use our DFA Master Station Service nor request that we review your DFA Data, then we do not collect your DFA Data; however, if you use our DFA Master Station Service or request that we review your DFA Data, then we collect your DFA Data.

WHAT DO WE DO WITH YOUR DATA?

We may use your DFA Data to assist you with DFA Analysis Service and for the purpose of improving our commercial products. Additionally, we may share your DFA Data with the Texas A&M Engineering Experiment Station (TEES) and their affiliates for their research projects. Your DFA Data will be included with similar DFA Data collected from other Customers. These research projects may, or may not, be disclosed in industry publications (see below).

WHAT DO WE NOT DO WITH YOUR DATA?

We do not monitor or review your data on a real-time, daily, weekly, monthly, or annual basis in order to determine if your Circuits are defective, down, or otherwise experiencing a dangerous condition or other problem. We are not a "home or business security" service provider that monitors your home or business on a 24x7 basis or contacts you if the hardware and or software installed in your home or business signals a problem. You are responsible for reviewing your DFA Data, at intervals that your experience deems appropriate, to determine whether your Circuits are experiencing a problem. If you contact us regarding a specific issue involving your Circuits, we may review your DFA Data and assist you in interpreting relevant DFA Data. If we, in the course of reviewing your DFA Data, discover an indication of a possible Circuit event or condition that we believe may be of interest to you, we may, at our discretion, initiate contact with you regarding that event or condition, but we have no responsibility to do so, and doing so in one instance creates no obligation or expectation that we would do so for future events.

WHAT DATA DO WE DISCLOSE?

Customer Lists, Press Releases, and Marketing Materials

Power Solutions may publish customer lists, to include the name of your company and the approximate number of DFA Devices and related services you have purchased or are contemplating purchasing, which will be in the nature of customer lists, press releases and/or marketing materials.

Research Publications

Descriptions, summaries, and analyses that use DFA Data from your Circuits may be disclosed in research documents, publications, or reports, which are published and released to the industry, provided the name of your company and your employees shall not be disclosed in conjunction with specific, traceable examples of DFA Data. Power Solutions and its affiliates do not otherwise disclose the name of your company in its reports, except with your permission or in publications made jointly with you or your employees.

8 DFA Cybersecurity and Software Updates and Maintenance

This chapter on "DFA Cybersecurity and Software Updates and Maintenance" uses terms as defined in the accompanying "Glossary of Terms."

This chapter outlines Power Solutions' general strategy with regard to cybersecurity and software maintenance. This strategy is subject to change without notice.

8.1 DFA Device Cybersecurity

DFA Devices installed in Customer substations have multiple safeguards against unauthorized intrusion. Each DFA Device has an internal firewall that is configured to drop all incoming connections. Additionally, communications between a DFA Device and DFA Master Station is initiated by the DFA Device, not the DFA Master Station, allowing the Customer to install and configure a firewall, in the substation, to block all inbound communications to the DFA Device.

DFA Devices run a long-term support (LTS) version of the Linux operating system. Critical security patches are applied as needed to the operating system and other component software, as part of the overall DFA Device Software update process. DFA Devices do not have a user interface or user-executed software, minimizing the risk of personnel inadvertently installing a malicious program.

Communications between each DFA Device and the DFA Master Station is encrypted using industry-standard protocols.

8.2 DFA Master Station Cybersecurity

8.2.1 DFA Master Station Service

DFA Master Station Hardware, operated as part of the DFA Master Station Service by Power Solutions, runs Linux as its operating system. The DFA Master Station resides behind an IDS/IPS and firewall, which helps mitigate network-based attacks. Power Solutions configures its DFA Master Station to install security patches and software updates on a regular basis and, in the event of a critical security patch, will update the DFA Master Station as soon as reasonably feasible after a patch is available.

Each Customer accesses DFA Data related to that Customer's fleet of DFA Devices via secure (https) login to the browser-based DFA Website, protected by Customer-specific usernames and passwords. No DFA Technology-specific software is installed on Customer-owned computers.

8.2.2 Customer-owned DFA Master Station

Any Customer that owns its own DFA Master Station is responsible for securing network access, configuring virus protection, administering patch application processes, and all other aspects of cybersecurity for its DFA Master Station.

8.3 DFA Software Updates and Maintenance

Power Solutions evaluates DFA Device Software and DFA Master Station Software for security vulnerabilities (e.g., XSS, CSRF, code injection, etc.) and fixes vulnerabilities that are discovered in a timely manner. Where technically and commercially feasible, Power Solutions uses commonly available libraries and frameworks (e.g., OpenSSL, Apache, Flask, etc.) to reduce exposure to vulnerabilities. Updates for security vulnerabilities will be provided as part of the update processes for DFA Device Software and DFA Master Station Software.

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9 DFA Data Backup and Retention

This chapter on "DFA Data Backup and Retention" uses terms as defined in the accompanying "Glossary of Terms."

If Power Solutions provides Customer with DFA Master Station Service, Power Solutions shall back up Customer's DFA Data and retain it for two years from the date the underlying Circuit events occurred. During that period, Power Solutions shall take commercially reasonable efforts to preserve Customer's DFA Data from loss. At its discretion, Power Solutions may choose for a backup copy of the data to reside on a cloud-based service, even if the DFA Master Station Service itself is not run on a cloud-based provider.

Customer's DFA Data shall not be deemed critical to Customer's operations, and Customer shall make no such assertion in the event of loss of DFA Data. At the end of the two-year retention period, Power Solutions may delete Customer's DFA Data, without notice to Customer and without backup by Power Solutions. Power Solutions may, at its discretion, maintain Customer's DFA Data past the two-year retention period, for purposes of product improvement.

Any Customer that owns and manages its own DFA Master Station is responsible for backing up its own data.

DFA Data backup and consequently retention presume proper function of Customer-provided network service between the Customer's fleet of DFA Devices and the DFA Master Station Service. DFA Data resident on a DFA Device is managed autonomously by the DFA Device and deleted substantially on a first-in-first-out (FIFO) basis, subject to the finite semi-permanent storage capacity of the DFA Device, described in section 3.1, "*DFA Devices*."

10 Special Provisions for Customers of Resellers

This chapter on "Special Provisions for Customers of Resellers" uses terms as defined in the accompanying "Glossary of Terms."

In some cases, Power Solutions may sell DFA Devices and/or DFA Master Station Service and/or DFA Analysis Service to a party (a "Reseller") whose intent it is to resell those products and services to an end-use customer.

10.1 Contractual Relationships

When a Reseller sells DFA Master Station Service and/or DFA Analysis Service to an end-use customer, the Reseller may fulfill those obligations to its end-use customer, fully or in part, via subcontract relationship between the Reseller and Power Solutions. In such an event, Power Solutions is acting as a subcontractor of the Reseller and does not have a direct contractual relationship with the end-use customer. The nature of this contractual relationship does not preclude direct interaction between Power Solutions personnel and personnel of the Reseller's end-use customer, on behalf of the Reseller.

10.2 Point of Delivery of Products and Services by Power Solutions

The point of delivery for DFA Devices, DFA Master Station Service, and DFA Analysis Service provided directly or indirectly to any party by Power Solutions is Brazos County, Texas, or other location within Texas designated by Power Solutions. This point-of-delivery designation applies to all products and services provided by Power Solutions, both for direct end-use customers of Power Solutions and to end-use customers of a Reseller that has subcontracted obligations to Power Solutions.

10.3 Jurisdiction, Venue, and Applicability of Limited Warranty

Consistent with this designated point of delivery for all Power Solutions products and services, the jurisdiction and venue for any dispute or other matter related to DFA Technology provided by Power Solutions is Brazos County, Texas. All provisions of chapter 6, "Statement of Limited Warranty and Limitations of Remedies," apply to direct end-use customers of Power Solutions and to end-use customers of Reseller.

11 Effects of Circuit Configuration on DFA Device Software

This chapter on "Effects of Circuit Configuration on DFA Device Software" uses terms as defined in the accompanying "Glossary of Terms."

This chapter uses the terms ground, grounded, and grounding interchangeably with the terms earth, earthed, and earthing.

The DFA Technology System was developed based on electrical waveform data from Circuits employing the most common configuration in the United States, namely three-phase, four-wire, solidly grounded Circuits operating at a nominal system frequency of 60 Hz. Many electricity customers on such Circuits receive service via single-phase transformers, having their primary terminals connected between one of the Circuit's phase conductors and its grounded neutral conductor. In this configuration, the neutral conductor intentionally carries current during normal operations.

Circuit configurations used by some Customers differ from the aforementioned configuration. Chief differences include the nature of the grounding of the distribution system neutral, the intentional use of the neutral conductor as a current-carrying conductor under normal system operation conditions, and the nominal system frequency, although there also may be other relevant configuration differences.

DFA Device Hardware is intended to operate at either 50 Hz or 60 Hz and without regard to the grounding of the Circuit neutral or the use of the Circuit neutral as a current-carrying conductor, but variations in Circuit configuration will affect some results produced by the DFA Device Software. Power Solutions believes that most functions of the DFA Technology System will work substantially as intended, without adaptation, but that adaptation of DFA Device Software will be required for some functions to work properly. The feasibility and amount of time necessary to develop, test, and deploy DFA Device Software adaptations depends on multiple factors, some beyond the control of Power Solutions, and therefore cannot be predicted with certainty. A fundamental requirement to enable such adaptation is the availability to Power Solutions of relevant DFA Data and other Customer-provided event information from Circuits having differing configurations. Power Solutions believes it possible to implement adaptations to address most variations in Circuit configuration but makes no specific guarantees.

A specific Circuit configuration that differs more dramatically from the typical United States configuration is known as "single-wire, earth return," or SWER. Power Solutions believes that the DFA Technology System will be able to be adapted to infer some events that occur on SWER lines but recognizes that SWER represents a more dramatic departure from more conventional Circuit configurations and therefore that SWER will present a greater challenge for adaptation and a greater uncertainty of outcome. As with other variations in Circuit configuration, provision to Power Solutions of adequate data from Circuits having SWER segments will be fundamental to enabling analysis of waveform differences and thus the possibility of adaptations of DFA Device Software.

12 Miscellaneous Terms

This chapter on "Miscellaneous Terms" uses terms as defined in the accompanying "Glossary of Terms."

12.1 Customer Consent

By purchasing and or using a DFA Technology System, the Customer consents and agrees to all of the terms and conditions set forth in this "DFA Technology System Manual."

12.2 Copyright and Trademark

Power Solutions, the Power Solutions logo, and all trademarks and service marks are trademarks and service marks of Power Solutions.

12.3 Customer Service

Issues related to the DFA Technology System should be sent to support@powersolutionsllc.us. Power Solutions will attempt to respond within two business days, but it does not represent that it will respond or that it will respond in a timely manner.

12.4 Governing Law and Jurisdiction

The purchase and use of the DFA Technology System, as well as the use and construction of the "DFA Technology System Manual" shall be governed, construed, and enforced in accordance with the laws of the state of Texas, United States of America without reference to conflicts of law principles. The parties agree that the exclusive jurisdiction of any legal dispute or actions arising out of, relating to, or in any way connected with the purchase and or use of a DFA Technology System shall be in the state or federal courts, as applicable, governing Brazos County, Texas, United States of America.

12.5 Licenses

To the extent that any Customer needs a license to use any aspect of a DFA Technology System, Power Solutions hereby grants the Customer a non-exclusive license to use the DFA Technology System in accordance with the purposes, terms, and conditions of this "DFA Technology System Manual."

13 DFA Device Installation

This chapter on "DFA Device Installation" uses terms as defined in the accompanying "Glossary of Terms." In this chapter, the terms "user" and "installer" are used to mean the Customer or an installer working at the behest of the Customer, and the terms "device(s)" and "unit(s)" mean DFA Device(s). The term "DFA Device" is used interchangeably with term "DFA-Plus Device."

13.1 Important Warnings – Risk of Serious Injury or Damage

DFA Devices should only be connected in accordance with the user's established practices, procedures, and policies. Installation shall be done only by qualified personnel familiar with the user's established practices, operation of the DFA Device, external components being connected to, and all associated hazards.

Only persons with electrical safety training and certification appropriate to installations in substations should install the DFA Device or access the connection terminals once the equipment has been installed.

Improper wiring or use of electrical circuitry may result in serious personal injury, damage or outage of the associated power system, and/or damage to the device, and may void warranty.

13.2 DFA Device Main Components

Prior to installing or commissioning a DFA Device, the user should be able to identify its main components and understand its basic connections.

The device is intended for installation in a 19-inch rack. None of the device's internal components are to be accessed by the user.

The device's front panel, shown in Figure 1, provides a Management Port that is intended for use only during installation and troubleshooting of the device. The device's rear panel, shown in Figure 2, has terminals for connection of three CTs, three PTs, battery-backed Unit Power, and an Ethernet port to enable continuous communications between the device and a centrally located DFA Master Station. User access to DFA Data is provided via the DFA Master Station only, not via direct connection to the Management Port or to the Ethernet port.

Figure 1: Front panel of DFA Device

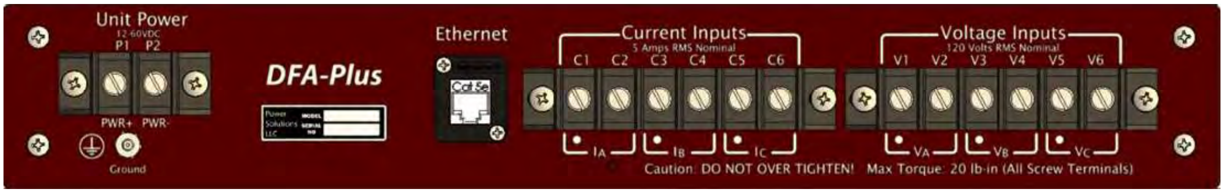


Figure 2: Rear panel of DFA Device

13.3 Device Installation Overview

Installation of a DFA Device requires the following steps.

- Preparing for the installation.
- Verifying that the device has the correct Current Input range, either five-amp or one-amp.
- Determining the proper configuration of CT and PT connection for the Circuit to be monitored.
  Important Note: No PT or other transformer that is to be used as a voltage input to the device (i.e., that is to be connected to a PT input terminal) may be used to supply power to the device or to any other equipment. Such use would distort the voltage waveforms coming from the PT or transformer and result in degraded, unpredictable results from the DFA Technology System.
- Selecting a rack-mount position for the device (19”, 1.5U [2-5/8”]).
- Ensuring adequate long-term environmental conditions for the device where it will be installed.
- Arranging a suitable source of uninterrupted (i.e., battery-backed) DC Unit Power for the device.
- Providing a suitable grounding/earthing system.
- Preparing the necessary cabling, terminated with suitable terminals and associated hardware.
- Planning the installation to ensure no open circuiting of CT secondary circuits. Serious personal injury to personnel or damage to the DFA Device and/or other equipment may result.
- Arranging suitable network communications hardware and service.

The following tools are normally necessary for a standard installation:

- Torque screwdrivers (flat; for CT, PT, and Unit Power terminal screws)
- Pliers, wire cutters, wire strippers
- Shorting leads
- Crimping tools
- Multi-meter capable of measuring AC currents and AC and DC voltages.

Caution: Do not over-torque screw terminals on the device. Maximum torque is 20 lb-in.

13.4 Mounting DFA Device

This chapter provides guidance on how to mount and wire the device.

13.4.1 General Considerations

Mount the device in a 19″ rack with 1.5U (2-5/8″) rack size clearance and long-term provision for ventilation and cooling.

Make provision for uninterrupted supply of DC Unit Power and determine the optimal redundancy of such supply to comply with desired reliability requirements.

Mount the device horizontally and upright.

Note the exact serial number of the device for each circuit. The correct serial number for each Circuit's DFA Device must be used to configure the DFA Master Station, which uses the serial number to identify each specific device and consequently the Circuit to which it is applied.

Ensure proper phase and polarity when connecting all Current Inputs, Voltage Inputs, and Unit Power inputs. DFA Device Software analyzes phase relationships between Current Inputs and Voltage Inputs, and unexpected results will occur if phases are "rolled" or wired with incorrect polarity.

13.5 Wiring the Electrical Connections

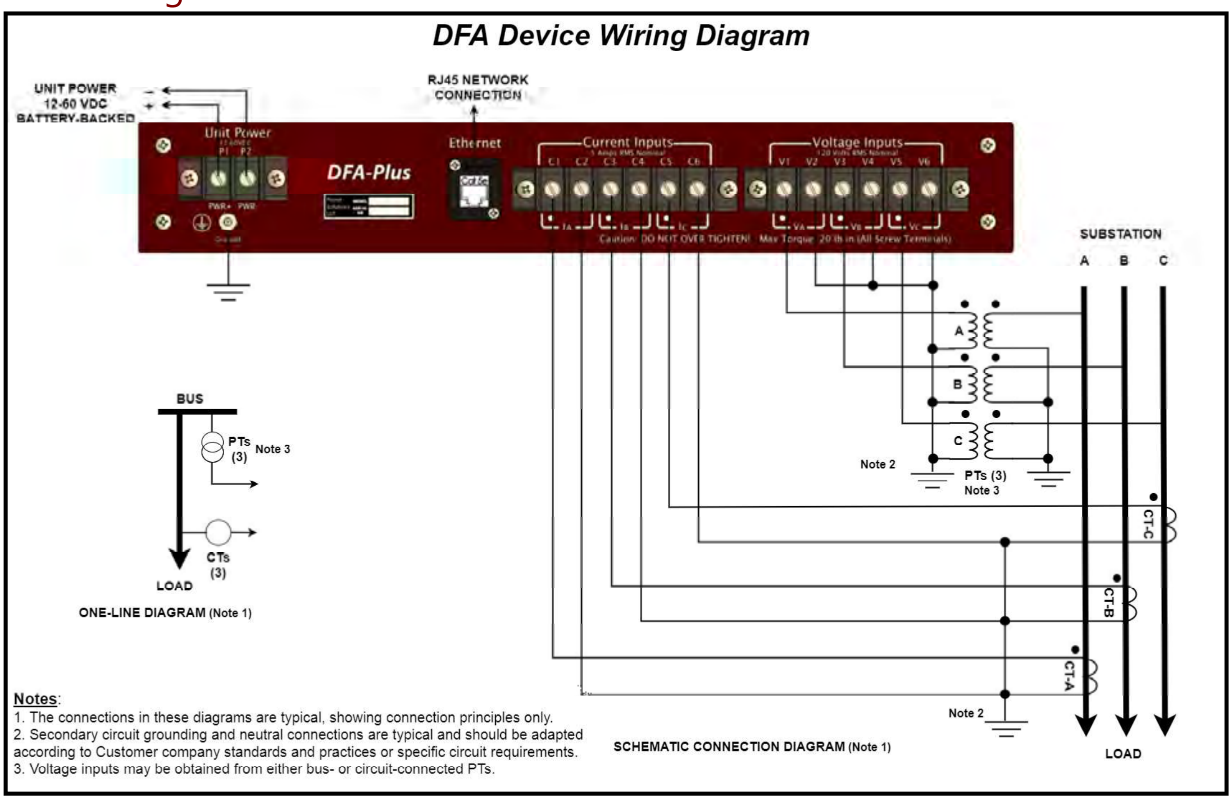


Figure 3: Wiring connection diagram and notes for DFA Device (note: some details of appearance may vary slightly from the diagram. If you have any uncertainty or question regarding connections, contact Power Solutions before commencing installation.)

13.5.1 Terminal Markings

Table 1 describes the markings and use of the Current Inputs (CTs), Voltage Inputs (PTs), and Unit Power terminals on the rear of each DFA Device. Input ranges for all inputs must be in accordance with the specifications for the specific model of DFA Device.

Table 1. DFA Device terminal designations (rear panel)

DFA Device Terminal	Intended connection to user-supplied CT, PT, or Unit Power leads
P1	DC unit power, positive
P2	DC unit power, negative
C1	Phase-A CT input
C2	Phase-A CT return
C3	Phase-B CT input
C4	Phase-B CT return
C5	Phase-C CT input
C6	Phase-C CT return
V1	Phase-A PT input
V2	Phase-A PT reference
V3	Phase-B PT input
V4	Phase-B PT reference
V5	Phase-C PT input
V6	Phase-C PT reference
Ground	Chassis ground (earth), to be connected in accordance with all relevant local codes and user's approved standard practices

- SAFETY CAUTION: Ensure that all connections are made only to the proper terminals and have the proper range and polarity, in accordance with the designations of Table 1 and the model number of the DFA Device. Serious personal injury or damage to the DFA Device and/or other equipment may result from improper connections.
- SAFETY CAUTION: Check the model number (stamped on the rear of the device) to ensure that only one-amp devices (i.e., those whose model numbers begin with R1 or S1) are wired to one-amp CTs and that only five-amp devices (i.e., those whose model numbers begin with R5 or S5) are wired to five-amp CTs. Serious personal injury or damage to the DFA Device and/or other equipment may result if five-amp CTs are wired to one-amp devices. Improper operation may result if one-amp CTs are wired to five-amp devices.

13.5.2 Connecting CT Secondary Leads to the DFA Device Terminals

The following guidance applies to the CT connections:

- SAFETY CAUTION: Do NOT create or allow an open circuit condition in the CT leads in the course of installing the DFA Device or at any other time. Take all necessary precautions to prevent such a condition. Serious personal injury or damage to the DFA Device and/or other equipment may result.

- SAFETY CAUTION: Do NOT fuse-protect CT leads, as doing so may lead to an open circuit condition in CT leads. Serious personal injury or damage to the DFA Device and/or other equipment may result.
- Connect CT secondary leads to the device in accordance with the terminal designations of Table 1. Ensure correct polarity.
- The grounding method for CT lead connections shown in Figure 3 is typical but should be adjusted to conform to user's established practices.
- Consider installing shunt switches in the CT leads, in accordance with user's established practices, to facilitate insertion and removal of the device from CT secondary circuits.

13.5.3 Connecting PT Secondary Leads to the DFA Device Terminals

The following guidance applies to the PT connections:

- Connect PT secondary leads to the device in accordance with the terminal designations of Table 1. Ensure correct polarity.
- The grounding method for PT lead connections shown in Figure 3 is typical but should be adjusted to conform to user's established practices.
- Consider installing appropriately sized fuses in PT leads, in accordance with user's established practices.
- Consider installing switches in the PT leads, in accordance with user's established practices, to facilitate insertion and removal of the DFA Device from PT secondary circuits.

13.5.4 Connecting DC Unit Power to the DFA Device Terminals

The following guidance applies to connecting unit power.

- Connect DC Unit Power leads to the device in accordance with the terminal designations of Table 1. Ensure correct polarity.
- Ensure suitable mounting of the external DC source if so required.
- Ensure long-term, stable battery backup for the DC source.
- Consider installing switches and/or appropriately sized fuses in Unit Power leads, in accordance with user's established practices.
- Important Note: No PT or other transformer that is to be used as a voltage input to the device (i.e., that is to be connected to a PT input) may be used to supply power to the device or to any other equipment. Such use would distort the voltage waveforms coming from the PT or transformer and result in degraded, unpredictable results from the DFA Technology System.

13.5.5 Grounding (Earthing) the DFA Device Chassis

- Ground (earth) the device chassis via the supplied Ground terminal and ensure that each device is wired directly to a common station grounding point.
- Do not cascade Ground (earth) connections between devices.

13.5.6 Connecting Network Service to the DFA Device Ethernet Port

- The rear of each DFA Device features a single RJ45 Ethernet port, which allows the device to connect to a DFA Master Station via user-provided network service.
- The Management Port on the front of the DFA Device is not functionally interchangeable with the Ethernet port on the rear of the device.
- Use network cabling having minimum 300V insulation and spanning no more than 100 feet.
- Shielding of network cabling should be grounded at one end only. Grounding at both ends may cause poor communications and/or damage the device.
- Avoid sharp bends in network cabling.
- Avoid installing network cabling in any manner that might cause a trip hazard or risk the cable's being be damaged or pulled out by being in a walkthrough area in an unsecured manner.
- DFA Devices internally use IP Subnet 10.245.245.0/29. Any user for whom this will create a conflict should contact Power Solutions for an update script and instructions on changing the DFA Device internet IP subnet.
- Power Solutions cannot guarantee protection from external surges (such as lightning or external arc) over 1500V that could couple into the network service. It is the user's responsibility to isolate the network service line. An optical converter placed near the device is recommended for this purpose.

13.6 Installation Summary

The following is a summary of the installation process:

- Plan the configuration of CT and PT connections prior to commencing work.
- Select a suitable rack space with adequate ventilation.
- Arrange a suitable source of Unit Power, including battery backup and any desired redundancy.
- Do not provide power to the DFA Device or to any other equipment from any PT to be connected to any DFA Device PT lead.
- Use and verify correct polarities of CTs, PTs, and Unit Power.
- Use and verify appropriate grounding for CTs, PTs, and the DFA Device chassis.
- Ensure that network cabling, not more than 100 feet long, is isolated at one end, and, if desired, optically isolated.
- Record the correct device serial number for each Circuit.

13.7 Powering Up the Device

The following is a summary of the process to power up the DFA Device for the first time:

13.7.1 Important checks before powering up the DFA Device

The following checks should be made prior to providing DC supply to the device:

- Verify that CT polarities, PT polarities, and Unit Power polarities are correct.
- Verify that CT connections and PT connections are grounded properly and in accordance with user's established practices.
- Verify that the DFA Device chassis is grounded properly and in accordance with user's established practices.
- Verify that CT leads are NOT fuse-protected. Serious personal injury or damage to the DFA Device and/or other equipment may result from an open-circuit CT condition.
- Verify that network cabling is mounted correctly, grounded only at one end, not longer than 100 feet, and preferably terminated by a fiber optic converter.
- Verify that all screw terminals have proper torque.

13.7.2 Applying power and CT/PT inputs to the DFA Device

- Apply Unit Power and use a DC multi-meter to verify correct voltage and polarity at the Unit Power terminals on the rear of the device.
- Energize all CT and PT inputs and use an AC multi-meter to verify expected current and voltage levels at the DFA Device terminals.

The following steps allow the installer to use the Management Port on the front panel of the DFA Device to view basic device and electrical information and to view and set communications-related parameters. Viewing basic electrical information while still in the substation enables discovery and correct of common wiring problems, before the installer leaves the substation.

- Using an Ethernet cable, connect a laptop computer to the Management Port on the front panel of the DFA Device.
- Open a browser on the laptop and browse to address http://dfa-plus.local. A DFA-Plus Management screen (referred to hereafter as the Management screen) similar to Figure 4 will appear. (The appearance of the Management screen will vary slightly, because of factors such as screen resolution, variety of browser, and version of the DFA Device software. Also certain information in the figure is blurred intentionally so as to avoid revealing specific IP addresses, etc.)

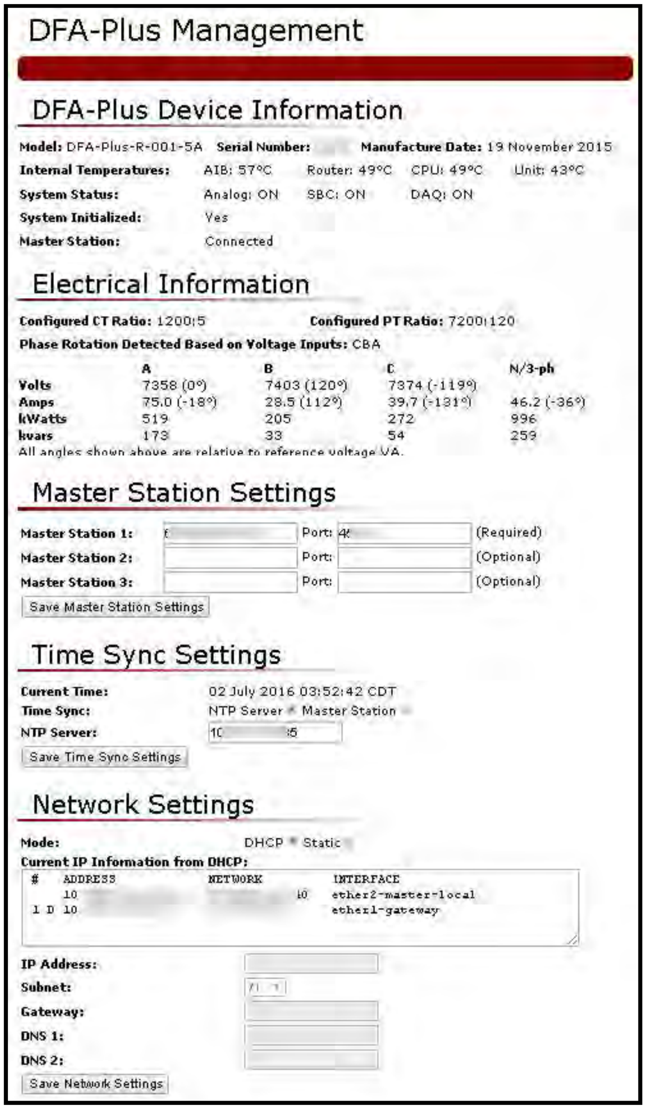


Figure 4: DFA-Plus Management Screen

- The DFA-Plus Device Information section of the Management screen provides basic information about the device itself.
- In the Electrical Information section of the Management screen:
    - Confirm that the Phase Rotation reading is as expected for the particular installation, either ABC or CBA. If there is no Phase Rotation reading, it may indicate that one or more PTs is not connected, that one or more PT switches is open, or that there is a wiring problem with one or more PTs.
    - Confirm that the Volts and Amps readings are reasonable and have expected values on all phases. If any readings (other than neutral amps) are near zero or have other unreasonable values, this may indicate that CT(s) or PT(s) may not be connected or that CT or PT test switches may not be in the correct position.

- Confirm that the kWatts readings are reasonable and have expected values on all phases. If all Volts and Amps readings seem reasonable, but kWatts do not seem reasonable, this may indicate a wiring error. If kWatts readings are negative on one or more phases, and negative power flow is not expected for the specific Circuit, this may indicate a wiring problem. Common wiring problems include reversed CT and/or PT polarities and/or "rolled phases" (e.g., one phase interchanged with another).
- Important Note: Amps, Volts, kWatts, and kvars are calculated based upon the CT and PT ratios programmed into the DFA Device. These ratios are shown in the Management screen. If CT and PT ratios displayed on the screen do not match the ratios of the CTs and PTs connected to the device, the installer should make note of this fact and report the correct CT and PT ratios to personnel responsible for managing the fleet of DFA Devices, so that they may correct the ratios remotely via the DFA Master Station. CT and PT ratios cannot be changed via the Management Port. For the purpose of validating correct installation of the DFA Device, if the CT and/or PT ratios are not correct, the installer can mentally adjust the Amps, Volts, kWatts, and kvars readings by dividing by the ratios shown on the Management screen and multiplying by the actual ratios of the connected CTs and PTs.

- Important Note: TCP ports 45123, 45124, and 45125 must be opened in the user's substation firewall to allow outbound connections from each DFA Device to the DFA Master Station. Each DFA Device also requires DNS and NTP access. If NTP is not provided, then the DFA Device can be configured to synchronize its real-time clock with the DFA Master Station, but with reduced time accuracy.
- In the Master Station Settings section of the Management screen, specify at least one Master Station to which the DFA Device is to connect, and then press the Save Master Station Settings button. At least one Master Station must be designated, and successful connection of the DFA Device to the Master Station must be accomplished to enable operation of the DFA Technology System. Note: Successful connection to a DFA Master Station requires that both the Master Station Settings and the Network Settings (see below) be correct.
- Important Note: It is not possible to connect to the DFA Device remotely unless both the Master Station Settings and the Network Settings are correct. Therefore it is critical that the Master Station Settings and Network Settings be configured correctly while at the substation. The Management screen will show a warning if the DFA Device is unable to communicate with a DFA Master Station.
- (optional) In the Time Sync Settings section of the Management screen, select whether time synchronization will be accomplished by synchronizing to a standard NTP time source or alternatively to the DFA Master Station (with possible loss of time accuracy), and then press the Save Time Sync Settings button. Setting of the Time Sync Settings can be accomplished via the Management screen or via the Master Station, provided that the Master Station is configured properly and communicating.

- In the Network Settings section of the Management screen, select either DHCP or Static as the IP Address Mode. If Static is selected, also enter network configuration parameters provided by your company's information technology department. Press the Save Network Settings button. Information in this section determines operation of the Ethernet port on the rear of the device, not of the Management Port on the front of the device.
- Note: The Management Port connection on the front of the device is used only for verifying basic wiring and for configuring device communications. The Management Port is not intended to be connected during normal operation. During normal operation, communications from the DFA Device to the DFA Master Station occurs via the Ethernet port on the rear of the device, and the user access DFA Data via a centrally located DFA Master Station, not via direct connection to the device. The Management Port on the front of the device is not functionally interchangeable with the Ethernet port on the rear of the device.

14 DFA Device Technical Specifications

The following technical specifications are preliminary and subject to change without notice.

14.1 Models and Input Ranges

DFA-Plus Devices are supplied with the following model numbers:

- Model R5A1-0: Rack configuration DFA-Plus Device with 5-amp current inputs
- Model R1A1-0: Rack configuration DFA-Plus Device with 1-amp current inputs
- Model S5A1-0: Stack configuration DFA-Plus Device with 5-amp current inputs
- Model S1A1-0: Stack configuration DFA-Plus Device with 1-amp current inputs

The four models differ by packaging configuration (rack and stack) and by nominal current input range (5-amp and 1-amp). Installation instructions and photographs provided in this "DFA Technology System Manual" correspond to the rack configurations. Stack-specific instructions and photographs have not been developed as of the writing of this document but may be developed and provided as a modification or supplement at a later date. The rack and stack configurations have identical intended function. Models beginning with R5 or S5 have five-amp nominal Current Inputs. Models beginning with R1 or S1 have one-amp nominal Current Inputs. Ratings for the Voltage Inputs are the same for all models.

14.2 Performance

- Analog-to-digital converters (six): 24-bit hardware resolution; >18-bit effective resolution
- Sampling rate: 256 samples per cycle per channel
    - 15,360 samples per second per channel for 60 Hz Circuits
    - 12,800 samples per second per channel for 50 Hz Circuits

14.3 Environmental

- Operating Temperature: -40 to +55 C
- Operating Humidity: 0-95% RH
- Storage Humidity: 5-95% non-condensing

14.4 Physical Dimensions

- 19" rack-mount enclosure of 1.5 U (2-5/8") height
- DFA Device enclosure: 19" W x 2-5/8" H x 11-3/16" D
  48.3 cm W x 6.7 cm H x 28.4 cm D
- DFA Device enclosure + rear terminal strips: 19" W x 2-5/8" H x 12-3/16" D
  48.3 cm W x 6.7 cm H x 31 cm D
- Weight: 13 lbs.
  5.9 kg

14.5 Electrical Inputs

- DFA Device power: 12-60VDC, external, battery-backed (power source not supplied).
- Power consumption: 25 VA
- Current Inputs (5A models): Three phases, 5 amps AC nominal per phase.
- Current Inputs (1A models): Three phases, 1 amp AC nominal per phase.
- Voltage Inputs: Three phases, 120 volts nominal AC per phase.
- Sensing input burdens: < 1 VA CTs; < 1 VA PTs

14.6 Network Communications

14.6.1 Physical Connection

- The rear of the DFA Device has a single RJ45 (twisted pair) Ethernet port for connection to user-supplied Internet service, for the purpose of enabling the DFA Device to establish and maintain communications with a DFA Master Station. The Management Port on the front of the device is not functionally interchangeable with the Ethernet port on the rear.

14.6.2 Internet Requirements

- Recommended speed of at least one megabit per second per DFA Device. Lower Internet speeds can be accommodated with possible reduction in timeliness of information delivery.
- TCP ports 45123, 45124, and 45125 must be opened in the substation firewall to allow outbound connections from each DFA Device to a remote DFA Master Station.
- Each DFA Device requires DNS access.
- Each DFA Device ideally requires NTP access. If NTP is not provided, then the DFA Device can be configured to synchronize its time with a DFA Master Station, but time accuracy will be reduced.
- DFA Devices internally use IP Subnet 10.245.245.0/29. Any user for whom this will create a conflict should contact Power Solutions for an update script and instructions on changing the DFA Device internet IP subnet.

14.7 Timing Synchronization

- The DFA Device will support NTP synchronization with an in-substation clock source. If no in-substation clock source is available, the DFA Device can synchronize its time to NTP servers (e.g., maintained by the client or by a third party such as CERN, NIST, et. al.).

14.8 Memory Capacity

- DFA Device: Typically four weeks, depending on level of Circuit activity. Longer for certain types of events (e.g., recurrent faults).
- DFA Master Station: Indefinite and limited only by the DFA Data download and storage policies that the user may adopt. (See also chapter 9, "DFA Data Backup and Retention.")

14.9 Wiring Connections

All connections are on rear of DFA Device, except where otherwise noted.

- Current Inputs: Three pairs of screw terminals for connection of 5 AAC or 1 AAC (depending on model) secondary leads of current transformers (CTs)
- Voltage Inputs: Three pairs of screw terminals for connection of 120 VAC secondary leads of potential (voltage) transformers (PTs)
- Unit Power: One pair of screw terminals for battery-backed DC Unit Power
- Threaded lug and nut for device chassis safety grounding (earthing)
- RJ45 (twisted-pair copper) Ethernet connector on rear of device for long-term connection to remote (i.e., not in substation) DFA Master Station via Internet
- RJ45 (twisted-pair copper) Management Port connector on front of device, for temporary connection to laptop or similar, to facilitate installation and commissioning
- Wiring for CTs, PTs, DC Unit Power, Ethernet, and Ground to be supplied by Customer
- Battery-backed DC Unit Power to be supplied by Customer

15 Document Version History

Versions of this manual have been released on the following dates:

01 December 2017 (first version with tracked version date)

02 October 2018

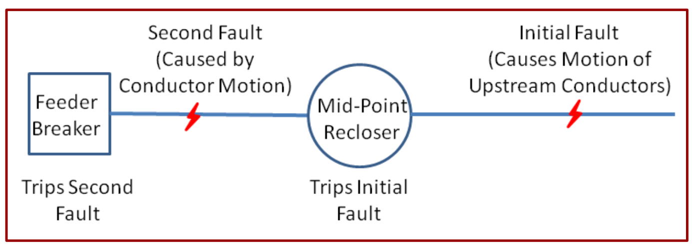
Tutorial: Fault-Induced Conductor Slap

Introductory Overview

The DFA technology system detects and reports multiple types of events that occur along the length of a distribution circuit.[1] One type of event is fault-induced conductor slap, abbreviated FICS. FICS occurs when an initial fault at one location on a circuit causes upstream conductors to slap together, resulting in a second fault. Because the second fault occurs closer to the substation, often much closer, it draws more fault current, and clearing it affects more customers. FICS involves conductor-to-conductor contact, emitting showers of hot or burning particles and damaging conductors. Susceptible spans can experience FICS repeatedly and incur cumulative damage. Correcting the cause of FICS prevents future interruptions, outages, system damage, and possible broken conductors, but correction requires awareness that FICS has occurred.

The FICS Phenomenon

Significant work has gone into understanding the FICS phenomenon, with Ward having provided perhaps the best practical description and mathematical modelling to predict the occurrence of the phenomenon based on line configuration parameters.[2]



The one-line diagram shown here is useful for understanding the basic FICS phenomenon. Consider an Initial Fault between two phase conductors. Fault current flows from the substation to the fault through one phase conductor and back through the other. These parallel, opposite-direction currents induce magnetic forces that push the conductors away from one another, displacing them from rest. After a time, the mid-point recloser trips, interrupting the fault current and suddenly removing the magnetic forces. Gravity pulls the displaced conductors toward their normal resting positions, and momentum causes them to pendulum through those resting positions. Under the right set of conditions, they can contact one another, resulting in a Second Fault. Most typically this occurs upstream of the mid-point recloser, sometimes while that device is open. The Second Fault is closer to the substation, so it draws more fault current than the Initial Fault and often trips protection upstream of the mid-point recloser. Therefore, a fault that should have operated only the mid-point recloser, affecting a relatively small number of customers, instead trips upstream protection and affects more customers.

[1] DFA's On-Line Waveform Characterization Engine detects and reports events based upon signal processing of current and voltage waveforms measured from substation current and potential transformers (CTs and PTs) and does not require communications with substation relays, SCADA/RTUs, or line reclosers. DFA Technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, and is commercially available from Power Solutions LLC (www.powersolutionsllc.us).

[2] Daniel J. Ward, "Overhead Distribution Conductor Motion Due to Short-Circuit Forces," *IEEE Transactions on Power Delivery*, vol. 18, no. 4, October 2003, pp. 1534-1538.

Typical FICS Scenario

This section describes a composite scenario based on multiple documented FICS events and actions that utility companies have taken in response. Elements of the scenario have been documented multiple times via DFA field installations. Often, the underlying circuit was fitted with DFA, but DFA was being used in an evaluation mode, providing opportunity to document FICS and conventional utility responses.

The Event

Three miles from a substation, a tree leans into an overhead line and pushes two phase conductors together. This causes a phase-to-phase fault, which trips a mid-point recloser two miles from the substation, interrupting 500 customers. The recloser auto-recloses multiple times, but the fault condition is permanent, so the recloser locks open. The mid-point recloser has operated properly to sectionalize the circuit and limit the extent of the outage, but the substation circuit breaker trips and locks out, too, resulting in an outage to 2000 customers.

The Response

Upon detecting the outage, the utility dispatches a line crew to search for the cause, make repairs, and restore service. The crew first patrols the portion of the circuit between the substation and the mid-point recloser, because operation of the substation circuit breaker usually implies that the fault is on that portion of the circuit. The crew eventually expands the search and locates the tree fault, well downstream of the mid-point recloser. They make repairs, find no other damage to the system, and restore service. The duration of the outage has been prolonged because they initially spent time patrolling near the substation, far from the actual location of the tree fault.

The Investigation

In the aftermath of the outage and restoration, utility company personnel note that the mid-point recloser should have sectionalized the tree fault to prevent the circuit-wide outage. They also note that, following the unsuccessful initial patrol, closing the substation circuit breaker resulted in no ongoing fault upstream of the mid-point recloser. This set of facts typically indicates improper coordination between the substation and mid-point protection. Personnel analyze settings and trip curves for both locations. They retrieve and analyze records from relevant electronic devices, such as the substation relay and the mid-point recloser. They temporarily take the mid-point and substation protection devices out of service to test them. In the end, they identify no issue and close the investigation with "cause unknown."

Subsequent Events

The same sequence occurs a year later: a phase-to-phase fault, beyond the same mid-point recloser, results in another circuit-wide outage. The same sequence continues to happen from time to time. The underlying cause of the seemingly improper protection coordination and broadened outage remains identified.

Important Clarification

The foregoing discussion of a typical FICS scenario and utility company response is not intended as a criticism of utilities, their personnel, or their practices. Rather it demonstrates the inadequacy of conventional processes to diagnose FICS. By contrast, DFA technology often can detect FICS, report it to the utility, and provide parameters that enable the utility to locate the FICS and take corrective action. It also illustrates another aspect of FICS, namely that spans susceptible to FICS can experience it repeatedly, sometimes with long periods of time passing between episodes.

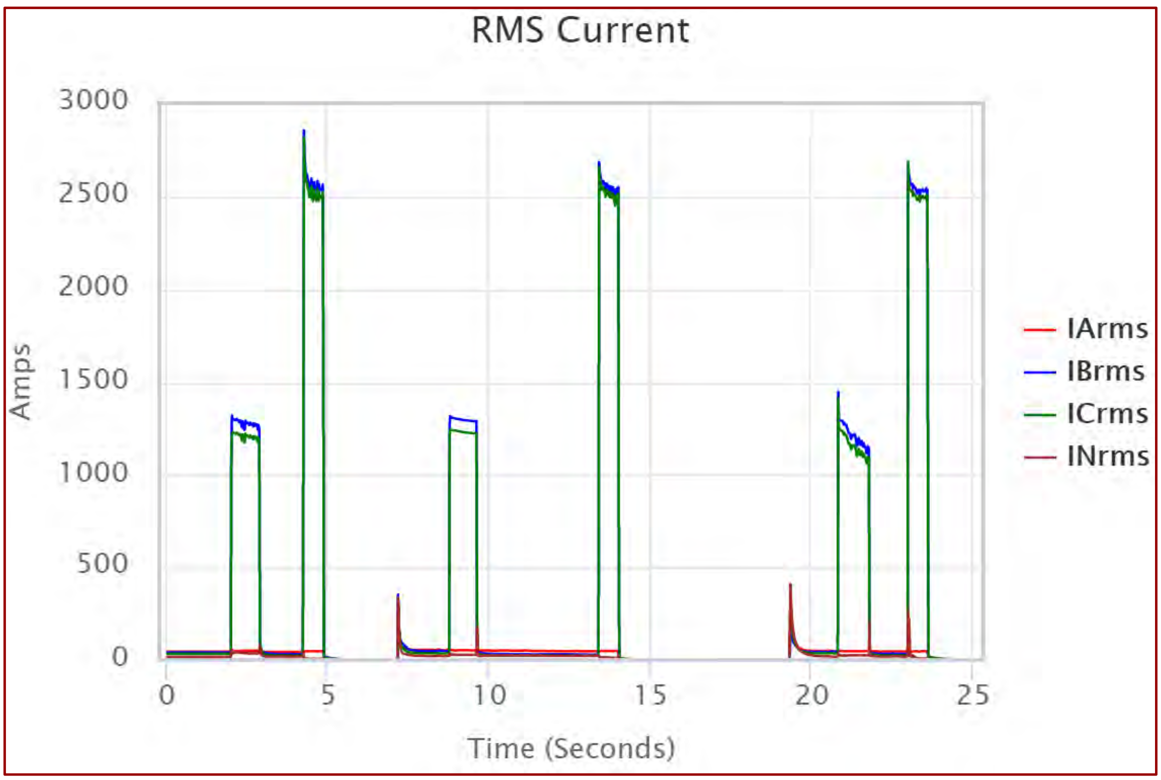
Real-World Example

This section details a specific, real-world example involving FICS on a DFA-monitored circuit.

DFA Web Report and Waveform Data

The DFA Web report below was available within minutes of the underlying event. It indicates that the substation circuit breaker locked out, which the utility company already knew via SCADA. It also reports 'Possible conductor-slap,' related to the event, which the utility company did not know. The graph below, also available via DFA Web, shows the RMS line currents that DFA recorded at the substation during the event, which took place over a period of approximately 22 seconds. DFA records high-speed current and voltage waveforms at a rate of 256 samples per cycle, but an RMS plot often provides the best "big picture" view. DFA software automatically detects the possible conductor-slap event by analyzing the recorded high-speed current and voltage waveforms.

Circuit	Event Type	Phases	Comments	Count	Last Occurred
[illegible]	Possible conductor-slap	BC	Breaker trip F-(53.0c,1267A,BC)-T-(0,24,32)%-1.4s- F-(37.0c,2595A,BC)-T-2.3s-C-1.6s- F-(51.0c,1272A,BCN)-T-(0,32,34)%-3.8s- F-(37.0c,2581A,BC)-T-5.3s-C-1.5s- F-(58.0c,1256A,BCN)-T-(0,24,31)%-1.2s- F-(37.0c,2591A,BCN)-T	6 ops	2018-03-18 11:26:09



Analysis of DFA Report

The preceding DFA Web report contains a sequence of events describing the six fault episodes, all involving phases B and C, and the protection system response. Information in the table below comes from the report's sequence of events. This remainder of this section then analyzes that information.

		% Load Interrupted			
Fault Episode	Amps	A	B	C	Protection Device (Inferred)
1	1267	0	24	32	Mid-Point Recloser (B and C only)
2	2595	All	All	All	Substation Circuit Breaker
3	1272	0	32	34	Mid-Point Recloser (B and C only)
4	2581	All	All	All	Substation Circuit Breaker
5	1256	0	24	31	Mid-Point Recloser (B and C only)
6	2591	All	All	All	Substation Circuit Breaker

Fault Current Amplitude

The amplitudes of the six fault episodes fall into two distinct groups, one having amplitudes ranging from 1256 to 1272 amps and the other having amplitudes ranging from 2581 to 2595 amps. The preceding graph of RMS currents also makes clear the two distinct groupings of amplitudes. Using terminology from the one-line diagram on the first page of this tutorial, the fault episodes with the lower amplitudes correspond to an Initial Fault, and the fault episodes with the higher amplitudes correspond to the Second Fault. Having two distinct groups of fault current amplitude is consistent with a diagnosis of FICS.

Protection Devices Involved

For the trips associated with the first, third, and fifth fault episodes, the SOE indicates interruption of essentially none of the phase-A load, 24-32 percent of the phase-B load, and 31-34 percent of the phase-C load. These values estimate the amount of load interrupted by the trips, as a percentage of the total pre-fault circuit load measured from the substation. Minor episode-to-episode variations in interrupted-load estimates (e.g., 24% versus 32% versus 24% for phase B; 32% versus 34% versus 31% for phase C) are common. That B and C both experienced partial load loss, by similar percentages, implies that phases B and C of a mid-point bank of single-phase reclosers tripped for those episodes. Effectively all load on all three phases was interrupted in response to the other three episodes, indicating trips of the substation circuit breaker.

In summary, analysis of the sequence of events indicates that phases B and C of a mid-point recloser tripped in response to the first, third, and fifth fault episodes and that the substation circuit breaker tripped in response to other three. A sequence that intermingles operations of a mid-point recloser and operations of the substation circuit breaker is consistent with a diagnosis of FICS.

Swing Times of Conductors

The timing information in the SOE is consistent with conductor-to-conductor contact, at the location of the Second Fault, occurring 1.4 seconds, 3.8 seconds, and 1.2 seconds after the three trips of the mid-point recloser. These time intervals seem believable for the periods of time that conductors might swing about, after interruption of the Initial Fault relaxes the magnetic forces, before contacting one another. Swinging conductors represent a dynamic condition, making it believable that one contact might take 3.8 seconds to occur and another just 1.2 seconds. The timing information is consistent with a diagnosis of FICS.

Field Investigation

Field investigation to locate this example of FICS proceeded based upon the following information.

- The Initial Fault was between phases B and phase C and had been determined by field personnel to have been caused by a tree pushing phase conductors together at a specific, known location.
- The mid-point recloser that operated to clear the Initial Fault had been identified.
- DFA reported a FICS (i.e., a Second Fault) as a consequence of the Initial Fault.
- DFA reported that the Second Fault was between phases B and C and drew 2590 amps.
- Because of the nature of the FICS phenomenon, the Second Fault must lie directly on the path between the substation and the mid-point recloser that cleared the Initial Fault.

The utility company used its circuit model and fault location software to predict circuit locations that would produce 2590 amps of fault current for a phase-to-phase fault. They considered only locations lying along the path between the substation and the mid-point recloser that cleared the Initial Fault.

Once an approximate location for the Second Fault has been predicted by circuit model software, evidence of FICS often is found to be in an unusual span near the prediction. Unusual span conditions can include excess slack, a longer-than-usual span, a transition span between horizontal and vertical, reduced spacing between the faulted phase conductors, etc.

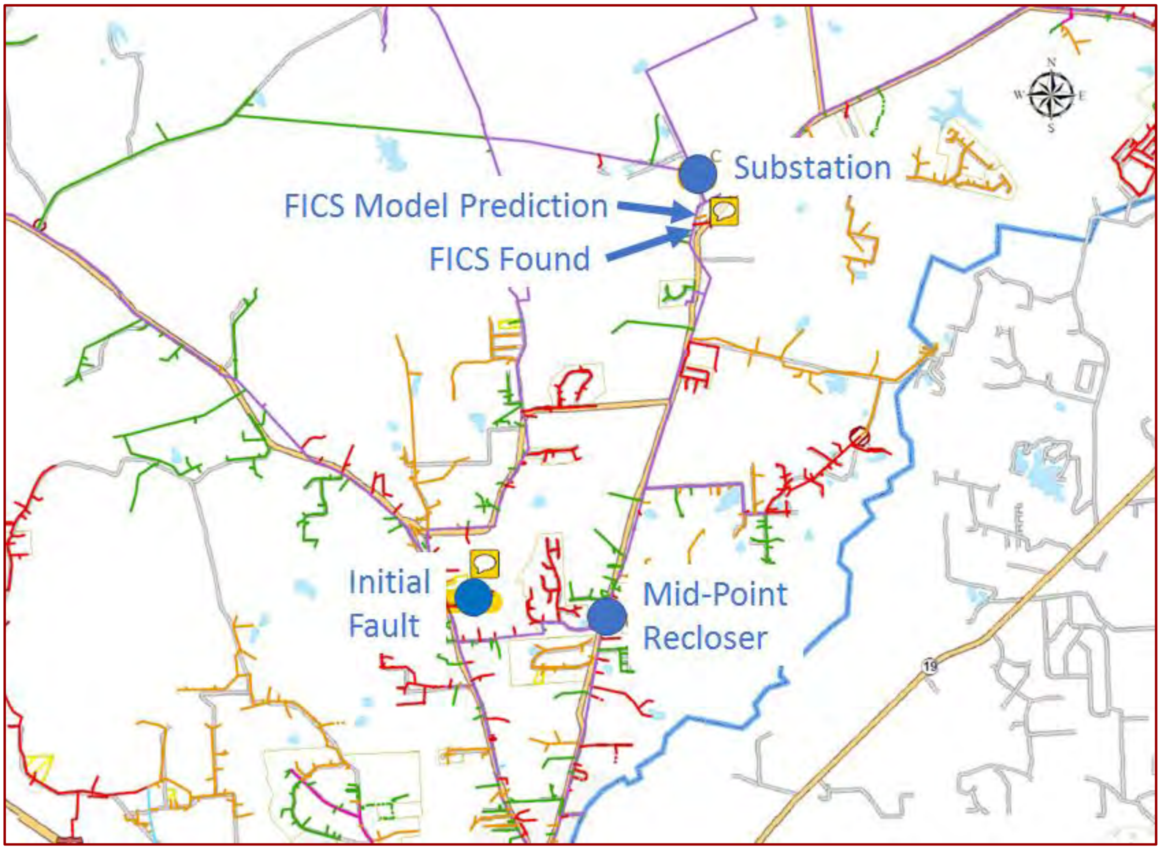
In the subject case, this process found evidence of FICS (i.e., the Second Fault), in the form of conductor pitting and “bright spots” five spans downstream of the model-predicted location. The FICS was near the substation and more than four miles upstream of the mid-point recloser. The FICS span was a transition from vertical to horizontal and had a length of 335 feet of 336.4 MCM ACSR.

Variations and Use of Judgment

Similar but distinct scenarios can result in FICS. Variations on the scenario include the following.

- The Initial Fault may be cleared by a mid-point line fuse, rather than an auto-reclosing device, although the one-shot nature of a fuse reduces the probability of multiple slaps at the point of the Second Fault and therefore lockout by upstream protection.
- There may be two mid-point reclosers in series between the Initial Fault and the substation, in which case the protection that clears the Second Fault may be a mid-point recloser, instead of the substation circuit breaker.
- The initial fault may involve one phase conductor and the circuit neutral conductor, rather than two phases, although all cases fully documented by DFA programs have involved at least two phases.

The real-world example detailed in this tutorial exhibited clear differentiation between the estimated amplitude of the Initial Fault (1260 amps) and that of the Second Fault (2590 amps). This was because the two fault locations were more than four miles apart. By contrast, however, if the two estimated amplitudes hypothetically were 1500 amps and 1600 amps, a diagnosis of FICS would be less clear. The 100-amp difference in fault current estimates could result from the faults occurring at two different locations, indicative of FICS. Alternatively, however, the two faults could be at the same location but have different amplitude estimates because of minor variations in fault geometry or other vagaries and therefore not be indicative of FICS.



Concluding Remarks

Fault-induced conductor slap, or FICS, represents a complex, difficult-to-diagnose phenomenon that can occur on distribution circuits. One fault induces another, often miles away, resulting in a more widespread interruption or outage. Seemingly (but not actual) improper coordination of system protection can misdirect patrols and prolong the outage. If the utility takes note of the seemingly improper protection coordination and attempts to use conventional methods to analyze the issue, the effort often fails. Intelligent signal processing, such as embedded in the DFA technology system, can recognize specific electrical patterns caused by FICS and provide parameters to assist in its location, based on CT and PT signals available at the substation. Proper diagnosis and correction of FICS are important, because they can prevent repeated outages, additional conductor damage, and possibly even a downed conductor.

Intent of This Document

This document describes in general terms the FICS phenomenon and related use of DFA technology. It does not purport to cover all scenarios. The intended audience is utility company personnel. Users should apply the information in this document in conjunction with sound engineering judgement, operational experience, and their inherently superior knowledge of their systems.

Tutorial: Series Arcing and DFA Arcing Switch/Clamp Reports

Introductory Overview

The DFA technology system detects and reports multiple types of events that occur along the length of a distribution circuit.[1] One type of event is series arcing. Series arcing often results in low-amplitude variations in line current and voltage and represents an incipient failure, or “hot spot,” that is developing in the jaws of a load-carrying line device, such as a switch or a clamp. The condition can exist for hours, days, or weeks without customer complaints or other notice to the utility. It causes progressive erosion of line conductors and of the affected device’s contacts and ultimately can result in intermittent voltage fluctuations, flickering lights, unexplained protection operations, and even broken conductors.

Related Types of Failures

A fused cutout can develop an incipient, series-arcing failure in its contacts, just as a blade switch can. Therefore, this discussion of incipient switch failure should be understood to include incipient failure of the contacts of a fused cutout.

DFA has not recorded a known failure of an in-line splice, which also may involve series arcing and manifest similar electrical signatures.

This discussion of series arcing does not include switches or other devices associated with capacitor banks. An incipient failure of a device associated with a capacitor bank behaves differently than one associated with a load-carrying device. DFA reports incipient failures of capacitor-related devices, but it reports them as capacitor issues, not as series arcing.

The Series Arcing Phenomenon

From a scientific point of view, the series arcing phenomenon is not fully understood. A theory generally consistent with observed manifestations is that degraded contact surfaces of a clamp, switch or other load-carrying device create a “hot spot” that behaves as a highly variable electrical impedance. The variable impedance, with load current flowing through it, results in “modulation” of line voltage downstream of the device. The modulated voltage and the resulting dynamic current response of downstream load cause a variety of symptoms, as described herein.

[1] DFA’s On-Line Waveform Characterization Engine detects and reports events based upon signal processing of current and voltage waveforms measured from substation current and potential transformers (CTs and PTs) and does not require communications with substation relays, SCADA/RTUs, or line reclosers. DFA Technology was developed by Texas A&M Engineering, in collaboration with the Electric Power Research Institute, and is commercially available from Power Solutions LLC (www.powersolutionsllc.us).

Observations Regarding the Behavior of Series Arcing

The following observations are based on investigations of multiple series arcing events that have occurred on DFA-fitted circuits. Events were recorded electrically by DFA and documented collaboratively by utility personnel and DFA researchers.

Intermittent Flare Ups

A device that is experiencing series arcing often flares up intermittently. A flare up may last for a fraction of a second or for many minutes. Quiescent periods between flare ups may last minutes at a time or days at a time. During flare ups, the condition can cause symptoms listed hereinafter. During quiescent periods, voltage may be steady and there may be no readily observable symptoms.

Even for a series arcing condition that causes hundreds of events, if those events are spread across a period of days, then the condition is active only for a small fraction of the total time period. This intermittency creates challenges for line crews attempting to diagnose symptoms such as flickering lights or mysterious operations of overcurrent protection, because symptoms may not be present when the crew is on site.

Loading and Environmental Influences

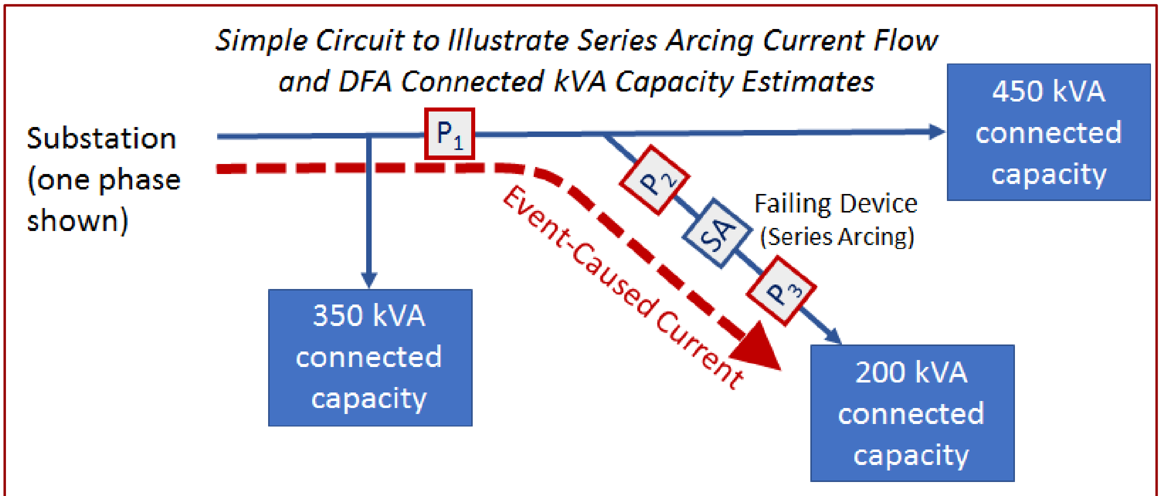
The amount of load current flowing through a failing device may influence series arcing. Environmental factors also can influence series arcing. On multiple occasions, clamps have been observed to flare up during periods of rain but become quiescent during non-rain periods. Heavy dew may have a similar effect. Wind can move conductors and apparatus mechanically, which may influence flare ups. Ambient temperature also may cause flare ups, although that effect may be partly indirect, as a consequence of the increased circuit loading that results during temperature extremes.

Mysterious Overcurrent Protection Operations

Series arcing modulates downstream line voltage, resulting in dynamic response of downstream loads and variations in line current. This Event-Caused Current, as it is referred to in the diagram that follows, usually has relatively small amplitude, but there are multiple documented cases in which series arcing has caused sufficient Event-Caused Current to operate conventional overcurrent protection.

Following a protection operation, replacing a fuse or resetting a recloser may restore service successfully, with the subject outage attributed to “unknown cause,” “weak fuse,” or similar, when in reality the root cause was incipient failure of a clamp or switch. Series arcing will return after a time and may cause additional overcurrent protection operations or other symptoms. Those subsequent episodes may result in identification and repair of the series arcing, perhaps without anyone’s recognizing that the same defect caused the earlier episode(s).

Although it is counterintuitive, series arcing can cause operation of overcurrent protection either upstream or downstream of the series arcing. This is because the Event-Caused Current flows from the substation source, through the failing device, to connected load downstream of the failing device, and therefore through all protection devices in that path. In the diagram, for example, the failing device labeled SA results in Event-Caused Current flowing through the illustrated path and resulting in possible operation of the protection devices at the points labeled P_1, P_2, and P_3.



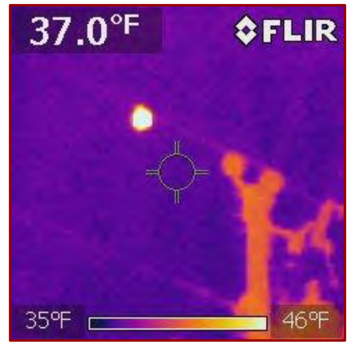
The total connected kVA capacity for this simple circuit is 350 + 450 + 200 = 1000 kVA. The failing device serves 200 kVA of that connected capacity. In the example shown, the DFA estimate likely would fall between 100 and 300 kVA, which would enable one to rule out consideration of a clamp or a switch serving three 15 kVA transformers, for example, but not to distinguish between taps with 150 kVA and 250 kVA of connected capacity.

The following overcurrent protection operations have been documented on DFA-fitted circuits.

1. Operation of a fuse upstream of a failing clamp. This case occurred on a DFA-fitted circuit, but the responding crew was unaware of DFA and therefore acted without DFA information. The subject 30-amp fuse protected a lateral serving more than a dozen customers. The failing clamp was downstream of the fuse and served three of those customers. When the fuse was replaced, the series arcing was not actively flaring up, so the fuse held and the crew concluded that the original fuse had been weak. The series arcing flared up again the next day and caused multiple additional problems, prior to the clamp's ultimately being determined to be the root cause.
2. Operation of a fuse downstream of a failing clamp. In this case, the fuse of a CSP (completely self-protected) transformer blew because of series arcing upstream of the transformer. The responding crew believed the transformer to be bad and replaced it, but they later tested it and found it to be healthy, except for the blown fuse.
3. Operation of a recloser downstream of a failing clamp. A 50-amp hydraulic recloser, downstream of a failing clamp, experienced multiple momentary interruptions and finally locked out, because of series arcing. The clamp flared up intermittently over the course of a month and is believed to have caused more than a dozen momentary operations of the recloser, prior to the lockout.
4. Operation of a recloser upstream of a failing clamp. In this case, a failing clamp caused a single momentary operation of a hydraulic recloser that was upstream of the failing clamp.

Audible Buzzing

Transformers downstream of series arcing may buzz abnormally. It is believed that voltage modulation causes dynamic magnetostriction in the transformer, resulting in the abnormal buzzing. Transformers and other line equipment may buzz during normal operation, but buzzing associated with series arcing may be more pronounced than normal. Crews responding to complaints of flickering lights and hearing abnormal buzzing may conclude incorrectly that a transformer is faulty and causing the flicker.



Radio Frequency (RF) and Infrared Effects

Series arcing can generate infrared (heat) and radio frequency (RF) signatures, which are believed most likely to be prevalent during flare ups. A series arcing failure can generate dozens or hundreds of DFA-detected events, each lasting a few cycles or a few minutes. If those events are spread across a period of days or weeks, however, the total cumulative duration of active flare up still may be a small fraction of the total elapsed time. Infrared cameras and RF detectors likely will identify a device experiencing series arcing if it is scanned during an active period but may not if that same device is scanned during a quiescent period.

Event-Caused Current Influenced Largely by Connected Capacity

The amplitude of the current variations that an active flare up causes appears to be influenced largely by the amount of connected load capacity downstream of the failing device. For example, series arcing of a failing clamp that has 250 kVA of downstream connected capacity tends to produce greater current variation ("Event-Caused Current" in the preceding diagram) than would series arcing of the same failing clamp if it had only 25 kVA of downstream connected capacity. The amplitude of the Event-Caused Current appears to be influenced more by downstream connected capacity than by how much of that load is switched on. DFA reports a gross estimate of the connected kVA past the failing device.

DFA Reports of Switch/Clamp (Series Arcing) Failures

The following image is a series arcing report, copied from the DFA website. Because series arcing most commonly involves a switch or clamp, the DFA report says "probable failure of switch or clamp," as this is believed to be accurate in most cases and more obvious in meaning than would be a report of "series arcing." As discussed in the section on "Related Types of Failures," failing devices related to capacitor banks exhibit different electrical manifestations and are reported separately by DFA.

In the report, the Count column indicates that DFA detected 496 transients, related to this single series arcing failure, and that those transients occurred over a period of 31 days. The DFA report does not list 496 lines of information, however. Instead it clusters the 496 transients together in a single, summary line item on the website. Clicking the + sign enables the user to expand the list to show the times of individual events within the cluster. As an aside, the list illustrates intermittency, showing that the last five events occurred at distinct times between 6:51 and 10:07 a.m. The Amps columns of the sub-events give a sense of the relative severity of the multiple events but should not be used for other purposes.

The report also provides a gross estimate of the kVA of connected capacity downstream of the failing device. Use of the reported kVA parameter is discussed further in the section on Locating Series Arcing.

Switches, clamps, and other connectors all can experience series arcing. The electrical manifestation of series arcing is fundamentally similar for all device types. Based on subtle differences that sometimes appear to differentiate switches from clamps, DFA software attempts to distinguish between the two and reports relative probabilities in the Comments column. Field experience, however, has shown that switches experiencing series arcing tend to go to final failure more quickly than do clamps. Switches often go to final failure within hours, whereas clamps often continue arcing intermittently for multiple days or weeks. Therefore an event that persists for many days likely is a clamp rather than a switch.

Expand	Substation	Circuit	Event Type	Phases	Comments	Count	Last Occurred
+	[illegible]	[illegible]	Probable failure of switch or clamp	B	Estimated load beyond switch/clamp: 194 kVA 80% likelihood switch; 20% likelihood clamp	496 transients (31 days)	2017-10-24 10:07:15

Event Type	Phases	Phase A Amps	Phase B Amps	Phase C Amps	Transients	Last Occurred
Probable failure of switch or clamp(C)	B	14	108	10	1	2017-10-24 10:07:15
Probable failure of switch or clamp(S)	B	10	64	8	6	2017-10-24 09:41:26
Probable failure of switch or clamp(I)	B	9	70	8	3	2017-10-24 09:11:26
Probable failure of switch or clamp(I)	B	5	57	6	2	2017-10-24 06:52:43
Probable failure of switch or clamp(I)	B	8	37	7	1	2017-10-24 06:51:30
Probable failure of switch or clamp(I)	B	8	102	8	1	2017-10-24 06:50:21

DFA's Bias to Minimize False Alarms

Based on industry feedback, DFA biases its reports, including series arcing reports, to minimize false alarms. It is possible for non-arcing events to mimic series arcing for a limited period of time. Such events, however, tend to be infrequent and non-recurring. Therefore part of the DFA's bias toward avoiding false alarms is to report series arcing only after detecting multiple individual events in a relatively short period of time. This inherently delays reporting for some period of time, and can cause some events to not be reported, but this intentional bias is believed to be consistent with general industry feedback and guidance.

Locating Series Arcing

Locating series arcing is challenging, but DFA-reported parameters can provide some help. The following information is intended to overview the use of DFA information for this purpose and to provide observations from field experience.

Because series arcing tends to cause switches to fail more quickly than clamps, an event that continues for more than a few hours likely involves a clamp rather than a switch. This is true even if DFA software, based on analysis of electrical waveform manifestations, reports high likelihood of a switch.

Because incipient failure of a device associated with a capacitor bank causes different electrical behavior than incipient failure of a load-carrying device, a DFA series-arcing report likely does not indicate a problem with capacitor bank hardware, including vacuum bottles, oil switches, fused cutouts, clamps, or any other hardware associated with a capacitor bank. Therefore inspection priority can be given to non-capacitor devices over capacitor devices.

DFA reports a gross estimate of connected kVA capacity downstream of the series arcing. As a rule of thumb, actual connected kVA capacity downstream of series arcing likely is between half of the DFA-reported value and twice the DFA-reported value. This gross estimate can be useful in some cases. The previously illustrated DFA series arcing report, for example, estimated 194 kVA, so that failure was unlikely to involve a device serving a 15 kVA transformer or a device serving 500 kVA of connected capacity. Conversely if DFA software were to provide an estimate of 30 kVA, then a device serving a single small transformer would be a reasonable target for consideration, but a device upstream of 500 kVA of connected capacity would not.

The kVA estimate should be compared to connected capacity, not to the amount of load that is switched on at the time of the transient. For example, if a clamp connects a single 15 kVA transformer, that 15 kVA capacity figure should be used, without regard to whether the transformer is lightly or heavily loaded at any given moment in time.

Where switches or clamps are used to connect an in-line recloser, the devices on the line and load sides of the recloser both should be examined, subject to estimated kVA being reasonable for the location.

Passage of fault current through a device can stress the device and precipitate series arcing. Therefore devices that recently have carried fault current may be good candidates for inspection. Devices can begin to exhibit series arcing without having been stressed by a recent fault, so it would not appropriate to consider only devices with recent fault exposure, but such exposure may prioritize searches.

For a conventional fault, the fault current amplitude depends largely on the impedance of the conductor and other system components upstream of the fault. On a given circuit, a conventional fault close to the substation produces more fault current than does one far from the substation. This is not true for series arcing. The amplitude of the Event-Caused Current seems relatively independent of conductor length or type, instead influenced more by the connected kVA capacity past the failing device. Consequently, conventional approaches to fault location, which use measured fault current amplitude (or quantities such as calculated impedance or distance to fault, which are based on measured fault current) are not applicable for predicting the location of series arcing.

Location of DFA-reported series arcing often requires use of DFA-reported information in conjunction with other information that system operators may have. For a variety of reasons discussed herein, it may prove impractical to locate some cases of series arcing prior to experiencing other trouble. This may be especially true where the DFA kVA estimate is small and therefore consistent with any one of many clamps connecting single transformers. When a trouble call is received, the DFA series arcing report may inform the ensuing troubleshooting activities. For example, if a fuse blows or a recloser operates on a circuit with an active DFA report of series arcing, but there is no record of a high-current event or other obvious cause for the operation, and if the fuse or recloser holds when replaced or reset, then it may be appropriate to instruct the responding line crew to look for a failing clamp or switch upstream or downstream of that protection device. As another example, if customers on a circuit with an active DFA series arcing report experience intermittently flickering lights, but the responding crew finds solid voltage and observes no flicker when on site, then it may be appropriate to instruct them to look for a failing clamp or switch. Use of the DFA report can prevent incorrect diagnoses (e.g., healthy transformers believed to have failed) and repeated complaints of symptoms such as flickering lights.

Use of Smart Meters to Assist in the Location of Series Arcing

Symptoms such as buzzing transformers and flickering lights, during series arcing events, are consistent with the belief that customer service voltage is modulated heavily by series arcing. There are no known high-fidelity recordings, however, of secondary customer voltages or of primary voltages downstream of a clamp or switch that is experiencing series arcing.

Some smart meters can detect certain voltage anomalies, such as sags, swells, interruptions, and in some cases harmonics. A reasonable question, therefore, would be whether smart meters might provide information that could assist the location of series arcing, even before customers report problems. To date there have been limited opportunities to assess this possibility, as described below.

The circuit that experienced the aforementioned 31-day, 496-transient series arcing event has a modern AMI system. A failing clamp was located and definitively determined to be the cause of the DFA-reported series arcing event. Subsequent analysis was conducted on data from smart meters downstream of the clamp. The AMI system is configured to record sags and brownouts, but the analysis found no evidence that the meters had detected such events for the subject failure. One possible explanation is that the line voltage may have experienced momentary reductions, perhaps many of them, but those individual voltage reductions were too short-lived to satisfy the meters' criteria for reporting "sag" or "brownout."

AMI systems can report a "blink" when a series arcing condition results in momentary operation of a recloser, just as they can for any other momentary protection operation. In some cases this may provide information useful to guide a search for series arcing, although its usefulness is limited by the fact that a recloser that operates in such a case can be either upstream or downstream of the series arcing.

AMI meters and systems have varying capabilities and configurable parameters that affect their sensitivity to blinks, brownouts, and other anomalies. This frustrates attempts to form generalized conclusions regarding the use of AMI to provide information related to detecting, confirming, or localizing series arcing. Other than blink counts, the limited opportunities to assess usefulness of AMI data for these purposes have not generated any relevant information.

Using DFA Series Arcing Reports to Assess Effectiveness of Repair

Preceding sections have described cases in which line crews, acting without knowledge of a DFA series arcing report, have replaced transformers or replaced fuses, without recognizing that series arcing was at the root of the problem. DFA can be used to confirm that repair actions truly have solved a problem, or conversely, that they have not. Because series arcing tends to have flare ups and quiescent periods, irregularly spaced in time, flickering lights and other symptoms may cease temporarily following repair actions, even if those actions did not actually address the underlying series arcing problem. Following repair actions, if a DFA series arcing report continues to indicate flare ups, even after hours or days of quiescence, then operators and line crews can use that fact as an indication that the problem remains unresolved, and they can take further appropriate actions.

A Comment Regarding Line Crew Actions

Nothing in this document should be taken as critical of operators or field personnel, the decisions they make, or the actions they take. They act based upon experience and upon information available to them at the time. More often than not, incorrect diagnoses such as those described herein result from a lack of good information, rather than from unsound judgement by field personnel. In the cited cases, the point is not that field personnel acted improperly, but rather that they need improved situational information, which in the case of series arcing sometimes can be provided by DFA.

Concluding Remarks

Incipient failure of a load-carrying switch or clamp can cause series arcing. Series arcing results in a variety of typically intermittent symptoms that can be difficult for line crews to diagnose and can cause operations of conventional overcurrent protection, either upstream or downstream of the failing device.

The DFA technology system reports series arcing as "probable failure of switch or clamp." DFA-provided parametric information can be used to learn of and better diagnose such conditions, particularly when used in conjunction with other information, such as mysterious protection operations and customer reports of intermittently flickering lights. DFA series arcing reports also can be used to help determine whether repair actions have been effective.

Intent of This Document

This document describes in general terms the series arcing phenomenon and related use of DFA technology. It does not purport to cover all scenarios. The intended audience is utility company personnel. Users should apply the information in this document in conjunction with sound engineering judgement, operational experience, and their inherently superior knowledge of their systems.

FAQ: Can my relays, power quality meters, and other devices (or waveform data recorded by those devices) be used to perform DFA functionality? Is the sampling rate sufficient?

Response: Relays and other devices do not provide data suitable for the practice of DFA. The sampling rate for DFA devices is 256 samples per cycle, which DFA developers have found to be sufficient for DFA functionality, but that does not mean that data from relays or other devices with sampling rates of 256 samples per cycle would be suitable.

Explanation: An example is useful for illustrating why sampling rate is but one factor in determining the suitability of a device for providing data for practicing DFA. Figures 1 and 2, on the pages that follow, show line currents and voltages of a circuit that is carrying several tens of amperes of normal load on each phase and that has a hotline clamp that has developed a "hot spot." The photograph at right shows a hotline clamp that has experienced a similar failure process.

The waveforms of Figure 1 are sampled 256 times per second. For the sake of clarity, the figure shows current and voltage only for the phase with the failing clamp. Figure 2 shows RMS currents and voltages, at a rate of one value per cycle, and is intended to give the "big picture."

Overcurrent relays trigger on relatively high-amplitude currents, and power quality meters on significant sags or swells in voltage. Figures 1 and 2 make it clear that the clamp-failure event manifests little change in either current or voltage. Consequently relays and power quality meters do not trigger, and therefore do not provide data for detecting such events, regardless of sampling rate.

More Details: The preceding paragraphs are intended to provide an illustration, in summary form, of why relays and other devices cannot provide data suitable for the practice of DFA. The following paragraphs are for the reader interested in additional details.

The data shown in Figures 1 and 2 come from a DFA device that monitors a 12.47 kV, multi-grounded-wye circuit of typical overhead construction that is serving several hundred customers. The DFA device is connected to conventional bus PTs and circuit CTs available at the substation head of the subject circuit.

A customer on the circuit reported "blinking lights." When a utility lineman responded, the lights were not blinking, and voltage levels at the customer's premises were proper and stable. The lineman checked and tightened secondary service connections as a precaution. Sometime after the lineman left, the customer again reported blinking lights. The lineman's second visit had similar findings. Based on experience and on the fact that only a single customer was reporting trouble, the lineman concluded that the problem likely was on the customer's side of the service transformer. Consequently, he initiated a service request for a recording voltmeter to be placed at the customer's service entrance, to help diagnose the nature and location of the problem.

Prior to the recording voltmeter's being placed, however, a system operator found that the DFA website was reporting "probable failure of switch or clamp" on the same phase as the customer with blinking lights. Figure 3 is a screen capture of the DFA website. The main line item at the top of the report indicates that DFA had detected multiple individual episodes of the event and provides the time of the latest such episode. The user can expand the item, as shown in the figure, to list the times of individual events.

This DFA report of a "failing switch or clamp" refocused the lineman's attention to the primary, instead of the secondary (or the customer's premises wiring), and he then identified an arcing hotline clamp a few spans upstream of the customer's service. Replacing the clamp solved the problem.

Knowing of and locating the failing clamp saved multiple service calls and restored proper service to the customer days earlier than otherwise would have been likely. It also avoided further etching of the conductor and the possibility of a broken conductor. DFA detected the failing clamp based solely on its monitoring of CT and PT signals. DFA algorithms act autonomously to provide the report of Figure 3, so that the user does not have to analyze waveform data, but that data is made available if the user chooses to view it.

Figures 1 and 2 show that each of the circuit's phases was carrying 38 to 70 amps of normal load current. The failing clamp is on phase A of the circuit. Minor variations in load current are visible in the figures, particularly for the currents of phases B and C. Figure 1 shows the high-speed (256 samples per cycle) data for the affected phase for a ten-second period of time. Figure 2 shows the RMS quantities for the same ten-second period, with a time resolution of one cycle, and is intended to show the "big picture." The graphs show no obvious anomalies that would trigger recording by a relay or power quality meter. DFA uses specialized signal processing techniques to detect signal characteristics that are indicative of specific types of circuit events, in this case a failing switch or clamp on phase A, but that are not apparent to visual observation of the graphs. The point is that, although DFA can detect this event and classify it as a failing switch or clamp, the signals would not have triggered recording by a relay or power quality meter. If the event data is not recorded, then it cannot be analyzed to determine the underlying cause. Therefore, relays and power quality meters cannot provide data sufficient for the practice of DFA technology.

This is one of many events that illustrate the inadequacy of data from relays and power quality meters to support DFA functionality. Those devices are designed for specific purposes, and they serve those purposes well, but their purposes and consequently their data differ in important ways from DFA.

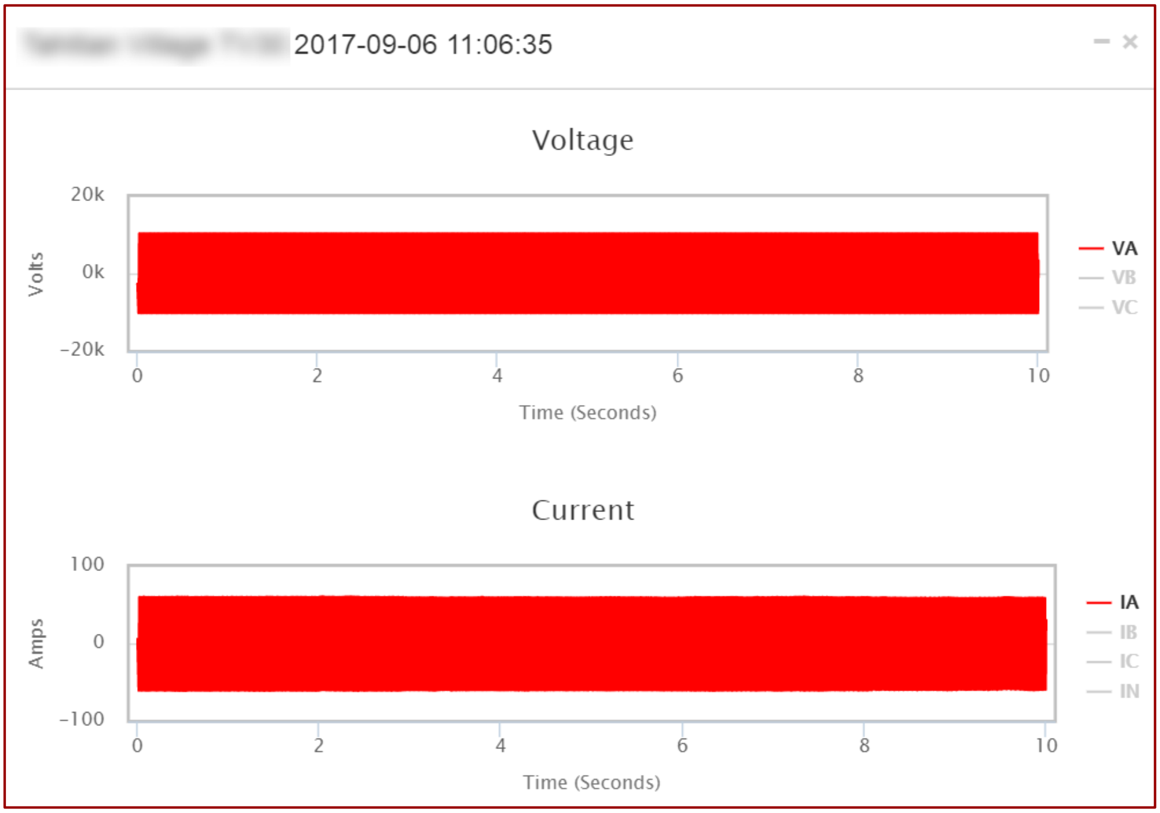


Figure 1. High-speed waveforms for a ten-second period in which a hotline clamp was actively arcing in its jaws. DFA records all three currents and all three voltages, but, for purposes of clarity, this figure shows only the phase with the failing clamp. The DFA gets its signals from substation-based CTs and PTs, so the signals contain all of the circuit's normal load, in addition to the manifestation of the failing clamp. The DFA On-Line Waveform Classification Engine software automatically identified this event as a "probable failure of switch or clamp." (256 samples per cycle.)

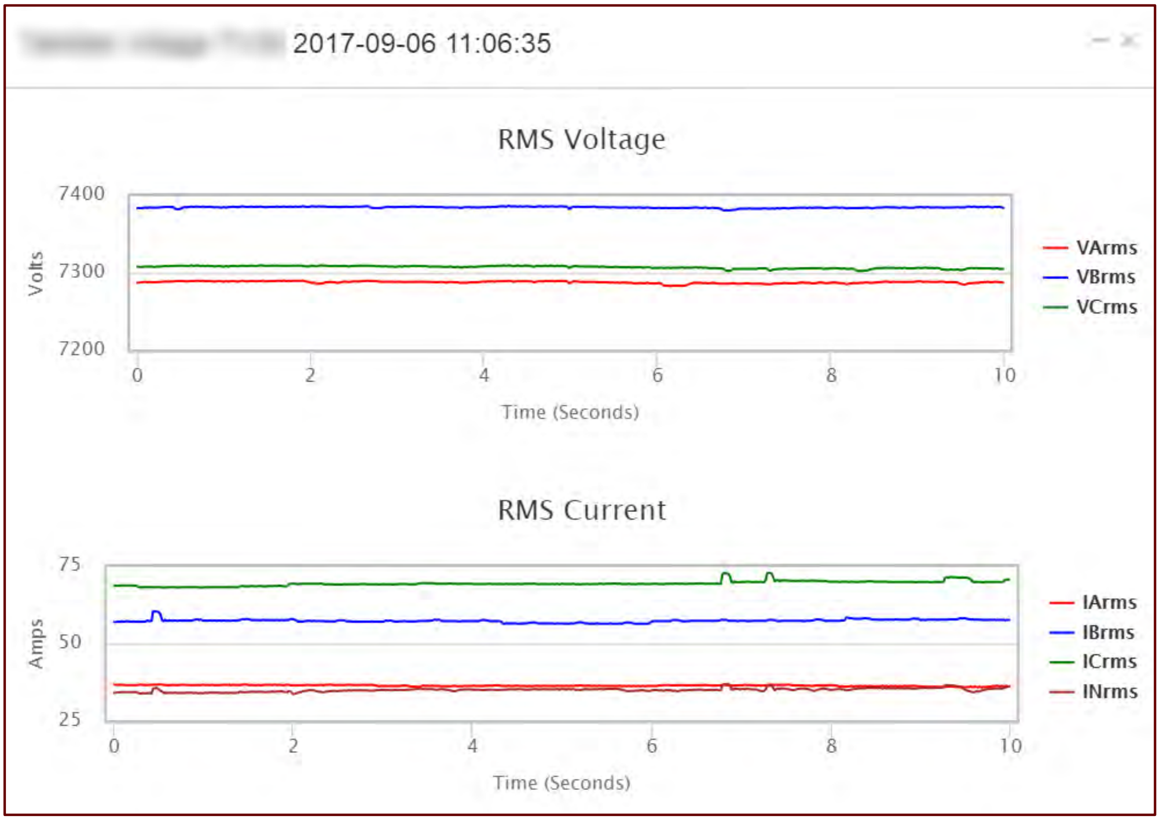


Figure 2. RMS line voltages and currents for the same ten-second interval as Figure 1. The DFA On-Line Waveform Classification Engine software automatically identified this event as a "probable failure of switch or clamp." (12.47 kV circuit. One RMS value per cycle.)

Expand	Substation	Circuit	Event Type	Phases	Average Amps	Max Amps	Count	Last Occurred
+	[illegible]	[illegible]	Probable failure of switch or clamp	A	25, -, -	40, -, -	79 transients (8 days)	2017-09-06 11:19:19

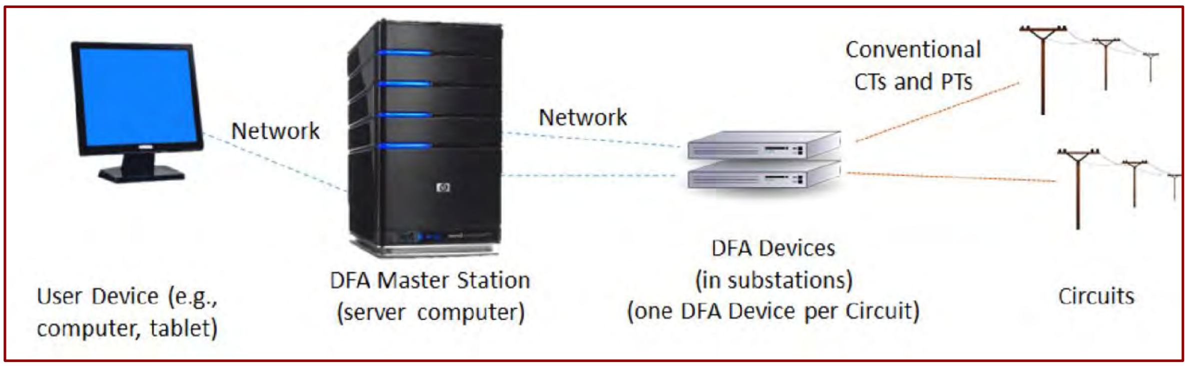
Event Type	Phases	Phase A Amps	Phase B Amps	Phase C Amps	Transients	Last Occurred
Probable failure of switch or clamp(I)	A	19	9	5	1	2017-09-06 11:19:19
Probable failure of switch or clamp(I)	A	16	3	5	1	2017-09-06 11:18:56
Probable failure of switch or clamp(I)	A	30	4	6	4	2017-09-06 11:18:34
Probable failure of switch or clamp(C)	A	29	4	4	2	2017-09-06 11:14:11
Probable failure of switch or clamp(I)	A	15	3	4	1	2017-09-06 11:13:46
Probable failure of switch or clamp(I)	A	15	5	7	1	2017-09-06 11:07:43
Probable failure of switch or clamp(I)	A	19	2	4	2	2017-09-06 11:07:00
Probable failure of switch or clamp(I)	A	27	2	5	1	2017-09-06 11:06:44
Probable failure of switch or clamp(C)	A	15	5	6	1	2017-09-06 11:06:35
Probable failure of switch or clamp(I)	A	29	6	4	2	2017-09-06 11:05:38
Probable failure of switch or clamp(I)	A	21	3	7	2	2017-09-06 11:05:11
Probable failure of switch or clamp(I)	A	24	4	6	1	2017-09-06 11:04:46
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

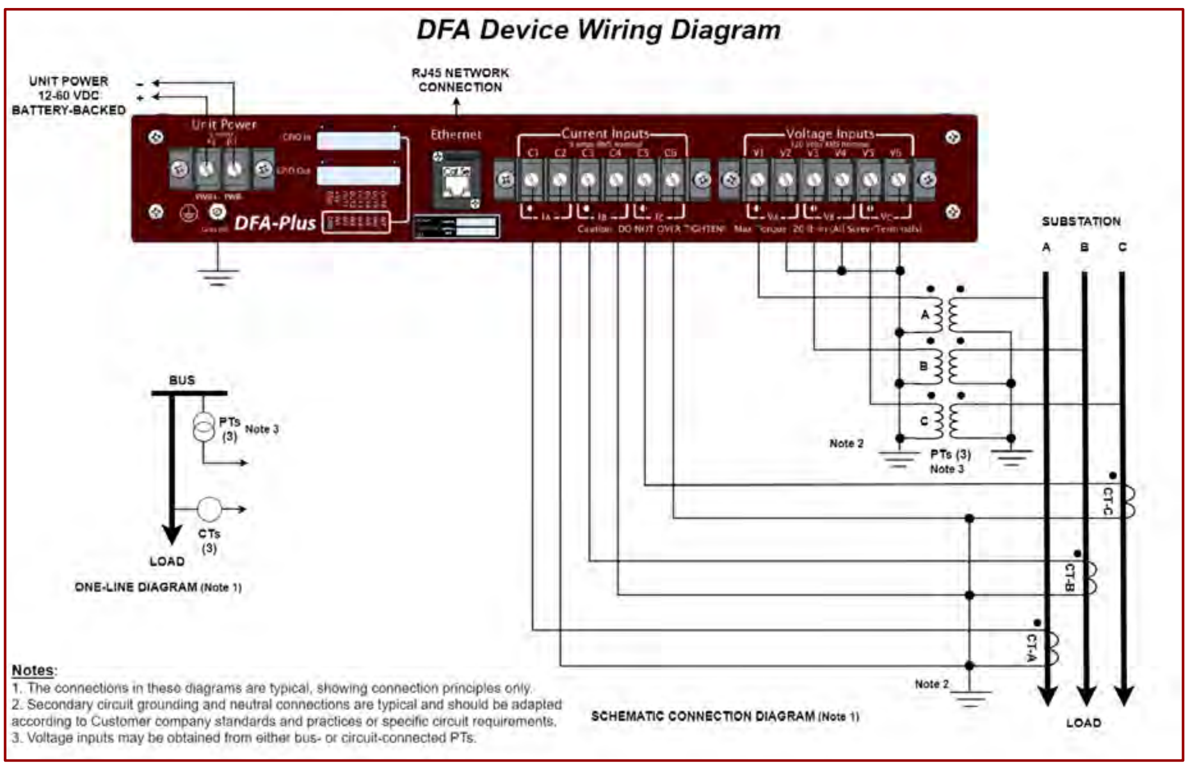
Figure 3. Screen image showing DFA web report of “probable failure of switch or clamp.”

FAQ: What are the components of the DFA Technology system, and how is the system installed and used?

Response: The DFA Technology system is implemented as a fleet of DFA Devices and a centrally located DFA Master Station server computer.

The DFA Master Station retrieves reports and other data from the fleet of DFA Devices and makes that information available to authenticated users via secure DFA web portal.[1] The first image below illustrates the relationships between the various components of the DFA Technology system. The second illustrates typical wiring for a DFA Device.





[1] A FAQ document, entitled, "I am concerned about the security of my DFA-related data and communications. What safeguards does the DFA system use to keep me from being hacked?" provides information on DFA data and communications security safeguards.

Each DFA Device is installed in a substation, to monitor a single circuit, and connects to conventional, three-phase current and potential transformers (CTs and PTs). The customer provides the CTs, PTs, battery-backed unit power, network service, and all associated racks, wiring, etc. DFA Device CT and PT inputs present low burden, enabling them to be “daisy chained” with the inputs of other substation equipment.

Each DFA Device continuously monitors its CT and PT inputs and uses sophisticated signal processing software, known as the Online Waveform Classification Engine, to infer circuit events. It sends pre-analyzed DFA reports to the DFA Master Station, via encrypted Internet, for access by authenticated users. The individual DFA Devices, not the DFA Master Station, apply the Online Waveform Classification Engine software to waveforms to create the reports. As updates to the Online Waveform Classification Engine software become available, the DFA Master Station deploys those updates to the fleet of DFA Devices, via the network.

The following screen captures come from the DFA website and provide two examples of DFA-reported incipient failure conditions. These reports were generated autonomously by the DFA Technology system, without human intervention. The first report relates to a phase-B hotline clamp or switch that has experienced arcing in its jaws intermittently over a period of eighteen days. The second report relates to a single incipient condition that has caused three phase-A faults, over a period of 20 days, each time causing a single trip/close operation of an unmonitored, single-phase recloser. Unless corrected, each condition likely will evolve to cause customer trouble and/or additional damage to system apparatus.

Probable failure of switch or clamp	B	Estimated load beyond switch/clamp: 212 kVA	14 transients (18 days)	2017-10-11 06:46:48

Phases	Phase A Amps	Phase B Amps	Phase C Amps	Transients	Last Occurred
B	12	34	12	1	2017-10-11 06:46:48
B	14	16	16	1	2017-10-11 06:33:50
B	9	106	10	1	2017-10-10 11:38:45
B	8	136	9	1	2017-10-10 11:38:12
B	6	81	6	1	2017-10-09 10:58:21
B	11	52	10	1	2017-10-07 23:38:41

Single-phase recurrent fault	A	Single-phase fault, 746 Amps	3 (20 days)	2017-10-09 08:01:05

Comments	Count	Last Occurred
F-(3.0c,757A,AN,68°)-T-(21,0,0)%-2.2s-C Est imp (ohms): 15.72z = 10.27r + 11.90x	1 op	2017-10-09 08:01:05
F-(3.5c,749A,AN,90°)-T-(12,0,0)%-2.2s-C Est imp (ohms): 16.05z = 10.72r + 11.94x	1 op	2017-09-18 13:52:36
F-(3.5c,733A,AN,84°)-T-(13,0,0)%-2.2s-C Est imp (ohms): 16.39z = 11.11r + 12.05x	1 op	2017-09-18 10:58:24

Incipient Conditions on Electric Power Circuits

A White Paper – April 2017

Carl L. Benner and Dr. B. Don Russell

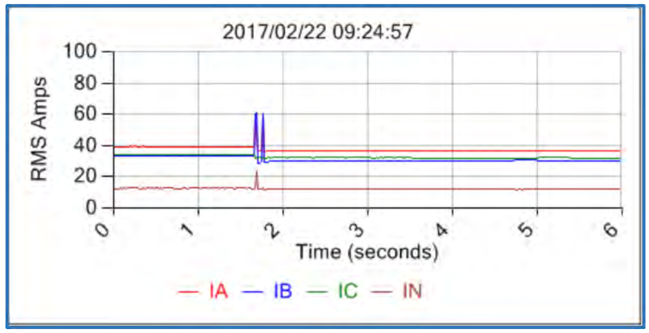
Incipient: *adjective; beginning to develop or exist; beginning to come into being or to become apparent.* (source: Merriam-Webster online)

A practical definition of an incipient condition on an electric power circuit is anything likely to cause a fault, outage, or other negative event in the future. A common misconception holds that incipient conditions manifest themselves only as low-amplitude electrical events, and conversely that high-amplitude electrical events do not represent incipient conditions. More than a decade of Distribution Fault Anticipation (DFA) field investigations demonstrates that this often is not true. Incipient conditions can manifest themselves as high-amplitude electrical events, although often in ways that conventional systems and processes fail to recognize as predictors of future events. Field experience demonstrates that an incipient condition may have any combination of the following characteristics:

- It may or may not have caused past customer complaint(s).
- It may or may not have caused past high-amplitude electrical event(s).
- It may or may not have caused past conventional protection operation(s).
- It may or may not have caused past outage(s).

It is the potential to cause negative future events, not the amplitude of past events, that makes a condition incipient. Incipient conditions are predictive of consequential events that may occur in the future. Documented examples of incipient conditions include the following:

- Fault-induced conductor slap (FICS) – FICS events draw substantial current and often cause circuit-level momentary interruptions or sustained outages. FICS events represent incipient conditions, because a span that has experienced FICS once is prone to experiencing it again. FICS conditions are difficult to diagnose with conventional tools and practices, and therefore often are not diagnosed properly or corrected. FICS events tend to occur repeatedly in a given location. Future consequences of this type of incipient condition can include additional faults, interruptions, outages, equipment stress, progressive conductor damage, and possibly broken conductors.
- Cracked bushings – A cracked bushing may result in a high-amplitude flashover fault, often when rain or dew wets the surface of the bushing. Momentary trip/close operations can clear individual flashover incidents but leave the underlying incipient failure condition undiagnosed. Future high-moisture events can result in additional flashover faults and trip/closes. Potential consequences of this type of incipient condition include additional faults, system stresses, damaged conductors, catastrophic equipment failures, outages, and possibly broken conductors.
- "Hot spots" in clamps and switches – A failing in-line clamp or switch can develop a "hot spot," which can cause progressive erosion both of the clamp and of the conductor. Over time such a condition can cause intermittent power quality issues, mysterious fuse operations, eroded conductors, and possibly broken conductors.



- Failing capacitor switches – Switched capacitor banks experience a high incidence of failures, including failures of their switches. Vacuum and oil switches can develop incipient failures that produce electrical transients that are not detected by conventional systems, including sophisticated capacitor controls. These incipient failures can evolve and cause substantial power quality problems and catastrophic switch failures.

The foregoing list is not intended to be exhaustive but rather to demonstrate that incipient conditions take many forms and cause both high-amplitude and low-amplitude electrical events. Of the examples listed, early-stage "hot spots" and capacitor failures may cause only low-amplitude electrical activity, but FICS and cracked bushings can cause high-amplitude events and interruptions. Personnel often are unaware of incipient conditions, even those that cause intermittent, high-amplitude events, and their lack of awareness limits their ability to diagnose the problems and take appropriate corrective action.

Distribution Fault Anticipation (DFA) Technology and Incipient Faults

DFA technology, developed collaboratively by Texas A&M Engineering and the Electric Power Research Institute, Inc. (EPRI), is a multi-function, data-driven technology that provides utility companies with awareness of circuit conditions that conventional monitoring and protection systems do not provide. DFA technology detects and helps locate existing problems. DFA technology also detects and helps locate incipient conditions. It does this by continuously monitoring circuit current and voltage waveforms, in high fidelity, from substation CTs and PTs, and applying sophisticated digital signal processing, pattern matching, and other software techniques that report ongoing and developing circuit events and conditions.

- DFA technology can detect the unique electrical signature caused by FICS and provide information to target a search for its location.
- DFA reports intermittent flashover faults, caused by such things as cracked bushings, and provides information to help locate the underlying, incipient problem. It does this even when fault episodes are separated in time by weeks of inactivity.
- DFA reports in-line clamp and switch "hot spots" as they evolve, often intermittently over periods of days to weeks, so that a utility company can make informed responses to vague, hard-to-diagnose symptoms such as mysterious fuse operations and intermittently flickering lights.
- DFA reports multiple specific types of capacitor bank failures and incipient failures, including those not detected by advanced capacitor controls, so that the utility company can take corrective action.

With conventional systems and processes, utilities often remain unaware of such conditions and therefore unable to correct them. A DFA incipient fault report can be the first or only notice they receive. It is this awareness that enables them to act upon these incipient conditions.

DFA technology does not purport to detect all negative circuit conditions or prevent all problems, incipient or otherwise, but it has demonstrated the ability to alert utility companies to numerous existing and incipient conditions that are not found by conventional means. Improved awareness enables the utility to be more proactive in addressing some incipient conditions, thereby preventing some negative future events and outages, and to respond with faster, more targeted responses to outages and other trouble.

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-2.12
Respondent:	S. Pfeuffer
	1 of 1

Question: What portion/number of outage events during the historical year 2020 were due to non-tree related failure of poles; crossarms; pole top equipment; primary conductor; secondary conductor; distribution transformers; and sensing/control equipment (such as relays, switches, sensors, capacitors etc.)?

Answer: The Company does not have sufficient data from which to derive an accurate portion or number. The Company uses cause codes for outages as shown in Exhibit A-23, Schedule M1, Exhibit 7.2.3.1 on page 126. During emergent events several pieces of equipment could fail in one location causing the outage event; crews dispatched are focused on restoring customers as quickly as possible and do not always have time to diagnose which failed piece of equipment failed first causing the outage. The data that the Company does have is attached as U-20836 MNSCDE-2.12-01 Equipment Outage Contribution.

Attachment: U-20836 MNSCDE-2.12-01 Equipment Outage Contribution

Material Affected	% SAIFI
Unknown or no data	42.62%
Conductor or cable	18.62%
Fuse cutout	9.11%
Recloser, sectionalizer, or breaker	6.11%
Transformer	5.76%
Pole or structure	3.97%
Crossarm or stand off	3.57%
PTS or PSC switch	1.90%
Disconnect	1.75%
Cable pole, pothead, fanout	1.28%
Lightning arrester	0.86%
Connector sleeve, splice, or joint	0.85%
Regulator or boost	0.83%
Fuse block	0.76%
Connector bolt on	0.55%
Insulator pin	0.50%
Insulator linepost	0.47%
Connector hot tap	0.37%
Terminal or pedestal	0.07%
Ground wire, shield wire, or guy wire	0.01%
Capacitor	0.01%
Meter bases	0.01%
Meter, relay, or controls	0.00%
Insulator dead end	0.00%
OH other	0.00%
Substation other	0.00%
UG Other	0.00%

Material Affected	% SAIDI
Unknown or no data	43.49%
Conductor or cable	20.03%
Fuse cutout	9.04%
Transformer	5.86%
Pole or structure	5.22%
Recloser, sectionalizer, or breaker	3.79%
Crossarm or stand off	2.81%
Lightning arrester	2.37%
PTS or PSC switch	1.53%
Cable pole, pothead, fanout	1.26%
Disconnect	1.13%
Insulator pin	0.98%
Fuse block	0.86%
Connector sleeve, splice, or joint	0.71%
Insulator linepost	0.29%
Connector hot tap	0.22%
Connector bolt on	0.19%
Regulator or boost	0.10%
Terminal or pedestal	0.06%
Ground wire, shield wire, or guy wire	0.03%
Capacitor	0.01%
Meter bases	0.01%
Meter, relay, or controls	0.00%
Insulator dead end	0.00%
OH other	0.00%
Substation other	0.00%
UG Other	0.00%

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-4.4a
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 68, regarding the 8 components of the Detroit Hardening program:

a. If in the Hardening of a particular circuit, a pole and its crossarm were deemed to be in good condition, and regardless of the good condition of such wooden crossarm, will that crossarm be automatically replaced pursuant to DTE's Hardening protocol (see component #2 in the list of 8 components of program scope)? Please explain your response.

Answer: DTE Electric objects to the request for the reason that it is unclear and incapable of answer in its present form, as it is unclear what is meant by "good condition." In further answer and without waiving the objection, the Company states as follows:

Pole condition is tested and those that fail are reinforced or replaced with a new pole of the current standard. There is no test for cross arm condition. The company is hardening the circuit to increase its resilience until a later conversion is performed, and for this reason all wooden cross arms are replaced with the current standard fiberglass cross arms.

Attachment: N/A

Co-Respondent: Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-4.4b
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 68, regarding the 8 components of the Detroit Hardening program:

b. Does component (2) “Replace wooden crossarms with fiberglass crossarms” entail reinstalling existing pole top hardware/equipment (e.g., insulators etc.) in reasonable operating condition? How does DTE account for labor and overheads for removing and then reinstalling such existing hardware/equipment? In the response indicate whether these expenses are assigned to the Hardening program, if they are expensed and/or capitalized, and what portion, if any, is included in Exhibit A-12, page 8 of 12, line 9.

Answer: DTE Electric objects to the request for the reason that it is unclear and incapable of answer in its present form, as it is unclear what is meant by “reasonable condition.” In further answer and without waiving the objection, the Company states as follows:

The Company does not reinstall existing pole top equipment on new cross arms. Replacement of retirement units are capitalized according to DTEE’s standard accounting procedure. All of these costs are assigned in the hardening program and included in Exhibit A12 schedule B5.4, page 12 line 9.

Attachment: N/A

Co-Respondent: Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-4.4c
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 68, regarding the 8 components of the Detroit Hardening program:

c. Does component (2) “Replace wooden crossarms with fiberglass crossarms” include the replacement of broken, damaged, or obsolete (not meeting DTE current standards) pole top hardware/equipment with new hardware/equipment? If yes, how Does DTE account for labor and overheads for the removal and disposal, less salvage value of the existing hardware/equipment; and labor, overheads and materials relating to the installation of the new crossarm and pole top assets? In the response indicate whether these expenses are assigned to the Hardening program, if they are expensed and/or capitalized, and what portion, if any, is included in Exhibit A-12, page 8 of 12, line 9.

Answer: All investments referred to in this question are assigned to the Hardening program and capitalized. They can be found in Exhibit A-12, page 8 of 12, line 9. Salvage value is accounted for at the coporate level and does not appear in the project.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-4.4d
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 68, regarding the 8 components of the Detroit Hardening program:

d. Referring to question (b) above: If broken, damaged, or obsolete equipment or hardware is replaced concurrent with replacement of the pole/crossarm infrastructure under the Hardening program, are the installed costs of such assets (labor and materials and overheads) included in the Hardening program (Exhibit A- 12 page 8 of 12, line 9) or attributed to another program such as the PTMM program (Exhibit A-12, page 8 of 12, line 10), or both. Please explain.

Answer: All investments referred to in this question are assigned to the Hardening program and capitalized. They can be found in Exhibit A-12, page 8 of 12, line 9.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-4.4e
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 68, regarding the 8 components of the Detroit Hardening program:

e. Regarding component (3) the removal of deenergized Detroit PLD arc wire, and component (4) the removal of Detroit PLD distribution wire not serving customers, how does DTE account for the labor and overhead expenses associated with such activities? In the response indicate whether these expenses are assigned to the Hardening program, if they are expensed and/or capitalized, and what portion, if any, is included in Exhibit A-12, page 8 of 12, line 9. If any portion of expenses are not included on line 9, indicate where such expenses are reflected.

Answer: The removal of deenergized Detroit PLD arc wire is part of the Hardening program and is capitalized. PLD primary distribution wire must be returned to the city of Detroit and associated costs are included in the PLD amount as shown in U-20836 Exhibit A12 Schedule B5.4 Page 1, Line 14.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-4.4f
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 68, regarding the 8 components of the Detroit Hardening program:

f. As tree trimming required to support construction activities is part of the scope of the Hardening program, how does DTE allocate the cost between the various removal and installation activities?

Answer: 80% of costs are allocated to installation activities and 20% are allocated to removal activities.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-4.4g
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 68, regarding the 8 components of the Detroit Hardening program:

g. Does DTE schedule crews to implement the Hardening program, the PTMM program, the Cable Replacement program, and the Breaker program (any other?) programs simultaneously on the same substation/distribution circuits in Detroit? Please explain. If not, please explain why not? If yes, which programs are implemented simultaneously at the same substation/circuit; and are some costs (e.g. overhead, labor, tree trimming) allocated across all such programs?

Answer: The PTMM program excludes circuits that were hardened or are scheduled to be hardened in the next 10 years, consistent with the 10-year PTMM cycle the Company targets.

In some cases, the Company may schedule work on a substation such as Cable or Breaker replacement, while another crew is simultaneously working on PTMM or Hardening on circuits fed from the same substation.

Cable and Breaker replacement program scopes target different field assets and do not overlap with Hardening or PTMM.

PTMM and Hardening program scopes have overlap but are not performed on the same circuits. PTMM/Hardening program scopes do not have overlap with Cable or Breaker Replacement programs.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-4.4h
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 68, regarding the 8 components of the Detroit Hardening program:

h. Are program components 1-7 of the Hardening program implemented simultaneously on circuits being hardened, i.e. all components could be part of the same job?

Answer: The program components have a sequence:

Component 6 (Tree Trim activities) is performed first.

Component 1 (Testing all utility poles that have Company equipment attached and replacing or reinforcing those poles as needed) is performed second.

Then the construction phase is performed which includes components 2 (Replace wooden cross arms with fiberglass crossarms), 3 (Remove Detroit PLD arc wire), 4 (Remove Detroit PLD distribution wire), 5 (Remove service lines to abandoned properties), and 7 (Any additional necessary work as dictated by field conditions).

All components are typically completed within one year of each other.

The complete description of program components can be seen on page SGP – 68 question 84.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-4.4i
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 68, regarding the 8 components of the Detroit Hardening program:

i. Please break down the 2022 and 2023 projected Hardening program costs by substation/circuits, and then further by Hardening component categories. If DTE did not project costs in this manner, please explain how such capital costs were projected, and the underlying break down.

Answer: Please refer to the attached file U-20836 MNSCDE-4.4i-01 2022-2023 4.8kV Projected Investments.

Attachment: U-20836 MNSCDE-4.4i-01 2022-2023 4.8kV Projected Investments

U-20836 MNSCDE-4.4i-01 2022-2023 4.8kV Projected Investments

2022 Projected 4.8kV Hardening Investments

Circuits	Substation	Tree Trim	Inspection & Reinforcement	Design	Construction	Total
ANNCH1	ANNCH	$ -		$ 1,411	$ 59,338	$ 60,749
ANNCH2	ANNCH	$ -		$ -	$ 160,238	$ 160,238
ANNCH3	ANNCH	$ -		$ -	$ 706,423	$ 706,423
ANNCH4	ANNCH	$ -		$ -	$ 1,631,417	$ 1,631,417
ANNCH5	ANNCH	$ -		$ -	$ 1,300,678	$ 1,300,678
ANNCH6	ANNCH				$ 979,272	$ 979,272
ANNCH7	ANNCH	$ -		$ -	$ 2,322,188	$ 2,322,188
ANNCH8	ANNCH	$ -		$ -	$ 770,983	$ 770,983
ANNCH9	ANNCH				$ 752,079	$ 752,079
ANNCH10	ANNCH				$ 1,027,860	$ 1,027,860
ANNCH11	ANNCH				$ 1,327,228	$ 1,327,228
ANNCH12	ANNCH				$ 1,964,438	$ 1,964,438
ANNCH13	ANNCH				$ 1,007,244	$ 1,007,244
CHAND1	CHAND	$ -		$ -	$ 260,071	$ 260,071
CHAND2	CHAND				$ 37,163	$ 37,163
CHAND3	CHAND				$ 92,635	$ 92,635
CHAND4	CHAND	$ -		$ -	$ 175,750	$ 175,750
CHAND5	CHAND				$ 608,203	$ 608,203
CHAND6	CHAND	$ -		$ -	$ 159,405	$ 159,405
CHAND7	CHAND				$ 509,394	$ 509,394
CHAND8	CHAND	$ 10,705		$ 2,319	$ 2,222,413	$ 2,235,437
CHAND9	CHAND	$ -		$ -	$ 1,887,784	$ 1,887,784
CHAND10	CHAND	$ -		$ -	$ 3,639,933	$ 3,639,933
CHAND11	CHAND	$ -		$ -	$ 1,174,316	$ 1,174,316
CHAND12	CHAND	$ -		$ -	$ 1,632,825	$ 1,632,825
CHAND13	CHAND	$ -		$ -	$ 617,205	$ 617,205
CHAND14	CHAND	$ -		$ -	$ 1,118,602	$ 1,118,602
CHAND15	CHAND	$ -		$ -	$ 1,045,495	$ 1,045,495
CHAND16	CHAND	$ -		$ -	$ 857,847	$ 857,847
CHAND17	CHAND	$ 11,029		$ 1,558	$ 1,846,914	$ 1,859,501
CHAND18	CHAND	$ -		$ -	$ 1,731,387	$ 1,731,387
CHAND19	CHAND	$ -		$ -	$ 958,901	$ 958,901
CHAND20	CHAND	$ -		$ -	$ 1,561,354	$ 1,561,354
CHIGO1	CHIGO	$ 772		$ 7,923	$ 513,358	$ 522,053
CHIGO2	CHIGO	$ -		$ 472	$ 1,126,053	$ 1,126,525
CHIGO3	CHIGO	$ -		$ 1,783	$ -	$ 1,783
CHIGO4	CHIGO	$ -		$ 6,168	$ 1,976,751	$ 1,982,919
CHIGO5	CHIGO	$ -		$ 3,510	$ 3,063,838	$ 3,067,348
CHIGO6	CHIGO	$ -		$ 6,043	$ 1,054	$ 7,097
CRTIS1	CRTIS					$ -
EIGMI1	EIGMI	$ 267,972	$ 19,321	$ 16,635		$ 303,928
EIGMI2	EIGMI	$ 4,133	$ 298	$ 257		$ 4,688
EIGMI3	EIGMI	$ 350,637	$ 25,281	$ 21,766		$ 397,685
EIGMI4	EIGMI	$ 258,328	$ 18,626	$ 16,036		$ 292,990
EIGMI5	EIGMI	$ 332,037	$ 23,940	$ 20,612		$ 376,590
EIGMI6	EIGMI	$ 455,346	$ 32,831	$ 28,266		$ 516,444
EIGMI7	EIGMI	$ 500,812	$ 36,109	$ 31,089		$ 568,010
EIGMI8	EIGMI	$ 348,570	$ 25,132	$ 21,638		$ 395,341
EIGMI9	EIGMI	$ 434,680	$ 31,341	$ 26,984		$ 493,004
EIGMI10	EIGMI	$ 399,547	$ 28,808	$ 24,803		$ 453,158

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2022 Projected 4.8kV Hardening Investments

Circuits	Substation	Tree Trim	Inspection & Reinforcement	Design	Construction	Total
EIGMI11	EIGMI	$ 307,238	$ 22,152	$ 19,072		$ 348,463
EVRGN1	EVRGN	$ 86,887	$ 6,265	$ 5,394		$ 98,546
EVRGN2	EVRGN	$ 86,023	$ 6,202	$ 5,340		$ 97,566
EVRGN3	EVRGN	$ 55,743	$ 4,019	$ 3,460		$ 63,222
EVRGN4	EVRGN	$ 40,853	$ 2,946	$ 2,536		$ 46,334
EVRGN5	EVRGN	$ 26,688	$ 1,924	$ 1,657		$ 30,269
EVRGN6	EVRGN	$ 4,657	$ 336	$ 289	$ 47,612	$ 52,894
EVRGN7	EVRGN	$ 60,774	$ 4,382	$ 3,773		$ 68,928
EVRGN8	EVRGN	$ 73,152	$ 5,274	$ 4,541		$ 82,967
EVRGN9	EVRGN	$ 397,880	$ 28,688	$ 24,699		$ 451,267
EVRGN10	EVRGN	$ 547,181	$ 39,453	$ 33,967		$ 620,601
EVRGN11	EVRGN	$ 604,114	$ 43,558	$ 37,502		$ 685,173
EVRGN12	EVRGN	$ 431,305	$ 31,098	$ 26,774		$ 489,177
EVRGN13	EVRGN	$ 286,120	$ 20,630	$ 17,761		$ 324,511
EVRGN14	EVRGN	$ 349,188	$ 25,177	$ 21,676		$ 396,041
EVRGN15	EVRGN	$ 295,801	$ 21,328	$ 18,362		$ 335,491
EVRGN16	EVRGN	$ 651,998	$ 47,010	$ 40,474	$ 45,862	$ 785,343
EVRGN17	EVRGN	$ 430,434	$ 31,035	$ 26,720		$ 488,189
EVRGN18	EVRGN	$ 444,772	$ 32,069	$ 27,610	$ 296	$ 504,746
EVRGN19	EVRGN	$ 584,935	$ 42,175	$ 36,311		$ 663,421
EVRGN20	EVRGN	$ 332,239	$ 23,955	$ 20,624		$ 376,818
EVRGN21	EVRGN	$ 327,420	$ 23,607	$ 20,325		$ 371,353
FLANE1	FLANE	$ -		$ 2,425	$ 2,400,510	$ 2,402,935
FLANE2	FLANE	$ -		$ 5,779	$ 3,095,408	$ 3,101,187
FLANE3	FLANE	$ 853		$ 2,446	$ 879,064	$ 882,363
FRISB1	FRISB				$ 320,633	$ 320,633
FRISB2	FRISB				$ 208,828	$ 208,828
FRISB3	FRISB				$ 38,515	$ 38,515
FRISB4	FRISB				$ 207,135	$ 207,135
FRISB5	FRISB	$ -		$ 37,423	$ 25,880	$ 63,303
FRISB6	FRISB	$ -		$ -	$ 639,712	$ 639,712
FRISB7	FRISB				$ 90,015	$ 90,015
FRISB8	FRISB	$ -		$ -	$ 198,983	$ 198,983
FRISB9	FRISB	$ -		$ -	$ 545,575	$ 545,575
FRISB10	FRISB				$ 612,410	$ 612,410
FRISB11	FRISB				$ 479,507	$ 479,507
FRISB12	FRISB	$ -		$ -	$ 1,716,122	$ 1,716,122
FRISB13	FRISB	$ 1,615		$ -	$ 649,138	$ 650,753
FRISB14	FRISB	$ -		$ -	$ 2,391,145	$ 2,391,145
FRISB15	FRISB				$ 807,603	$ 807,603
FRISB16	FRISB	$ -		$ -	$ 841,855	$ 841,855
GARY1	GARY				$ 1,175,706	$ 1,175,706
GARY2	GARY				$ 658,801	$ 658,801
GARY3	GARY				$ 172,302	$ 172,302
GARY4	GARY	$ -		$ 4,583	$ 1,154,331	$ 1,158,914
GARY5	GARY	$ -		$ 5,445	$ 170,721	$ 176,166
GARY6	GARY	$ -		$ 3,474	$ 534,373	$ 537,847
GARY7	GARY	$ -		$ 1,699	$ 1,475	$ 3,174
GARY8	GARY	$ -		$ -	$ 2,249	$ 2,249
GARY9	GARY	$ -		$ 287	$ -	$ 287

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2022 Projected 4.8kV Hardening Investments

Circuits	Substation	Tree Trim	Inspection & Reinforcement	Design	Construction	Total
GRANT1	GRANT	$ -		$ 1,493	$ 8,352	$ 9,845
GRANT2	GRANT	$ -		$ 4,889	$ -	$ 4,889
GRANT3	GRANT	$ -		$ 5,351	$ 410,499	$ 415,851
GRANT4	GRANT	$ -		$ -	$ 12,380	$ 12,380
HAWTH1	HAWTH	$ 3,323		$ -	$ 337	$ 3,660
HAWTH2	HAWTH	$ -		$ 5,915	$ 13,086	$ 19,001
HAWTH3	HAWTH	$ -		$ -	$ -	$ -
HAWTH4	HAWTH	$ -		$ -	$ 239,170	$ 239,170
HAWTH5	HAWTH	$ -		$ -	$ 105	$ 105
HAWTH6	HAWTH	$ -		$ -	$ -	$ -
HAWTH7	HAWTH	$ -		$ -	$ 1,638	$ 1,638
HAWTH8	HAWTH	$ -		$ -	$ 13,910	$ 13,910
MCGRW1	MCGRW	$ 160,341	$ 11,492	$ 9,894	$ -	$ 181,727
MCGRW2	MCGRW	$ 80,195	$ 5,782	$ 4,978		$ 90,956
MCGRW3	MCGRW	$ 216,598	$ 15,617	$ 13,446		$ 245,660
MCGRW4	MCGRW	$ 187,006	$ 13,483	$ 16,330	$ -	$ 216,820
MCGRW5	MCGRW	$ 4,773	$ 344	$ 296		$ 5,413
MCGRW6	MCGRW	$ 151,295	$ 10,856	$ 9,347	$ -	$ 171,498
MCGRW7	MCGRW	$ 74,159	$ 5,347	$ 4,604		$ 84,110
MCGRW8	MCGRW	$ 31,838	$ 2,296	$ 1,976		$ 36,110
MCGRW9	MCGRW	$ 57,110	$ 4,118	$ 3,545		$ 64,773
MCGRW10	MCGRW	$ 448,323	$ 32,325	$ 27,830		$ 508,478
MCGRW11	MCGRW	$ 483,637	$ 34,871	$ 30,023		$ 548,531
MCGRW12	MCGRW	$ 324,009	$ 23,362	$ 20,113		$ 367,484
MCGRW13	MCGRW	$ 516,727	$ 37,257	$ 32,077		$ 586,060
MCGRW14	MCGRW	$ 277,461	$ 20,005	$ 17,224		$ 314,690
MCGRW15	MCGRW	$ 388,553	$ 28,015	$ 24,120		$ 440,688
MCGRW16	MCGRW	$ 72,333	$ 5,215	$ 4,490		$ 82,038
MCGRW17	MCGRW	$ 452,844	$ 32,651	$ 28,111		$ 513,606
MCGRW18	MCGRW	$ 198,682	$ 14,325	$ 12,334		$ 225,340
MEYRS1	MEYRS	$ 432,300		$ -	$ 1,470,295	$ 1,902,595
MEYRS2	MEYRS	$ 30,914		$ -	$ 1,391,692	$ 1,422,606
MEYRS3	MEYRS	$ 34,845		$ -	$ -	$ 34,845
MEYRS4	MEYRS	$ 251,724		$ -	$ 1,220,302	$ 1,472,027
MEYRS5	MEYRS	$ 167,204		$ -	$ 1,396,050	$ 1,563,254
MEYRS6	MEYRS	$ 36,874		$ -	$ 505,884	$ 542,758
MEYRS7	MEYRS	$ 8,320		$ -	$ -	$ 8,320
NAVAR1	NAVAR	$ 227,159	$ 16,378	$ 14,101		$ 257,639
NAVAR2	NAVAR	$ 16,461	$ 1,187	$ 1,022		$ 18,670
NAVAR3	NAVAR	$ 8,562	$ 617	$ 532		$ 9,711
NAVAR4	NAVAR	$ 81,483	$ 5,875	$ 5,058		$ 92,416
NAVAR5	NAVAR	$ 31,730	$ 2,288	$ 1,970		$ 35,987
NAVAR6	NAVAR	$ 53,817	$ 3,880	$ 3,341		$ 61,038
NAVAR7	NAVAR	$ 146,643	$ 10,573	$ 9,103		$ 166,320
NAVAR8	NAVAR	$ 489,567	$ 35,299	$ 30,391		$ 555,257
NAVAR9	NAVAR	$ 314,021	$ 22,641	$ 19,493		$ 356,155
NAVAR10	NAVAR	$ 379,783	$ 27,383	$ 23,576		$ 430,742
NAVAR11	NAVAR	$ 248,316	$ 17,904	$ 15,415		$ 281,634
NAVAR12	NAVAR	$ 488,773	$ 35,241	$ 30,341		$ 554,355
NAVAR13	NAVAR	$ 616,285	$ 44,435	$ 38,257		$ 698,977

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2022 Projected 4.8kV Hardening Investments

Circuits	Substation	Tree Trim	Inspection & Reinforcement	Design	Construction	Total
NAVAR14	NAVAR	$ 546,900	$ 39,432	$ 33,950		$ 620,282
NAVAR15	NAVAR	$ 316,895	$ 22,849	$ 19,672		$ 359,415
SAVAN1	SAVAN	$ 72,145	$ 5,202	$ 4,479		$ 81,825
SAVAN2	SAVAN	$ 248,518	$ 17,918	$ 15,427		$ 281,863
SAVAN3	SAVAN	$ 12,732	$ 918	$ 790		$ 14,441
SAVAN4	SAVAN	$ 7,823	$ 564	$ 486		$ 8,873
SAVAN5	SAVAN	$ 573,307	$ 41,336	$ 35,589		$ 650,233
SAVAN6	SAVAN	$ 401,991	$ 28,984	$ 24,954		$ 455,929
SAVAN7	SAVAN	$ 310,949	$ 22,420	$ 19,303		$ 352,671
SAVAN8	SAVAN	$ 161,395	$ 11,637	$ 10,019		$ 183,050
SAVAN9	SAVAN	$ 561,803	$ 40,507	$ 34,875		$ 637,185
SAVAN10	SAVAN	$ 258,995	$ 18,674	$ 16,078		$ 293,746
SAVAN11	SAVAN	$ 561,068	$ 40,454	$ 34,829		$ 636,351
SAVAN12	SAVAN	$ 281,015	$ 20,262	$ 17,445		$ 318,721
SAVAN13	SAVAN	$ 480,710	$ 34,660	$ 29,841		$ 545,211
SAVAN14	SAVAN	$ 306,941	$ 22,131	$ 19,054		$ 348,126
SAVAN15	SAVAN	$ 322,993	$ 23,288	$ 20,050		$ 366,331
VILLA1	VILLA	$ -		$ 67,989	$ 138,185	$ 206,175
VILLA2	VILLA	$ -		$ -	$ 726,423	$ 726,423
VILLA3	VILLA				$ 1,096,834	$ 1,096,834
VILLA4	VILLA				$ 815,194	$ 815,194
VILLA5	VILLA				$ 1,834,545	$ 1,834,545
VILLA6	VILLA				$ 1,308,104	$ 1,308,104
VILLA7	VILLA				$ 1,187,770	$ 1,187,770
VILLA8	VILLA				$ 620,632	$ 620,632
VILLA9	VILLA				$ 1,156,696	$ 1,156,696
WAGNR1	WAGNR	$ -		$ -	$ 236,687	$ 236,687
WAGNR2	WAGNR	$ -		$ -	$ 20,755	$ 20,755
WAGNR3	WAGNR				$ 84,330	$ 84,330
WAGNR4	WAGNR	$ 7,196		$ -	$ 914,702	$ 921,898
WAGNR5	WAGNR				$ 1,388,344	$ 1,388,344
WAGNR6	WAGNR	$ -		$ -	$ 1,826,102	$ 1,826,102
WAYBN1	WAYBN	$ 54,929		$ -	$ 2,556,801	$ 2,611,730
WAYBN2	WAYBN	$ 37,691		$ -	$ 1,330,166	$ 1,367,856
WAYBN3	WAYBN				$ 1,352,542	$ 1,352,542
WAYBN4	WAYBN	$ 1,413		$ -	$ 113,469	$ 114,882
WAYBN5	WAYBN	$ 120,753		$ -	$ 1,346,766	$ 1,467,519
WAYBN6	WAYBN	$ -		$ -	$ 261,378	$ 261,378
WAYBN7	WAYBN	$ -		$ -	$ 522,675	$ 522,675
WAYBN8	WAYBN	$ -		$ -	$ 281,088	$ 281,088
WAYBN9	WAYBN	$ -		$ -	$ 105,589	$ 105,589
WAYBN10	WAYBN	$ -		$ -	$ 750	$ 750
WAYBN11	WAYBN				$ 260,926	$ 260,926
WAYBN12	WAYBN				$ 963,916	$ 963,916
4.8kV Hardening	**2022 Total**	**$ 23,644,582**	**$ 1,617,268**	**$ 1,577,519**	**$ 92,074,877**	**$ 118,914,246**

U-20836 MNSCDE-4.4i-01 2022-2023 4.8kV Projected Investments

2023 Projected 4.8kV Hardening Investments

Circuits	Substation	Tree Trim	Inspection & Reinforcement	Design	Construction	Total
COOLG1	COOLG	$ 28,078	$ 1,872	$ 1,685		$ 31,634
COOLG2	COOLG	$ 95,388	$ 6,359	$ 5,723		$ 107,471
COOLG3	COOLG	$ 131,717	$ 8,781	$ 7,903		$ 148,401
COOLG4	COOLG	$ 148,707	$ 9,914	$ 8,922		$ 167,543
COOLG5	COOLG	$ 441,970	$ 29,465	$ 26,518		$ 497,953
COOLG6	COOLG	$ 650,128	$ 43,342	$ 39,008		$ 732,478
COOLG7	COOLG	$ 423,679	$ 28,245	$ 25,421		$ 477,345
COOLG8	COOLG	$ 512,530	$ 34,169	$ 30,752		$ 577,451
COOLG9	COOLG	$ 399,407	$ 26,627	$ 23,964		$ 449,999
COOLG10	COOLG	$ 416,321	$ 27,755	$ 24,979		$ 469,056
COOLG11	COOLG	$ 365,427	$ 24,362	$ 21,926		$ 411,714
COOLG12	COOLG	$ 373,195	$ 24,880	$ 22,392		$ 420,466
COOLG13	COOLG	$ 317,318	$ 21,155	$ 19,039		$ 357,512
CORTL1	CORTL	$ 201,074	$ 13,238	$ 11,914		$ 226,227
CORTL2	CORTL	$ 61,619	$ 3,941	$ 3,547		$ 69,107
CORTL3	CORTL	$ 176,818	$ 11,621	$ 10,459		$ 198,898
CORTL4	CORTL	$ 660,023	$ 43,835	$ 39,451		$ 743,310
CORTL5	CORTL	$ 237,661	$ 15,677	$ 14,110		$ 267,448
CORTL6	CORTL	$ 70,203	$ 4,514	$ 4,062		$ 78,779
CORTL7	CORTL	$ 413,994	$ 27,433	$ 24,690		$ 466,117
CORTL8	CORTL	$ 356,620	$ 23,608	$ 21,247		$ 401,475
CORTL9	CORTL	$ 275,097	$ 18,173	$ 16,356		$ 309,626
CORTL10	CORTL	$ 283,892	$ 18,759	$ 16,883		$ 319,534
CORTL11	CORTL	$ 29,702	$ 1,813	$ 1,632		$ 33,148
CORTL12	CORTL	$ 26,912	$ 1,627	$ 1,465		$ 30,004
DCATR1	DCATR	$ 560,500	$ 37,200	$ 33,480	$ 1,684,715	$ 2,315,895
DCATR2	DCATR	$ 476,500	$ 31,600	$ 28,440	$ 1,431,102	$ 1,967,642
DCATR3	DCATR	$ 346,023	$ 22,902	$ 20,611	$ 1,037,164	$ 1,426,700
DCATR4	DCATR	$ 419,067	$ 27,771	$ 24,994	$ 1,257,700	$ 1,729,532
DCATR5	DCATR	$ 126,308	$ 8,254	$ 7,429	$ 373,803	$ 515,794
DCATR6	DCATR	$ 37,268	$ 2,318	$ 2,086	$ 104,972	$ 146,645
DCATR7	DCATR	$ 15,094	$ 840	$ 756	$ 38,025	$ 54,714
EIGMI1	EIGMI				$ 880,852	$ 880,852
EIGMI2	EIGMI				$ 13,586	$ 13,586
EIGMI3	EIGMI				$ 1,152,581	$ 1,152,581
EIGMI4	EIGMI				$ 849,151	$ 849,151
EIGMI5	EIGMI				$ 1,091,442	$ 1,091,442
EIGMI6	EIGMI				$ 1,496,770	$ 1,496,770
EIGMI7	EIGMI				$ 1,646,220	$ 1,646,220
EIGMI8	EIGMI				$ 1,145,787	$ 1,145,787
EIGMI9	EIGMI				$ 1,428,838	$ 1,428,838
EIGMI10	EIGMI				$ 1,313,353	$ 1,313,353

U-20836 MNSCDE-4.4i-01 2022-2023 4.8kV Projected Investments

2023 Projected 4.8kV Hardening Investments

Circuits	Substation	Tree Trim	Inspection & Reinforcement	Design	Construction	Total
EIGMI11	EIGMI				$ 1,009,923	$ 1,009,923
EVRGN1	EVRGN				$ 285,608	$ 285,608
EVRGN2	EVRGN				$ 282,767	$ 282,767
EVRGN3	EVRGN				$ 183,232	$ 183,232
EVRGN4	EVRGN				$ 134,287	$ 134,287
EVRGN5	EVRGN				$ 87,726	$ 87,726
EVRGN6	EVRGN				$ 199,770	$ 199,770
EVRGN7	EVRGN				$ 240,457	$ 240,457
EVRGN8	EVRGN				$ 1,307,874	$ 1,307,874
EVRGN9	EVRGN				$ 1,798,641	$ 1,798,641
EVRGN10	EVRGN				$ 1,985,786	$ 1,985,786
EVRGN11	EVRGN				$ 1,417,746	$ 1,417,746
EVRGN12	EVRGN				$ 940,505	$ 940,505
EVRGN13	EVRGN				$ 1,147,816	$ 1,147,816
EVRGN14	EVRGN				$ 972,330	$ 972,330
EVRGN15	EVRGN				$ 2,143,185	$ 2,143,185
EVRGN16	EVRGN				$ 1,414,881	$ 1,414,881
EVRGN17	EVRGN				$ 1,462,011	$ 1,462,011
EVRGN18	EVRGN				$ 1,922,744	$ 1,922,744
EVRGN19	EVRGN				$ 1,092,104	$ 1,092,104
EVRGN20	EVRGN				$ 1,076,264	$ 1,076,264
EVRGN21	EVRGN				$ 15,308	$ 15,308
FRMNT1	FRMNT	$ 326,486	$ 21,599	$ 19,439		$ 367,524
FRMNT2	FRMNT	$ 354,521	$ 23,468	$ 21,121		$ 399,111
FRMNT3	FRMNT	$ 434,999	$ 28,833	$ 25,950		$ 489,782
FRMNT4	FRMNT	$ 291,384	$ 19,259	$ 17,333		$ 327,976
FRMNT5	FRMNT	$ 729,675	$ 48,478	$ 43,631		$ 821,784
FRMNT6	FRMNT	$ 664,917	$ 44,161	$ 39,745		$ 748,823
FRMNT7	FRMNT	$ 47,500	$ 3,000	$ 2,700		$ 53,200
GNSTN1	GNSTN	$ 183,971	$ 12,265	$ 11,038		$ 207,274
GNSTN2	GNSTN	$ 4,206	$ 280	$ 252		$ 4,738
GNSTN3	GNSTN	$ 117,998	$ 7,867	$ 7,080		$ 132,945
GNSTN4	GNSTN	$ 107,805	$ 7,187	$ 6,468		$ 121,460
GNSTN5	GNSTN	$ 518,804	$ 34,587	$ 31,128		$ 584,519
GNSTN6	GNSTN	$ 526,855	$ 35,124	$ 31,611		$ 593,590
GNSTN7	GNSTN	$ 863,725	$ 57,582	$ 51,823		$ 973,130
GNSTN8	GNSTN	$ 359,153	$ 23,944	$ 21,549		$ 404,645
LAUDR1	LAUDR	$ 13,560	$ 904	$ 814		$ 15,278
LAUDR2	LAUDR	$ 279,700	$ 18,647	$ 16,782		$ 315,129
LAUDR3	LAUDR	$ 393,302	$ 26,220	$ 23,598		$ 443,120
LAUDR4	LAUDR	$ 408,136	$ 27,209	$ 24,488		$ 459,833
LAUDR5	LAUDR	$ 36,915	$ 2,461	$ 2,215		$ 41,591

U-20836 MNSCDE-4.4i-01 2022-2023 4.8kV Projected Investments

2023 Projected 4.8kV Hardening Investments

Circuits	Substation	Tree Trim	Inspection & Reinforcement	Design	Construction	Total
LAUDR6	LAUDR	$ 359,790	$ 23,986	$ 21,587		$ 405,364
LAUDR7	LAUDR	$ 293,302	$ 19,553	$ 17,598		$ 330,454
LAUDR8	LAUDR	$ 370,059	$ 24,671	$ 22,204		$ 416,934
LAUDR9	LAUDR	$ 566,166	$ 37,744	$ 33,970		$ 637,880
MCGRW1	MCGRW				$ 523,910	$ 523,910
MCGRW2	MCGRW				$ 263,610	$ 263,610
MCGRW3	MCGRW				$ 711,979	$ 711,979
MCGRW4	MCGRW				$ 614,708	$ 614,708
MCGRW5	MCGRW				$ 494,939	$ 494,939
MCGRW6	MCGRW				$ 243,769	$ 243,769
MCGRW7	MCGRW				$ 187,726	$ 187,726
MCGRW8	MCGRW				$ 1,473,683	$ 1,473,683
MCGRW9	MCGRW				$ 1,589,766	$ 1,589,766
MCGRW10	MCGRW				$ 1,065,052	$ 1,065,052
MCGRW11	MCGRW				$ 1,698,535	$ 1,698,535
MCGRW12	MCGRW				$ 912,043	$ 912,043
MCGRW13	MCGRW				$ 1,277,214	$ 1,277,214
MCGRW14	MCGRW				$ 237,765	$ 237,765
MCGRW15	MCGRW				$ 1,488,545	$ 1,488,545
MCGRW16	MCGRW				$ 653,087	$ 653,087
MCGRW17	MCGRW				$ 104,654	$ 104,654
MCGRW18	MCGRW				$ 15,690	$ 15,690
MEYRS1	MEYRS				$ 1,640,706	$ 1,640,706
MEYRS2	MEYRS				$ 118,697	$ 118,697
MEYRS3	MEYRS				$ 1,602,248	$ 1,602,248
MLVDL1	MLVDL	$ 123,253	$ 8,050	$ 7,245		$ 138,548
MLVDL2	MLVDL	$ 186,720	$ 12,281	$ 11,053		$ 210,054
MLVDL3	MLVDL	$ 86,969	$ 5,631	$ 5,068		$ 97,668
MLVDL4	MLVDL	$ 383,440	$ 25,396	$ 22,856		$ 431,692
MLVDL5	MLVDL	$ 450,500	$ 29,867	$ 26,880		$ 507,246
MLVDL6	MLVDL	$ 297,795	$ 19,686	$ 17,718		$ 335,199
MLVDL7	MLVDL	$ 319,843	$ 21,156	$ 19,041		$ 360,040
MLVDL8	MLVDL	$ 446,897	$ 29,626	$ 26,664		$ 503,187
MLVDL9	MLVDL	$ 393,242	$ 26,049	$ 23,444		$ 442,736
MLVDL10	MLVDL	$ 355,112	$ 23,507	$ 21,157		$ 399,776
MLVDL11	MLVDL	$ 436,472	$ 28,931	$ 26,038		$ 491,442
MLVDL12	MLVDL	$ 12,019	$ 635	$ 571		$ 13,224
NAVAR1	NAVAR				$ 746,695	$ 746,695
NAVAR2	NAVAR				$ 267,842	$ 267,842
NAVAR3	NAVAR				$ 176,901	$ 176,901
NAVAR4	NAVAR				$ 482,032	$ 482,032
NAVAR5	NAVAR				$ 1,609,259	$ 1,609,259

U-20836 MNSCDE-4.4i-01 2022-2023 4.8kV Projected Investments

2023 Projected 4.8kV Hardening Investments

Circuits	Substation	Tree Trim	Inspection & Reinforcement	Design	Construction	Total
NAVAR6	NAVAR				$ 1,032,218	$ 1,032,218
NAVAR7	NAVAR				$ 1,248,386	$ 1,248,386
NAVAR8	NAVAR				$ 816,240	$ 816,240
NAVAR9	NAVAR				$ 1,606,647	$ 1,606,647
NAVAR10	NAVAR				$ 2,025,794	$ 2,025,794
NAVAR11	NAVAR				$ 1,797,716	$ 1,797,716
NAVAR12	NAVAR				$ 1,041,667	$ 1,041,667
NAVAR13	NAVAR				$ 104,299	$ 104,299
NAVAR14	NAVAR				$ 54,109	$ 54,109
NAVAR15	NAVAR				$ 28,146	$ 28,146
OUTDR1	OUTDR	$ 350,791	$ 23,386	$ 21,047		$ 395,225
OUTDR2	OUTDR	$ 224,448	$ 14,963	$ 13,467		$ 252,878
OUTDR3	OUTDR	$ 149,186	$ 9,946	$ 8,951		$ 168,083
OUTDR4	OUTDR	$ 515,985	$ 34,399	$ 30,959		$ 581,343
OUTDR5	OUTDR	$ 152,868	$ 10,191	$ 9,172		$ 172,231
OUTDR6	OUTDR	$ 474,510	$ 31,634	$ 28,471		$ 534,615
OUTDR7	OUTDR	$ 260,834	$ 17,389	$ 15,650		$ 293,873
SAVAN1	SAVAN				$ 237,147	$ 237,147
SAVAN2	SAVAN				$ 816,904	$ 816,904
SAVAN3	SAVAN				$ 1,884,521	$ 1,884,521
SAVAN4	SAVAN				$ 1,321,386	$ 1,321,386
SAVAN5	SAVAN				$ 1,022,121	$ 1,022,121
SAVAN6	SAVAN				$ 530,522	$ 530,522
SAVAN7	SAVAN				$ 1,846,705	$ 1,846,705
SAVAN8	SAVAN				$ 851,342	$ 851,342
SAVAN9	SAVAN				$ 1,844,289	$ 1,844,289
SAVAN10	SAVAN				$ 923,724	$ 923,724
SAVAN11	SAVAN				$ 1,580,144	$ 1,580,144
SAVAN12	SAVAN				$ 1,008,948	$ 1,008,948
SAVAN13	SAVAN				$ 1,061,711	$ 1,061,711
SAVAN14	SAVAN				$ 41,853	$ 41,853
SAVAN15	SAVAN				$ 25,716	$ 25,716
STOPL1	STOPL	$ 395,303	$ 26,187	$ 23,568		$ 445,058
STOPL2	STOPL	$ 454,065	$ 30,104	$ 27,094		$ 511,263
STOPL3	STOPL	$ 296,480	$ 19,599	$ 17,639		$ 333,717
STOPL4	STOPL	$ 282,407	$ 18,660	$ 16,794		$ 317,862
STOPL5	STOPL	$ 820,616	$ 54,541	$ 49,087		$ 924,244
STOPL6	STOPL	$ 434,473	$ 28,798	$ 25,918		$ 489,190
STOPL7	STOPL	$ 225,114	$ 14,841	$ 13,357		$ 253,312
STOPL8	STOPL	$ 192,212	$ 12,647	$ 11,383		$ 216,242
STOPL9	STOPL	$ 132,281	$ 8,652	$ 7,787		$ 148,720
STOPL10	STOPL	$ 80,514	$ 5,201	$ 4,681		$ 90,395

U-20836 MNSCDE-4.4i-01 2022-2023 4.8kV Projected Investments

2023 Projected 4.8kV Hardening Investments

Circuits	Substation	Tree Trim	Inspection & Reinforcement	Design	Construction	Total
STOPL11	STOPL	$ 90,929	$ 5,895	$ 5,306		$ 102,130
STOPL12	STOPL	$ 204,192	$ 13,446	$ 12,102		$ 229,740
STOPL13	STOPL	$ 139,362	$ 9,291	$ 8,362		$ 157,014
4.8kV Hardening	**2023 Total**	**$ 26,699,999**	**$ 1,771,667**	**$ 1,594,500**	**$ 83,020,336**	**$ 113,086,502**

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-4.6c
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 69-70:
c. Please provide DTE's 2020, and 2021 assessments of program effectiveness and cost.

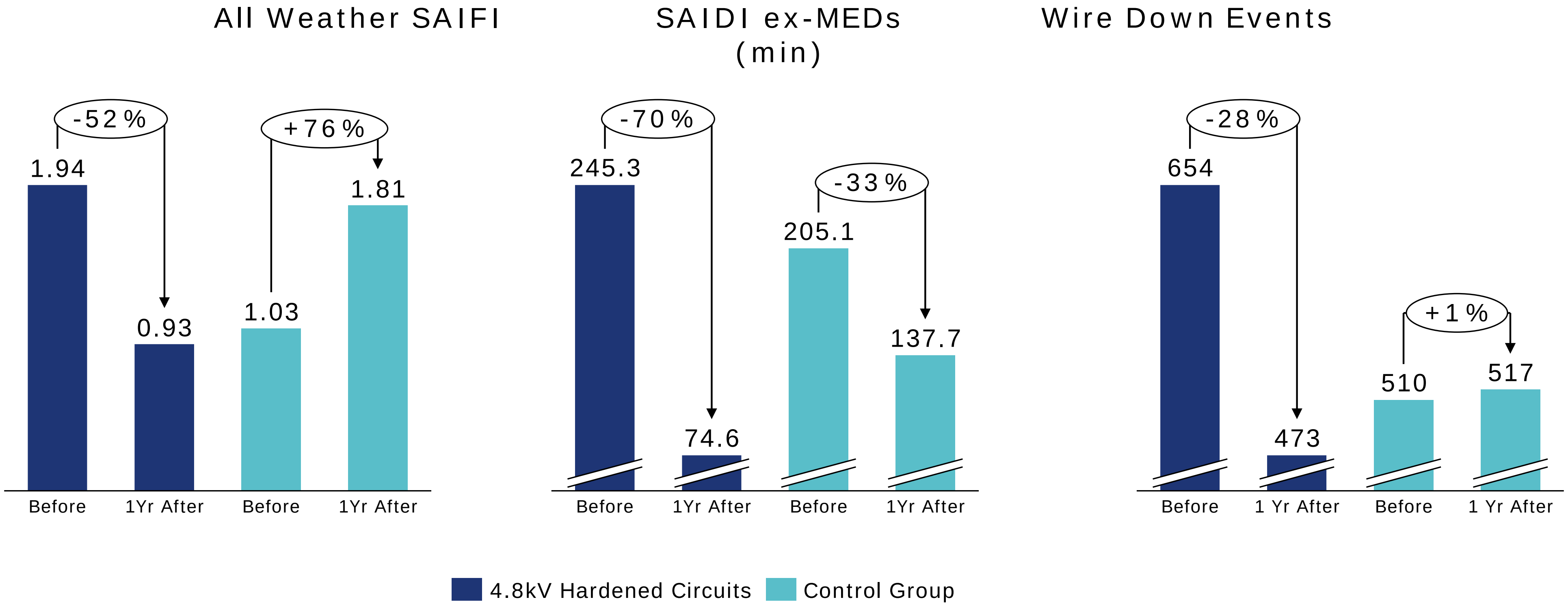
Answer: The 2020 hardened circuits have seen 52% of improvement in SAIFI, 70% in SAIDI ex-MEDs and 28% in wire down events, yielding significantly better performance than the control group. This analysis is based on 29 circuits hardened in 2020 using three-year historic average (2017 – 2019) compared to one year after (2021). Please refer to the analysis attached U-20835 MNSCDE-4.6c-01 2020 Hardened Effectiveness Analysis

We have not yet performed the effectiveness analysis for circuits hardened in 2021.

For cost, please refer to Exhibit A12 Schedule B5.4 Page 8 Line 9.

Attachment: U-20835 MNSCDE-4.6c-01 2020 Hardened Effectiveness Analysis

2020 Hardened Circuits
The hardened circuits have seen 52% of improvement in SAIFI, 70% in SAIDI ex-MEDs and 28% in wire down events, yielding much better performance than the control group



Note 1: Analysis based on 29 circuits hardened in 2020 using three-year historic average (2017 – 2019) compared to one year after (2021)
Note 2: Performance deterioration for control group is largely driven by weather
Note 3: SAIDI during MEDs is heavily influenced by circuit restoration prioritization; hence SAIDI ex-MEDs is considered a better metric to reflect the program improvements

DTE

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-6.1ai
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 78-79, regarding the Pole Top Maintenance and Modernization (PTMM) program:

a. Does repair/replacement under the PTMM program follow the approximate 10-year cycle of inspections associated with the annual pole and pole top inspection sub-program?

i. Is the DTE distribution system essentially divided into approximately 10 sections, with one section inspected each year? Please explain, and provide documentation demonstrating the sections or how they are determined.

Answer: The Company does not divide the distribution system into sections for the purposes of the Pole PTMM program. Circuits are selected for the Pole and PTMM program based on factors that include when the circuit was last tree trimmed and how long it has been since the last time the circuit received inspection through the Pole and PTMM program.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.8ci
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the response of Sharon Pfeuffer, to MSNC's discovery question MNSCDE-6.1ai regarding the Pole and Pole Top Maintenance and Modernization (PTMM) program "Circuits are selected … based on factors that include when the circuit was last tree trimmed and how long it has been since the last time the circuit received inspection …":

c. Please provide the most current list of prioritized circuits and the date of such prioritization:

i. Please include the date, and time interval since each circuit was last tree trimmed.

Answer: Please see attached U-20836 MNSCDE-9.8c-01 2022 Pole and PTMM Circuits.

Attachment: U-20836 MNSCDE-9.8c-01 2022 Pole and PTMM Circuits

Co-Respondent(s): S. Hartwick

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.8cii
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the response of Sharon Pfeuffer, to MSNC's discovery question MNSCDE-6.1ai regarding the Pole and Pole Top Maintenance and Modernization (PTMM) program "Circuits are selected … based on factors that include when the circuit was last tree trimmed and how long it has been since the last time the circuit received inspection …":

c. Please provide the most current list of prioritized circuits and the date of such prioritization:

ii. Please provide the date and time interval since each circuit was last inspected.

Answer: Please see attached U-20836 MNSCDE-9.8c-01 2022 Pole and PTMM Circuits.

Attachment: U-20836 MNSCDE-9.8c-01 2022 Pole and PTMM Circuits

U-20836 MNSCDE-9.8c-01 2022 Pole and PTMM Circuits

Total Circuits
193

Circuit Count	Circuit (Traditional)	Last TT	Last PTM
1	Circuit1	2021	2005
2	Circuit2	2012	2009
3	Circuit3	2021	1995
4	Circuit4	2021	2013
5	Circuit5	2012	2014
6	Circuit6	2012	2007
7	Circuit7	2021	1996
8	Circuit8	2021	2013
9	Circuit9	2021	2013
10	Circuit10	2013	2013
11	Circuit11	2021	1999
12	Circuit12	2021	1999
13	Circuit13	2012	2003
14	Circuit14	2012	2003
15	Circuit15	2012	2003
16	Circuit16	2021	2001
17	Circuit17	2011	2014
18	Circuit18	2021	2011
19	Circuit19	2021	2011
20	Circuit20	2021	2003
21	Circuit21	2014	1995
22	Circuit22	2014	2007
23	Circuit23	2021	2011
24	Circuit24	2021	2011
25	Circuit25	2021	2011
26	Circuit26	2021	2011
27	Circuit27	2021	2016
28	Circuit28	2013	1999
29	Circuit29	2021	2003
30	Circuit30	2011	2006
31	Circuit31	2021	2002
32	Circuit32	2021	2002
33	Circuit33	2021	1995
34	Circuit34	2021	2013
35	Circuit35	2021	2002
36	Circuit36	2021	1995
37	Circuit37	2021	2001
38	Circuit38	2021	2010
39	Circuit39	2021	2013
40	Circuit40	2021	2009
41	Circuit41	2021	2010
42	Circuit42	2021	2009

U-20836 MNSCDE-9.8c-01 2022 Pole and PTMM Circuits

Total Circuits
193

Circuit Count	Circuit (Traditional)	Last TT	Last PTM
43	Circuit43	2021	2014
44	Circuit44	2011	2015
45	Circuit45	2011	2015
46	Circuit46	2013	2006
47	Circuit47	2013	2005
48	Circuit48	2021	1997
49	Circuit49	2021	1997
50	Circuit50	2021	2000
51	Circuit51	2021	2000
52	Circuit52	2021	2000
53	Circuit53	2021	2000
54	Circuit54	2021	2006
55	Circuit55	2021	2006
56	Circuit56	2021	2001
57	Circuit57	2013	2001
58	Circuit58	2021	2002
59	Circuit59	2021	2002
60	Circuit60	2012	2014
61	Circuit61	2012	2014
62	Circuit62	2011	2011
63	Circuit63	2011	2011
64	Circuit64	2014	2017
65	Circuit65	2021	2008
66	Circuit66	2021	2006
67	Circuit67	2021	2007
68	Circuit68	2021	2007
69	Circuit69	2021	2007
70	Circuit70	2021	2009
71	Circuit71	2021	2009
72	Circuit72	2021	2009
73	Circuit73	2021	2009
74	Circuit74	2021	2006
75	Circuit75	2021	2006
76	Circuit76	2021	2006
77	Circuit77	2021	2006
78	Circuit78	2021	1996
79	Circuit79	2014	2006
80	Circuit80	2014	2006
81	Circuit81	2010	1994
82	Circuit82	2021	2000
83	Circuit83	2010	2011
84	Circuit84	2010	2011
85	Circuit85	2010	1998

U-20836 MNSCDE-9.8c-01 2022 Pole and PTMM Circuits

Total Circuits
193

Circuit Count	Circuit (Traditional)	Last TT	Last PTM
86	Circuit86	2010	2011
87	Circuit87	2013	2003
88	Circuit88	2013	2003
89	Circuit89	2021	2007
90	Circuit90	2013	2008
91	Circuit91	2021	2006
92	Circuit92	2010	2006
93	Circuit93	2021	2011
94	Circuit94	2021	2011
95	Circuit95	2021	2011
96	Circuit96	2021	2011
97	Circuit97	2021	2011
98	Circuit98	2021	2011
99	Circuit99	2010	2011
100	Circuit100	2013	2013
101	Circuit101	2014	2013
102	Circuit102	2014	2001
103	Circuit103	2012	2007
104	Circuit104	2021	2001
105	Circuit105	2021	2007
106	Circuit106	2013	2013
107	Circuit107	2011	2013
108	Circuit108	2011	2013
109	Circuit109	UnKnown	
110	Circuit110	2011	2011
111	Circuit111	2014	2000
112	Circuit112	2021	2015
113	Circuit113	2021	2009
114	Circuit114	2021	2009
115	Circuit115	2021	2007
116	Circuit116	2014	1996
117	Circuit117	2014	1996
118	Circuit118	2021	2007
119	Circuit119	2021	2003
120	Circuit120	2021	1999
121	Circuit121	2021	2000
122	Circuit122	2021	2000
123	Circuit123	2021	2010
124	Circuit124	2021	2012
125	Circuit125	2021	2009
126	Circuit126	2021	2007
127	Circuit127	2021	2007
128	Circuit128	2021	2007

U-20836 MNSCDE-9.8c-01 2022 Pole and PTMM Circuits

Total Circuits
193

Circuit Count	Circuit (Traditional)	Last TT	Last PTM
129	Circuit129	2021	2008
130	Circuit130	2013	2001
131	Circuit131	2013	2007
132	Circuit132	2021	2000
133	Circuit133	2021	2001
134	Circuit134	2021	2000
135	Circuit135	2014	2000
136	Circuit136	2021	2009
137	Circuit137	2021	1997
138	Circuit138	2021	1997
139	Circuit139	2013	2007
140	Circuit140	2013	2009
141	Circuit141	2021	1999
142	Circuit142	2021	1999
143	Circuit143	2021	2013
144	Circuit144	2021	2000
145	Circuit145	2021	2000
146	Circuit146	2021	2000
147	Circuit147	2021	2013
148	Circuit148	2021	1997
149	Circuit149	2021	2000
150	Circuit150	2021	2000
151	Circuit151	2021	2000
152	Circuit152	2021	2001
153	Circuit153	2021	2011
154	Circuit154	2021	2009
155	Circuit155	2021	2012
156	Circuit156	2021	2009
157	Circuit157	2021	2013
158	Circuit158	2021	2013
159	Circuit159	2021	2004
160	Circuit160	2021	2006
161	Circuit161	2021	2004
162	Circuit162	2021	2007
163	Circuit163	2021	2008
164	Circuit164	2021	2006
165	Circuit165	2021	2011
166	Circuit166	2021	2002
167	Circuit167	2021	2011
168	Circuit168	2021	2006
169	Circuit169	2021	2004
170	Circuit170	2021	1999
171	Circuit171	2021	1998

U-20836 MNSCDE-9.8c-01 2022 Pole and PTMM Circuits

Total Circuits
193

Circuit Count	Circuit (Traditional)	Last TT	Last PTM
172	Circuit172	2021	2006
173	Circuit173	2021	2013
174	Circuit174	2021	2007
175	Circuit175	2021	2011
176	Circuit176	2021	2010
177	Circuit177	2021	2006
178	Circuit178	2021	1997
179	Circuit179	2021	2013
180	Circuit180	2012	2009
181	Circuit181	2012	2007
182	Circuit182	2013	2006
183	Circuit183	2021	1999
184	Circuit184	2021	2000
185	Circuit185	UnKnown	2017
186	Circuit186	UnKnown	
187	Circuit187	2013	2014
188	Circuit188	2009	2004
189	Circuit189	2012	2007
190	Circuit190	2021	1999
191	Circuit191	2021	1996
192	Circuit192	2014	2014
193	Circuit193	2013	2009

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-6.1c
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 78-79, regarding the Pole Top Maintenance and Modernization (PTMM) program:

c. If a pole, crossarm, and/or associated pole top hardware/equipment is inspected and deemed to be in good condition, meeting DTE new standards, and thus not designated for replacement, how is the cost of inspecting such distribution assets recovered?

Answer: DTE Electric objects to the request for the reason that it is unclear and incapable of answer in its present form, as it is unclear what is meant by "good condition."

To further answer, without waiving the objection, the Company would state as follows: Under the Pole and PTMM program the Company performs inspections at the circuit level and each circuit is considered as a unit of work. Every circuit inspected may contain poles that fail inspection and/or pole top hardware that fails inspections. As such the cost associated with inspecting the circuit is considered capital under the Pole and PTMM program and is unitized against the replaced, reinforced poles and/or replaced pole top hardware of that circuit.

Attachment: N/A

Co-Respondent: Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-6.1ci
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 78-79, regarding the Pole Top Maintenance and Modernization (PTMM) program:

c. If a pole, crossarm, and/or associated pole top hardware/equipment is inspected and deemed to be in good condition, meeting DTE new standards, and thus not designated for replacement, how is the cost of inspecting such distribution assets recovered?

i. Is it included in the capitalized cost of the PTMM program, as delineated on Exhibit A-12, page 8, Line 10? If yes, what is the amortization or depreciation period?

Answer: DTE Electric objects to the request for the reason that it is unclear and incapable of answer in its present form, as it is unclear what is meant by “good condition.”

In further answer and without waiving the objection, the Company would state as follows: see response to MNSCDE-6.1c. Assets in the Pole and PTMM program are considered to have an average life of 35 years.

Attachment: N/A

Co-Respondent: Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-6.1cii
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 78-79, regarding the Pole Top Maintenance and Modernization (PTMM) program:

c. If a pole, crossarm, and/or associated pole top hardware/equipment is inspected and deemed to be in good condition, meeting DTE new standards, and thus not designated for replacement, how is the cost of inspecting such distribution assets recovered?

ii. If not, what O&M account(s) are such inspection costs recovered?

Answer: DTE Electric objects to the request for the reason that it is unclear and incapable of answer in its present form, as it is unclear what is meant by "good condition." In further answer and without waiving the objection, the Company would state as follows:

Inspections done as part of the PTMM program are part of the capital program cost.

Attachment: N/A

Co-Respondent: Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-6.1d
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 78-79, regarding the Pole Top Maintenance and Modernization (PTMM) program:

d. If a pole, crossarm, and/or associated pole top hardware/equipment is inspected and is deemed to be in poor condition/not meeting new DTE standards, and thus designated for replacement, how is the cost of inspection of such distribution assets recovered?

Answer: DTE Electric objects to the request for the reason that it is unclear and incapable of answer in its present form, as it is unclear what is meant by "poor condition." In the context of equipment that is damaged or degraded, the Company does not consider damaged or degraded condition of equipment and equipment that does not meet current standards as interchangeable. Pole, crossarm, and/or associated pole top hardware/equipment is not replaced for the sole reason that it does not meet new DTE standards for new installations. In further answer and without waiving the objection, the Company would state as follows: Inspections done as part of the PTMM program are part of the capital program cost.

Attachment: N/A

Co-Respondent: Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-6.1di
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of Sharon Pfeuffer, page 78-79, regarding the Pole Top Maintenance and Modernization (PTMM) program:

d. If a pole, crossarm, and/or associated pole top hardware/equipment is inspected and is deemed to be in poor condition/not meeting new DTE standards, and thus designated for replacement, how is the cost of inspection of such distribution assets recovered?

i. If for example, a pole is inspected, and replaced on the basis of such inspection, is the inspection cost included in the cost-of-removal (net salvage value) of the old pole and thus expensed? If not, please explain how such inspection costs are recovered?

Answer: DTE Electric objects to the request for the reason that it is unclear and incapable of answer in its present form, as it is unclear what is meant by "poor condition." In the context of equipment that is damaged or degraded, the Company does not consider damaged or degraded condition of equipment and equipment that does not meet current standards as interchangeable. Pole, crossarm, and/or associated pole top hardware/equipment is not replaced for the sole reason that it does not meet new DTE standards for new installations. In further answer and without waiving the objection, the Company would state as follows:

When a condemned pole is replaced, a new pole is installed at the same time, and this activity is considered one activity and costs are capitalized as 80% installation and 20% removal.

Attachment: N/A

Co-Respondent: Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.1b
Respondent:	S. Pfeuffer
	1 of 1

Question: Please refer to the testimony of S. Pfeuffer, page 78, wherein it is stated that: "This program proactively identifies damaged or defective equipment before failures occur.

b. What is DTE's criteria for the identification of damaged equipment and of defective equipment? Please be specific as to what constitutes qualifying damages or defects, including but not limited to the extent of damage, or defect, for all categories of equipment encompassed by the program, including poles. If there are written requirements or guidelines, please provide such.

Answer: See attached U-20836 MNSCDE-9.1b-01 Pole Top Hardware Patrol Items for the current list of pole top hardware assets inspected under the Pole and PTMM program.

Attachment: U-20836 MNSCDE-9.1b-01 Pole Top Hardware Patrol Items

POLE TOP MAINTENANCE SPECIFICATION

Objective

The objective of the Pole Top Maintenance Specification is to maintain the system's mechanical and electrical integrity, for the safety of DTE employees, contractors, and the public under the conditions specified by IEEE, vendor recommendations and DTE approved standards. This objective is accomplished by inspecting and testing pole top distribution equipment to identify any equipment that do not meet conditional requirements. The pole top equipment mentioned in this document will be reported or replaced, based on the criteria specific in this document. The inspection criteria apply to all DTE pole top equipment.

Scope

This specification is intended as a basis for the inspection and replacement of pole top equipment. As a result of the pole top inspection program, all pole top equipment that meet the in-service criteria will be inspected on a 5-year cycle. Pole top equipment inspected within the last 5 years shall not be re-inspected.

POLE TOP MAINTENANCE SPECIFICATION

Urgent Repairs

Following scenarios need to be reported immediately if there are found:

- **Contact [redacted] for the following:**
  - Downed Wire
  - Floating Neutral
  - Wrapped Primary or Secondary
  - Broken Pole
  - Large limbs on conductor
  - Exposed Cables
  - Wires touching buildings
  - Problems that need immediate attention
- **Contact [redacted] for any transformers leaking oil** (Ground level or Over-head look thesame.)

Downed Wires to be reported immediately

Transformers with Oil Leakage to be reported immediately.

POLE TOP MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported* if **PCB contamination** is found**.**

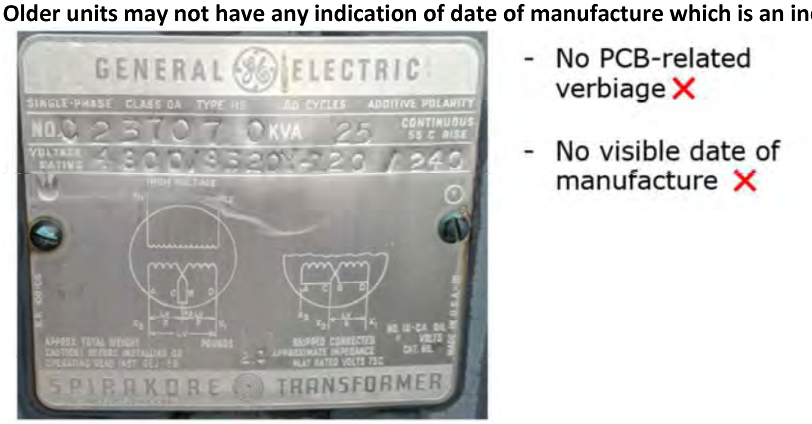
Transformers – PCB Contamination:

Defects:
Transformers contaminated with PCB need to be reported and replaced.

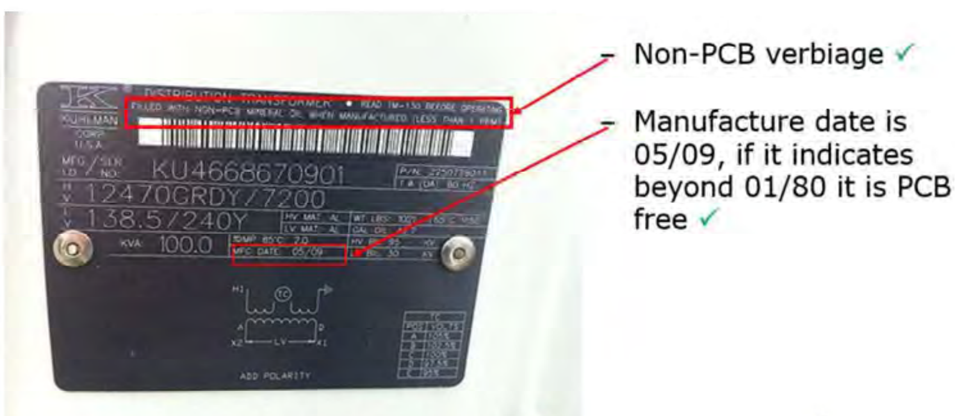
Dark shaded transformers and porcelain/glass insulators are the main visual cues for PCB contamination. Other methods of finding contamination goes as follows (see photos below).

- Dark grey and black shade on the body of the transformer
- Brown, white, and glass- porcelain type of insulators on the transformers for the primary and secondary bushing
- Pole construction may also have porcelain insulators, arresters, and or vintage fuse holders
- It should be assumed that units manufactured prior to July 1979 contain PCB
- Check for nameplates for manufactured dates. Plates might be faded in many cases

Older units may not have any indication of date of manufacture which is an indicator of possible contamination



Newer units will indicate non-PCB verbiage and key manufacture moth/year



POLE TOP MAINTENANCE SPECIFICATION

PCB Contamination (CONT):

An example of a dark shaded transformer with porcelain insulators that have a shine during daylight.

POLE TOP MAINTENANCE SPECIFICATION

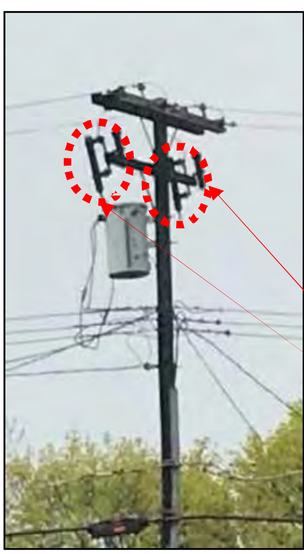
CUTOUTS:

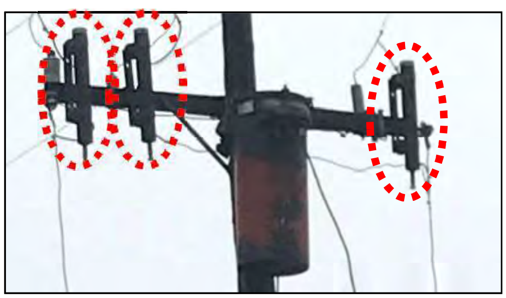
Defects:
Porcelain cutout: To be replaced
Polymer cutout: Burnt, Melted, Arching.

Engineering Standards / Bulleting reference:
Verify with DTE if any document has been updated
EB-2005-OH-05 (See appendix)

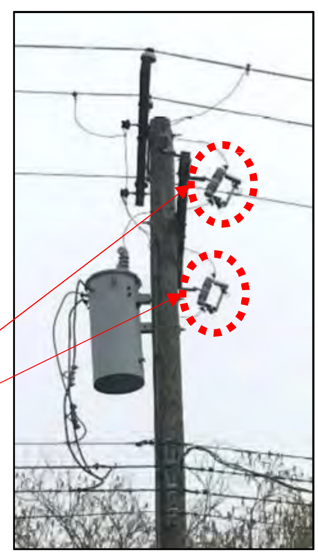
All porcelain cutouts must be replaced; only polymer cutouts are the current standard. Polymer cutout should be replaced if the cutout is burnt, melted, and arcing. More reference on EB-2005-OH-05 / EB-2005-OH-05

Porcelain Cutouts: S&C R9, R10, AB Chance Cutouts





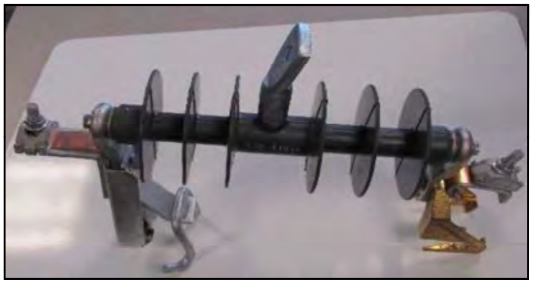
Cato Fuse Porcelain Cutouts



Locations of cutouts

POLE TOP MAINTENANCE SPECIFICATION

CUTOUT (Cont.):



Acceptable Hubbell Power Systems Polymer Cutout

Acceptable S&C Electric Polymer Cutout

Also look for broken cutouts as shown below:

Broken S&C Porcelain cutout just above the transformer

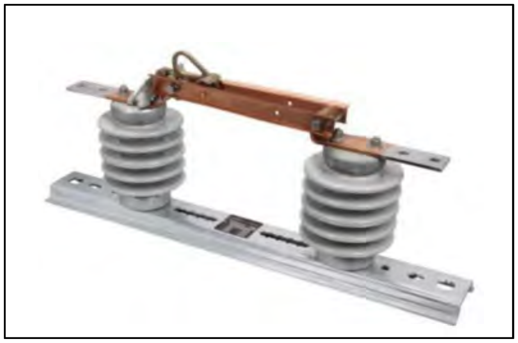
POLE TOP MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported* if the items are **defective**.

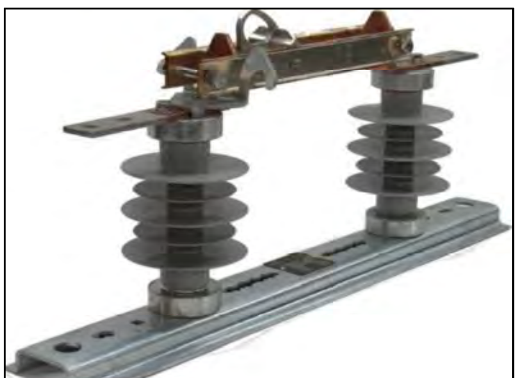
CABLE POLE DISCONNECTS:

Defects:

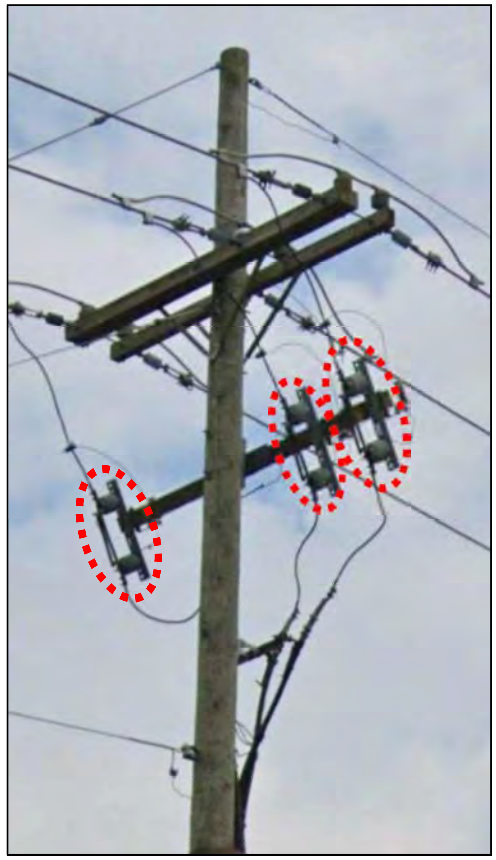
Cable Pole Porcelain Disconnect Switch: To be reported if is cracked.
Cable Pole Polymer Disconnect Switch: To be reported if is burnt, melted, arching.



Acceptable Porcelain Disconnect Switch



Acceptable Polymer Disconnect Switch



Location of Disconnect Switch

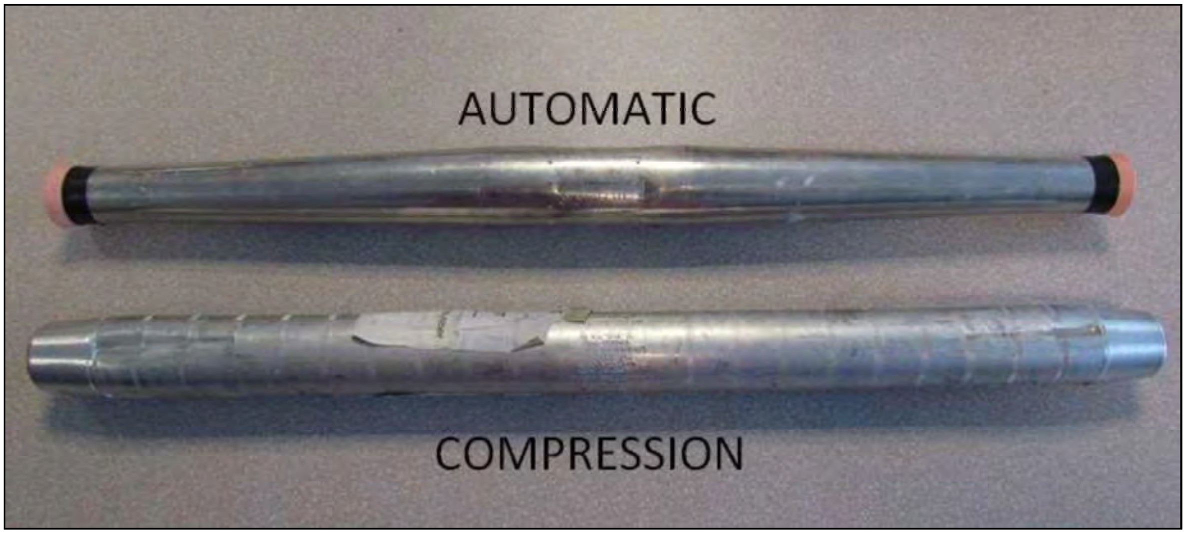
POLE TOP MAINTENANCE SPECIFICATION

AUTOMATIC SLEEVES:

Defects:
Automatic Sleeves: To be replaced
Compression Sleeves: Broken Wires.

Engineering Standard / Bulleting reference:
Verify with DTE if any document has been updated
EB-2014-OH-10 (See appendix)

Any automatic sleeves must be replaced; the current standard is the compression sleeve. Compressionsleeves must be replaced if the conductor, on either side, has a broken wire. Reference EB-2014-OH-10



Automatic Sleeve to be reported.

POLE TOP MAINTENANCE SPECIFICATION

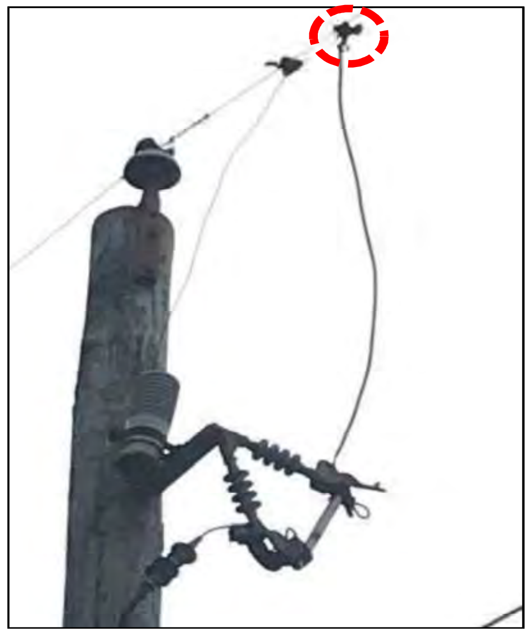
BLACKBURN HOT TAPS:

Defects:
Blackburn: To be replaced

Engineering Standards / Bulleting reference:
Verify with DTE if any document has been updated
EB-95-OH-34 (See appendix)

According to EB-95-OH-34 the Blackburn taps should be removed and replaced with an approvedtap.

Blackburn Hot taps shall be reported and replaced



Location of Blackburn Hot Tap

POLE TOP MAINTENANCE SPECIFICATION

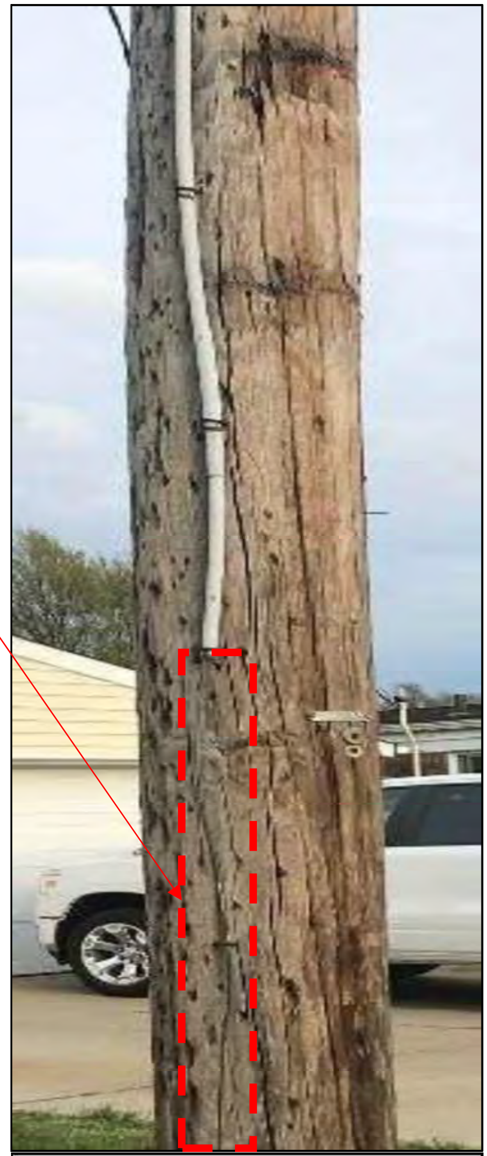
The equipment listed below is to be *reported* if the items are **defective**.

GROUND WIRE:

Defects:
Ground Wire: To be reported if is broken, missing or detached from pole.

Any missing ground wire, must be replaced. The ground wire goes inside the plastic molding and must becontinuous from the top of the pole to the ground. In the case described below wire and molding shouldbe replaced.

Difference



Acceptable Ground Wire. Continuous from top of the pole all the way until the floor

Defective Ground Wire (non-continuous)

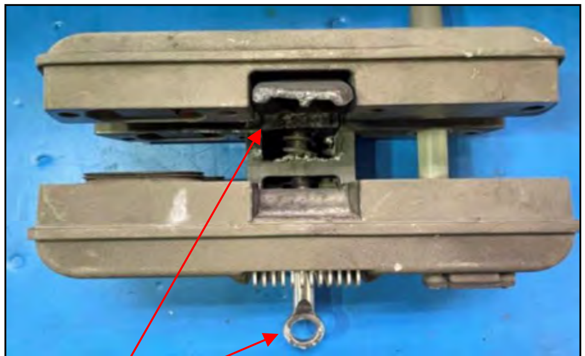
POLE MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported* if the items are **defective**.

Defects:
Burn Conductor/Sensor: To be reported if the conductor/sensor show signs of burning.

All smart fault Indicators that show signs of burning on either the conductor wire or sensor needs to be reportedand replaced. Sensor will typically show signs of damage on the duckbill and eyebolt. Attached are photos of theburned conductors and sensors.

Burned Conductor



Burned Smart Fault Indicator

Location of the Smart Fault Indicators

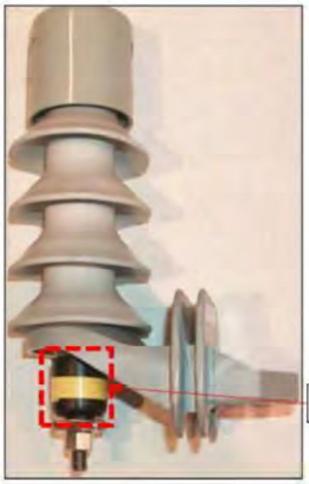
POLE TOP MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported* if the items are **defective**.

ARRESTERS:

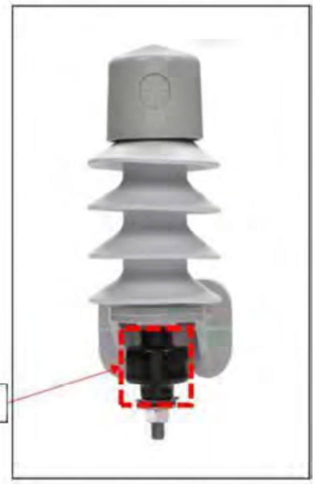
Defects:
Arresters: To be reported if blown Isolator, melted, burnt or arching.

Arresters that have a blown isolator must be replaced. The arrester should be replaced if melted, andburnt, arcing. All Vari-Gap designed arresters must be replaced broken or unbroken. The Vari-Gap arresters stopped being installed in 2002.

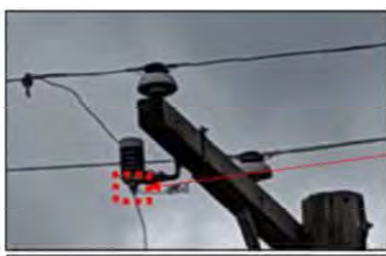


Acceptable 13.2kV Arrester

Intact Isolator

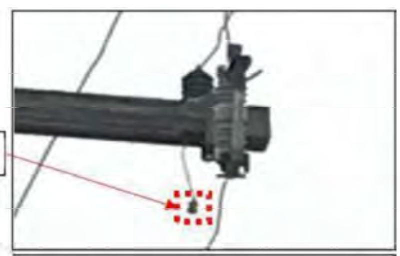


Acceptable 4.8kV Arrester



Acceptable Arrester

Difference



Defective Arrester, is not connected

Side View of Arrestor

Vari-Gap Arrestor

Top View of Arrestor

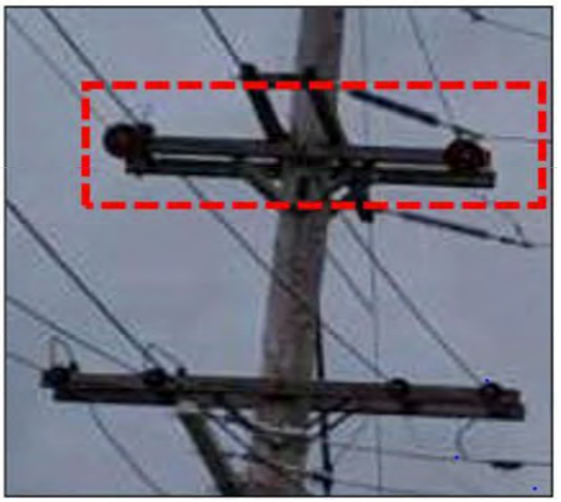
POLE MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported* if the items are **defective**.

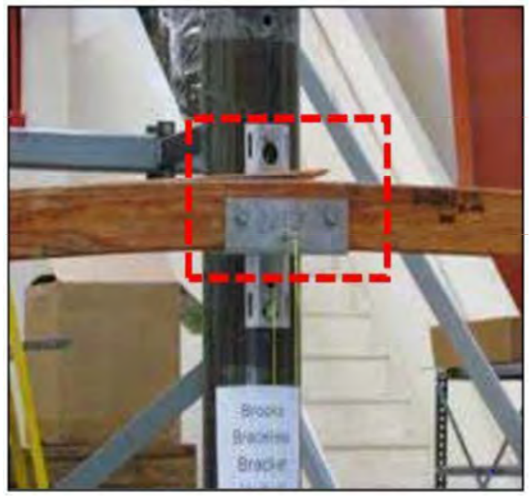
CROSS-ARM PARTS:

Defects:
Cross-arms: To be reported if is broken, cracked/decayed and affecting hardware.
Cross-arm Brace: To be reported if is broken, cracked/decayed and affecting hardware.
Cross-arm Brace Nut-Bolt: To be reported if is missing.
Cross-arm Nut-Bolt: To be reported if is missing.
Cross-arm Pin Insulator: To be reported if defective and affecting hardware.

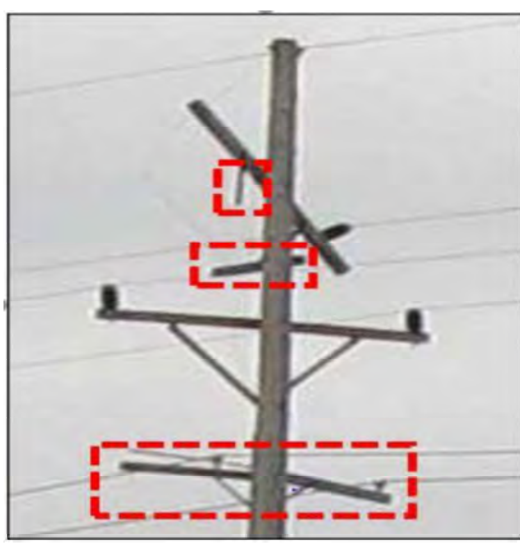
Cross-arms or braces that are cracked, warped, or broken, must be replaced. If a fiberglass cross-arm is missing any end caps, the cross-arm must be replaced



48” Acceptable cross-arm



Cracked 48” cross-arm that needs to be replaced.

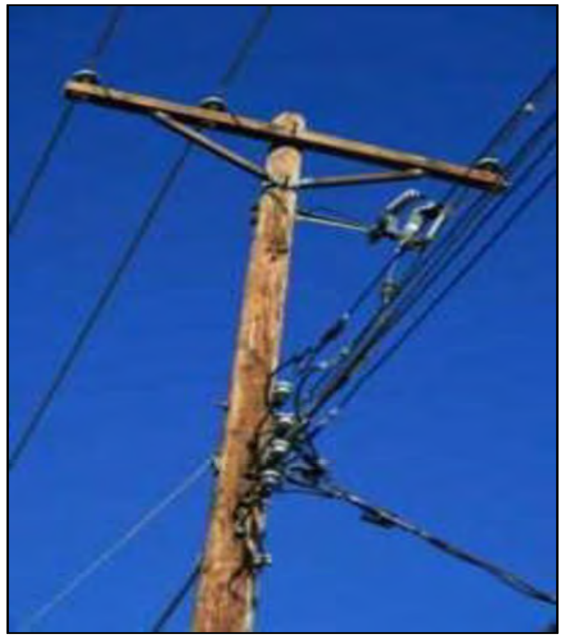


Defective 120” Cross-arms

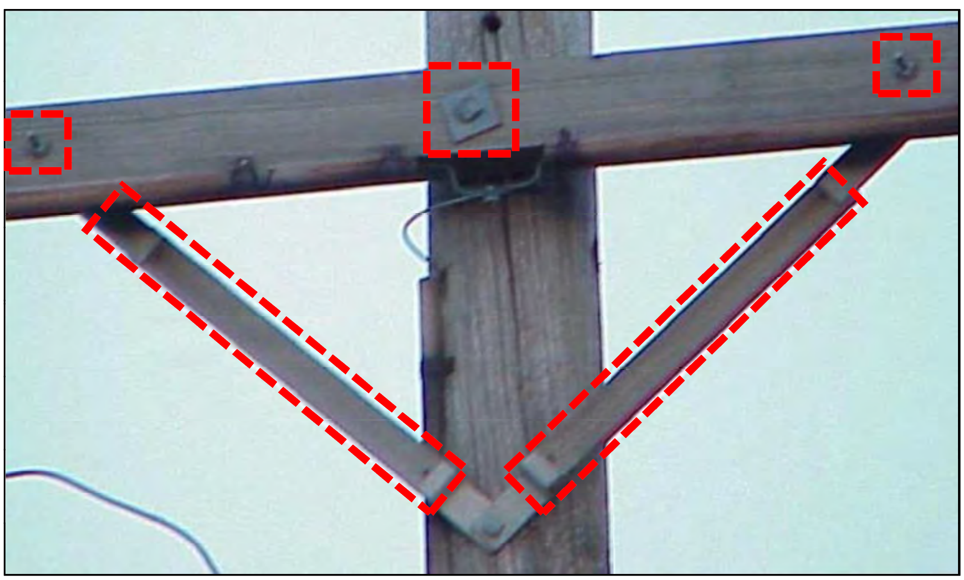
POLE TOP MAINTENANCE SPECIFICATION

CROSS-ARM PARTS (Cont.):

Acceptable Fiberglass Cross-arm



Acceptable 96" Cross-arm



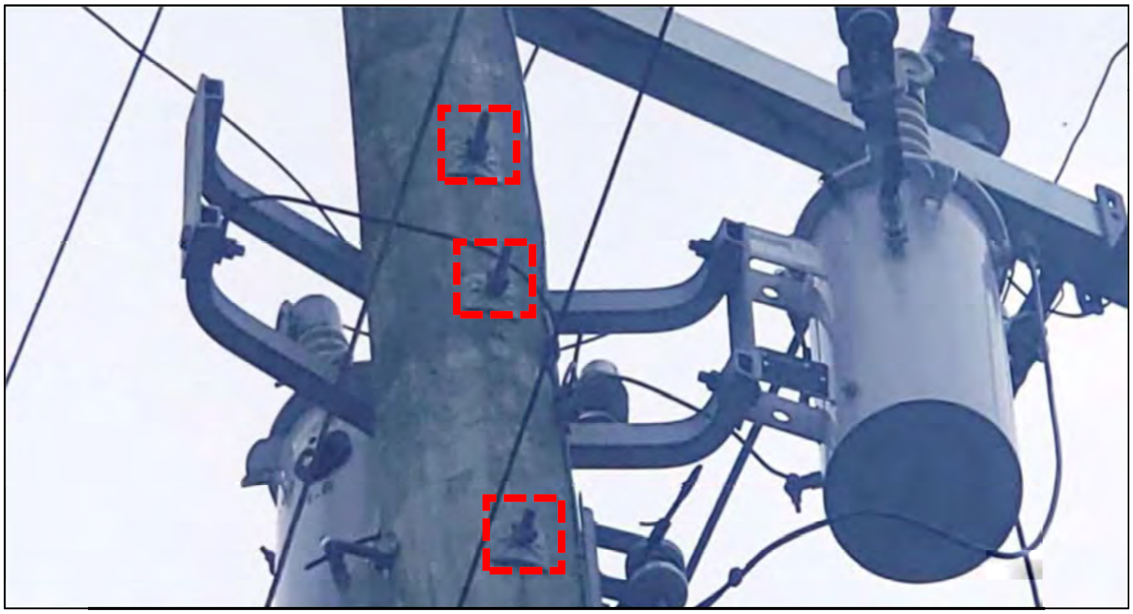
Acceptable Cross-arm Braces, Brace Components, and Cross-arm Components

POLE TOP MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported* if the items are **defective**.

TRANSFORMER PARTS:

Defects:
Transformer Nut-Bolt: To be reported if missing
Check bolts and nuts.



Acceptable Transformer Nuts and Bolts. Report it if some of them is missing.

POLE TOP MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported* if the items are **defective**.

DISC AND PIN INSULATORS:

Defects:
Disc Insulator: To be reported if is cracked
F-neck Insulator: To be reported if is crackedPorcelain Post
Insulator: To be replaced
Polymer Post Insulator: To be reported if is burnt, melted, arching, crackedInsulator Nut-
Bolt: To be reported if is missing

Engineering Standards / Bulleting reference:
Verify with DTE if any document has been updated
EB-99-OH-2 SB-2005-OH-02 (See appendix)

Acceptable F-neck, Disc, and Line-Post

Defective Line-Post Insulator

Defective Disc

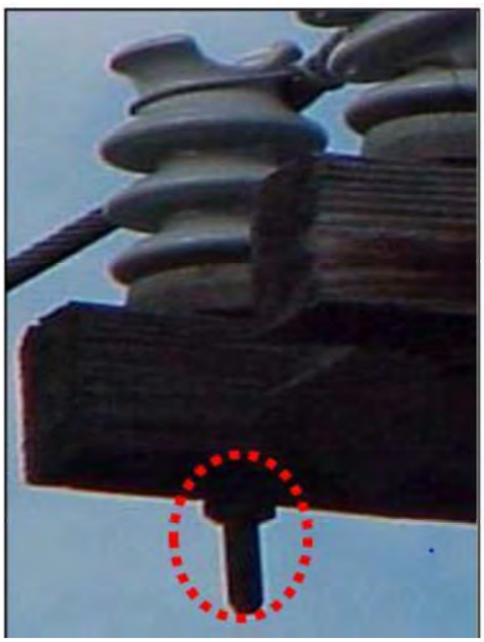
POLE TOP MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported* if the items are **defective**.

DISC AND PIN INSULATORS (Cont.):

Insulator locations

Damaged insulator



Acceptable Nut and Bolt, report if missing

POLE TOP MAINTENANCE SPECIFICATION

POLE TOP:

Defects:
Pole Top: To be reported if decay affects hardware
Pole tops that impact the integrity of any hardware and do not have a through bolt, must be replaced.

Defective Pole Top


Acceptable Pole Top

PRIMARY LINE SAG:

Defects:
Primary lines: To be reported if is over sagged

If a line is too loose then it shall be re-tensioned or replaced.

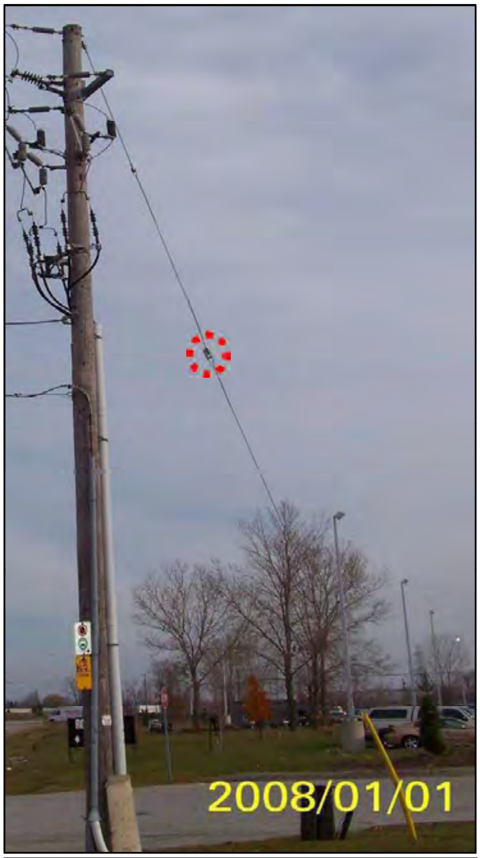

Acceptable Line Sag

POLE TOP MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported* if the items are **defective**.

ALL RELATED GUY WIRE COMPONENTS:

Defects:
Guy wires: To be reported if broken strands are observed or it is loose.Johnny Ball: To be reported if it's broken or disconnected.



Acceptable Guy Wire and Johnny Ball

Defective Guy Wire

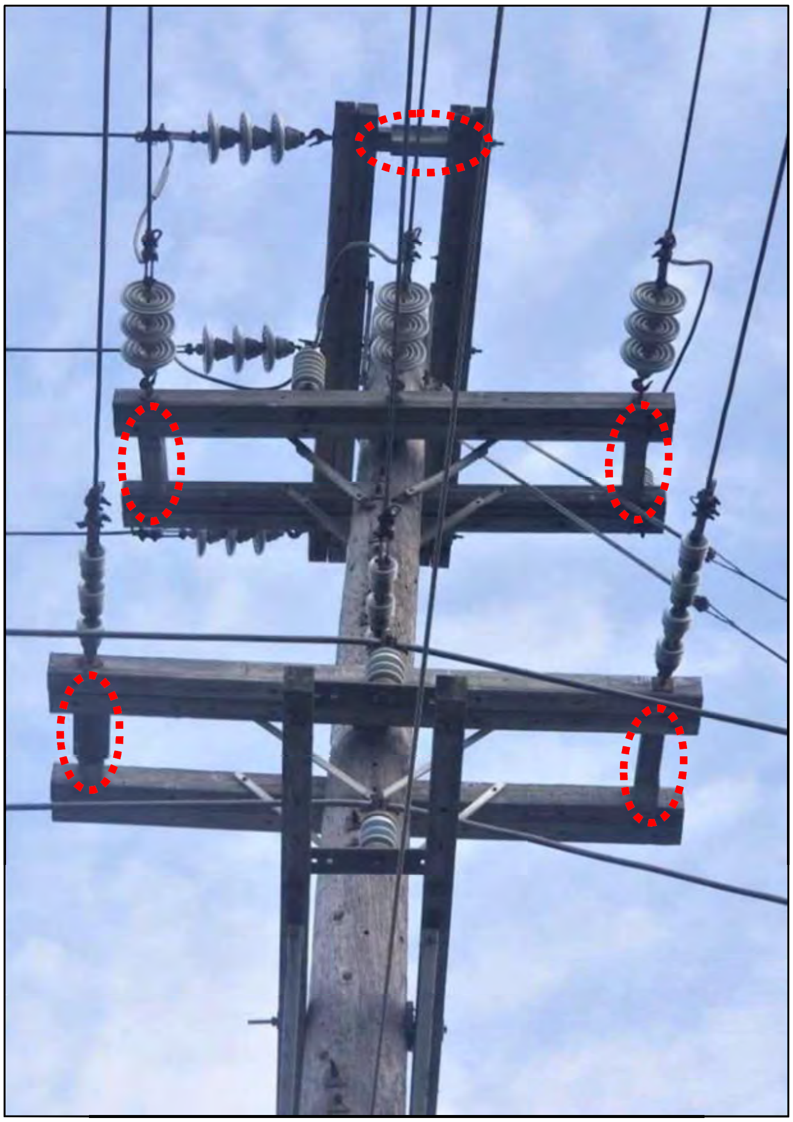
Defective Johnny Ball

POLE TOP MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported*, only if there is an item that is **defective** from the above/previous listings on the same pole.

SPACER BLOCK:

Defects:
Spacer block: To be reported if it's broken and affecting hardware.



Acceptable Spacers Blocks. If some of the spacer block is broken, it should be reported.

POLE TOP MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported*, only if there is an item that is **defective** from the above/previous listings on the same pole.

NEUTRALS ON SECONDARY TAP:

Defects:
Neutrals on secondary taps: To be reported if it's disconnected

Neutral should be reported if it's disconnected. For more details see the diagram below.

Acceptable Neutral Tap on Secondary

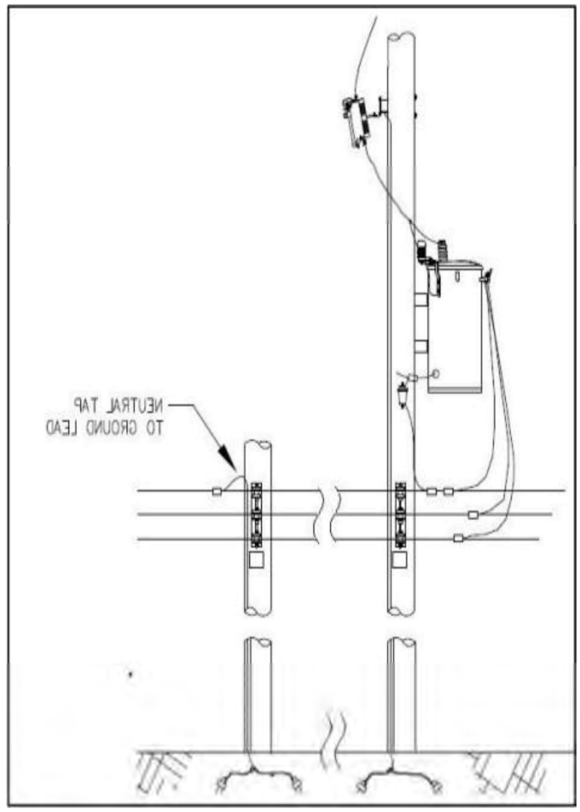


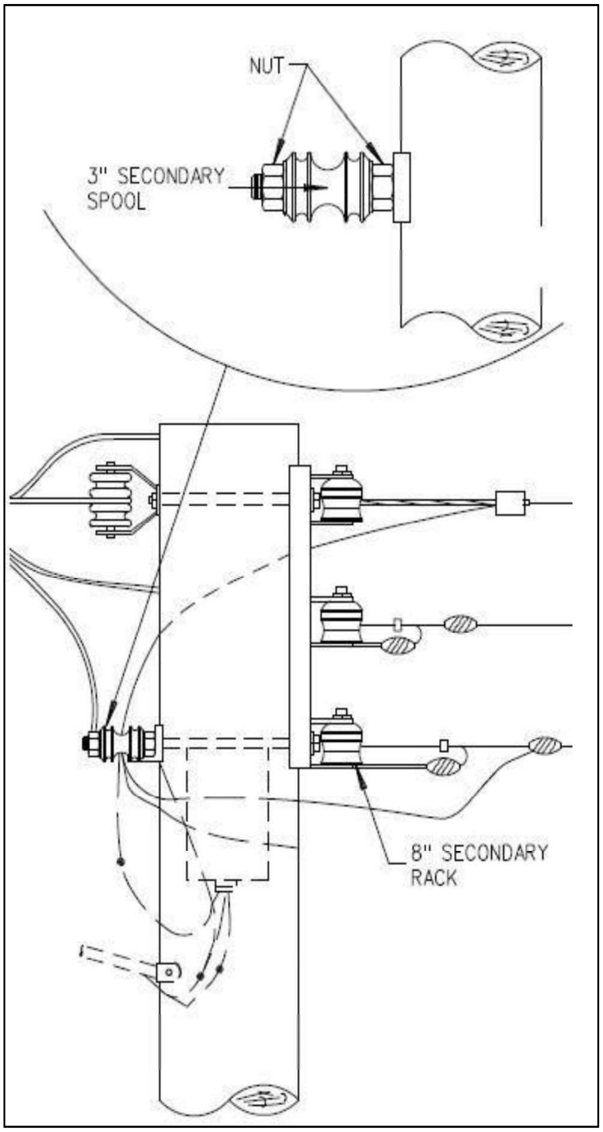
Diagram of good connections on the neutral

POLE TOP MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported*, only if there is an item that is **defective** from the above/previous listings on the same pole.

SECONDARY EQUIPMENT:

Defects:
Secondary Spool: To be reported if it's broken



Acceptable Secondary Spools and Rack

Acceptable Neutral Spool Assembly

Acceptable Spool Rack

If any of the elements contained in the picture is broken including porcelain insulators, rack, or bolts should be reported

POLE MAINTENANCE SPECIFICATION

The equipment listed below is to be *reported* if the items are **defective**.

ALL RELATED Fiberglass Brackets:

Defects:
Fiberglass Brackets: To be reported if bracket shows signs of damage.

Fiberglass brackets may experience discoloration, warping, delamination, blistering, and cracking. Attached beloware photos of the different fiberglass brackets that out in the field.

Single Phase Fiberglass Bracket with Insulator

Single Phase Fiberglass Bracket

Three Phase Equipment Fiberglass Bracket

Single Phase Fiberglass Bracket

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.2a
Respondent:	S. Pfeuffer
	1 of 1

Question: Please refer to the testimony of S. Pfeuffer, page 26, wherein it is stated: "…permanent replacements are done in the weeks following the storms and involves replacing aged, outdated equipment with equipment that meets our newer standard, such as poles that rated to a higher class, or fiberglass crossarms instead of wooden crossarms. Replacing with this higher standard of equipment rather than repairing equipment drives up the cost of restoration but leaves a grid that is more robust to future severe weather."

a. What are the criteria for replacement-over-repair decisions for the Storm, Non- storm, Substation Reactive, Hardening, and Pole and PTMM programs? Please note if the replacement-rather-than-repair criteria are identical, and if not, explain how they differ.

Answer: The partial quote provided in the question refers to storm practices; as stated on page SGP-25 lines 9-10 "During storms, the company follows industry practice where crews first make quick temporary fixes in lieu of more time-consuming permanent repairs."

For the Non-storm emergent and Substation Reactive work, the decisions are made by field crews based on their knowledge and experience.

For the Hardening, and Pole and PTMM programs, these programs involve replacements only.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.2ai
Respondent:	S. Pfeuffer
	1 of 1

Question: Please refer to the testimony of S. Pfeuffer, page 26, wherein it is stated: "…permanent replacements are done in the weeks following the storms and involves replacing aged, outdated equipment with equipment that meets our newer standard, such as poles that rated to a higher class, or fiberglass crossarms instead of wooden crossarms. Replacing with this higher standard of equipment rather than repairing equipment drives up the cost of restoration but leaves a grid that is more robust to future severe weather."

a. What are the criteria for replacement-over-repair decisions for the Storm, Non- storm, Substation Reactive, Hardening, and Pole and PTMM programs? Please note if the replacement-rather-than-repair criteria are identical, and if not, explain how they differ.

i. Please explain if there is a distinction between a replacement-over-repair decision that is implemented in order to make the grid more robust, vis-à- vis replacement over repair where the replacement provides the same level of service.

Answer: Please see MNSCDE-9.2a.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.2aii
Respondent:	S. Pfeuffer
	1 of 1

Question: Please refer to the testimony of S. Pfeuffer, page 26, wherein it is stated: "…permanent replacements are done in the weeks following the storms and involves replacing aged, outdated equipment with equipment that meets our newer standard, such as poles that rated to a higher class, or fiberglass crossarms instead of wooden crossarms. Replacing with this higher standard of equipment rather than repairing equipment drives up the cost of restoration but leaves a grid that is more robust to future severe weather."

a. What are the criteria for replacement-over-repair decisions for the Storm, Non- storm, Substation Reactive, Hardening, and Pole and PTMM programs? Please note if the replacement-rather-than-repair criteria are identical, and if not, explain how they differ.

ii. Please provide several examples from each program, where a component that failed inspection was replaced rather than repaired, where a repair was a viable option to maintain service, but the Company chose to replace in order to enhance the robustness of the grid. Please include a description of how costs were allocated between capital replacement and cost of removal under these circumstances.

Answer: The Company does not maintain a log of each decision its field crews make to repair a pole or cross-arm versus replacing it, and vice versa. For the Hardening, and Pole and PTMM programs, these programs involve replacements only.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.2aiii
Respondent:	S. Pfeuffer
	1 of 1

Question: Please refer to the testimony of S. Pfeuffer, page 26, wherein it is stated: "…permanent replacements are done in the weeks following the storms and involves replacing aged, outdated equipment with equipment that meets our newer standard, such as poles that rated to a higher class, or fiberglass crossarms instead of wooden crossarms. Replacing with this higher standard of equipment rather than repairing equipment drives up the cost of restoration but leaves a grid that is more robust to future severe weather."

a. What are the criteria for replacement-over-repair decisions for the Storm, Non- storm, Substation Reactive, Hardening, and Pole and PTMM programs? Please note if the replacement-rather-than-repair criteria are identical, and if not, explain how they differ.

iii. With respect to the Hardening, and Pole and PTMM programs, is preemptive replacement of wooden crossarms with a new fiberglass crossarm undertaken for each and every wooden crossarm on a circuit that is selected under the programs? If not, what is the approximate average percentage of a circuit's crossarms that are preemptively replaced under each program?

Answer: DTE objects to the request for the reason that it is unclear what "preemptive" means. In further answer and without waiving the objection, the Company would state as follows:

It is unclear in this context what is meant by "preemptive". The Hardening program replaces every wooden cross arm on a circuit with a fiberglass cross arm. For the Pole and PTMM programs, some but not each and every wood crossarm is replaced within a circuit.

Attachment: N/A

Co-Respondent: Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.2aiii1
Respondent:	S. Pfeuffer
	1 of 1

Question: Please refer to the testimony of S. Pfeuffer, page 26, wherein it is stated: "…permanent replacements are done in the weeks following the storms and involves replacing aged, outdated equipment with equipment that meets our newer standard, such as poles that rated to a higher class, or fiberglass crossarms instead of wooden crossarms. Replacing with this higher standard of equipment rather than repairing equipment drives up the cost of restoration but leaves a grid that is more robust to future severe weather."

a. What are the criteria for replacement-over-repair decisions for the Storm, Non- storm, Substation Reactive, Hardening, and Pole and PTMM programs? Please note if the replacement-rather-than-repair criteria are identical, and if not, explain how they differ.

iii. With respect to the Hardening, and Pole and PTMM programs, is preemptive replacement of wooden crossarms with a new fiberglass crossarm undertaken for each and every wooden crossarm on a circuit that is selected under the programs? If not, what is the approximate average percentage of a circuit's crossarms that are preemptively replaced under each program?

1. Are the priority criteria for selection of a circuit, pursuant to the Hardening and Pole and PTMM program sufficient basis for a crossarm replacement under the Company's policy, or is failure of inspection the needed basis of each crossarm replacement?

Answer: Under the 4.8kV Hardening program all wood cross arms are replaced. In the Pole and PTMM program only cross arms that are damaged or defective are replaced.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.3
Respondent:	S. Pfeuffer
	1 of 1

Question: Please specify the nature of the (Hardening and Pole and PTMM programs) field inspections performed to identify damage or defect, such as helicopter, drone, drive by, foot survey, corona camera etc.? In responding, please note if there are differing timelines associated with each type of field inspection, and, with respect to the Pole and PTMM program, how the mix of survey techniques is used to pursue the target cycle of 10 years.

Answer: The Hardening program utilizes foot patrols and cameras for capturing the condition of the poles and pole top hardware. The Pole and PTMM program utilizes foot patrols, cameras, and pole testing for capturing the condition of the poles and pole top hardware. DO is doing some experimentation with drones and their use is still being investigated. All inspections under these programs are performed at the same time, the entire circuit is inspected.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.5a
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to the Hardening program, and the Pole and PTMM program, and in reference to the competitive bidding for 3rd party contractors to implement the programs:
a. Please provide the latest Request for Proposal (RFP) for each program. If there is more than one RFP per program, please provide each.

Answer: DTE Electric objects for the reason that the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Electric, its ratepayers, and its customers competitive harm, and will only be produced to parties who have executed nondisclosure agreements pursuant to the Protective Order in this matter. In further answer and without waiving the objection, the Company would state as follows:

The Company did not issue a separate RFP for hardening. See attached 2020 RFP documents for Pole and PTMM.

Attachment: U-20836 MNSCDE-9.5b-01 2020_Pole_Inspection_Program_RFP-Redacted NDA
U-20836 MNSCDE-9.5b-02 2020_Pole_Reinforcement_Program_RFP-Redacted NDA

Co-Respondent(s): Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.5a (Supplemental)
Respondent:	S. Pfeuffer
	1 of 2

Question: With respect to the Hardening program, and the Pole and PTMM program, and in reference to the competitive bidding for 3rd party contractors to implement the programs:

a. Please provide the latest Request for Proposal (RFP) for each program. If there is more than one RFP per program, please provide each.

Answer: DTE Electric objects to the request for the reasons that the request is overly broad, seeks excessive detail, seeks confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm, seeks information involving Cyber Security, CEII (either critical energy infrastructure information or critical electric infrastructure information), North American Electric Reliability Corporation (NERC) NERC-CIP (including but not limited to BES Cyber Asset information subject to protection under the Information Protection Program pursuant to NERC Reliability Standards CIP-003-6 and CIP-011-2), Supervisory Control and Data Acquisition (SCADA), confidential Midcontinent Independent System Operation (MISO) and ITC Holdings Corp and/or its affiliate companies' information in the possession of DTE Electric, U.S. export control laws and regulations, including but not limited to 10 C.F.R. Part 810 *et. seq*., or 10 CFR Part 2.390 and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. DTE Electric has sought, through its Appeal in this proceeding dated March 15, 2022, further restrictions than those provided in the Protective Order issued March 1, 2022 in this proceeding, including that such material not be disclosed."

In further answer and without waiving the objections, the Company would state as follows:

For the reasons stated above, as the responsive documents are proprietary, these responsive documents will only be provided to those who have executed a nondisclosure agreement subject to the protective order entered in this case.

Co-Respondent(s): Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.5a (Supplemental)
Respondent:	S. Pfeuffer
	2 of 2

Furthermore, the attached documents marked “redacted” have been redacted to remove plant-specific emergency contacts, location of emergency assembly and evacuation assembly locations, and the signals the Company uses to signal emergencies, evacuations and all clears, because this constitutes information about DTE Electric’s system or assets, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters and that could be useful to a person in planning an attack on critical infrastructure and is more than simply the general location of the critical infrastructure.

See attached exhibits to the previously produced RFPs.

Attachment: *NDA U-20836 MNSCDE-9.5a-03 Appendix A Insurance Provided by Contractor.pdf*
NDA U-20836 MNSCDE-9.5a-04 Contractor Notification of Accident Report.pdf
NDA U-20836 MNSCDE-9.5a-05 DTE Gas ISO 14001Environmental ContractorHandbook_Redacted.pdf
NDA U-20836 MNSCDE-9.5a-06 DTE Energy Contractor Safety Standards.pdf
NDA U-20836 MNSCDE-9.5a-07 ISO 14001 Environmental Handbook_Redacted.pdf
NDA U-20836 MNSCDE-9.5a-08 Pole Reinforcement Spec.pdf
NDA U-20836 MNSCDE-9.5a-09 Pole Top Maintenance Specification.pdf
NDA U-20836 MNSCDE-9.5a-10 PowerAdvocate-Supplier-FAQs.pdf
NDA U-20836 MNSCDE-9.5a-11 PowerAdvocate-Supplier-Quick_Start-Guide.pdf
NDA U-20836 MNSCDE-9.5a-12 Terms and Conditions for Services.pdf
NDA U-20836 MNSCDE-9.5a-13 Terms and Conditions for the Protection of Company Confidential Information.pdf
NDA U-20836 MNSCDE-9.5a-14 Wood Pole Spec.pdf

Co-Respondent(s): Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.5b
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to the Hardening program, and the Pole and PTMM program, and in reference to the competitive bidding for 3rd party contractors to implement the programs:

b. Are standardized contracts used to contract with 3rd party contractors? If so, please provide a copy of such standardized contract for each program. If standardized contracts are not used, please provide a copy of each variant. If contracts are unique for each contractor, redacted contracts are an acceptable response.

Answer: DTE Electric objects for the reason that the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Electric, its ratepayers, and its customers competitive harm, and will only be produced to parties who have executed nondisclosure agreements pursuant to the Protective Order in this matter. In further answer and without waiving the objection, the Company would state as follows:

In the Hardening and Pole/PTMM programs, we do use standardized contracts, although slight variations are possible. Redacted examples of sample standard contracts are attached in NDA U-20836 MNSCDE-9.5b-01 Redacted Contract, NDA U-20836 MNSCDE-9.5b-02 Redacted Contract, NDA U-20836 MNSCDE-9.5b-03 Redacted Contract, NDA U-20836 MNSCDE-9.5b-04 Redacted Contract, NDA U-20836 MNSCDE-9.5b-05 Redacted Contract, and NDA U-20836 MNSCDE-9.5b-06 Redacted Contract.

Attachment: NDA U-20836 MNSCDE-9.5b-01 Redacted Contract
NDA U-20836 MNSCDE-9.5b-02 Redacted Contract
NDA U-20836 MNSCDE-9.5b-03 Redacted Contract
NDA U-20836 MNSCDE-9.5b-04 Redacted Contract
NDA U-20836 MNSCDE-9.5b-05 Redacted Contract
NDA U-20836 MNSCDE-9.5b-06 Redacted Contract

Co-Respondent(s): Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.5c
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to the Hardening program, and the Pole and PTMM program, and in reference to the competitive bidding for 3rd party contractors to implement the programs:

c. Are subcontractor invoices submitted to DTE for the Hardening and Pole and PTMM programs priced on a per circuit basis with a uniform fee for each circuit completed? If not, how are fees structured?

Answer: Hardening and Pole and PTMM invoices are submitted to DTE on a per unit basis with a set price per unit of work (i.e., inspection, excavation, replacement of equipment, etc.). Tree trimming invoices as part of these programs are submitted on a per-circuit basis. The price for the circuit is based on an agreed price for the substation, after an estimate for the particular substation, with substation costs attributed to each circuit on that substation based on circuit miles.

Attachment: N/A

Co-Respondent(s): S. Hartwick

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.5d
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to the Hardening program, and the Pole and PTMM program, and in reference to the competitive bidding for 3rd party contractors to implement the programs:

d. What are the instructions to subcontractors regarding how the total cost per circuit completed is to be itemized in their billing to DTE, i.e., with respect to tree trimming, inspections, repairs, removal, installation, materials, labor, overheads, transportation, fuel, etc.? If costs are not itemized on a per circuit basis, are they itemized by corresponding substation, or another basis?

Answer: See MNSCDE-9.5c.

Attachment: N/A

Co-Respondent(s): S. Hartwick

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.5e
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to the Hardening program, and the Pole and PTMM program, and in reference to the competitive bidding for 3rd party contractors to implement the programs:

e. With respect to component replacements, is labor, materials, and other costs separately itemized for work associated with removal activities and installation activities?

Answer: See MNSDE-9.5c.

Attachment: N/A

Co-Respondent(s): S. Hartwick

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.5f
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to the Hardening program, and the Pole and PTMM program, and in reference to the competitive bidding for 3rd party contractors to implement the programs:

f. Please provide a typical (redacted or generic) invoice received by DTE for each program.

Answer: DTE Electric objects for the reason that the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Electric, its ratepayers, and its customers competitive harm, and will only be produced to parties who have executed nondisclosure agreements pursuant to the Protective Order in this matter. In further answer and without waiving the objection, the Company would state as follows:

In lieu of an actual invoice document, most contractors enter units into a DTE online system by circuit. Tree Trim also uses a DTE online system to report tree trim by circuit, See U-20836 MNSCDE-9.5f-01 Construction Invoice, U-20836 MNSCDE-9.5f-02 Traffic Control Invoice, U-20836 MNSCDE-9.5f-03 Reinforcement Invoice, U-20836 MNSCDE-9.5f-04 Inspection Invoice, U-20836 MNSCDE-9.5f-05 Tree Trim Invoice, and U-20836 MNSCDE-9.5f-06 Engineering & Design Invoice, which are printouts from the online system.

Attachment:
U-20836 MNSCDE-9.5f-01 Construction Invoice
U-20836 MNSCDE-9.5f-02 Traffic Control Invoice
U-20836 MNSCDE-9.5f-03 Reinforcement Invoice
U-20836 MNSCDE-9.5f-04 Inspection Invoice
U-20836 MNSCDE-9.5f-05 Tree Trim Invoice
U-20836 MNSCDE-9.5f-06 Engineering & Design Invoice

Co-Respondent(s): Legal, S. Hartwick

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.5b
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to the Hardening program, and the Pole and PTMM program, and in reference to the competitive bidding for 3rd party contractors to implement the programs:

b. Are standardized contracts used to contract with 3rd party contractors? If so, please provide a copy of such standardized contract for each program. If standardized contracts are not used, please provide a copy of each variant. If contracts are unique for each contractor, redacted contracts are an acceptable response.

Answer: DTE Electric objects for the reason that the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Electric, its ratepayers, and its customers competitive harm, and will only be produced to parties who have executed nondisclosure agreements pursuant to the Protective Order in this matter. In further answer and without waiving the objection, the Company would state as follows:

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Attachment: NDA U-20836 MNSCDE-9.5b-01 Redacted Contract
NDA U-20836 MNSCDE-9.5b-02 Redacted Contract
NDA U-20836 MNSCDE-9.5b-03 Redacted Contract
NDA U-20836 MNSCDE-9.5b-04 Redacted Contract
NDA U-20836 MNSCDE-9.5b-05 Redacted Contract
NDA U-20836 MNSCDE-9.5b-06 Redacted Contract

Co-Respondent(s): Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.5f
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to the Hardening program, and the Pole and PTMM program, and in reference to the competitive bidding for 3rd party contractors to implement the programs:
f. Please provide a typical (redacted or generic) invoice received by DTE for each program.

Answer: DTE Electric objects for the reason that the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Electric, its ratepayers, and its customers competitive harm, and will only be produced to parties who have executed nondisclosure agreements pursuant to the Protective Order in this matter. In further answer and without waiving the objection, the Company would state as follows:

In lieu of an actual invoice document, most contractors enter units into a DTE online system by circuit. Tree Trim also uses a DTE online system to report tree trim by circuit, See U-20836 MNSCDE-9.5f-01 Construction Invoice, U-20836 MNSCDE-9.5f-02 Traffic Control Invoice, U-20836 MNSCDE-9.5f-03 Reinforcement Invoice, U-20836 MNSCDE-9.5f-04 Inspection Invoice, U-20836 MNSCDE-9.5f-05 Tree Trim Invoice, and U-20836 MNSCDE-9.5f-06 Engineering & Design Invoice, which are printouts from the online system.

Attachment: U-20836 MNSCDE-9.5f-01 Construction Invoice
U-20836 MNSCDE-9.5f-02 Traffic Control Invoice
U-20836 MNSCDE-9.5f-03 Reinforcement Invoice
U-20836 MNSCDE-9.5f-04 Inspection Invoice
U-20836 MNSCDE-9.5f-05 Tree Trim Invoice
U-20836 MNSCDE-9.5f-06 Engineering & Design Invoice

Co-Respondent(s): Legal, S. Hartwick

SITEID	CONT_ADMIN	PONUM	DTE_WORKDATE_1	ENTERDATE_1	POLINENUM	DTE_VENDREF_NUM	VENDOR_NAME	ITEMNUM
2199	[redacted]		10/20/2020	11/6/2020	1	[redacted]		8000590
2199	[redacted]		10/20/2020	11/6/2020	1	[redacted]		8001150
2199	[redacted]		10/20/2020	11/6/2020	1	[redacted]		8000590
2199	[redacted]		10/20/2020	11/6/2020	1	[redacted]		8001150
2199	[redacted]		10/20/2020	11/6/2020	1	[redacted]		6000371
2199	[redacted]		10/20/2020	11/6/2020	1	[redacted]		6000373
2199	[redacted]		10/20/2020	11/6/2020	1	[redacted]		6000371
2199	[redacted]		10/20/2020	11/6/2020	1	[redacted]		6000373
2199	[redacted]		10/20/2020	11/6/2020	1	[redacted]		6000369
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		8000590
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		8001150
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		8000590
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		8001150
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		8000590
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		8001150
2199	[redacted]		10/30/2020	11/10/2020	1	[redacted]		8000590
2199	[redacted]		10/30/2020	11/10/2020	1	[redacted]		8001150
2199	[redacted]		10/31/2020	11/10/2020	1	[redacted]		8000590
2199	[redacted]		10/31/2020	11/10/2020	1	[redacted]		8001150
2199	[redacted]		10/22/2020	11/10/2020	1	[redacted]		6000371
2199	[redacted]		10/22/2020	11/10/2020	1	[redacted]		6000373
2199	[redacted]		10/22/2020	11/10/2020	1	[redacted]		6000365
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		6000371
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		6000373
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		6000369
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		6000371
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		6000368
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		6000371
2199	[redacted]		10/29/2020	11/10/2020	1	[redacted]		6000373
2199	[redacted]		10/30/2020	11/10/2020	1	[redacted]		6000371
2199	[redacted]		10/30/2020	11/10/2020	1	[redacted]		6000373
2199	[redacted]		10/31/2020	11/10/2020	1	[redacted]		6000371
2199	[redacted]		10/31/2020	11/10/2020	1	[redacted]		6000373

SITEID	CONT_ADMIN	PONUM	DTE_WORKDATE_1	ENTERDATE_1	POLINENUM	DTE_VENDREF_NUM	VENDOR_NAME	ITEMNUM
2199	[redacted]	[redacted]	10/31/2020	11/10/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	10/31/2020	11/10/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	10/29/2020	11/10/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	10/29/2020	11/10/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	10/30/2020	11/10/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	10/30/2020	11/10/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	11/9/2020	11/19/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	11/9/2020	11/19/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	11/9/2020	11/19/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	11/9/2020	11/19/2020	1	[redacted]	[redacted]	8001150
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2199	[redacted]	[redacted]	11/11/2020	11/19/2020	1	[redacted]	[redacted]	6000373
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2199	[redacted]	[redacted]	11/9/2020	11/19/2020	1	[redacted]	[redacted]	6000373
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2199	[redacted]	[redacted]	11/10/2020	11/19/2020	1	[redacted]	[redacted]	6000371
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2199	[redacted]	[redacted]	11/11/2020	11/19/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	11/11/2020	11/19/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	11/11/2020	11/19/2020	1	[redacted]	[redacted]	6000371
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2199	[redacted]	[redacted]	11/11/2020	11/19/2020	1	[redacted]	[redacted]	6000373
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2199	[redacted]	[redacted]	11/11/2020	11/19/2020	1	[redacted]	[redacted]	6000373
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2199	[redacted]	[redacted]	11/12/2020	11/19/2020	1	[redacted]	[redacted]	6000368
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2199			11/6/2020	11/19/2020	1			6000369
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2199			11/9/2020	11/19/2020	1			6000371
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2199			11/12/2020	11/19/2020	1			6000371
2199			11/12/2020	11/19/2020	1			6000373
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2199			11/13/2020	11/19/2020	1			6000373

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2199	[redacted]		12/3/2020	12/14/2020	1	[redacted]		6000369
2199	[redacted]		12/3/2020	12/14/2020	1	[redacted]		6000371
2199	[redacted]		12/3/2020	12/14/2020	1	[redacted]		6000369
2199	[redacted]		12/3/2020	12/14/2020	1	[redacted]		6000365
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SITEID	CONT_ADMIN	PONUM	DTE_WORKDATE_1	ENTERDATE_1	POLINENUM	DTE_VENDREF_NUM	VENDOR_NAME	ITEMNUM
2199	[redacted]		12/3/2020	12/14/2020	1	[redacted]		6000373
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2199			12/3/2020	12/14/2020	1			6000371
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2199			12/3/2020	12/14/2020	1			6000373
2199			11/27/2020	12/14/2020	1			6000373
2199			12/2/2020	12/14/2020	1			6000371
2199			12/2/2020	12/14/2020	1			6000373
2199			12/3/2020	12/14/2020	1			6000371
2199			12/3/2020	12/14/2020	1			6000373
2199			12/4/2020	12/14/2020	1			6000365
2199			12/4/2020	12/14/2020	1			6000371
2199			12/4/2020	12/14/2020	1			6000373
2199			12/4/2020	12/14/2020	1			6000371
2199			12/4/2020	12/14/2020	1			6000373
2199			12/4/2020	12/14/2020	1			6000373
2199			12/4/2020	12/14/2020	1			6000371
2199			12/4/2020	12/14/2020	1			6000373
2199			12/4/2020	12/14/2020	1			6000371
2199			12/4/2020	12/14/2020	1			6000373
2199			12/5/2020	12/14/2020	1			6000371
2199			12/5/2020	12/14/2020	1			6000373
2199			12/5/2020	12/14/2020	1			6000365
2199			12/5/2020	12/14/2020	1			6000371
2199			12/5/2020	12/14/2020	1			6000373
2199			12/5/2020	12/14/2020	1			6000371
2199			12/5/2020	12/14/2020	1			6000373
2199			12/5/2020	12/14/2020	1			6000371
2199			12/5/2020	12/14/2020	1			6000373
2199			12/6/2020	12/14/2020	1			6000371
2199			12/6/2020	12/14/2020	1			6000373
2199			12/6/2020	12/14/2020	1			6000371
2199			12/6/2020	12/14/2020	1			6000373

SITEID	CONT_ADMIN	PONUM	DTE_WORKDATE_1	ENTERDATE_1	POLINENUM	DTE_VENDREF_NUM	VENDOR_NAME	ITEMNUM
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/4/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/4/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/5/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/5/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/4/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/4/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/5/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/5/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/5/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/4/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/4/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/4/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/2/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/2/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/3/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/3/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/5/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/5/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/6/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/4/2020	12/14/2020	1	[redacted]	[redacted]	8000171

SITEID	CONT_ADMIN	PONUM	DTE_WORKDATE_1	ENTERDATE_1	POLINENUM	DTE_VENDREF_NUM	VENDOR_NAME	ITEMNUM
2199	[redacted]	[redacted]	12/4/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/4/2020	12/14/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/7/2020	12/17/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/7/2020	12/17/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/7/2020	12/17/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/7/2020	12/17/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/7/2020	12/17/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/7/2020	12/17/2020	1	[redacted]	[redacted]	6000365
2199	[redacted]	[redacted]	12/7/2020	12/17/2020	1	[redacted]	[redacted]	6000367
2199	[redacted]	[redacted]	12/7/2020	12/17/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/7/2020	12/17/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000369
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000373

SITEID	CONT_ADMIN	PONUM	DTE_WORKDATE_1	ENTERDATE_1	POLINENUM	DTE_VENDREF_NUM	VENDOR_NAME	ITEMNUM
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000365
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/8/2020	12/17/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/9/2020	12/17/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/6/2020	12/21/2020	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/6/2020	12/21/2020	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/6/2020	12/21/2020	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/6/2020	12/21/2020	1	[redacted]	[redacted]	6000373
2199	[redacted]	[redacted]	12/6/2020	12/21/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/6/2020	12/21/2020	1	[redacted]	[redacted]	8000171
2199	[redacted]	[redacted]	12/17/2020	1/12/2021	1	[redacted]	[redacted]	8000590
2199	[redacted]	[redacted]	12/17/2020	1/12/2021	1	[redacted]	[redacted]	8001150
2199	[redacted]	[redacted]	12/17/2020	1/12/2021	1	[redacted]	[redacted]	6000371
2199	[redacted]	[redacted]	12/17/2020	1/12/2021	1	[redacted]	[redacted]	6000373

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 4	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	70FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	70FT	[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	70FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	70FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER APPRENTICE LEVEL 5				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER APPRENTICE LEVEL 1				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER APPRENTICE LEVEL 5				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 2	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 4	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 2	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 4	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 2	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 3	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	70FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	70FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	OT	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	OT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 3	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 3	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 3	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	70FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	70FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	BUCKET TRUCK .	[redacted]	[redacted]	[redacted]	ST	55FT	[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]
2199	DISC CHIPPER .	[redacted]	[redacted]	[redacted]	ST		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	BUCKET TRUCK .	[redacted]			ST	55FT	[redacted]
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	70FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	70FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	70FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	BUCKET TRUCK .				OT	55FT	
2199	DISC CHIPPER .				OT		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 3	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 3	[redacted]			DAYST		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 5	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYST		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYOT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER FOREMAN A	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	TREE TRIMMER JOURNEYMAN	[redacted]	[redacted]	[redacted]	DAYDT		[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]
2199	MEALS .	[redacted]	[redacted]	[redacted]			[redacted]

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	MEALS .	[redacted]					[redacted]
2199	MEALS .						
2199	BUCKET TRUCK .				ST	70FT	
2199	DISC CHIPPER .				ST		
2199	BUCKET TRUCK .				ST	55FT	
2199	DISC CHIPPER .				ST		
2199	BUCKET TRUCK .				ST	55FT	
2199	DISC CHIPPER .				ST		
2199	BUCKET TRUCK .				ST	55FT	
2199	DISC CHIPPER .				ST		
2199	BUCKET TRUCK .				ST	55FT	
2199	DISC CHIPPER .				ST		
2199	BUCKET TRUCK .				ST	55FT	
2199	DISC CHIPPER .				ST		
2199	BUCKET TRUCK .				ST	70FT	
2199	DISC CHIPPER .				ST		
2199	BUCKET TRUCK .				ST	55FT	
2199	DISC CHIPPER .				ST		
2199	BUCKET TRUCK .				ST	55FT	
2199	DISC CHIPPER .				ST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER APPRENTICE LEVEL 1				DAYST		
2199	TREE TRIMMER APPRENTICE LEVEL 3				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER APPRENTICE LEVEL 5				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		

SITEID	ITEM_DESCRIPTION	QUANTITY	UNITCOST	LINECOST	DTE_RATERENTCODE	DTE_UNSIZECAP	DTE_APPROVER
2199	TREE TRIMMER APPRENTICE LEVEL 1	[redacted]			DAYST		[redacted]
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		
2199	BUCKET TRUCK .				OT	70FT	
2199	DISC CHIPPER .				OT		
2199	TREE TRIMMER FOREMAN A				DAYDT		
2199	TREE TRIMMER JOURNEYMAN				DAYDT		
2199	MEALS .						
2199	MEALS .						
2199	BUCKET TRUCK .				ST	55FT	
2199	DISC CHIPPER .				ST		
2199	TREE TRIMMER FOREMAN A				DAYST		
2199	TREE TRIMMER JOURNEYMAN				DAYST		

SITEID	DTE_SAPREFERENCEID	DTE_CONTRACTREFNUM	DTE_SERVMASTER	REMARKS	ENTERBY	VENDOR
2199	1018331038	[redacted]	[redacted]	Generated by VTS~ES-654480	MAXADMIN	[redacted]
2199	1018331045	[redacted]	[redacted]	Generated by VTS~ES-654481	MAXADMIN	[redacted]
2199	1018331046	[redacted]	[redacted]	Generated by VTS~ES-654582	MAXADMIN	[redacted]
2199	1018331043	[redacted]	[redacted]	Generated by VTS~ES-654583	MAXADMIN	[redacted]
2199	1018331039	[redacted]	[redacted]	Generated by VTS~CS-800015	MAXADMIN	[redacted]
2199	1018331041	[redacted]	[redacted]	Generated by VTS~CS-800016	MAXADMIN	[redacted]
2199	1018331042	[redacted]	[redacted]	Generated by VTS~CS-800149	MAXADMIN	[redacted]
2199	1018331040	[redacted]	[redacted]	Generated by VTS~CS-800150	MAXADMIN	[redacted]
2199	1018331044	[redacted]	[redacted]	Generated by VTS~CS-800151	MAXADMIN	[redacted]
2199	1018392767	[redacted]	[redacted]	Generated by VTS~ES-666688	MAXADMIN	[redacted]
2199	1018392774	[redacted]	[redacted]	Generated by VTS~ES-666689	MAXADMIN	[redacted]
2199	1018392766	[redacted]	[redacted]	Generated by VTS~ES-666715	MAXADMIN	[redacted]
2199	1018392761	[redacted]	[redacted]	Generated by VTS~ES-666716	MAXADMIN	[redacted]
2199	1018392754	[redacted]	[redacted]	Generated by VTS~EO-666688	MAXADMIN	[redacted]
2199	1018392755	[redacted]	[redacted]	Generated by VTS~EO-666689	MAXADMIN	[redacted]
2199	1018392750	[redacted]	[redacted]	Generated by VTS~EO-668721	MAXADMIN	[redacted]
2199	1018392777	[redacted]	[redacted]	Generated by VTS~EO-668722	MAXADMIN	[redacted]
2199	1018392763	[redacted]	[redacted]	Generated by VTS~EO-670157	MAXADMIN	[redacted]
2199	1018392759	[redacted]	[redacted]	Generated by VTS~EO-670158	MAXADMIN	[redacted]
2199	1018392751	[redacted]	[redacted]	Generated by VTS~CS-814562	MAXADMIN	[redacted]
2199	1018392760	[redacted]	[redacted]	Generated by VTS~CS-814563	MAXADMIN	[redacted]
2199	1018392762	[redacted]	[redacted]	Generated by VTS~CS-814564	MAXADMIN	[redacted]
2199	1018392764	[redacted]	[redacted]	Generated by VTS~CS-815407	MAXADMIN	[redacted]
2199	1018392756	[redacted]	[redacted]	Generated by VTS~CS-815408	MAXADMIN	[redacted]
2199	1018392770	[redacted]	[redacted]	Generated by VTS~CS-815409	MAXADMIN	[redacted]
2199	1018392748	[redacted]	[redacted]	Generated by VTS~CS-815445	MAXADMIN	[redacted]
2199	1018392775	[redacted]	[redacted]	Generated by VTS~CS-815446	MAXADMIN	[redacted]
2199	1018392776	[redacted]	[redacted]	Generated by VTS~CO-815407	MAXADMIN	[redacted]
2199	1018392757	[redacted]	[redacted]	Generated by VTS~CO-815408	MAXADMIN	[redacted]
2199	1018392772	[redacted]	[redacted]	Generated by VTS~CO-818081	MAXADMIN	[redacted]
2199	1018392768	[redacted]	[redacted]	Generated by VTS~CO-818082	MAXADMIN	[redacted]
2199	1018392752	[redacted]	[redacted]	Generated by VTS~CO-819063	MAXADMIN	[redacted]
2199	1018392765	[redacted]	[redacted]	Generated by VTS~CO-819064	MAXADMIN	[redacted]

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SITEID	LINETYPE	REFWO	DTE_VALIDTO_1	DTE_VALIDFROM_1	DTE_FIRSTNAME	DTE_LASTNAME	WO_DESCRIPTION
2199	SERVICE	[redacted]					PERFORM LINE CLEARANCE
2199	SERVICE						PERFORM LINE CLEARANCE
2199	SERVICE						PERFORM LINE CLEARANCE
2199	SERVICE						PERFORM LINE CLEARANCE
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2199	SERVICE						PERFORM LINE CLEARANCE
2199	SERVICE						PERFORM LINE CLEARANCE

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SITEID	WO_GLACCOUNT	BILLTOATTN	BILLTOATTN_NAME
2199	[redacted]		
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MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.15
Respondent:	S. Pfeuffer
	1 of 2

Question: Please provide a typical or representative inspection report for 5 inspections under the Pole and PTMM program from each from 2020 to 2022. If the company is unable to identify typical or representative inspection reports, then please provide a random inspection report for 5 inspections under the Pole and PTMM program in each year from 2020 to 2022.

Answer: DTE Electric objects to the request for the reasons that the request is overly broad, seeks excessive detail, seeks confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm, seeks information involving Cyber Security, CEII (either critical energy infrastructure information or critical electric infrastructure information), North American Electric Reliability Corporation (NERC) NERC-CIP (including but not limited to BES Cyber Asset information subject to protection under the Information Protection Program pursuant to NERC Reliability Standards CIP-003-6 and CIP-011-2), Supervisory Control and Data Acquisition (SCADA), confidential Midcontinent Independent System Operation (MISO) and ITC Holdings Corp and/or its affiliate companies' information in the possession of DTE Electric, U.S. export control laws and regulations, including but not limited to 10 C.F.R. Part 810 *et. seq.*, or 10 CFR Part 2.390 and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. DTE Electric has sought, through its Appeal in this proceeding dated March 15, 2022, further restrictions than those provided in the Protective Order issued March 1, 2022 in this proceeding, including that such material not be disclosed.

The Company also objects to provision of confidential customer and vendor information, for instance names and addresses.

Subject to these objections and without waiver thereof, the Company would answer as follows:

Co-Respondent: Legal

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.15
Respondent:	S. Pfeuffer
	2 of 2

The Company does not yet have Pole and PTMM inspections reports for 2022. See attached for random inspection reports from 2020 and 2021.
The attachments have been redacted to conceal geospatial and location information, which in conjunction with infrastructure condition information in the attached constitutes specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that relates details about the production, generation, transportation, transmission, or distribution of energy that could be useful to a person in planning an attack on critical infrastructure and is more than simply the general location of the critical infrastructure.

The attachments have also been redacted to conceal customer and vendor names, customer ID numbers, and addresses, along with the identity of the owners of non-DTE-owned poles.

Attachment:

U-20836 MNSCDE-9.15-01 PIT CIRCUIT 1 2020.PDF
U-20836 MNSCDE-9.15-02 PTP CIRCUIT 1 2020.PDF
U-20836 MNSCDE-9.15-03 PIT CIRCUIT 2 2020.PDF
U-20836 MNSCDE-9.15-04 PTP CIRCUIT 2 2020.PDF
U-20836 MNSCDE-9.15-05 PIT CIRCUIT 3 2020.PDF
U-20836 MNSCDE-9.15-06 PTP CIRCUIT 3 2020.PDF
U-20836 MNSCDE-9.15-07 PIT CIRCUIT 4 2020.PDF
U-20836 MNSCDE-9.15-08 PTP CIRCUIT 4 2020.PDF
U-20836 MNSCDE-9.15-09 PIT CIRCUIT 5 2020.PDF
U-20836 MNSCDE-9.15-10 PTP CIRCUIT 5 2020.PDF
U-20836 MNSCDE-9.15-11 PIT CIRCUIT 1 2021.PDF
U-20836 MNSCDE-9.15-12 PTP CIRCUIT 1 2021.PDF
U-20836 MNSCDE-9.15-13 PIT CIRCUIT 2 2021.PDF
U-20836 MNSCDE-9.15-14 PTP CIRCUIT 2 2021.PDF
U-20836 MNSCDE-9.15-15 PIT CIRCUIT 3 2021.PDF
U-20836 MNSCDE-9.15-16 PTP CIRCUIT 3 2021.PDF
U-20836 MNSCDE-9.15-17 PIT CIRCUIT 4 2021.PDF
U-20836 MNSCDE-9.15-18 PTP CIRCUIT 4 2021.PDF
U-20836 MNSCDE-9.15-19 PIT CIRCUIT 5 2021.PDF
U-20836 MNSCDE-9.15-20 PTP CIRCUIT 5 2021.PDF

Co-Respondent: Legal

	A	B	C	D
1	GlobalID_PIT	GLNX-GLNY_PIT	GPSLatitude_PIT	GPSLongitude_PIT
2	{00868303-C5B2-4DE4-A693-4C82B84BCA30}	148850-284477	[redacted]	[redacted]
3	{0097E057-DB7C-450B-BE4E-C3DD8C5BD828}	148671-286665	[redacted]	[redacted]
4	{02EAAB72-81CD-4B8A-A2C3-BD206E064D1C}	149319-286681	[redacted]	[redacted]
5	{09E57BF0-8D45-4A7E-A827-A218569CC76B}	148801-285349	[redacted]	[redacted]
6	{12FAE264-3D2E-4E49-A267-871EC4776444}	147982-286686	[redacted]	[redacted]
7	{17D3692D-E498-4BB6-9C43-283DCC08DABE}	149914-284973	[redacted]	[redacted]
8	{1993E949-E56C-41D7-866A-4B7952656F3A}	147917-285549	[redacted]	[redacted]
9	{1B4398F4-017C-4B06-ADA2-66F34E653F4A}	148441-285339	[redacted]	[redacted]
10	{1D3CAD87-B81A-4D1D-871B-B033AD6F3B26}	147983-286647	[redacted]	[redacted]
11	{1EC4069B-3121-4E58-805F-66ADBDB1630B}	148817-285024	[redacted]	[redacted]
12	{2075C201-F852-4F3F-8609-A99EFE4B7497}	149615-284503	[redacted]	[redacted]
13	{264620E7-955E-4424-8A44-DEF8FD83D789}	148370-286052	[redacted]	[redacted]
14	{2746EF0F-D2E6-44AF-9335-908BA73F5D89}	148783-284594	[redacted]	[redacted]
15	{27C752C8-C8C7-4723-896C-F4E4C203AF8C}	149028-285174	[redacted]	[redacted]
16	{2B22E0C4-F662-4FDB-A399-370A5A87CBD3}	149815-284723	[redacted]	[redacted]
17	{2BDDF768-84CF-4C97-933A-1350FBD0ADC2}	149558-285017	[redacted]	[redacted]
18	{2E4209B9-BE59-44F4-B1F3-336ADA4ECCC2}	149640-284288	[redacted]	[redacted]
19	{3E210400-99ED-4F0D-92F6-72999E1E8F43}	148762-284201	[redacted]	[redacted]
20	{416615E3-5FC6-41A7-9DEA-BAEAE7B1533F}	149683-284877	[redacted]	[redacted]
21	{430A5760-B2DF-4C58-958E-56041E0486A3}	149468-285032	[redacted]	[redacted]
22	{4440540B-1BE7-497C-B878-8A68E87D5569}	148279-286215	[redacted]	[redacted]
23	{456D19A6-9717-4DA1-BDCE-493ADD7B7E29}	148734-283603	[redacted]	[redacted]
24	{45BF422B-F2B4-4817-9416-20BA53A87D2D}	148158-286653	[redacted]	[redacted]
25	{46BFEBA3-FF41-49C4-AD9D-A0CA5F94A2EF}	149048-284015	[redacted]	[redacted]
26	{47986A53-F154-4AEB-80E8-1C28DBC7A665}	148156-285455	[redacted]	[redacted]
27	{4C2ED322-BD97-470E-B4DA-494139D4F1CE}	149120-286676	[redacted]	[redacted]
28	{4E07B2A3-FF73-4701-92E7-61CCDB8D76F6}	148918-284667	[redacted]	[redacted]
29	{539E6328-1025-47BC-84EC-FB77157A241B}	149758-284033	[redacted]	[redacted]
30	{5B1C066B-9065-450D-B019-68E90DC7B65D}	147979-286799	[redacted]	[redacted]
31	{5F4D69C2-FBDA-40F4-BF8A-3B9761CE2349}	149647-284163	[redacted]	[redacted]
32	{6143C824-2737-4621-B6CF-867D5554AF85}	149901-284903	[redacted]	[redacted]
33	{627B5DF2-886D-477B-98F0-094282F93949}	149718-283729	[redacted]	[redacted]
34	{62E57791-D88A-4B23-98F5-CDE2291F90DA}	148837-285171	[redacted]	[redacted]
35	{637764AA-8A41-4FCB-9653-C1DECD49B6AA}	148814-284979	[redacted]	[redacted]
36	{642D11E3-85E2-4B0E-8645-25C464272684}	148727-283407	[redacted]	[redacted]
37	{65E9CEBD-6C23-4B5E-9AF3-816D4824E838}	148579-285719	[redacted]	[redacted]
38	{69F48E24-9D05-453F-837E-3298F960AC9B}	148805-286950	[redacted]	[redacted]
39	{6ABF077F-AEBE-4463-BA05-76869B36F5C2}	149475-286681	[redacted]	[redacted]
40	{6AFFDCF5-B585-4B37-BDFE-C4406FD2FBDA}	149362-286682	[redacted]	[redacted]
41	{6D1B2E7F-1B8F-4C14-9A61-7B3BDE896DFD}	149723-283582	[redacted]	[redacted]
42	{7247418D-7182-4590-B2E5-4A8B4C36DC0D}	148751-284012	[redacted]	[redacted]
43	{7519A1C6-E2F8-4DA2-AC13-EFE0CCA279A4}	148579-285762	[redacted]	[redacted]

	E	F	G	H	I
1	OHPrimaryCircuitNumber_PIT	Add Remove Update Pole_PIT	Cable Pole Type_PIT	CrewId _PIT	Decay Location_PIT
2	[redacted]	Update	Not Applicable	197227	Internal
3		Update	Primary	197227	Internal
4		Update	Primary	197227	No Decay
5		Update	Primary	197227	Internal
6		Update	Not Applicable	197227	No Decay
7		Remove	Not Applicable	197227	No Decay
8		Update	Secondary	197227	Internal
9		Update	Joint Use	197227	Internal
10		Update	Not Applicable	197227	Internal
11		Update	Primary	197227	No Decay
12		Update	Secondary	197227	External and Internal
13		Update	Primary	197227	Internal
14		Update	Primary	197227	Internal
15		Update	Joint Use	197227	External and Internal
16		Update	Not Applicable	197227	No Decay
17		Update	Not Applicable	197227	No Decay
18		Update	Secondary	197227	No Decay
19		Update	Not Applicable	197227	Internal
20		Update	Secondary	197227	External and Internal
21		Update	Joint Use	197227	No Decay
22		Update	Primary	197227	Internal
23		Update	Not Applicable	197227	No Decay
24		Update	Not Applicable	197227	Internal
25		Update	Primary	197227	Internal
26		Update	Primary	197227	Internal
27		Update	Joint Use	197227	No Decay
28		Update	Not Applicable	197227	Internal
29		Update	Not Applicable	197227	Internal
30		Update	Not Applicable	197227	No Decay
31		Update	Not Applicable	197227	External and Internal
32		Update	Not Applicable	197227	External and Internal
33		Update	Not Applicable	197227	No Decay
34		Update	Not Applicable	197227	No Decay
35		Update	Not Applicable	197227	Internal
36		Update	Primary	197227	No Decay
37		Update	Not Applicable	197227	Internal
38		Update	Not Applicable	197227	Internal
39		Update	Not Applicable	197227	No Decay
40		Update	Primary	197227	No Decay
41		Update	Primary	197227	External and Internal
42		Update	Not Applicable	197227	Internal
43		Update	Primary	197227	External and Internal

	J	K	L
1	Decay Measurements_PIT	Groundline Circumference _PIT	Inspection Date_PIT
2	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	47	9/21/2020
3	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	52	9/23/2020
4	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	52	9/23/2020
5	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	52	9/23/2020
6	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	35	9/23/2020
7	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	28	9/22/2020
8	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	70	9/24/2020
9	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	53	9/24/2020
10	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	39	9/23/2020
11	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	45	9/22/2020
12	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	36	9/22/2020
13	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	54	9/23/2020
14	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	56	9/21/2020
15	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	30	9/22/2020
16	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	38	9/22/2020
17	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	36	9/22/2020
18	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	37	9/22/2020
19	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	60	9/21/2020
20	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	40	9/22/2020
21	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	28	9/22/2020
22	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	48	9/23/2020
23	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	32	9/21/2020
24	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	48	9/23/2020
25	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	52	9/21/2020
26	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	48	9/24/2020
27	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	54	9/23/2020
28	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	50	9/21/2020
29	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	33	9/21/2020
30	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	47	9/23/2020
31	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	45	9/22/2020
32	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	34	9/22/2020
33	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	46	9/21/2020
34	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	50	9/22/2020
35	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	50	9/22/2020
36	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	32	9/21/2020
37	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	55	9/23/2020
38	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	34	9/23/2020
39	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	36	9/23/2020
40	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	46	9/23/2020
41	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	49	9/21/2020
42	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	54	9/21/2020
43	+90,0.0,0.0,0.0,-90,0.0,0.0,0.0,+LOL,0.0,0.0,0.0,-LOL,0.0,0.0,0.0	49	9/23/2020

	M	N	O	P	Q
1	Inspection Fully Excavated Sides_PIT	Inspection Partial Excavated Sides_PIT	Inspection Tag Type_PIT	Minimum Measured Below Groundline Circumference_PIT	Minimum Measured Shell Thickness Inches_PIT
2	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
3	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
4	Not Fully Excavated	0	Visual	Pole Not Excavated	Pole Not Bored
5	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
6	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
7	Not Fully Excavated	0	Visual	Pole Not Excavated	Pole Not Bored
8	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
9	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
10	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
11	Not Fully Excavated	0	Visual	Pole Not Excavated	Pole Not Bored
12	3	0	Full Excavation	Pole Not Excavated	Pole Not Bored
13	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
14	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
15	3	0	Full Excavation	Pole Not Excavated	Pole Not Bored
16	Not Fully Excavated	0	Visual	Pole Not Excavated	Pole Not Bored
17	Not Fully Excavated	0	Visual	Pole Not Excavated	Pole Not Bored
18	Not Fully Excavated	1	Partial Excavation	Pole Not Excavated	Pole Not Bored
19	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
20	3	0	Full Excavation	Pole Not Excavated	Pole Not Bored
21	Not Fully Excavated	0	Visual	Pole Not Excavated	Pole Not Bored
22	Not Fully Excavated	1	Partial Excavation	Pole Not Excavated	Pole Not Bored
23	Not Fully Excavated	2	Sound & Bore	Pole Not Excavated	Pole Not Bored
24	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
25	Not Fully Excavated	1	Partial Excavation	Pole Not Excavated	Pole Not Bored
26	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
27	Not Fully Excavated	0	Partial Excavation	Pole Not Excavated	Pole Not Bored
28	Not Fully Excavated	0	Sound & Bore	Pole Not Excavated	Pole Not Bored
29	Not Fully Excavated	0	Sound & Bore	Pole Not Excavated	Pole Not Bored
30	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
31	4	0	Full Excavation	Pole Not Excavated	Pole Not Bored
32	4	0	Full Excavation	Pole Not Excavated	Pole Not Bored
33	Not Fully Excavated	0	Visual	Pole Not Excavated	Pole Not Bored
34	Not Fully Excavated	0	Visual	Pole Not Excavated	Pole Not Bored
35	Not Fully Excavated	1	Partial Excavation	Pole Not Excavated	Pole Not Bored
36	Not Fully Excavated	2	Sound & Bore	Pole Not Excavated	Pole Not Bored
37	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
38	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
39	Not Fully Excavated	0	Sound & Bore	Pole Not Excavated	Pole Not Bored
40	Not Fully Excavated	0	Visual	Pole Not Excavated	Pole Not Bored
41	3	0	Full Excavation	Pole Not Excavated	Pole Not Bored
42	Not Fully Excavated	2	Partial Excavation	Pole Not Excavated	Pole Not Bored
43	3	0	Full Excavation	Pole Not Excavated	Pole Not Bored

	R	S	T	U
1	Number Of Fumigant Holes_PIT	PO_PIT	Pole Groundline Site Type_PIT	Pole Inspection Comments_PIT
2	4	4701487501	Soil	N/A
3	5	4701487501	Soil	N/A
4	0	4701487501	Soil	N/A
5	5	4701487501	Soil	N/A
6	0	4701487501	Soil	N/A
7	0	4701487501	Soil	[redacted]
8	5	4701487501	Soil	N/A
9	5	4701487501	Soil	N/A
10	3	4701487501	Soil	N/A
11	0	4701487501	Soil	N/A
12	3	4701487501	Soil	N/A
13	5	4701487501	Soil	Height 60ft
14	5	4701487501	Gravel	N/A
15	3	4701487501	Soil	N/A
16	0	4701487501	Soil	Guy pole
17	0	4701487501	Soil	N/A
18	0	4701487501	Soil	N/A
19	5	4701487501	Soil	N/A
20	4	4701487501	Soil	N/A
21	0	4701487501	Soil	N/A
22	4	4701487501	Soil	Height 60ft
23	0	4701487501	Soil	N/A
24	4	4701487501	Soil	N/A
25	4	4701487501	Soil	N/A
26	5	4701487501	Soil	N/A
27	0	4701487501	Soil	N/A
28	5	4701487501	Concrete	N/A
29	3	4701487501	Concrete	N/A
30	0	4701487501	Soil	N/A
31	4	4701487501	Soil	N/A
32	3	4701487501	Soil	N/A
33	0	4701487501	Soil	N/A
34	0	4701487501	Soil	N/A
35	5	4701487501	Soil	N/A
36	0	4701487501	Soil	N/A
37	5	4701487501	Soil	N/A
38	3	4701487501	Soil	N/A
39	0	4701487501	Soil	N/A
40	0	4701487501	Soil	N/A
41	4	4701487501	Soil	N/A
42	4	4701487501	Soil	N/A
43	4	4701487501	Soil	N/A

	V	W	X	Y	Z	AA	AB	AC
1	Pole Status_PIT	Pole Tag Attached _PIT	Pole Tag Class_PI T	Pole Tag Installation Year_PIT	Pole Tag Length_ PIT	Pole Tag Owner _PIT	Pole Tag Species Treatment Code_PIT	Reason For Pole Rejection_PIT
2	Non-Reject	Y	1	1961	45	DTE	E	Pole Not Rejected
3	Non-Reject	Y	2	1958	60	DTE	E	Pole Not Rejected
4	Non-Reject	Y	3	2007	55	DTE	ND	Pole Not Rejected
5	Non-Reject	Y	1	1965	65	DTE	E	Pole Not Rejected
6	Non-Reject	Y	4	1999	40	DTE	ND	Pole Not Rejected
7	Non-Reject	N	5	1962	35	[redacted]	G	Pole Not Rejected
8	Non-Reject	Y	2	1973	65	DTE	BB	Pole Not Rejected
9	Non-Reject	Y	3	1960	70	DTE	E	Pole Not Rejected
10	Non-Reject	Y	4	1982	40	DTE	E	Pole Not Rejected
11	Non-Reject	Y	3	2014	45	DTE	ND	Pole Not Rejected
12	Non-Reject	N	4	1959	45	DTE	H	Pole Not Rejected
13	Non-Reject	Y	1	1965	60	DTE	E	Pole Not Rejected
14	Non-Reject	Y	2	1980	60	DTE	E	Pole Not Rejected
15	Non-Reject	N	5	1960	35	[redacted]	G	Pole Not Rejected
16	Non-Reject	Y	1	2003	30	DTE	ND	Pole Not Rejected
17	Non-Reject	Y	4	2014	40	DTE	ND	Pole Not Rejected
18	Non-Reject	N	4	1995	50	DTE	GD	Pole Not Rejected
19	Non-Reject	Y	2	1952	60	DTE	E	Pole Not Rejected
20	Non-Reject	Y	4	1954	45	DTE	E	Pole Not Rejected
21	Non-Reject	N	5	1960	35	[redacted]	G	Pole Not Rejected
22	Non-Reject	Y	1	1965	60	DTE	E	Pole Not Rejected
23	Non-Reject	Y	5	1996	40	DTE	GD	Pole Not Rejected
24	Non-Reject	Y	2	1958	60	DTE	E	Pole Not Rejected
25	Non-Reject	Y	1	1996	70	DTE	BB	Pole Not Rejected
26	Non-Reject	N	3	1986	60	DTE	BB	Pole Not Rejected
27	Non-Reject	N	3	1965	55	DTE	E	Pole Not Rejected
28	Non-Reject	Y	1	1969	50	DTE	H	Pole Not Rejected
29	Non-Reject	N	4	1952	40	[redacted]	G	Pole Not Rejected
30	Non-Reject	N	2	2003	45	DTE	GD	Pole Not Rejected
31	Non-Reject	N	3	1987	50	DTE	BB	Pole Not Rejected
32	Non-Reject	Y	4	1966	45	DTE	G	Pole Not Rejected
33	Non-Reject	Y	3	2014	60	DTE	ND	Pole Not Rejected
34	Non-Reject	Y	1	2016	60	DTE	T	Pole Not Rejected
35	Non-Reject	Y	2	1957	60	DTE	E	Pole Not Rejected
36	Non-Reject	Y	3	1996	40	DTE	GD	Pole Not Rejected
37	Non-Reject	N	1	1961	65	DTE	H	Pole Not Rejected
38	Non-Reject	N	5	1940	35	DTE	B	Pole Not Rejected
39	Non-Reject	Y	4	1965	50	DTE	G	Pole Not Rejected
40	Non-Reject	Y	3	2005	55	DTE	ND	Pole Not Rejected
41	Non-Reject	Y	2	1957	60	DTE	E	Pole Not Rejected
42	Non-Reject	Y	2	1957	60	DTE	E	Pole Not Rejected
43	Non-Reject	Y	1	1955	50	DTE	E	Pole Not Rejected

	AD	AE	AF	AG	AH
1	Reason Pole Cant Be Restored At Inspection_PIT	Reason Pole Was Not Inspected_PIT	Reason Pole Was Not Treated_PIT	Reinforced Pole_PIT	Remaining Percent Pole Strength_PIT
2	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
3	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
4	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
5	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
6	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
7	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
8	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
9	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
10	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
11	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
12	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
13	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
14	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
15	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
16	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
17	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
18	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
19	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
20	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
21	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
22	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
23	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
24	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
25	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
26	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
27	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
28	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
29	Pole Not Rejected	Pole Was Inspected	Pole Was Treated	N	Not Calculated
30	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
31	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
32	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
33	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
34	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
35	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
36	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
37	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
38	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
39	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
40	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
41	Pole Not Rejected	Pole Was Inspected	Pole Was Treated	N	Not Calculated
42	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated
43	Pole Not Rejected	Pole Was Inspected	No Decay Found	N	Not Calculated

	AI	AJ	AK	AL	AM
1	Retreatment For Voids_PIT	Retreatment Below Groundline_PIT	Retreatment Internal_PIT	Structure Type_PIT	Truck Accessible_PIT
2	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
3	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
4	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
5	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
6	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	N
7	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
8	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
9	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
10	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	N
11	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
12	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
13	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
14	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
15	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
16	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
17	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
18	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
19	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
20	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
21	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
22	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	N
23	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	N
24	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	N
25	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
26	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
27	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
28	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
29	No Retreatment Applied	No Retreatment Applied	Durafume II	Wood	Y
30	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
31	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
32	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
33	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
34	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
35	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
36	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
37	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
38	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
39	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	N
40	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
41	No Retreatment Applied	MP500-EXT	Durafume II	Wood	Y
42	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y
43	No Retreatment Applied	No Retreatment Applied	No Retreatment Applied	Wood	Y

	A	B	C	D	E
1	GlobalID_PTP	GLNX-GLNY_PTP	GPS Latitude_PTP	GPS Longitude_PTP	OH Primary Circuit Number_PTP
2	{8FD0128A-78AB-42ED-BD24-9EA3B1002169}	148157-286710	[redacted]	[redacted]	[redacted]
3	{69F48E24-9D05-453F-837E-3298F960AC9B}	148805-286950	[redacted]	[redacted]	[redacted]
4	{F38E3D9B-317F-4423-8360-280106277077}	148944-286671	[redacted]	[redacted]	[redacted]
5	{0097E057-DB7C-450B-BE4E-C3DD8C5BD828}	148671-286665	[redacted]	[redacted]	[redacted]
6	{92AE3E3B-1CEE-45DB-9D17-3A852A37D088}	148838-286670	[redacted]	[redacted]	[redacted]
7	{6ABF077F-AEBE-4463-BA05-76869B36F5C2}	149475-286681	[redacted]	[redacted]	[redacted]
8	{4C2ED322-BD97-470E-B4DA-494139D4F1CE}	149120-286676	[redacted]	[redacted]	[redacted]
9	{B1367D77-330D-42C1-A4F9-0FBFC3FFE7F4}	148540-286662	[redacted]	[redacted]	[redacted]
10	{CC30D232-F21C-4256-868A-84D275BF4D96}	149423-286682	[redacted]	[redacted]	[redacted]
11	{953E16DC-8943-4803-8829-F69502E627A3}	149275-286680	[redacted]	[redacted]	[redacted]
12	{45BF422B-F2B4-4817-9416-20BA53A87D2D}	148158-286653	[redacted]	[redacted]	[redacted]
13	{4440540B-1BE7-497C-B878-8A68E87D5569}	148279-286215	[redacted]	[redacted]	[redacted]
14	{264620E7-955E-4424-8A44-DEF8FD83D789}	148370-286052	[redacted]	[redacted]	[redacted]
15	{6AFFDCF5-B585-4B37-BDFE-C4406FD2FBDA}	149362-286682	[redacted]	[redacted]	[redacted]
16	{7EE6E73D-EBB1-4E46-A135-FB58AF5AA179}	149655-284030	[redacted]	[redacted]	[redacted]
17	{B90C15E4-9E0A-422A-A091-24E46FEA3951}	148661-285240	[redacted]	[redacted]	[redacted]
18	{A610C285-57E0-46D7-A386-C2EC0D6A23C0}	148480-285896	[redacted]	[redacted]	[redacted]
19	{47986A53-F154-4AEB-80E8-1C28DBC7A665}	148156-285455	[redacted]	[redacted]	[redacted]
20	{09E57BF0-8D45-4A7E-A827-A218569CC76B}	148801-285349	[redacted]	[redacted]	[redacted]
21	{00868303-C5B2-4DE4-A693-4C82B84BCA30}	148850-284477	[redacted]	[redacted]	[redacted]
22	{F932AC16-E073-43E2-9B08-9B439D0D9F9C}	148075-285391	[redacted]	[redacted]	[redacted]
23	{D05DEBD7-C629-4261-9506-9AEC0C0E7465}	149356-284022	[redacted]	[redacted]	[redacted]
24	{7519A1C6-E2F8-4DA2-AC13-EFE0CCA279A4}	148579-285762	[redacted]	[redacted]	[redacted]
25	{E51812FB-174B-4373-896E-23284070DDE7}	148232-285424	[redacted]	[redacted]	[redacted]
26	{1B4398F4-017C-4B06-ADA2-66F34E653F4A}	148441-285339	[redacted]	[redacted]	[redacted]
27	{89A29A79-AAE6-4833-955E-317B7A7BA80E}	148760-284346	[redacted]	[redacted]	[redacted]
28	{2746EF0F-D2E6-44AF-9335-908BA73F5D89}	148783-284594	[redacted]	[redacted]	[redacted]
29	{46BFEBA3-FF41-49C4-AD9D-A0CA5F94A2EF}	149048-284015	[redacted]	[redacted]	[redacted]

	F	G	H	I	J
1	Arrester_PTP	Blackburn Hot Taps_PTP	Crossarm_PTP	Crossarm Brace_PTP	Crossarm Brace Nut Bolt_PTP
2	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
3	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
4	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
5	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
6	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
7	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
8	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
9	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
10	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
11	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
12	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
13	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
14	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
15	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
16	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
17	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
18	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
19	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
20	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
21	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
22	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
23	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
24	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
25	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
26	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
27	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
28	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
29	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable

	K	L	M	N	O
1	Crossarm Nut Bolt_PTP	Cutout Polymer_PTP	Cutout Porcelain_PTP	Disc Insulator_PTP	Ground Wire For Grounded Pole_PTP
2	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
3	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
4	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
5	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
6	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
7	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
8	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
9	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
10	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
11	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
12	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
13	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
14	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
15	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
16	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
17	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
18	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
19	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
20	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
21	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
22	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
23	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
24	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
25	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
26	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
27	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
28	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable
29	Acceptable or Not Applicable	Acceptable or Not Applicable	N	Acceptable or Not Applicable	Acceptable or Not Applicable

	P	Q	R	S
1	Guy Wire_PTP	Insulator Fneck_PTP	Insulator Nut Bolt_PTP	Insulator Pin_PTP
2	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
3	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
4	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
5	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
6	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
7	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
8	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
9	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
10	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
11	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
12	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
13	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
14	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
15	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
16	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
17	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
18	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
19	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
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21	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
22	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
23	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
24	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
25	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
26	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Defective and Affecting Hardware
27	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
28	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
29	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable

	T	U	V	W	X	Y
1	Johnny Ball_PTP	Line Post Insulator Non Porcelain_PTP	Line Post Insulator Porcelain_PTP	Neutrals On Secondary Tap_PTP	Poletop_PTP	Primary Line Sag_PTP
2	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
3	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
4	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
5	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
6	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
7	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
8	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
9	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
10	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
11	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
12	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
13	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
14	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
15	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
16	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
17	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
18	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
19	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
20	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
21	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
22	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
23	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
24	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
25	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
26	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
27	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
28	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable
29	Acceptable or Not Applicable	Acceptable	N	Acceptable or Not Applicable	Acceptable	Acceptable or Not Applicable

	Z	AA	AB	AC
1	Secondary Spool_PTP	Secondary Wire_PTP	Sleeve_PTP	Spacer Block_PTP
2	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
3	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
4	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
5	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
6	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
7	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
8	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
9	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
10	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
11	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
12	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
13	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
14	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
15	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
16	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
17	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
18	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
19	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
20	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
21	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
22	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
23	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
24	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
25	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
26	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
27	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
28	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable
29	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable	Acceptable or Not Applicable

	AD
1	Transformer Nut Bolt_PTP
2	Acceptable or Not Applicable
3	Acceptable or Not Applicable
4	Acceptable or Not Applicable
5	Acceptable or Not Applicable
6	Acceptable or Not Applicable
7	Acceptable or Not Applicable
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28	Acceptable or Not Applicable
29	Acceptable or Not Applicable

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.19a
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to discovery response MDSCDE-6.1aiii, DTE responded in part that: “Circuits selected for the 4.8 kV Hardening program receive their own inspections prior to construction activities beginning.”

a. What is the timeline between inspection and construction activities? Is the timeline the same as for the Pole and PTMM program? Please explain differences.

Answer: In general, it takes two years to harden a circuit. In year one the Hardening program trims the trees, perform PTMM inspections and writes up the job (design work). In year two the overhead construction work is performed.

Prior to 2022 the Pole and PTMM program did not have an explicit timeline between inspection and construction activities. The Company’s goal, as of 2022, is to reinforce or replace poles that fail inspection within a 12-month period of failed inspection, and replace pole top hardware between 12 to 24 months after inspeciton, as stated in response MNSCDE-6.1aiv.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.19b
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to discovery response MDSCDE-6.1aiii, DTE responded in part that: "Circuits selected for the 4.8 kV Hardening program receive their own inspections prior to construction activities beginning."

b. Has DTE successfully hardened all circuits that were inspected in 2017, 2018, 2019, 2020 and 2021? If not, please explain.

Answer: The Hardening program started in 2018. Yes, DTE hardened all circuits inspected for the Hardening program from 2018-2020. The circuits inspected in 2021 are still in progress in 2022.

Attachment: *N/A*

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.19c
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to discovery response MDSCDE-6.1aiii, DTE responded in part that: "Circuits selected for the 4.8 kV Hardening program receive their own inspections prior to construction activities beginning."

c. Were there circuits that DTE trimmed and inspected under the hardening program, but where no construction (e.g., replacing wooden cross arms, remove DPLD wire or service lines) was performed, from 2017 to 2021? Please explain your response.

Answer: No.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.19d
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to discovery response MDSCDE-6.1aiii, DTE responded in part that: "Circuits selected for the 4.8 kV Hardening program receive their own inspections prior to construction activities beginning."

d. In selecting circuits to harden, does DTE ensure that those circuits that have not been inspected for 10-years, or more, are prioritized for selection under the Hardening program? Please explain.

Answer: The selection process for the 4.8kV Hardening program is explained on pages SGP-69 and SGP-70 and does not include date since last inspection. The 4.8kV Hardening program has its own inspections; however, if a circuit was recently inspected under the Pole and PTMM program, the 4.8kV Hardening program will use the results of that inspection instead of performing another one.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.19e
Respondent:	S. Pfeuffer
	1 of 1

Question: With respect to discovery response MDSCDE-6.1aiii, DTE responded in part that: “Circuits selected for the 4.8 kV Hardening program receive their own inspections prior to construction activities beginning.”

e. After a circuit is hardened, is that circuit placed on an approximate 10-year timeline for the next inspection, but under the Pole and PTMM program?

Answer: Yes.

Attachment: N/A

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.25a
Respondent:	S. Pfeuffer
	1 of 1

Question: With reference to Base and Strategic capital programs delineated on Exhibit A-12, Schedule B5.4, page 1 of 12, please provide a break-out for each capital program of all cost categories that have been allocated to each program, such that the sum equals the amount shown on Exhibit A-12, Schedule B5.4, page 1 of 12. The break-out should include all relevant cost categories including tree trimming, inspections, labor, materials, and overheads. Labor should be separately delineated for removal, installation, and repairs, if available. Materials should be separately delineated for installation and repairs, if available. The break-out should include fuel, transportation, and any other cost items, if those items are not included the overheads.

a. Please provide the data for the historical calendar years 2020 and 2021, and for the 10-months ending 10/1/22 and 12-months ending 10/1/23.

Answer: The Company has the requested expenditures broken out by labor, material, and other. Please note that CIAC is shown in the attached files in the “other” category to balance the expenditures, CIAC comes in as a credit and does not offset any one particular category. Please see attachments U-20836 MNSCDE-9.25a-01 2020 Exh A-12 Sch B5.4 Breakdown and U-20836 MNSCDE-9.25a-02 2021 Exh A-12 Sch B5.4 Breakdown. Assuming the question is asking for bridge period 10-months ending 10/31/22 and test year 12-months ending 10/31/23, see attached U-20836 MNSCDE-9.25a-03 2022-2023 Exh A-12 Sch B5.4 Breakdown.

Attachment: U-20836 MNSCDE-9.25a-01 2020 Exh A-12 Sch B5.4 Breakdown
U-20836 MNSCDE-9.25a-02 2021 Exh A-12 Sch B5.4 Breakdown
U-20836 MNSCDE-9.25a-03 2022-2023 Exh A-12 Sch B5.4 Breakdown

U-20836 MNSCDE-9.25a01 2020 Exh A-12 Sch B5.4 Breakdown

Michigan Public Service Commission
DTE Electric Company
Distribution Plant
($000)

Line No.	Description	Capital Expenditures: Historical 12 mos. ended 12/31/2020	Labor	Material	Other
1	**Base Capital Programs**				
2	Emergent Replacements				
3	Storm	150,897	116,036	16,460	18,401
4	Non - Storm	155,324	108,609	16,173	30,542
5	Substation Reactive	38,131	28,028	6,007	4,096
6	Emergent Replacement Reduction Based on Strategic Spend	-	-	-	-
7	Subtotal Emergent Replacements	344,352	252,673	38,640	53,039
8	Customer Connections, Relocations & Other				
9	Connections and New Load	137,221	107,109	14,828	15,284
10	Relocations	24,128	25,225	1,763	(2,859)
11	Electric System Equipment	56,182	7,025	42,558	6,599
12	NRUC and Improvement Blankets	27,168	19,761	4,163	3,245
13	General Plant, Tools & Equipment and Miscellaneous	8,569	4,488	3,159	922
14	Public Lighting Department Project	21,051	19,340	496	1,215
15	Subtotal Customer Connections, Relocations & Other	274,320	182,947	66,967	24,406
16	Customer Advances for Construction	(21,395)	-	-	(21,395)
17	**Total Base Capital Programs**	**597,277**	**435,620**	**105,607**	**56,049**
18	**Strategic Capital Programs**				
19	Infrastructure Resilience and Hardening	167,035	130,385	20,497	16,154
20	Infrastructure Redesign and Modernization	49,311	30,812	9,838	8,662
21	Technology and Automation	91,293	70,029	9,531	11,732
22	**Subtotal Strategic Capital Programs**	**307,640**	**231,226**	**39,865**	**36,548**
23	**Total Capital**	**904,916**	**666,847**	**145,473**	**92,597**

Michigan Public Service Commission
DTE Electric Company
Distribution Plant - Infrastructure Resilience and Hardening
($000)

		Capital Expenditures			
Line No.	Description	Historical 12 mos. ended 12/31/2020	Labor	Material	Other
1	**Infrastructure Resilience and Hardening**				
2	Mobile Fleet Program	2,386	1,682	542	162
3	Substation Risk: Drexel	1,378	1,024	11	343
4	Substation Risk: Chestnut	-	-	-	-
5	Substation Risk: Savage	1,161	887	129	145
6	Substation Risk: Apache	172	129	-	43
7	Substation Risk: Port Huron	3,775	2,329	863	583
8	Substation Risk: Belleville Switchgear Decommission	5	5	-	0
9	4.8 kV Hardening	55,165	44,310	6,660	4,195
10	Pole and Pole Top Hardware (PTMM)	36,364	30,347	1,176	4,842
11	Cable Replacement Program	12,139	9,019	2,005	1,114
12	Cable Replacement: Harsen's Island	353	289	0	64
13	Frequent Outage Program (CEMI) including Circuit Renewal	26,374	21,171	3,458	1,745
14	System Resiliency - Efficient Frontier	1,795	1,648	268	(121)
15	Breaker Replacement Program	10,931	7,632	2,087	1,213
16	Pontiac Vaults	4,880	3,390	644	847
17	URD Replacement Program	964	752	123	89
18	URD Replacement Program: Detroit URD 1-1	59	31	-	28
19	4.8 kV Relay Improvements (Delta Ground Detection Program)	2,052	1,710	516	(174)
20	40 kV: Automatic Pole Top Switch	819	426	293	100
21	Disconnect and Switcher Replacement	2,093	1,311	504	278
22	SCADA Pole Top Device Replacement	1,446	536	728	183
23	Substation Regulator Replacement	-	-	-	-
24	Steel Pole Highway Crossings	-	-	-	-
25	Station Upgrade: Warren (Relay Replacement)	2,260	1,573	272	416
26	Station Upgrade: Northeast (Relay Replacement)	464	185	219	61
27	Station Upgrade: Lincoln	-	-	-	-
28	Station Upgrade: Navarre	-	-	-	-
29	**Total Infrastructure Resilience and Hardening Projects and Programs**	**167,035**	**130,385**	**20,497**	**16,154**

U-20836 MNSCDE-9.25a-02 2021 Exh A-12 Sch B5.4 Breakdown
Michigan Public Service Commission
DTE Electric Company
Distribution Plant
($000)

Line No.	Description	Capital Expenditures: Historical 12 mos. ending 12/31/2021	Labor	Material	Other
1	**Base Capital Programs**				
2	Emergent Replacements				
3	Storm	395,286	340,810	20,591	33,886
4	Non - Storm	209,236	156,680	18,514	34,043
5	Substation Reactive	46,008	34,737	5,452	5,819
6	Emergent Replacement Reduction Based on Strategic Spend	-	-	-	-
7	Subtotal Emergent Replacements	650,531	532,227	44,557	73,747
8	Customer Connections, Relocations & Other				
9	Connections and New Load	184,772	140,307	25,455	19,010
10	Relocations	24,113	20,501	2,362	1,250
11	Electric System Equipment	30,471	5,021	19,402	6,048
12	NRUC and Improvement Blankets	22,905	16,616	4,201	2,088
13	General Plant, Tools & Equipment and Miscellaneous	7,445	2,319	4,433	693
14	Public Lighting Department Project	19,353	17,133	903	1,317
15	Subtotal Customer Connections, Relocations & Other	289,059	201,897	56,756	30,406
16	Customer Advances for Construction	(24,783)	-	-	(24,783)
17	**Total Base Capital Programs**	914,806	**734,124**	**101,312**	**79,370**
17	**Strategic Capital Programs**				
18	Infrastructure Resilience and Hardening	187,433	144,962	24,403	18,067
19	Infrastructure Redesign	94,857	60,897	20,128	13,832
20	Technology and Automation	76,633	54,212	10,017	12,404
21	**Subtotal Strategic Capital Programs**	358,923	**260,071**	**54,548**	**44,303**
22	**Total Capital**	1,273,729	**994,195**	**155,861**	**123,673**

U-20836 MNSCDE-9.25a-02 2021 Exh A-12 Sch B5.4 Breakdown

Michigan Public Service Commission

DTE Electric Company

Distribution Plant - Infrastructure Resilience and Hardening

($000)

Line No.	Description	Historical 12 mos. ending 12/31/2021	Labor	Material	Other
1	**Infrastructure Resilience and Hardening**				
2	Mobile Fleet Program	5,984	1,405	4,068	511
3	Substation Risk: Drexel	1,663	1,207	81	375
4	Substation Risk: Chestnut	534	411	-	124
5	Substation Risk: Savage	211	154	(4)	61
6	Substation Risk: Apache	1,908	441	1,243	224
7	Substation Risk: Port Huron	2,969	2,152	189	628
8	Substation Risk: Belleville Switchgear Decommission	298	140	128	29
9	4.8 kV Hardening	65,362	53,269	7,525	4,568
10	Pole and Pole Top Hardware	31,647	26,827	1,272	3,547
11	Cable Replacement Program	14,984	11,696	1,662	1,626
12	Cable Replacement: Harsen's Island	-	-	-	-
13	Frequent Outage Program (CEMI) including Circuit Renew	23,251	18,351	2,946	1,953
14	System Resiliency - Efficient Frontier	-			
15	Breaker Replacement Program	17,365	12,595	2,816	1,954
16	Pontiac Vaults	3,044	2,109	309	626
17	URD Replacement Program	4,705	3,780	523	403
18	URD Replacement Program: Detroit URD 1-1	1,595	1,065	303	226
19	4.8 kV Relay Improvements (Delta Ground Detection Prog	3,186	3,176	117	(108)
20	40 kV: Automatic Pole Top Switch	1,301	841	327	133
21	Disconnect and Switcher Replacement	3,863	2,744	707	412
22	SCADA Pole Top Device Replacement	999	675	169	155
23	Substation Regulator Replacement	-	-	-	-
24	Steel Pole Highway Crossings	18	16	-	2
25	Station Upgrade: Warren (Relay Replacement)	115	(219)	22	313
26	Station Upgrade: Northeast (Relay Replacement)	2,431	2,126	-	306
27	Station Upgrade: Lincoln	-	-	-	-
28	Station Upgrade: Navarre	-	-	-	-
29	**Total Infrastructure Resilience and Hardening Projects and Programs**	**187,433**	**144,962**	**24,403**	**18,067**

U-20836 MNSCDE-9.25a-03 2022-2023 Exh A-12 Sch B5.4 Breakdown

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
M. Elliott-Andahazy 6/
P. Smith 7/
Page: 1 of 12

	(a)	(d)				(f)			
		Capital Expenditures				Capital Expenditures			
		Bridge Period				Test Year			
Line No.	Description	10 mos. ending 10/31/2022	Labor	Material	Other	12 mos. ended 10/31/2023	Labor	Material	Other
1	**Base Capital Programs**								
2	Emergent Replacements								
3	Storm	141,803	106,353	28,360	7,090	174,276	130,708	34,855	8,713
4	Non - Storm	143,721	107,792	28,744	7,185	176,634	132,477	35,326	8,831
5	Substation Reactive	36,954	27,716	7,391	1,848	45,417	34,063	9,083	2,271
6	Emergent Replacement Reduction Based on Strategic Spend	(12,684)	-	-	(12,684)	(24,615)	-	-	(24,615)
7	Subtotal Emergent Replacements	309,794	241,861	64,495	3,438	371,711	297,247	79,264	(4,801)
8	Customer Connections, Relocations & Other								
9	Connections and New Load	140,230	105,172	21,034	14,023	172,342	129,257	25,851	17,234
10	Relocations	22,936	17,202	3,440	2,294	27,332	20,499	4,100	2,733
11	Electric System Equipment	33,883	8,471	22,702	2,711	41,642	10,411	27,900	3,331
12	NRUC and Improvement Blankets	25,412	20,330	2,541	2,541	31,232	24,986	3,123	3,123
13	General Plant, Tools & Equipment and Miscellaneous	10,306	1,546	7,730	1,031	9,665	1,450	7,249	967
14	Public Lighting Department Project	7,700	6,817	359	524	-	-	-	-
15	Subtotal Customer Connections, Relocations & Other	240,467	159,538	57,807	23,123	282,214	186,602	68,224	27,389
16	Customer Advances for Construction	(22,044)	-	-	(22,044)	(27,092)	-	-	(27,092)
17	**Total Base Capital Programs**	**528,217**	**401,399**	**122,302**	**4,517**	**626,833**	**483,849**	**147,488**	**(4,504)**
18	**Strategic Capital Programs**								
19	Infrastructure Resilience and Hardening	265,694	193,734	52,184	19,777	346,091	249,438	69,968	26,685
20	Infrastructure Redesign and Modernization	215,146	143,847	61,627	9,672	314,334	209,869	89,868	14,597
21	Technology and Automation	99,551	67,486	20,669	11,395	137,342	87,066	36,862	13,414
22	**Subtotal Strategic Capital Programs**	**580,391**	**405,068**	**134,480**	**40,844**	**797,767**	**546,373**	**196,699**	**54,696**
23	**Total Capital**	**1,108,609**	**806,466**	**256,782**	**45,361**	**1,424,600**	**1,030,222**	**344,186**	**50,191**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Resilience and Hardening
($000)

Case No.: U-20836
Exhibit: A-12
Schedule: B5.4
Witness: S. G. Pfeuffer
Page: 8 of 12

	(a)	(f)				(g)	
		Capital Expenditures					
Line No.	Description	Bridge Period 10 mos. ending 10/31/2022	Labor	Material	Other	Test Year 12 mos. ended 10/31/2023	Labor
1	**Infrastructure Resilience and Hardening**						
2	Mobile Fleet Program	3,733	622	2,924	187	3,501	407
3	Substation Risk: Drexel	705	564	71	71	141	113
4	Substation Risk: Chestnut	417	230	145	42	2,527	1,224
5	Substation Risk: Savage	34	25	5	3	7	5
6	Substation Risk: Apache	7,080	4,036	2,336	708	9,104	5,189
7	Substation Risk: Port Huron	6	5	1	1	1	1
8	Substation Risk: Belleville Switchgear Decommission	943	604	245	94	189	121
9	4.8 kV Hardening	96,548	72,411	19,310	4,827	114,310	85,732
10	Pole and Pole Top Hardware (PTMM)	49,094	36,339	7,845	4,909	87,735	64,942
11	Cable Replacement Program	29,271	20,783	5,854	2,634	42,688	30,308
12	Cable Replacement: Harsen's Island	-	-	-	-	-	-
13	Frequent Outage Program (CEMI) including Circuit Renewal	38,366	30,693	4,988	2,686	26,068	20,855
14	System Resiliency - Efficient Frontier	-	-	-	-	-	-
15	Breaker Replacement Program	12,865	9,648	2,187	1,029	17,573	13,180
16	Pontiac Vaults	513	308	154	51	103	62
17	URD Replacement Program	5,023	3,516	1,155	352	9,338	6,537
18	URD Replacement Program: Detroit URD 1-1	2	1	0	0	-	-
19	4.8 kV Relay Improvements (Delta Ground Detection Program)	2,563	1,615	769	179	7,596	4,786
20	40 kV: Automatic Pole Top Switch	4,417	3,224	883	309	6,133	4,477
21	Disconnect and Switcher Replacement	2,938	2,438	294	206	3,547	2,944
22	SCADA Pole Top Device Replacement	1,188	748	356	83	1,821	1,147
23	Substation Regulator Replacement	354	255	71	28	425	306
24	Steel Pole Highway Crossings	2,500	1,300	600	600	7,167	3,327
25	Station Upgrade: Warren (Relay Replacement)	-	-	-	-	-	-
26	Station Upgrade: Northeast (Relay Replacement)	6,861	4,117	1,990	755	1,372	823
27	Station Upgrade: Lincoln	275	253	-	22	4,472	2,701
28	Station Upgrade: Navarre	-	-	-	-	275	253
29	**Total Infrastructure Resilience and Hardening Projects and Programs**	**265,694**	**193,734**	**52,184**	**19,777**	**346,091**	**249,438**

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.28b
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the testimony of S. Pfeuffer, pages 79-80, Q&A 101, addressing its proposed “enhancements” to the Pole and PTMM project.

b. Please provide the company’s benchmarking analysis referenced in this testimony.

Answer: See attached U-20836 MNSCDE-9.28b-01 Bench Marking Notes.

Attachment: U-20836 MNSCDE-9.28b-01 Bench Marking Notes

4 All peers have OH and UG circuit maintenance programs with defined processes to prioritize and fix issues before they become trouble work

DTE Energy

Annually

Patrol 20-25% of Circuits

- OH/UG patrolled for conductor and equipment condition and standards violations
  - Pole Top Equipment
  - URD Transformers
  - Manholes
- Internal inspection employees – current / former linemen or similarly knowledgeable internal employees
- Most utilities perform infrared inspections to identify hotspots
- [redacted] pole testing is separate from pole top inspections

Apply Remediation Framework

- All utilities prioritize identified problems
- Typical prioritization framework:
  - Priority 1 – Immediate
  - Priority 2 – Within 24 hours
  - Priority 3 – Within 30 days
  - Priority 4 – Within 90 days
  - Priority 5 – Within 1-year
- Peer utilities have standard guidelines to prioritize typical problems identified

Fix the Issue

- Most utilities maintain a greater than 90% remediation adherence within the specified timeframe
- Some utilities prioritize maintenance work close to expiration over new business
- Benefits include:
  - Prevent future trouble events and limit storm size
  - Reduce complaints
  - Collect asset information and identify targets for circuit programs (i.e., TT, circuit renewal, CEMI)

[redacted]

Inspection practices

[redacted]					
-Inspect feeders on a 5 year cycle - looking for asset condition issues and standards violations -Don't reinforce poles -Inspect URD transformers -Use 10 inspectors and achieve a 90% repair rate to PSC requirements (within 1 or 3 years depending on the issue) -Need to submit inspection and repair reports to the PSC -4 year manhole inspections	[redacted] regulates 5 year visual circuit inspection (including PTM, padmount). TE uses 2 man lines crews to follow a specific route (dedicated to inspections), document and fix what they can when they are out there -> larger fixes are written up/follow-up. Pole inspection is 10 year cycle, performed by [redacted] (including pole designs on replacement). TE is now on the second cycle for hitting their 10-year pole cycle (started in 2003). Seeing 1.5% failure rate. [redacted]. [redacted] -> maximum backlog is 5 years old, TE has max of 1 year old (priority less than 90 days)	10 year [redacted] pole testing program 5 year PTM inspection program (Rate problems on a priority scale - priority 10 = immediate issue, priority 20 = with 24 hours, priority 30 = fix in short term, priority 40 = fix in the long term) URD transformer inspection Large inspection group - made up partly of ex-linemen who can no longer do lineman work	Every 4 years all line miles are inspected and IR scanned, look for: -Conductor and Equipment issues -Standard violations -Physical standards violations Test engineers do the inspections and give issues priority 1, 2, 3	[redacted] does pole inspections and top of pole inspections (20k per year) Train foresters and tree crews to do inspections Contractor inspects pad mounted transformers Inspections are logged electronically into an ARCGIS system using a mobile app (same app they use for damage assessment IR scans are performed by trouble shooters	[redacted] IR scan half of the mainline feeders annually

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.30
Respondent:	S. Pfeuffer
	1 of 1

Question: Provide the data (including date, circuit, event, cause, duration, number of customers affected) supporting the assertion by S. Pfeuffer on page 82, Q&A 104, that “overhead equipment related outages account for almost 25% of all events.”

Answer: The Company does not have the analysis as requested, the 25% was calculated at the system level and not by circuit, date, or other data requested. Please see attached U-20836 MNSCDE-9.30-01 Equipment Related Outages that shows how the 25% was calculated.

Attachment: U-20836 MNSCDE-9.30-01 Equipment Related Outages

U-20836 MNSCDE-9.30-01 Equipment Related Outages

Year	Cause Code	Customers Interrupted	Customer-Minutes Interrupted	Events
2016	All Other	115,397	24,888,185	2,403
2016	Animal	96,309	11,955,512	3,057
2016	Customer	177	44,446	123
2016	Equipment	578,808	96,101,000	16,667
2016	Intentional	112,733	8,819,311	2,694
2016	Loading	14,099	1,128,524	65
2016	Public Interference	101,423	11,978,856	1,572
2016	Trees/Wind	967,807	328,444,503	16,248
2016	Unknown	126,873	22,576,680	10,686
2016	Weather	43,835	15,632,446	577
2017	All Other	13,744	1,319,468	86
2017	Animal	111,193	12,243,614	2,883
2017	Customer	75	17,261	43
2017	Equipment	676,184	156,094,388	14,705
2017	Intentional	111,564	13,419,376	2,853
2017	Loading	25,437	1,296,731	217
2017	Public Interference	93,025	11,848,148	1,391
2017	Trees/Wind	1,760,733	1,924,390,904	23,865
2017	Unknown	189,917	129,958,270	14,730
2017	Weather	49,308	13,933,448	896
2018	All Other	170,134	84,517,537	5,479
2018	Animal	64,802	7,617,752	2,633
2018	Customer	1,620	394,288	226
2018	Equipment	600,157	107,835,730	11,017
2018	Intentional	187,893	12,223,655	3,719
2018	Loading	36,639	3,448,603	356
2018	Public Interference	66,572	8,526,517	773
2018	Trees/Wind	1,333,901	589,037,320	17,237
2018	Unknown	183,707	40,752,291	3,005
2018	Weather	223,767	184,585,684	3,605
2019	All Other	116,717	37,913,384	6,286
2019	Animal	76,057	8,714,634	2,693
2019	Customer	1,191	250,459	351
2019	Equipment	537,331	83,755,435	10,858
2019	Intentional	205,592	15,065,934	4,122
2019	Loading	17,813	4,208,558	123
2019	Public Interference	59,086	7,049,019	808
2019	Trees/Wind	1,471,196	744,567,790	20,780
2019	Unknown	296,166	59,807,532	3,508
2019	Weather	72,048	39,088,979	1,216
2020	All Other	113,843	22,714,959	4,623
2020	Animal	77,266	8,813,517	3,094
2020	Customer	1,487	429,093	262
2020	Equipment	649,700	101,641,626	10,896
2020	Intentional	193,516	10,626,312	4,045
2020	Loading	23,384	2,619,825	196
2020	Public Interference	71,941	10,650,728	841
2020	Trees/Wind	1,295,718	532,386,605	17,413
2020	Unknown	163,126	25,301,031	3,233
2020	Weather	76,862	31,747,310	995

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-9.37ax
Respondent:	S. Pfeuffer
	1 of 1

Question: Refer to the discovery response to MNSCDE-4.6c and the document provided in U-20836 MNSC-4.6c-01 2020 Hardened Effectiveness Analysis. Refer also to the discovery response to STDE-7.23 (top 3 and bottom 3 scoring substations to be hardened in 2022). Refer also to direct testimony of S. Pfeuffer, page 69, discussing the prioritization for hardening substations.

a. For each substation service area that was hardened in 2020, provide the following:

x. Actual cost to harden the substation service area, together with cost for (a) tree trim, (b) inspection & reinforcement, (c) design, and (d) construction (see MNSCDE-4.41-01 2022-2023 4.8kV Projected Investments for spending categories).

Answer: The Company has not performed this analysis. Response MNSCDE-9.25a provides the total actual cost for the 4.8kV Hardening program broken out by labor, material, and other categories.

Attachment: N/A

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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 miscellaneous accounting authority.	U-20836

PROOF OF SERVICE

On the date below, an electronic copy of Direct Testimony of Robert G. Ozar P.E. on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan and Exhibits MEC-14 through MEC-35 was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MEC, NRDC, SC & CUB

Date: May 19, 2022

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