OLSON, BZDOK & HOWARD

June 13, 2023

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-21297

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Direct Testimony and Exhibits of Robert G. Ozar P.E. on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (Exhibit MEC-42 through MEC-49); and

Proof of Service.

Sincerely,

Digitally signed by Christopher M. Bzdok
DN: cn=Christopher M. Bzdok, o=Olson, Bzdok & Howard, PC, email=chris@envlaw.com, c=US
Date: 2023.06.13 16:43:39 -04'00'

Christopher M. Bzdok
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xc: Parties to Case No. U-21297

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-21297

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

June 13, 2023

DIRECT TESTIMONY OF ROBERT G. OZAR P.E. OBO MNSC
CASE NO. U-21297

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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 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 work experience is summarized in my resume, provided as Exhibit MEC-42.

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-42:	Resume of Robert G. Ozar
Exhibit MEC-43:	MNSCDE-9.7
Exhibit MEC-44:	MNSCDE-9.10
Exhibit MEC-45:	AGDE-4.103b with Att AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics
Exhibit MEC-46:	Vegetation Management Concepts and Principles 2010
Exhibit MEC-47:	Deferring Electric Utility Tree Maintenance
Exhibit MEC-48:	U.S Department of Agriculture RUS Bulletin, 17300B-121
Exhibit MEC-49:	MNSCDE-9.6

II. RECOMMENDATION SUMMARY

Q. Please summarize your recommendations?

A. I offer the following recommendations:

(1) I am recommending that the Commission reject DTE's proposed fourfold increase in 2024 PTMM spending over the historical year 2023 projected capital spend. I am recommending that the projected PTMM capital expenditure be set at a level of $63.445 million, which is the same level as projected in the 2023 bridge period, and nearly double the 2021 spend that the Commission set as the annual cap in U-20836. I further recommend that the Commission require DTE to formulate a plan to transform its PTMM program into a risk-based Pole and Pole Top Maintenance program, with a detailed plan filed in the Company's next rate case, with its next grid plan, in a stand-alone docket, or elsewhere. In addition, I

am recommending that the Commission require DTE to file annual Pole and Pole Top Maintenance reports.

(2) I am recommending that the Commission reject DTE's capitalization of tree trimming. I recommend that the Commission order DTE to reflect all maintenance tree trimming in its Exhibit A-13 schedule for Operation and Maintenance expenses. If new electric lines are constructed, and new right-of-way is opened for such lines, the cost of *"first clearing and grading of land and rights-of-way"* should be reflected in Exhibit A-12, Projected Capital Expenditures, Distribution Plant, as a single line representing the estimated cost of such first clearing. Exhibit A-22, detailing its tree trimming program, should specifically define to which capital programs the "first clearing land and rights-of-way" is projected to take place, including Hardening, PTMM, or 4.8 kV conversion. This will better enable parties to DTE's rate proceedings, and the Commission itself, to monitor and evaluate DTE's expenses. Lastly, and most importantly, with respect to the projected test year, the Commission should order that all projected tree trimming (that will not be a first clearing of ROW for new lines) be moved out of capital accounts, and into O&M. With respect to the 2023 bridge period, all improperly capitalized tree trimming should be excluded from rate base, the Company forfeiting O&M revenue requirements for such expenditures, as the Company has been improperly earning a return on maintenance tree trimming for years, despite the fact that the Commission authoritatively ruled against this in its order in the U-17767 DTE general rate proceeding.

(3) With respect to DTE's restoration O&M expense, I am recommending that the Commission reject DTE's inflation adjustment, in the amount of $17,509,000, as it is unjustified for DTE to include an adjustment for inflation and not an offsetting adjustment for distribution

system reliability productivity, while in the same rate proceeding request hundreds of millions of dollars in incremental surge trimming and strategic investments that the Company claims will improve reliability (and by extension reduce Restoration O&M).

(4) As DTE has refused to provide updated per foot charges in the Company's C-6 tariff, and considering how old the per foot line extension charges are, I am recommending that the Commission order DTE to calculate its current costs and update its C-6 tariff accordingly. The Company should file such updated tariff in the next rate case. As it would be fundamentally inconsistent for the Commission to approve DTE's request to update the standard CIAC allowances for large industrial customers, but simultaneously reject the updating of the per-foot line extension charges in the same C-6 tariff, I am recommending that the Commission reject the Company's request to update Section C-6.2, of the C-6 tariff.

(5) In consideration that DTE has essentially experienced a windfall in receiving full recovery of excess tree trimming costs from ratepayers, I am recommending that the Commission reject the Company's request to earn a long-term debt and equity return, as opposed to the currently approved short-term borrowing rate, on its tree trim regulatory asset deferrals As an appropriate alternative, the Commission could consider not approving any return on DTE's future deferred surge expenditures.

III. <u>POLE AND POLE TOP MAINTENANCE AND MODERNIZATION PROGRAM</u>

Q. What is DTE Electric's Pole and Pole Top Maintenance Program?

A. DTE Electric witness Morgan Elliott Andahazy describes the program in her direct testimony, pages 21 to 34. At bottom, this is a program to inspect poles and pole top hardware to identify and repair or replace damaged, defective, and "old and outdated" components.

Q. Please provide some background on the issues surrounding DTE's Pole and Pole Top Maintenance and Modernization program.

A. In last year's rate case, U-20836, I raised the issue of DTE's proposed near doubling of capital expenditures for the Pole and Pole Top Maintenance and Modernization (PTMM) program from the 2021 historical test year. I concluded that the core basis put forth by the Company's to support its need for additional funding was not compelling. That basis consisted of: (1) additional inspections; (2) the change from visual inspections to physical inspections for certain poles; and (3) higher pole class standards for replacement poles.[1]

To be specific, I concluded that it was not additional inspections that were driving the increase in proposed spend (as proposed inspections in 2023 would only be 10% greater than in 2018), but rather the "modernization" of lines that is driving up costs. I expressed doubt that slowly moving from a 10-to-12-year inspection cycle to a 10-year inspection cycle by 2025 justifies the significantly increased pole and pole top investment. With respect to the second and third bases for increased capital spend, which relate to the change from visual inspection to physical testing for certain poles, and to the higher pole class standard for replacement poles, I demonstrated neither justification is compelling. In conclusion, I proposed that the Commission cap the approved capital spend for the PTMM program equal to the 2021 historical spend ($33.444 million).[2] In its order in U-20836, the

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[1] Case No. U-20836, Direct Testimony of Robert G. Ozar, PE, 8 TR 3985-4016.

[2] Case No. U-20836, Ozar Direct, 8 TR 5958; Case No. U-20836, MNSC Initial Brief, p. 30.

Commission agreed with the analysis I put forth and disallowed the incremental proposed dollar amount as I recommended.[3]

Q. With respect to the PTMM program, what future capital spend is the Company now proposing for the projected 2024 calendar year?

A. In the current rate case, DTE again proposes a major expansion of spending (a near doubling) from expected calendar year 2023 levels of $63.5 million, to $120.6 million in calendar year 2024. This is a near four-fold expansion from the 2021 historical test year spend of $31.7 million, which I recommended be maintained and the Commission agreed. I would describe the requested investment level in the projected test period as a radical change in historical spending that is quite alarming.

Q. What is the Company's core support for such a major increase in capital spend in 2024?

A. From my review of the direct testimony of Company witness Morgan Elliot Andahazy, DTE presents nearly identical justifications to the three as presented in U-20836 to support its massive expansion in PTMM capital requirements. Namely, that the Company's "new" pole and pole top replacement standards, and "new" inspection procedures (which are not new as they have been in effect for several years[4]) necessitate the higher program costs.[5] In addition, in this rate request, DTE witness Andahazy discloses that the Company has

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[3] Case No. U-20836, Order dated November 18, 2022, pp. 96 ($32 million spent in 2021), 100 ("The Commission also finds that the incremental disallowance proposed by MNSC should be approved. The Commission notes that the company has the ability to spend above the level of capital approved in this case and may recover the amount in a future rate case after the spend is proven to be reasonable and prudent.").

[4] Direct Testimony of Morgan Elliot Andahazy, p. 22 (enhanced specifications adopted in 2019).

[5] Andahazy Direct, pp. 22-30.

two persistent backlogs: (1) a backlog of distribution assets that previously failed its PTMM inspection criteria but have not been remediated[6]; and (2) a backlog of off-cycle inspections that need to be cleared in order to achieve its goal of a 10-year pole and pole top inspection cycle by 2025.[7] (The pre-2022 backlog of poles failing inspection is expected to be addressed in 2023, the 2022 backlog in 2024.) As I see it, the Company's support for the substantial increase in PTMM capital spending in 2024 is derived from these four core reasons. I have ruled out all four reasons as a valid basis for such a profound increase in PTMM capital spend during the projected test period. I continue to be of the opinion that the Company did not provide a clear plan supporting such a massive increase in capital spending, given that DTE's stated goal is to achieve a 10-year pole and pole top inspection cycle by 2025, which is only marginally shorter, if at all, than reached in past years.[8] In addition, the persistent backlogs, exceptionally large variance in inspections from year to year, and unreasonable level of modernization, demonstrate substantial mismanagement of the program.

Q. What impact does the Company's goal to achieve a 5-year pole top inspection cycle have on the 2024 projected PTMM expenditures?

A. It has no apparent impact. Work toward transitioning to the Company's goal of reaching a 5-year pole top inspection cycle cannot start until after the Company attains a 10-year pole top inspection cycle, which is expected to occur in 2025.[9] Thus, a transition to a 5-year

[6] Andahazy Direct, p. 31, Table 9 (PTMM Pole Backlog & WIP as of 1/6/2023), Table 10 (PTMM Pole Top Hardware Backlog & WIP as of 1/6/2023).

[7] Andahazy Direct, p. 22.

[8] Case No. U-20836, Direct Testimony of Sharon G. Pfeuffer, 4 TR 303.

[9] Andahazy Direct, pp. 32-33.

cycle, and any incremental costs associated with that transition, cannot begin until 2026, well past the 2024 projected test period. Note that in the Company's discovery response to MNSC, witness Andahazy asserts: "The Company expects the number of pole top locations to remain high until it achieves a five-year cycle."[10] Since this initiative will not begin until 2026, the costs associated with transition to a 5-year cycle are irrelevant to setting costs for the 2024 projected test period.

Q. Why have you ruled out the new inspection standards and higher engineering standards for poles, and pole top equipment as a reason for massive new capital outlays?

A. Because DTE has not demonstrated a substantially increased failure rate of pole and pole top equipment, as such a change would be evident in the historical levels of equipment-related outages reported to the Commission in the Company's annual reliability reports (U-16065 docket). In addition, the new criteria for pole inspections should result in a decrease in pole failures, not an increase, because the earlier detection of decay allows for early remediation as opposed to replacement upon failure, whether actual or imminent. I do acknowledge that for those poles that are inspected and deemed in need of replacement, that the stronger and taller poles meeting the new engineering standards may cost more than poles meeting the previous standards.

[10] Ex MEC-44 (Company response to MNSCDE-9.10).

Q. Did the Company claim that it is experiencing a profound increase in pole and pole top locations needing replacement?

A. Yes. With respect to pole top replacements, the Company claimed that its replacement rate in 2022 vis-à-vis 2018-2021 increased more than twofold (3.6 replacements per mile/ 1.6 replacements per mile). Same for pole replacement, asserting a 2.5-fold increase in 2022, over the 2018-2021 period.[11] However, in my professional opinion, I find it unreasonable to accept that a single year data point (i.e., 2022) as compared to the prior three-year period indicates a long-term twofold upward trend in failures. In addition, the composition of the mix of circuits remediated from year to year, likely has a strong bearing on the variance in the per-mile replacement rates, especially since the Hardening program targeted poor performing circuits had a substantial ramp in work during 2022. Moreover, DTE's data suggests pole top replacements (modernization) in 2022 were not out of line compared to the prior four years (2018 through 2021):[12]

[11] Ex MEC-44 (Company Response to MNSCDE-9.10).

[12] Ex MEC-45 (Company Response to AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics).

U-21297 AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics 2017-2022							
Program	**Metric**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Pole and Pole Top Maintenance and Modernization (PTMM)	Miles Modernized	786	2,019	1,027	1,496	1,541	1,562
Pole and Pole Top Maintenance and Modernization (PTMM)	Poles Replaced	2,700	3,165	1,333	1,431	1,016	4,537
Pole and Pole Top Maintenance and Modernization (PTMM)	Poles Reinforced	N/A*	2,050	2,717	27	109	1,116
Pole and Pole Top Maintenance and Modernization (PTMM)	Pole Inspections	63,230	84,005	58,080	7,400	45,400	87,000
*The Company did not track this metric in 2017							

Q. Do you also take issue with the needed level of pole replacements versus pole reinforcements asserted by DTE witness Andahazy?

A. Yes. In The Company's discovery response to the MNSC, witness Andahazy asserts that 4,000 poles from the estimated 50,000 poles inspected in 2023 will need to be replaced in 2024.[13] She specifically states the 4,000 replacements represents an 8% "condemned pole rate". It is noteworthy that the same 8% level was presented in U-20836, but as representing the level of poles "either replaced or reinforced, based on specific criteria".[14] Thus, it appears that with respect to poles having reduced strength and needing to be remediated, that the Company has moved away from a policy that was accommodating of reinforcement

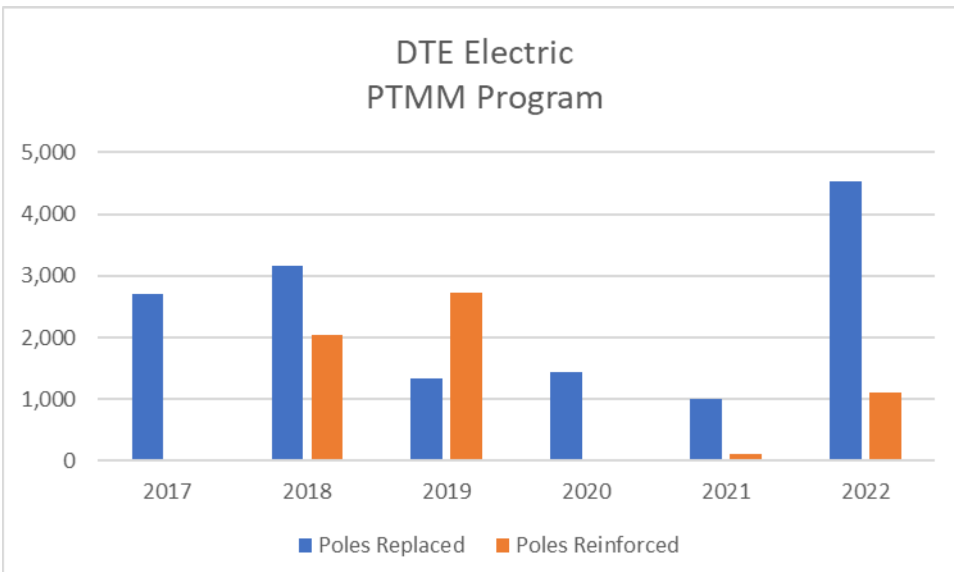
[13] Ex MEC-44 (Company response to MNSCDE-9.10).

[14] Case No. U-20836, Pfeuffer Direct, 4 TR 302.

as a cost effective means to address the need for remediation, to a policy of favoring pole replacement (i.e., modernization).

Q. Does the data in the above chart[15] corroborate a change in DTE policy that favors pole replacement over pole reinforcement?

A. Yes. I have graphed the data in such chart to provide a visualization of the increase in poles replaced and the decrease in the poles reinforced. The data strongly suggests a change in policy toward replacement (modernization) over reinforcement.



Q. Does DTE's aggressive move to pole replacements conflict with the "new" pole inspection standards that modified the age threshold (from 40 years to 20 years) for pole testing as opposed to visual inspection?

A. Yes. In U-20836, Company witness Pfeuffer, in context of the change in threshold for pole testing from visual inspection, noted that "Pole reinforcement is widely adopted by the

[15] See supra and Ex MEC-45 (Company Response to AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics).

utility industry as a cost-effective option to lengthen pole life. The enhanced pole inspection specification and process are aligned with industry best practices and expected to reduce the risk of pole failures …"[16] Bottom line is that the "new" pole inspection standards should increase the relative level of reinforcement and reduce the relative level of replacement, the opposite of what DTE projects. It may be thus inferred that the Company's alleged support for massive additional 2024 PTMM expenditures does not follow industry best practices, as articulated by the Company in U-20836, and is not likely cost-effective.

Q. In your opinion, what is the fundamental reason for DTE's perceived need for a fourfold increase in capital for its PTMM maintenance program.

A. As I concluded in the prior rate case, it is clearly not standard maintenance practice (which could include updated inspection criteria and stronger engineering standards for poles and pole top equipment), but "modernization" that is creating the perceived need for a radical increase in projected PTMM capital costs.

Q. Can you detail why the "modernization" function of DTE's pole and pole top maintenance program is flawed?

A. Yes. As I asserted in DTE prior rate proceeding, and which the Commission took note of in its order in U-20836, asset replacements should be based on the two core principles; (1) "replacement upon failure" (including incipient failure); and (2) "replacement upon imminent failure". These principles should be at the core of the utility's pole and pole top maintenance program; whereby the program's foundational goal would be to find and

[16] Case No. U-20836, Pfeuffer Direct, 4 TR 304.

replace those assets that have actually failed; that are in a state of failing (incipient failure); and may soon fail (imminent failure). It should be expected that the preponderance of DTE's asset replacements would be those in a state of actual or incipient failure. 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. Because outages due to equipment related failure have been relatively stable from year to year, asset replacements should also be relatively stable.

Q. What is DTE's modernization function in its PTMM program?

A. The numbers speak for themselves – the massive dollar requirement being requested can only be rationally understood in terms of a projected massive scale of replacement of existing poles and pole top hardware, irrespective of whether the condition of such assets meet the two foundations principles of replacement, i.e., have failed (actual or incipient), or are in a state of imminent failure.

Q. What other factors may be at play regarding over-replacement?

A. Most obviously, the regulatory structure itself creates an incentive to over-investing. The fact that DTE has slipped tree trimming into the capital requirements of the Hardening and PTMM programs is evidence of that. I will speak about the erroneous capitalization issue later. There is another explanation, although not readily apparent, contributing to the capital outlays being requested by DTE.

Q. What is that explanation?

A. The utility's uniform ten-year inspection cycle.

Q. **Please explain.**

A. It is my professional judgement that the time between inspections necessarily has a significant bearing on the decision-making process following inspections, and the go-ahead determination to modernize. What I mean by this is that the PTMM program's long inspection cycles, particularly those circuits at high or higher risk of outages, increase the level of risk of failure between inspections, putting customers at risk of outage events should a failure occur in-between inspections. In this way, DTE's once-a-decade inspection cycles, and the fact that program inspection cycles are uniform across all circuits, can distort a fair determination that an asset must be replaced. These factors necessarily create a commensurately large perceived need to replace, i.e., "modernize" equipment that may have additional service life but is replaced, none-the-less, because an inspection will not re-occur for another decade. Thus, DTE may very well assert that the program's "modernization" of circuits does in fact comport with the actual-incipient/imminent failure standard, but the projected high level of replacements is likely impacted by the program's inspection cycles. The massive expansion of proposed capital spending DTE is requesting, however, is largely unsupported. The Company simply fails to provide a reasonable plan for why they need such a massive capital infusion.

Q. **The Company currently is attempting to achieve a 10-year inspection cycle for both poles and pole top hardware, by 2025. Is a ten-year inspection cycle an industry best-practice?**

A. Witness Andahazy presents in Table 5, a benchmarking of four utilities.[17] That table shows that all four utilities set a 5-year, or less, inspection cycle for pole top equipment, and that

[17] Andahazy Direct, p. 24.

all four utilities set a 5-year, or less, visual inspection for poles. With respect to physical testing of poles, Table 5 shows two utilities undertake physical testing every 10 years. I would assume that the other two utilities (that are not shown as doing physical testing) do in fact undertake a 10-year pole-by-pole physical testing, as referenced by the Department of Agriculture, RUS Bulletin 1730B-121, which recommends physical testing every 10 years for USDA Zone 2, in which all the Midwest and northeast utilities in the chart are located.[18] Despite the fact that some utilities apparently do have a 10-year cycle, I am not convinced that a uniform 10-year inspection cycle can be viewed as a best practice for DTE. DTE intends to continue its 10-year pole inspection cycle, through the projected test-year, and out into the indefinite future.

Q. Why are you concluding that a 10-year pole inspection is not a best practice for DTE?

A. First, the Department of Agriculture, RUS Bulletin 1730B-121 contains highly relevant information regarding recommended deviation from its recommended cycle times (i.e., shorting the inspection cycle. The bulletin states: "As a general recommendation, the initial pole-by-pole inspection program should be inaugurated at a yearly rate of 10 percent of the poles on the entire system when the average age of the poles reaches 10 years." (the bulletin recommends 10% of total poles be inspected thereafter for Zone 2) "If a spot check indicates that decay is advanced in 1 percent of the pole sample, the inspection and maintenance program should be accelerated so that a higher percentage of poles are inspected and treated sooner than the figures shown above." Now, DTE is asserting that their reject pole rate is 8%. This is the percentage of DTE inspected poles having decay so advanced that the poles require replacement. This represents an advanced level of decay

[18] Ex MEC-MEC-48 (U.S. Dept. of Ag. RUS Bulletin 17300B-121).

eight times more widespread among poles than the 1% level, for which the bulletin recommends that the pole inspection cycle be reduced. The reason the bulletin recommends accelerating the timing of inspections is clear – "The greatest economic benefit from regular inspection is in locating the decaying/serviceable group. Treatment of poles in this group can extend pole life, thereby saving the cost of emergency replacement. Inspection and proper maintenance can more than pay dividends by extending the serviceable life of the poles. With the costs of replacing poles rising, the economics of extending the service life are more favorable." AS DTE is not following the Department of Agriculture guidelines, their PTMM program forfeits the benefits of extending service life of the "decaying/serviceable" poles, and is forced into a high cost replacement "modernization" mode.

Q. With respect to the Company's ultimate goal to be on a uniform 10-year pole inspection cycle, and 5-year pole top inspection cycle, what is your recommendation?

A. First, in light of the apparent high percentage of poles found to have advanced levels of decay (requiring 8% of inspected poles to be replaced), DTE needs to rethink its unwavering commitment to a 10-year pole inspection cycle, and consider following the recommendations of the Department of Agriculture in its RUS Bulletin 1730B-121, by scheduling a continuous pole inspection and maintenance program at a rate commensurate with the apparent high incidence of decay that DTE is finding. The shorter inspection cycle will provide a greater opportunity to remediate decaying poles rather than wait and replace.

Secondly, cycle-based management of the pole and pole top maintenance function is the wrong approach for DTE. It does not address the actual risk to DTE's pole and pole top infrastructure. I am recommending that DTE move to a risk-based pole and pole top maintenance program. Under a risk-based approach, circuit cycle times are variable, strategic, data driven, and focused on the circuits where risk is highest. These attributes are identical to the new risk-based vegetation management approaches now being implemented across the country. As DTE is developing a plan to move its tree trimming program to a variable cycle, risk-based structure, there may be some synergy with respect to technologies and data capturing approaches used to assess risk. Certainly, coordination of risk-based vegetation management with risk-based pole and pole top management should be a priority. In addition, with a risk-based pole and pole top maintenance program, the Company could conceivably incorporate learnings from its Customer Excellence program, which addresses issues on a sub-circuit level.

Third, in order for DTE's PTMM program's 10-year inspection cycle to be considered a best practice for DTE, DTE would have to be at the top of the industry with respect to reliability data, which they are not. Unfortunately, in light of the high level of customer outages experienced by DTE during storm and non-storm conditions, high restoration times, and in particular the high level of public concern that currently exists with respect to recurring outages and restoration times (as even the Michigan legislature is demanding action) it is apparent that the Company needs to rethink its PTMM program. In addition, the unsustainably high rate-increases for DTE's residential customers, (the residential customer class is allocated the largest share of distribution capital spending) underlies the critical need for cost effectiveness in the PTMM program. Being cost effective will require that DTE be budget limited, cost conscious and open to new methods and new technologies to manage its PTMM program, something I do not see in the context of a four-fold increase from historical capital spending.

Q. Should the Commission set a cap on the cycle times of a risk-based pole and pole top maintenance program?

A. No. that would be up to the Company to establish via its experience during implementation. I would expect, however, the average cycle time of a risk-based program should be significantly shorter than the current 10-years, and with respect to pole top inspections, possibly as short as the Company's long term goal to reach a 5-year cycle, as this would reduce the Company's pressure to replace marginally degraded assets, and focus on actual, incipient, or imminent failure.

Q. Will the conversion of 4.8 kV circuits to 12.2 kV be the solution to equipment related outages?

A. No. Cost effective maintenance programs are the solution to equipment-related outages. It is simply imprudent management for the Company to continue on its current path, barely meeting a 10-year PTMM inspection cycle, given the level of storm related and equipment related outages on DTE's distribution system and the intense scrutiny the Company is under both by the public and the Michigan legislature. The Company's newly reframed 4.8 kV conversion goals and investments are not the solution to the equipment related outage problem, as DTE's current 12.2 kV lines have little difference in reliability compared to their 4.8 kV lines (see the testimony of the Wired Group also representing the MNSC), and it would take decades to substantially convert older 4.8 kV circuits to 12.2 kV.

Q. Should the Commission order DTE to immediately begin developing a risk-based pole and pole top maintenance program?

A. Yes. Although equipment-related failures are causing a notable fraction of outage and non-outage events,[19] the Company's request for a four-fold increase in PTMM spending (over its historical 2021 spending), has not been demonstrated by DTE to be cost effective. The "modernization" component of the program appears to be the culprit, dominating over prudent "maintenance" of assets that have failed or are in a state of eminent failure, thus driving the preponderance of the additional costs requested. In addition, the current cycle-based approach is clearly not optimal, having a consequential interplay with "modernization" of pole and pole top equipment. It is imperative that the PTMM program be transformed into a risk-based Pole and Pole Top Maintenance program. The Company has demonstrated that it can make major improvements to its tree trimming program, and I have confidence that the utility can do the same with its PTMM program.

Q. Do you see value in DTE reporting annual metrics to the Commission with respect to its pole and pole top inspections and testing?

A. Yes. Such reporting would have substantial value with respect to accountability and transparency. Accountability and transparency are sorely needed, particularly in light of the questionable cost effectiveness of DTE's transformation of its pole and pole top program from a maintenance program into a "modernization" program. It is my professional opinion that annual reporting, similar to DTE's annual tree trimming reporting, would lead to better decision making by the Company, more insight by stakeholders, and better oversight by the Commission.

[19] See DTE 2021 Distribution Grid Plan, Ex A-23, Sch M7, p. 126.

Q. What is your recommendation for a reasonable projected level of PTMM funding?

A. I am recommending that the Commission reject DTE's proposed fourfold increase in 2024 PTMM spending over the historical year 2023 projected capital spend. I am recommending that the projected PTMM capital expenditure be set at a level of $63.445 million, which is the same level as projected in the 2023 bridge period, and nearly double the 2021 spend that the Commission set as the annual cap in U-20836. I further recommend that the Commission require DTE to formulate a plan to transform its PTMM program into a risk-based Pole and Pole Top Maintenance program, with a detailed plan filed in the Company's next rate case, with its next grid plan, in a stand-alone docket, or elsewhere. In addition, I am recommending that the Commission require DTE to file annual Pole and Pole Top Maintenance reports, and that such reports detail circuit-level inspections, testing, replacements, and repairs. The report should include an analysis of costs and benefits (including reliability benefits), and an analysis of the modernization impacts of the program. Data should include DTE's work on a service center basis (similar to the Annual Tree Trim Report) or and if relevant to a better understanding of the costs and benefits of the program, on a circuit level basis.

IV. CAPITALIZATION OF TREE TRIMMING

Q. Is DTE capitalizing its tree trimming expenditures?

A. Yes. The Company is requesting the capital recovery of a major portion of its projected tree trimming. Exhibit A-22 Schedule L1 indicates a 2024 amount of $67 million in the 2024 projected test period. However, MNSC discovery request MNSC-DE-10.1cii indicates that "none of the dollars in Exhibit A-22 are for trimming associated with PTMM or Hardening work." As the Company includes tree trimming as part of the scope of capitalized work in the Hardening and PTMM programs[20] and likely the 4.8kV conversion program, the level of requested capital recovery is significantly larger than $67 million.

Q. Does the Uniform System of Accounts (USOA) provide clarity regarding the capitalization of tree maintenance?

A. Yes, it does. I addressed this issue in DTE's last general rate case, U-20836. However, as a direct answer to the question of capitalization was not made by the Commission in its order in that case, I have performed a more thorough investigation of the issue in this current proceeding. My further research indicates that there is no ambiguity regarding the issue of capitalization of tree trimming. In particular, a clear answer to the what the term "tree trimming, initial cost" means is found within the USOA itself. Capitalization of tree trimming is restricted to a very precise and limited circumstance: the first clearing of rights-of-way for new electric lines. In addition, the Commission provided a definitive ruling, by its order in a DTE proceeding nearly ten years ago, that confirmed such interpretation of the USOA.

[20] Case No. U-20836, Pfeuffer Direct, 4 TR 293.

Q. Is the Michigan Uniform System of Accounts (USOA) based on the federal Uniform System of Accounts, promulgated by the Federal Energy Regulatory Commission?

A. Yes. With respect to the USOA, Michigan has adopted, by reference, the federal USOA promulgated by the Federal Energy Regulatory Commission, via Mich Admin Code R 460.902. All electric utilities subsect to the regulation of the Michigan Public Service Commission are required to follow the federal USOA. However, Rule 460.902 specifies that the applicability of the federal rules to Michigan regulated electric utilities, is ultimately subject to the orders of the Michigan Public Service Commission (MPSC). This flexibility allows the Commission the ability to interpret, clarify, or strengthen the rules as it seems appropriate.

Q. What do the relevant provisions of Rule 460.9002 say with respect to the Commission's jurisdiction and flexibility to administer the USOA?

A. Rule 460.9002 states in part:

Rule 1. (1) The federal uniform system of accounts for major and nonmajor electric utilities promulgated by the United States federal energy regulatory commission and codified at 18 CFR Part 101, as amended through April 1, 2010, is adopted by reference in these rules as of January 1, 2011. The rules are prescribed for the use of all electric utilities under the jurisdiction of the Michigan public service commission, subject to the following exceptions and conditions unless otherwise ordered by the Michigan public service commission: (a) All orders and practices of the Michigan public service commission in effect as of the effective date of this rule with accounting impacts that conflict with provisions of the uniform system of accounts for major and nonmajor electric utilities at the request of or affecting each specific utility shall remain in effect, and future orders and practices with such impacts shall supersede the provisions of the uniform system of accounts for major and nonmajor electric utilities for Michigan retail jurisdictional purposes.

Q. What does the federal USOA say regarding capitalization of tree trimming?

A. FERC USOA, Account 365, Overhead conductors and devices states: "Tree trimming, initial cost, including the cost of permits therefore." FERC Account 364, in contrast, Poles towers and fixtures does not provide an allowance for tree trimming at all. With respect to tree trimming, the term "initial cost" is somewhat ambiguous, but as it is only applicable to overhead conductors and devices, "initial cost" most likely refers to the initial clearing of right-of-way (ROW) prior to the initial installation of electric lines. In fact, the USOA confirms such an interpretation.

Q. Please explain.

A. USOA Electric Plant Instruction No. 9 clarifies any potential ambiguity with respect to Account 365 regarding what *initial cost* means for Michigan regulated electric utilities. With respect to the cost of equipment chargeable to the electric plant accounts, (e.g., Account 365, Overhead conductors and devices), Instruction No. 9 states: "*Also include those costs incurred in connection with the first clearing and grading of land and rights-of-way*". Let me make this clear. The Michigan USOA restricts capitalization of tree trimming to the first opening of right-of-way so as to accommodate newly constructed electric lines. In my professional opinion, any succeeding clearing of existing ROW, either for a regular maintenance program (i.e., cycle trimming) or for subsequent replacement of electric assets (i.e., construction trimming) is an operation and maintenance activity that is expensed.

Q. You mentioned earlier that the issue of the intent and meaning of the Michigan USOA with respect to tree trimming has been previously raised before the Commission?

A. Yes. In the DTE general rate case U-17767, the issue was raised in response to DTE's request to capitalize its new Enhanced Vegetation Management Program (whose name was changed to the Enhanced Tree Trimming Program (ETTP)). In this former proceeding, DTE claimed that the more rigorous trimming standard was in effect "a second initial clearing" of right-of-way because the first clearing was not performed to the new specification. That interpretation was firmly rejected by the Commission Staff's engineering specialist Peter Derkos.[21] The ALJ, and subsequently the Commission in its U-17767 order, agreed with Staff regarding the interpretation of the Michigan USOA, that that the new (ETTP) program is not a first clearing of rights-of-way, and thus is properly an operation and maintenance expense.[22]

Q. Please elaborate on what the Commission ruled with respect to interpreting the USOA.

A. The U-17767 order contained a section (4) entitled "Electric Distribution System – Vegetation Management Capitalization." In that section the Commission noted that: "DTE Electric provided testimony explaining that the Uniform System of accounts allows for these costs to receive capitalization treatment." The Commission then summarized Staff's reply: "Staff again argues against capitalization treatment for any EVMP amount that is allowed, noting that the first clearing of the existing ROW was completed years ago and "any further removal now is an O&M expense, even if it is executed in a new way."" The

[21] Case No. U-17767, Direct Testimony of Peter Derkos, 8 TR 2088.

[22] Case No. U-17767, PFD dated October 8, 2015, pp. 86-87; Order dated December 11, 2015, pp. 25-27.

Commission then concluded: "…the Commission is not persuaded that this cost category is appropriate for capitalization." "The EVMP effort is not a first clearing, because all of these ROW's have been cleared before, possibly multiple times…Having rejected capitalization treatment, the amount of allowed expense is addressed under net operating income." [23]

Q. How does the Michigan USOA apply to capitalized tree trimming that the Company has previously included (and projects to include) in its reactive, storm, or other distribution operations programs (such as the Hardening, PTMM, or 4.8 kV conversion programs)?

A. Irrespective of to which programs tree trimming has been assigned, DTE's capitalization of tree trimming is an unequivocal violation of the Michigan USOA as it is not a first clearing of rights-of-way.

Q. Do you have a perspective on the level of tree trimming expense that you would expect to see capitalized by the Company?

A. Yes, I do. As DTE is a utility with essentially flat load growth, the first clearing of new right-of-way for new distribution lines would be expected to be a very limited activity. As a result, the dollar amount of capitalized tree trimming should be diminutive.

Q. What is the relative size of DTE's historical and expected future capitalized tree trimming?

A. The total tree trimming that DTE capitalized during the 2021 historical test year and has projected for the 2022 through 2023 bridge period amounts to an astounding $258 million.

[23] Case No. U-17767, Order dated December 11, 2015, pp. 25-27.

DTE has buried an additional $67 million of tree trimming into its projected 2024 distribution capital requirements (those figures are not identified in DTE's Exhibit A-12, Projected Capital Expenditures Distribution Plant, but in a tree trimming savings exhibit, Exhibit A-22 Schedule L1 which does not include capitalized (pre-construction) tree trimming that DTE considers part of the scope of the work for the Hardening and PTMM programs). To gain a better perspective of the issue, Exhibit A-22 Schedule L1 contains an estimate of 2021 through 2031 capitalized tree trimming amounting to greater than three quarters of a billion dollars. As tree trimming is in essence a maintenance activity, the magnitude of the Company's erroneous capitalization policy should be of considerable concern to the Commission. In addition, distribution capital expenses are heavily allocated to residential customers via cost-of-service study (COSS) allocators, thus erroneously capitalized tree trimming is a patently unfair burden on residential customers.

Q. Do you have any rational basis for DTE's excessive level of tree maintenance capitalization?

A. Yes. As the DTE is investing heavily in what the Company refers to as strategic capital programs, and because the Company has been heavily off cycle with respect to trimming over a multi-year period, the extent of ETTP tree trimming preceding distribution asset replacement (pre-construction trimming) is commensurately large. This is likely a major reason for the large historical capitalization of tree trimming. Future capitalization of tree trimming is likewise large due to expected large future investments in strategic capital programs. Secondly, the Company has slipped tree trimming into its capitalized storm restoration and reactive maintenance activities, again erroneously assuming that pre-construction tree trimming can be capitalized.

Q. With respect to storm restoration or other restoration activities, did DTE request and received authorization to capitalize the cost thereof?

A. Yes. The Commission did allow the Company to capitalize restoration costs that were previously recovered as O&M expenses. This occurred in Case No. U-17767. No objections were raised at that time, most likely because the Company does replace depreciable distribution assets during some restoration activities. The Company, however, following Commission approval to capitalize such restoration costs, apparently slipped "construction" tree trimming into the cost bucket, similar to how they designated circuit-wide tree trimming an integral component of its Hardening and PTMM programs. With respect to the capitalization of restoration activities, and from my reading of the record in U-17767, it does not appear that the inclusion/capitalization of O&M tree trimming was explicitly noted by the Company in its request. As it does not comport with the Michigan USOA, as clarified by the Commission in that very proceeding, it would have been, in my opinion, rejected out-of-hand by the Commission if disclosed.

Q. What are your recommendations regarding capitalization of tree trimming?

A. I am recommending that the Commission reject DTE's capitalization of tree trimming. I recommend that the Commission order DTE to reflect all maintenance tree trimming in its Exhibit A-13 schedule for Operation and Maintenance expenses. If new electric lines are constructed, and new right-of-way is opened for such lines, the cost of *"first clearing and grading of land and rights-of-way"* should be reflected in Exhibit A-12, Projected Capital Expenditures, Distribution Plant, as a single line representing the estimated cost of such first clearing. Exhibit A-22, detailing its tree trimming program, should specifically define to which capital programs the "first clearing land and rights-of-way" is projected to take place, including Hardening, PTMM, or 4.8 kV conversion. This will better enable parties to DTE's rate proceedings, and the Commission itself, to monitor and evaluate DTE's expenses. Lastly, and most importantly, with respect to the projected test year, the Commission should order that all projected tree trimming (that will not be a first clearing of ROW for new lines) be moved out of capital accounts, and into O&M. With respect to the 2023 bridge period, all improperly capitalized tree trimming should be excluded from rate base, the Company forfeiting O&M revenue requirements for such expenditures, as the Company has been improperly earning a return on maintenance tree trimming for years, despite the fact that the Commission authoritatively ruled against this in its order in the U-17767 DTE general rate proceeding.

IV. RESTORATION O&M

Q. Are you recommending an adjustment to the Company's requested Restoration O&M expense?

A. Yes.

Q. What level of Restoration O&M is the Company requesting?

A. The Company is requesting a projected test year (12/1/23-11/30/24) Restoration O&M equal to $125,538,000. Restoration O&M is composed of two parts. Storm Restoration is estimated at $63,873,000 and Non-Storm Restoration is estimated at $61,665,000.[24]

[24] Exhibit A-13 Schedule C5.6, p. 2.

Q. By what method was such amount calculated?

A. According to Company Witness J. E. Robinson, the Company chose to use a 5-year average (2017-2012) of historical expenses, adjusted for inflation.[25] Mr. Robinson stated that this is the same method used in previous rate cases. Inflation adjustments were made both within the 5-year period ending in calendar year 2021, and three additional years through the projected test period. All inflation adjustments were made on a compound annual basis, so as to recognize the cumulative impact of year-over-year inflation. Due to compounding, Restoration O&M expenses in the oldest historical years had the largest inflation adjustments.

Q. By how much was the historical Restoration O&M adjusted for inflation?

A. Pursuant to Exhibit A-13, Schedule C5.6, the unadjusted 5-year average of historical Restoration O&M is $108,029,000. This figure was adjusted upward by $17,509,000 to account for inflation.

Q. Is use of a 5-year average of historical Restoration O&M an appropriate normalization methodology?

A. Yes. A simple arithmetic average over five years is a reasonable method to normalize historical cost data. I can support this normalization method because customer outages from year to year tend to follow a random and unpredictable pattern, as can readily be seen from the actual reported 5-year restoration data presented by DTE in Exhibit A-13, Schedule C5.6. This is especially true for Storm Restoration costs, which are logically

[25] Direct Testimony of Joseph E. Robinson, p. 25.

dependent upon the level and intensity of storms in any particular year. That being said, I am not in agreement with the Company's inflation adjustment.

Q. Is the Company's inflation adjustment defective?

A. Yes.

Q. Please explain.

A. The massive ramp in year-over-year investments the Company has made to improve reliability (e.g., tree trimming surge, hardening, grid modernization, and technology and automation), was justified to the Commission on the basis that it would result in a progressively increasing level of reliability in years future to such investments.[26] Significantly, the cumulative impact of such massive investments in increasing distribution system reliability are not fully reflected in DTE's historical O&M Restoration costs, in the same manner that inflation through the 2024 projected test period is not fully reflected in the historical O&M data. DTE's normalization method for setting its requested Restoration O&M increases the level of historical O&M to reflect the most recent and expected levels of inflation, yet the Company's normalization method ignores the full impact of its most recent and expected investments in distribution system reliability, that will serve to decrease the level of projected outage restoration costs. As a result, DTE's method is highly biased to produce the largest possible projected cost.

[26] See for example Case No. U-20836, Pfeuffer Direct, 4 TR 281 ("The investments will have a direct impact on the electric system in terms of improved reliability, safety, and avoided emergent costs…the investments will reduce long-term emergent costs.").

Q. Is there an economic term for the impact of the progressively increasing level of reliability on outage restoration costs?

A. Yes. The term is "productivity". With respect to outage restoration costs, productivity reflects the relative dollar impact of improving reliability. The massive scale of DTE's investments in distribution system reliability, (irrespective of whether or not they were completely cost effective), should result in a rapid reliability "productivity" evolution in the years preceding and including the 2024 projected test year. This necessarily follows from both the large ramp in investments, and the compounding effect of the Company's year-over-year investments in distribution system reliability, which are intended to have long-term impacts.

Q. What is the most significant reliability investment made by DTE with respect to distribution system reliability?

A. In my opinion, the most significant reliability investment is the Company's ETTP tree trimming program, which involves a substantial year-over-year ramp in tree trimming investments during the "Surge" years 2021 through 2024.

Q. Do you have an example of a DTE assertation to the Commission that its ETTP reliability investments would result in a substantial reduction in Restoration O&M?

A. Yes. See MPSC Order U-17776, the order approving the initial ETTP request. Therein, the Commission noted that DTE expects "avoided annual restoration costs of up to $45 million by the time the steady state of the EMVP is reached."[27] DTE noted that its EMVP (renamed

[27] Case No. U-17767, Order dated December 11, 2015, p. 60.

ETTP) would commence in 2015 and continue annually through 2025, for a total of $450 million in restoration cost savings over 10 years.

Since the projected test year of 2024 is only one year short of DTE's expected conclusion of Surge trimming, the cumulative impact of near attainment of the Company's goal of being fully on-cycle with respect to ETTP tree trimming demands that the normalized historical restoration costs by adjusted by annual productivity offsets through the 2024 projected test period (noting that restoration cost savings are associated not only with getting back on cycle with respect to tree trimming, but also as a result of the substantial strategic capital investments that have been made, such as in Hardening, PTMM, and grid automation). The bottom line is that DTE's exclusive use of inflation multipliers without corresponding productivity offsets is erroneous and highly unfair to its ratepayers and must be rejected.

Q. Despite the volatility inherent in outage restoration cost data, is it possible to see a downward trend in outage restoration costs due to the scale of reliability investments and their impact on the level of customer outages?

A. Yes. I would agree that the scale of strategic investment is so large (greater than $1 billion over the 10-year period (i.e., 2016 – 2024) that its progressive effects should be seen in DTE's historical Restoration O&M cost data. For example, recognizing that there is some volatility in the data, a clear downward trend can be seen in the 5-year historical data supporting DTE's non-storm restoration costs, 2017 through 2021.[28] The five-year averaging method removes the volatility in the data, but unfortunately also removes any

[28] See Ex A-13, Sch C5.6, p. 2, line 10.

underlying trend. Both the inflation adjustment and the productivity adjustment, in effect compensate for the limitations of the averaging methodology, and in particular with respect to productivity, the fact that DTE's distribution system is in a continuous state of rapid evolution rendering the oldest years of historical data non-reflective of future improvements in distribution system reliability. In my opinion, the Commission should rightly expect that the massive reliability investments that they are allowing to be recovered by rate payers would result in a 2024 projected test-year cost of outage restoration that is lower than historical O&M costs, even considering the impact of inflation. Otherwise, in my opinion, it would be difficult to consider such investments as being cost-effective, i.e., with respect to restoration O&M, a complete offset of inflation should be considered a bare-minimum standard of cost-effectiveness of DTE's massive reliability investments.

Q. What is your recommendation?

A. I recommend that the Commission reject DTE's inflation adjustment, in the amount of $17,509,000. It is unjustified for DTE to include an adjustment for inflation and not an offsetting adjustment for distribution system reliability productivity, while in the same rate proceeding request hundreds of millions of dollars in incremental surge trimming and strategic investments that the Company claims will improve reliability (and by extension reduce Restoration O&M). Further, the Commission should require future Restoration O&M projections that include inflation multipliers to include reliability productivity offsets and that DTE would propose and detail its inflation/productivity offset methodology in such future rate cases, if they want to include any adjustments to historical Restoration O&M costs forming the basis of a 5-year average normalization.

V. UPDATES TO C-6 TARIFF - PER-FOOT EXTENSION CONTRIBUTIONS IN AID OF CONSTRUCTION

Q. Please provide some background on the customer Contribution in Aid of Construction issues?

A. In prior DTE and Consumers Energy rate proceedings I recommended a new[29] approach to formulating customer CIAC contributions for electric distribution line and service line extensions that is based on the economic carrying cost of distribution rate base as originally developed by Mr. Douglas Jester, principal of 5 Lakes Energy.[30] Simultaneously with the issue of reformulating free allowances based on the principle of economic carrying cost, I also have recommended that any out-of-date line extension charges should be updated. Importantly, the determination of per-foot line extension charges is independent of the economic method for determining a cost-based allowance. Due to the complexity of implementing a major change in CIAC policy, the Commission, in its order in DTE's prior rate proceeding, declined to implement the new approach for determining allowances, moving the issue to an MPSC Staff led workgroup.[31]

While the Commission never addressed the specific issue of updating per-foot line extension charges in its order, it referenced that the prior CIAC Workgroup recommended such updating.[32]

[29] In Case No. U-21224, Consumers Energy's last electric rate proceeding, I demonstrated that the economic carrying cost is not new at all, but in fact identical to the method the Commission has adopted for many years to set large commercial and industrial allowances for Consumers. Case No. U-21224, Direct Testimony of Robert G. Ozar, PE, 8 TR 3806-24.

[30] See Case No. U-20561, Direct Testimony of Douglas B. Jester, 9 TR 3814-21.

[31] Case No. U-20836, Order dated November 18, 2022, pp. 473-76.

[32] *Id.*, p. 474.

Q. What did the Commission say with respect to out-of-date per-foot line extension charges?

A. On pages 474 to 475 of the Commission's order in U-20836, the Commission referenced and quoted the ALJ's summary of the CIAC Workgroup's first report, to which her recommendation was tied:

> The CIAC Workgroup provided several recommendations to the Commission for considering CIAC policy in the future, including: (1) **further consider updating the cost per foot of line extensions presented in tariffs, as whatever data used to create this allowance is likely obsolete**; (2) only change CIAC policy in general rate cases and not standalone proceedings due to the influence such a change could have on the revenue requirement, rates, and individual customers; and (3) continue CIAC workgroup meetings to further develop known issues and allow new proposals to be submitted and discussed." (Emphasis added)

The Commission further noted at page 476 that the ALJ's recommendation regarding CIAC policy was well reasoned, and concluded: "Therefore, the Commission adopts the ALJ's recommendation to continue discussion of the concerns regarding DTE Electric's CIAC policy through the CIAC workgroup."

Q. Is updating the price per foot charged for line extensions in excess of any free allowance a major change in CIAC policy?

A. No. Updating the price per foot charged for line extensions in excess of any free allowance is a necessary and straightforward step, as such prices delineated in DTE tariffs are far out-of-date with respect to the current actual costs of construction. DTE has not on its own initiative provided the Commission with data regarding its current actual costs to construct line extensions. Given how out-of-date such charges are, the Commission must order an update to DTE's C-6 tariff.

Q. How does DTE's apparent reticence to address the obsolete cost data behind the per-foot line extension charges impact rate base?

A. It constitutes an implicit (or indirect) rate increase. The per-foot line extension charges represented in the Company's C-6 tariff substantially understate actual construction costs. The shortfall in CIAC contributions associated with the variance of these charges from the current cost-basis is added to rate base as emergent capital requirements. So, it is manifest that year after year, the Company petitions the Commission to update its rate schedules on the basis of a shortfall in revenue requirements, but coincidentally excludes, year after year, any request to update its per-foot line extension charges in its C-6 tariff. Both actions clearly undermine the interests of its ratepayers. The former is self-evident, as the Company is requesting an 18% increase in residential rates. The latter, by virtue of the fact that per-foot line extension charges based on obsolete cost data directly increase the Company's emergent capital request, and thus expand its rate base, as the current charges as delineated in DTE's C-6 tariff are likely a fraction of the current cost of construction.

Q. Are there other considerations that bear on this issue?

A. Yes. Interestingly, in this current proceeding, the Company is requesting that the Commission approve the use of updated data to increase the standard allowances for its largest commercial and industrial customers (Section C-6.2). Approval of such increased allowances would decrease the CIAC contributions required by qualifying commercial and industrial customers, thereby serving to increase the level of DTE's future rate base.

Q. Would it be consistent for the Commission to approve DTE's request to update the standard CIAC allowances for large industrial customers, but simultaneously reject the updating of the per-foot line extension charges in the same C-6 tariff?

A. No, in my opinion, it would instead be fundamentally inconsistent. It should be noted that in this proceeding I am not recommending a change in the formula for standard allowances, as that issue has clearly been moved to the CIAC workgroup per the Commission's order in U-20836. However, the per-foot charges for line extensions are so woefully out of date, as observed by the prior CIAC workgroup, the ALJ in U-20836, and the Commission in its U-20836 order, that it befits the Commission to finally approve updated charges based on the costs that the utility is currently experiencing. The utility's thrust for modernization that include more rigorous (and more costly) standards for new poles and pole top hardware, for example, is further evidence that it is paramount that line extension charges be reflective of current construction costs.

Q. Have you made an attempt to obtain current per-foot costs of installing line extensions?

A. Yes. I requested via the discovery process that the Company provide updated costs for all per foot charges in its C-6 tariff. DTE refused to provide an update of its current costs.[33]

Q. What is your recommendation for this proceeding with respect to updating the per-foot charges for line extensions?

A. Considering how old the per foot line extension charges are in the Company's C-6 tariff, I am recommending that the Commission order DTE to calculate its current costs and update its C-6 tariff accordingly. The Company should file such updated tariff in the next rate case. As it would be fundamentally inconsistent for the Commission to approve DTE's request to update the standard CIAC allowances for large industrial customers, but

[33] Ex MEC-43 (Company response to MNSCDE-9.7).

simultaneously reject the updating of the per-foot line extension charges in the same C-6 tariff, I am recommending that the Commission reject the Company's request to update the C-6 tariff, Section C-6.2.

VI. OVERHEAD SERVICE LINES AND RELATED CUSTOMER OUTAGE ISSUES

Q. Is a reasonable estimate of the cost of restoration of overhead service lines appropriately included in DTE's Restoration O&M projections?

A. Yes, in my opinion, a reasonable estimate should be included. However, in my opinion, the imbedded historical costs of restoring overhead service lines (forming the basis of DTE's Restoration O&M normalization adjustment) should not be blindly used to estimate the future projected test-year costs.

Q. Why is that?

A. DTE has long recognized that the Company has an underlying issue with overgrowth of trees along its overhead service lines, and that the tree contact issue is contributing to a growth in customer outages.

Q. Has DTE's recognition of tree impact on overhead service lines been raised in prior DTE general rate cases?

A. Yes. The Company has been raising the issue of high levels of customer outages related to overhead services for years. For example, DTE raised the issue in its U-17767 rate request through its witness, Russel J. Pogats, who asserted that residential overhead services are

16 times as likely to fail as an underground service and that residential overhead services are the last to be restored after storms.[34]

Q. Post the U-17767 rate proceeding, did the Company provide any new insights regarding customer outages related to overhead service lines?

A. Yes. In DTE's most recent rate case, U-20836, the Company again raised the issue of outages directly related to overhead service lines, referring back to the U-17767 proceeding. The Company asserted that it was a significant issue, and in response requested that the Commission approve a pilot to allow the undergrounding of overhead service lines, at the Company's expense.[35] Therein, the Company's witness, Sharon Pfeuffer, pointed out that the "restoration challenges" associated with overhead service lines impact more than the directly attached customers experiencing outages, but that the Company was experiencing a "… growth in emergent repairs and replacements necessitated by weather and non-weather events."[36] As I see it, the key information conveyed in her testimony is the issue of "growth in emergent repairs and replacements". In other words, downed or otherwise damaged overhead service lines are not just an issue of customers experiencing electric outages, but that challenges of restoring overhead service lines are contributing to both capital and operating costs being borne by the ratepayers at large in the restoration of service. The Commission ultimately rejected the Company's proposed solution to the restoration issues - an undergrounding pilot that the Commission viewed as not being cost effective.

[34] Case No. U-17767, Pogats Direct, 4 TR 375.

[35] Case No. U-20836, Pfeuffer Direct, 4 TR 341-42.

[36] Ibid

Q. How does the overhead service line issue impact the current rate proceeding?

A. Only one year has passed since DTE last raised the issue of overhead service line outages in the prior rate proceeding. Unfortunately, an alternative, cost-effective solution, to the growth in overhead service-line restoration expenses has not yet been realized. Yet there is nothing in the DTE's current rate request to address the issue that the Company itself has raised multiple times. The issue of preemptively improving the reliability of overhead service lines remains highly relevant and has not simply gone away. Thus, the consequent impact on restoration costs is necessarily buried in the Company's requested revenue requirements in this rate proceeding.

Q. What is an overhead service line?

A. An overhead service line is the power line between an electric pole and a customer's house or building. Because the line is overhead, and typically drops in height from the pole top (distribution transformer or secondary lines) toward the connection with a customer's home, it is often referred to as a "service drop".

Q. Who owns residential overhead service lines, the Company or the customer?

A. Residential service lines belongs to DTE.[37]

Q. What information is provided by DTE to its customers regarding the impact of trees on power outages, and with respect to who is responsible for trimming trees along its electric lines?

A. Per DTE customer information available on its website, the Company informs customers that: "Fallen trees are responsible for nearly 70 percent of the time our customers spend

[37] Mich Admin Code 460.512, Extensions of residential distribution and service lines in the lower peninsula mainland.

without power. That's why we're stepping up efforts to trim overgrown trees to keep you safe, and the energy grid reliable. With tree trimming, customers experience 60 percent fewer outages." The Company also informs customers that: "Tree trimming is a common sense solution to prevent outages from happening in the first place."[38] However, with respect to who is responsible for trimming along overhead service drops (which are owned by the utility), the DTE website page called "Your questions on DTE tree trimming" states: "No, typically **DTE does not trim around the service drop**, or the line that runs from the utility pole to your home. Your service drop is your personal connection to the power grid. **DTE only maintains vegetation around the pole-to-pole wires**. Keeping branches and other brush away from your service drop is the homeowner's responsibility and can prevent an outage or other electrical problems."[39] (emphasis added).

Q. In your opinion, what is the relevance of the term "personal connection" used by DTE?

A. My interpretation of the term "personal connection' is that DTE is conveying to customers the thought that a particular service drop only serves their individual home. The clear implication, in my opinion, is that because tree contact with a service drop only affects a single customer, then that customer should be responsible for initiating tree maintenance along that service line and covering the resultant cost (a service drop is not a shared distribution asset, as for example, poles or primary or secondary conductor which can serve a significant number of customers).

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[38] https://newlook.dteenergy.com/wps/wcm/connect/dte-web/home/service-request/common/system-improvements/tree-trimming%20.

[39] https://www.dteenergy.com/us/en/residential/service-request/system-improvements/tree-trimming.html.

Q. Are there any exceptions to this implicit policy?

A. Yes. For instance, at the end of a line, the last pole and last distribution transformer could service a single customer. I am not aware of DTE excluding such distribution assets from its tree maintenance programs for which costs are recovered broadly from customers. The fact that a service drop may only serve a single customer is not a reasonable basis for not maintaining a utility line for which restoration costs are recovered in rates.

Q. Could right-of-way (ROW) be a factor differentiating the maintenance of conductor within and external to DTE ROW?

A. As justification for not trimming service drops, it is possible that DTE is making a distinction between distribution lines within its pole-to-pole ROW, as opposed to a service drop that is technically not in its ROW. However, DTE does trim hazard trees outside of its pole-to-pole ROW, and obtains a signed customer authorization prior to doing so.

Q. What impediment to DTE trimming along its overhead service lines are you aware of?

A. Because DTE has not addressed this issue specifically, I am not aware of any specific impediment to pre-emptive trimming of overgrowth impacting service drops, i.e., tree maintenance. If there are complicating factors, they can and should be addressed by DTE in light of the restoration "challenges" the Company has apprised the Commission that it is experiencing, and because of the growth in emergent repairs that non-action is causing, by DTE's own account.

Q. Is there an equity/energy justice issue with respect to service-line related outages?

A. Yes, in my opinion there is an equity/social justice concern. Overhead service lines often exist in older neighborhoods, where service was initiated prior to the Michigan rules for new service lines to be undergrounded. That rule, Mich Admin Code 460.511 took effect in 1979. The City of Detroit is a prime example where overhead service drops predominate.

Q. Should DTE be tackling this problem?

A. Yes. As it is imperative that DTE address all ways of economically reducing customer outages, the issue of tree related events at service drops must be viewed in context of the overall poor reliability of DTE system. It is also imperative that DTE takes reasonable action to reduce the growth in overhead service line restoration expenses. As the Company notes in its website, downed trees cause nearly 70% of customer outage time, and that tree trimming is a "common sense" solution.

Q. What would be an example of actions that DTE could take as part of an initiative to develop cost effective solutions to its overhead service line challenges?

A. It is up to DTE to develop an action plan to address the Company's recognition that it is experiencing challenges in service restoration involving downed or damaged service drops, and commensurately growing restoration costs. Given that trees are the largest cause of outages on DTE's distribution system, it is also reasonable to assume that the Company's decision to not preemptively trim overgrowth impacting its service-line assets, plays a significant role in service line outages. A comprehensive solution might start with the concept of the Company contacting customers along primary and secondary circuit ROW's that are scheduled to be trimmed under the current ETTP program, so as to obtain permission to trim overgrowth along those service lines identified as being at risk.

Q. Did the Commission previously order DTE to address "hazard" trees that are outside of its ROW?

A. Yes, following the U-17542 (ice storm proceeding), the Commission ordered DTE to implement a hazard tree maintenance program, as the Company was not previously managing such trees and their potential to cause customer outages.

Q. Seeing that DTE is not managing overgrowth around its customer service lines (which are outside of DTE's pole to pole ROW), and such mismanagement is contributing to customer outages and associated restoration costs, should the Commission likewise order DTE to develop a pre-emptive service line tree maintenance program?

A. Yes. I am recommending that the Commission order DTE to include an action plan in its next general rate filing. Such an action plan may include a pilot. The Commission may warn DTE that failure to develop and present such a plan may lead to cost disallowance for proposed restoration costs that are reflective of outage restoration of overhead service lines. The Commission should additionally order DTE in its next general rate filing to include detailed information regarding the capital and O&M costs associated with restoration of overhead service line outages over the past five years and expected costs included in its bridge and projected test year. I should note that the absence of an action plan in this current proceeding adds additional weight to my recommendation that DTE's Restoration O&M request, which includes an inflation adjustment, but no productivity offset, should be reduced, as I previously recommended.

VII. RETURN ON TREE TRIM SURGE REGULATORY ASSET

Q. Is the Company requesting the Commission to authorize a return on its tree trim regulatory asset deferrals that reflects both long-term debt and equity?

A. Yes. Both witness Adelle Crozer and Peter Lepczyk address this request. It should be noted that the Commission had previously, in Case No. U-20162, approved a return on its deferrals at the Company's short-term debt rate.

Q. Should the Commission approve DTE's request?

A. No. That request should be denied.

Q. Why is that?

A. It should be understood that the need for and execution of the Surge program is a direct consequence of DTE's imprudent tree trim maintenance deferrals in past years. Although the imprudent behavior took place prior to the implementation of the ETTP,[40] irrespective, there are persistent and long-term adverse consequences as a result of the Company's past practice. Those adverse consequences will continue through 2025 in the form of off-cycle circuits, and their consequent increased pruning costs and higher risk of tree contact.

Q. Is the "Surge" a prudent action?

A. The "Surge" is DTE's initiative to accelerate bringing its tree maintenance program into a five-year cycle that meets an industry standard of 10% to 15% tree contact, system wide,

[40] See Case No. U-17767, Order, Demceber 11, 2015, p. 63, where the Commission noted the Attorney General's assertion that "the Company has only spent about half of its proposed expense each year since 2008". The Commission also noted on page 43, "The record shows that, at least since 2016, DTE Electric has brought actual tree trimming spending into line with the approved amounts, and the Commission agrees with Staff that falling behind in this area will cost more money in the long run. Exhibit S-10.5: Tr 1900-1901."

by 2025. Although an acceleration in trimming of off-cycle circuits itself is a prudent action, (as trees and their overgrowth from past neglect in maintenance, are the primary cause of outages), DTE should not be rewarded for fixing a problem that they themselves created, especially considering that DTE has never been held accountable for the reliability burden and excess costs that the Company has placed on is ratepayers by its past neglect of tree maintenance.

Q. Is the 10% to 15% tree contact standard new?

A. No, the 10% to 15% tree contact standard has been in existence for over 25 years. Significantly, such standard was referenced in the May 1997 study, "The Economic Impacts of Deferring Tree Maintenance", published in the "Journal of Arboriculture"[41]. DTE acknowledges that its 5-year ETTP trimming cycle will enable the Company to meet such standard on a system wide basis once the surge is completed.[42]

Q. What are the adverse long-term consequences of deferring tree maintenance?

A. Tree maintenance deferral necessarily results in a backlog of off-cycle circuits (DTE's off-cycle circuits are currently at an approximate 8+ year cycle[43]). Five fundamental consequences result from such backlog of off-cycle circuits : (1) backlog circuits continue to experience poor reliability[44]; (2) the trimming of backlog circuits results in a cost penalty vis-à-vis the trimming of on-cycle circuits, (as noted in the journal article referenced above

[41] Ex MEC-47 (*The Economic Impacts of Deferring Tree Maintenance*, Journal of Arboriculture.)

[42] Ex MEC-49 (Response to MNSCDE -9.6).

[43] Hartwick Direct, p. 24.

[44] Hartwick Direct, p. 28.

and confirmed by DTE testimony in this proceeding[45]; (3) maintenance deferral inherently results in an intergenerational inequity, as O&M costs that should have been recovered in years past are recovered from future customers; (4) during the multi-year transition period whereby the utility catches up, total annual tree trimming expenses rise sharply, exacerbating the intergenerational inequity; (5) the sharp rise in annual tree maintenance creates rate shock that must be mitigated (via regulatory asset deferral of a portion of the expanded tree O&M), however, stretching out of cost recovery further exacerbates the intergenerational inequity.

Q. With respect to tree maintenance deferral, what are the relevant points that come out of the 1997 study published in the Journal of Arboriculture?

A. The study noted "a highly significant, positive curvilinear relationship was found to exist between the number of years a tree is allowed to grow, and the amount of time required to prune it."[46] Thus, the study found that the larger tree diameter, larger biomass, and higher disposal costs associated with pruning non-optimal (i.e., off-cycle circuits) resulted in a substantial negative impact on the time and cost of pruning. The conclusion was that "Every dollar of spending deferred until a later date must be replaced with more than one dollar in order to restore the program to the original cyclical maintenance schedule."[47] The study found that pruning at an 8-year cycle would result in a cost of $1.59 per $1 spent on an optimal 5-year trim cycle. This is the essence of the cost penalty associated with trimming off-cycle circuits.

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[45] Hartwick Direct, pp. 24-25.

[46] Ex MEC-47, p. 2 (Report p. 107).

[47] *Id.* at p. 5 (Report p. 110).

Q. Are you aware of any other published studies that corroborate the existence of a cost penalty of deferring tree maintenance?

A. Yes. Transmission and Distribution World published a 2010 paper authored by Siegfried Guggenmoos, President of Ecological Solutions Inc., entitled: "Vegetation Management Concepts and Principles".[48] The foundation of the study is the understanding that the two core factors that are responsible for service interruptions, tree growth (biomass addition) and tree mortality, change by exponential or logarithmic function. As a consequence, "the progression of tree related outages is, necessarily, also exponential".[49]

The author necessarily concluded that "The failure to manage the tree liability leads to both exponentially expanding future costs and tree related outages."[50] Because of the exponential relationship of costs and outages, the impact of underfunding of tree maintenance may be "imperceptible for a time".[51] However, there is a point where "the effect of annual compounding of workload and costs is large".[52] The study found that "At this point, the power of compounding is well under way and **only a very aggressive increase in funding will arrest the trend**."[53]

Q. What would you call the workload needed to arrest such a trend?

A. I would call such workload a "surge", same as the Company.

[48] Ex MEC-46, Guggenmoos, S. *Vegetation Management Concepts,* Ecological Solutions, Inc.)

[49] *Id.* at p. 3.

[50] *Id.*

[51] *Id.* at p. 5.

[52] *Id.*

[53] *Id.* (emphasis added).

Q. Did the Guggenmoos paper address the costs associated with a surge tree trimming initiative?

A. Yes. The study concluded that since "… the impacts of a dollar deferred this year cannot be erased with an investment of a dollar next year … failing to make the necessary investment in vegetation management will, in most circumstances, prove imprudent."[54] It is apparent that the Guggenmoos paper independently confirms the concepts and conclusions of the prior Journal of Arboriculture study, although it did not quantify a dollar amount for imprudent costs as did the 1997 study.

Q. Do the two studies that you have referenced suggest that DTE's surge expenditures necessarily include an implicit cost premium, vis-à-vis the costs that would have been incurred had the utility not deferred tree maintenance in the past, and which have resulted in off-cycle circuits?

A. Yes, DTE is aware of such cost premium, and in fact acknowledges such premium via a table quantifying excess costs that is a duplication of the table in the 1997 Journal of Arboriculture study.[55] However, DTE has not stripped out the cost penalty from its tree trim surge, and is thus asking for ratepayers to cover that additional cost. The magnitude of such cost premium is substantial. Trimming off-cycle circuits that are on an 8-year cycle, results in an approximate premium of \$0.40 to \$0.59 for every dollar that would have been spent if the maintenance was on an optimal 5-year cycle.[56]

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[54] Ex MEC-46, p. 6.

[55] Hartwick Direct, p. 25, Table 9.

[56] *Id.*

Q. What is your recommendation in regard to DTE's request to earn an equity return on its deferred Surge spending?

A. In consideration that DTE has essentially experienced a windfall in receiving full recovery of excess tree trimming costs from ratepayers, (and noting this in context of the five adverse consequences of deferring tree maintenance, that I previously listed), I am recommending that the Commission reject the Company's request to earn a long-term debt and equity return, as opposed to the currently approved short-term borrowing rate. As an appropriate alternative, the Commission could consider not approving any return on DTE's future deferred surge expenditures.

VIII. RECOMMENDATIONS

Q. Please summarize your recommendations.

A. (1) I am recommending that the projected PTMM capital expenditure be set at a level of $63.445 million. I further recommend that the Commission require DTE to formulate a plan to transform its PTMM program into a risk-based Pole and Pole Top Maintenance program, with a detailed plan filed in the Company's next rate case, with its next grid plan, in a stand-alone docket, or elsewhere. In addition, I am recommending that the Commission require DTE to file annual Pole and Pole Top Maintenance reports.

(2) I am recommending that the Commission reject DTE's capitalization of tree trimming. I recommend that the Commission order DTE to reflect all maintenance tree trimming in its Exhibit A-13 schedule for Operation and Maintenance expenses. If new electric lines are constructed, and new right-of-way is opened for such lines, the cost of *"first clearing and grading of land and rights-of-way"* should be reflected in Exhibit A-12, Projected Capital Expenditures, Distribution Plant, as a single line representing the

estimated cost of such first clearing. Exhibit A-22, detailing its tree trimming program, should specifically define to which capital programs the "first clearing land and rights-of-way" is projected to take place, including Hardening, PTMM, or 4.8 kV conversion. Lastly, and most importantly, with respect to the projected test year, the Commission should order that all projected tree trimming (that will not be a first clearing of ROW for new lines) be moved out of capital accounts, and into O&M. With respect to the 2023 bridge period, all improperly capitalized tree trimming should be excluded from rate base, the Company forfeiting O&M revenue requirements for such expenditures, as the Company has been improperly earning a return on maintenance tree trimming for years, despite the fact that the Commission authoritatively ruled against this in its order in the U-17767 DTE general rate proceeding.

(3) With respect to DTE's restoration O&M expense, I am recommending that the Commission reject DTE's inflation adjustment, in the amount of $17,509,000, as it is unjustified for DTE to include an adjustment for inflation and not an offsetting adjustment for distribution system reliability productivity.

(4) As DTE has refused to provide updated per foot charges in the Company's C-6 tariff, and considering how old the per foot line extension charges are, I am recommending that the Commission order DTE to calculate its current costs and update its C-6 tariff accordingly. The Company should file such updated tariff in the next rate case. As it would be fundamentally inconsistent for the Commission to approve DTE's request to update the standard CIAC allowances for large industrial customers, but simultaneously reject the updating of the per-foot line extension charges in the same C-6 tariff, I am recommending

that the Commission reject the Company's request to update Section C-6.2, of the C-6 tariff.

(5) In consideration that DTE has essentially experienced a windfall in receiving full recovery of excess tree trimming costs from ratepayers, I am recommending that the Commission reject the Company's request to earn a long-term debt and equity return, as opposed to the currently approved short-term borrowing rate, on its tree trim regulatory asset deferrals. As an appropriate alternative, the Commission could consider not approving any return on DTE's future deferred surge expenditures.

Q. Does that complete your testimony?

A. Yes.

Robert G. Ozar P.E.

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rozar@5lakesenergy.com

- 5Lakes Energy, Senior Consultant: Energy Analysis, Energy/Regulatory Policy, Electric/Gas Utility Engineering
- MPSC: Natural Gas Engineering Specialist • Manager, Electric Operations Section • Manager, Energy Efficiency Section • Assistant Director, Electric Reliability Division

WORK EXPERIENCE

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
- Analysis of basis differentials in regional natural gas markets
- 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 Depreciation 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 AND MENTORSHIP

Mr. Ozar has taught/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. Mr. Ozar has invested significant time in mentorship of young professionals at the Michigan Public Service Commission.

MPSC Case No: U-21297	
Requester: MNSC	
Question No.: MNSCDE-9.7	
Respondent: B. Hill	
Page: 1 of 1	

Question: Please provide current costs per foot, for all charges specified on a per foot basis in the Company's C6 Distribution Systems, Line extensions and Service Connections tariff.

Answer: DTE Electric's tariff is available on the MPSC's website, the link to it is here:

https://www.michigan.gov/mpsc/consumer/electricity/data-price/electric-rate-books/mpsc-approved-dte-electric-rate-books-and-cancelled-sheets

Attachment: None.

MPSC Case No: U-21297
Requester: MNSC
Question No.: MNSCDE-9.10
Respondent: M. Elliott Andahazy
Page: 1 of 1

Question: With respect to D. E. Andahazy's direct testimony, page 32, please describe the details of how the Company's 2024 PTMM workplan was developed so as to result in 2,000 circuit miles and 6,200 poles. Include a breakout of the backlog poles, backlog pole top hardware and backlog circuit miles included in the 2024 workplan estimates, and the year of the initial inspections of such backlogs. Also include the number of poles, pole top hardware and circuit miles to be modernized that are estimated to have failed the 50,000 2023 inspections.

Answer: As stated in my testimony on page 32 the Company expects to eliminate the pre-2022 backlog in 2023 so at this time the Company does not expect any of 2024 pole replacements to include pre-2022 backlog poles. The 6,200 poles to be replaced in 2024 will be a combination of those inspected in 2022, 2023, and 2024. Currently the Company estimates approximately 4,000 poles from the 50,000 inspections (~8% condemned pole rate) will need to be replace. As stated in my testimony on page MEA-26, the Company has experienced an increase in pole top locations replaced per circuit mile from 1.6 between 2018-2021 to 3.6 in 2022. The Company expects the number of pole top locations requiring replacement to remain high until it achieves a five-year cycle.

Attachment: None.

MPSC Case No: U-21297	
Requester: AG	
Question No.: AGDE-4.103b	
Respondent: M. Elliott Andahazy	
Page: 1 of 1	

Question: Refer to Exhibit A-12, Schedule B5.4.8. Please:

b. Provide in Excel the number of units, miles, activities, number of projects, and other data or metrics supporting the actual expenditures for each year 2017 to 2022 and forecasted for 2022, 2023, 2024, and the projected test year.

Answer: See attachment U-21297 AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics.

Attachment: *U-21297 AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics*

U-21297 AGDE-4.103b-01 PTMM and 4.8kV Hardening Metrics 2017-2022

Program	Metric	2017	2018	2019	2020	2021	2022
Pole and Pole Top Maintenance and Modernization (PTMM)	Miiles Modernized	786	2,019	1,027	1,496	1,541	1,562
Pole and Pole Top Maintenance and Modernization (PTMM)	Poles Replaced	2,700	3,165	1,333	1,431	1,016	4,537
Pole and Pole Top Maintenance and Modernization (PTMM)	Poles Reinforced	N/A*	2,050	2,717	27	109	1,116
Pole and Pole Top Maintenance and Modernization (PTMM)	Pole Inspections	63,230	84,005	58,080	7,400	45,400	87,000
4.8kV Hardening	Miles Hardened	-	105	128	209	202	475
4.8kV Hardening	Miles of Arc Wire Removed	-	53	54	120	71	224

*The Company did not track this metric in 2017

As regulators increasingly scrutinize reliability of electric service, storm response and mandate reliability targets, trees emerge as a major risk to utilities. Understanding the drivers of tree liability opens the door to managing tree risk and simultaneously minimizing tree-related outages and maintenance costs.

By Siegfried Guggenmoos
Siegfried Guggenmoos is president of Ecological Solutions Inc., a vegetation management and biotic greenhouse gas sequestration consultancy. (http://www.ecosync.com)

Vegetation Management Concepts and Principles

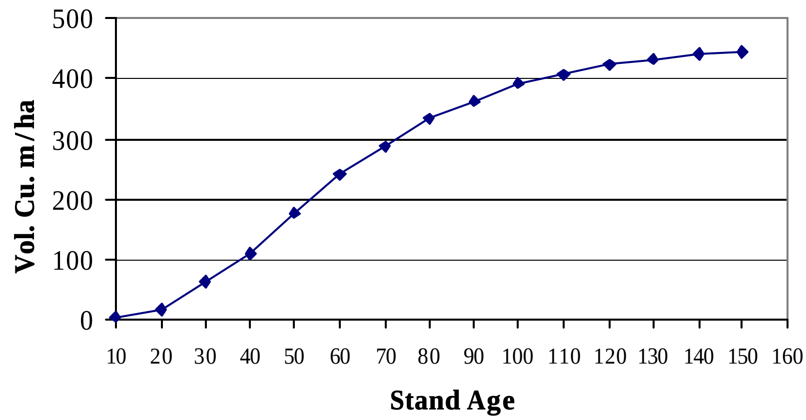
Trees that interrupt electric service can be categorized as in-growth trees and in-fall trees. The inventory of all trees that have the potential to either grow into a power line or, on failure (breakage), fall into and strike a conductor will be referred to as the utility forest. While we commonly think of forests in terms of more or less rectangular blocks the utility forest amounts to ribbons or transects of the service area. Generally, the centerline of these transects is the power line. The utility forest has the same characteristics as any forest. In most cases the tree species composition is what is native to the area and their intrinsic patterns of biomass addition (tree growth) and tree mortality apply. Both of these patterns are significant factors in power line security and both can be mathematically represented by logarithmic, exponential or sigmoid curves, as illustrated in *Exhibit 0-1* and *Exhibit 0-2.*

Biomass additions result in trees that encroach on conductors, thereby necessitating tree pruning and either mechanical or chemical (herbicide) brush clearing. Failure to mitigate this encroachment leads to deteriorating safety and reliability. *Exhibit 0-1* shows an asymptotic curve that is typical of biological populations.

Tree mortality produces decadent trees that are subject to breakage or tipping over (*Exhibit 0-2*). Tree mortality is not an event that occurs at a specific point in time. Rather, tree mortality occurs over a period of months and years. Natural tree mortality is a process of losing vigour either due to the stress of competition for light, water and nutrients or an inability to sustain the attained mass. In the early stages of senescence or decline there may be no visible defect. However, as the tree becomes increasingly decadent and subject to failure under increasingly less stress loading, symptoms of the decline become apparent. Such senescent trees must be identified as faulty and prone to failure under weather stress and must be removed prior to the occurrence of stress. *Exhibit 0-2* shows both the forest stand density over time and the population of trees of concern to utility facilities, the Decadent Trees. Because the capacity of the land-base to produce biomass is limited, the line for the evolution of decadent trees must be asymptotic. Indeed, over the eighty years of forest stand data (*Exhibit 0-2*), the line for Decadent Trees is seen to be asymptotic.

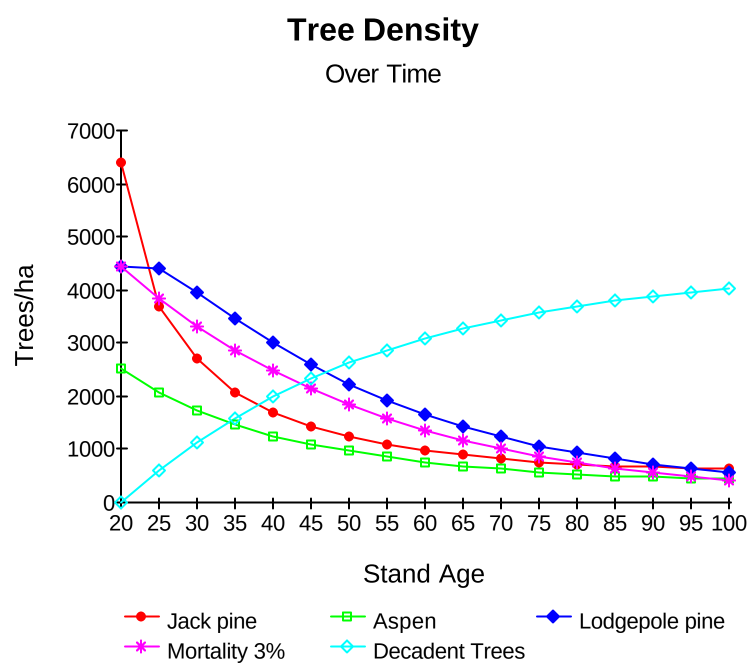
The nature of the expansion of the two sources of tree-caused interruptions, biomass addition (in-growth) and tree mortality (in-fall), is additive. This in conjunction with the

Exhibit 0-1
Forest Biomass Addition
Timber Production
Spruce on Good Site



Source: Freedman, Bill and Todd Keith, 1995. Planting Trees for Carbon Credits. Tree Canada Foundation.

Exhibit 0-2
Stand Density
Fire Origin Species



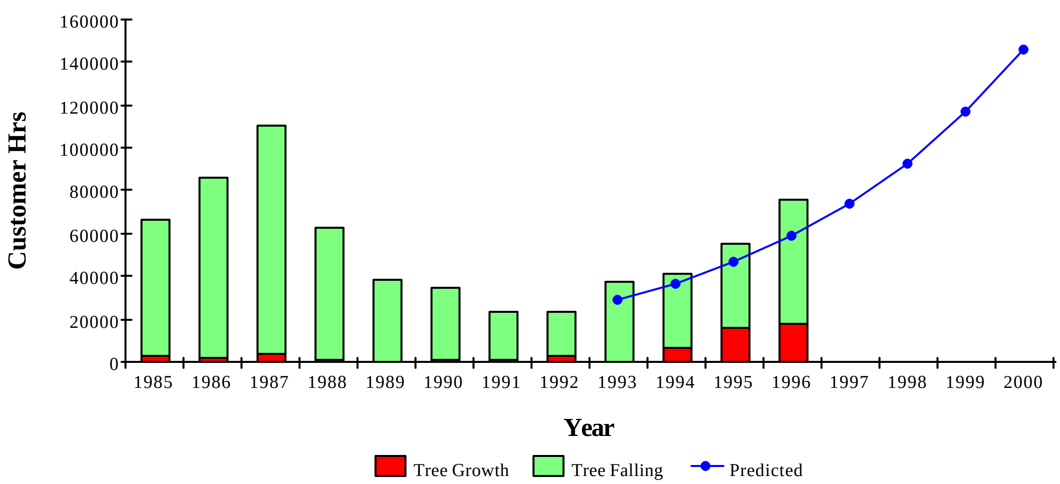
Source: Adapted from Johnstone, W.D. 1976 & Plonski's Yield Tables
Note: To the graph showing the remaining live, viable trees over time, a line showing the cumulative dead or dying trees, labelled Decadent Trees, has been added. It is these decadent or emerging hazard trees that are of interest to utilities because they hold the greatest potential to disrupt electrical service. From 40% to > 80% of trees in the 20 year-old stand die over the next 80 years.

process of tree mortality leads to insight into the consequences of failure to manage trees in proximity to power lines.

From a utility perspective, trees represent a liability in both the legal and financial sense. The fact that utility forest expansion follows an exponential or logarithmic function is significant. It means that the tree liability, if not managed, will grow exponentially.

Trees cause service interruptions by growing into energized conductors and establishing either a phase-to-phase or phase-to-ground fault. Trees also disrupt service when they or their branches fail, striking the line and causing phase-to-phase faults or phase-to-ground faults or breaking the continuity of the circuit. Because the two factors that are responsible for service interruptions, tree growth (biomass addition *Exhibit 0-1*) and tree mortality (*Exhibit 0-2*), change by exponential or logarithmic function, the progression of tree-related outages is, necessarily, also exponential (*Exhibit 0-3*). Failure to manage the tree liability leads to both exponentially expanding future costs and tree-related outages. Conversely, it is possible to simultaneously minimize vegetation management costs and tree-related outages (*Exhibit 0-4*).

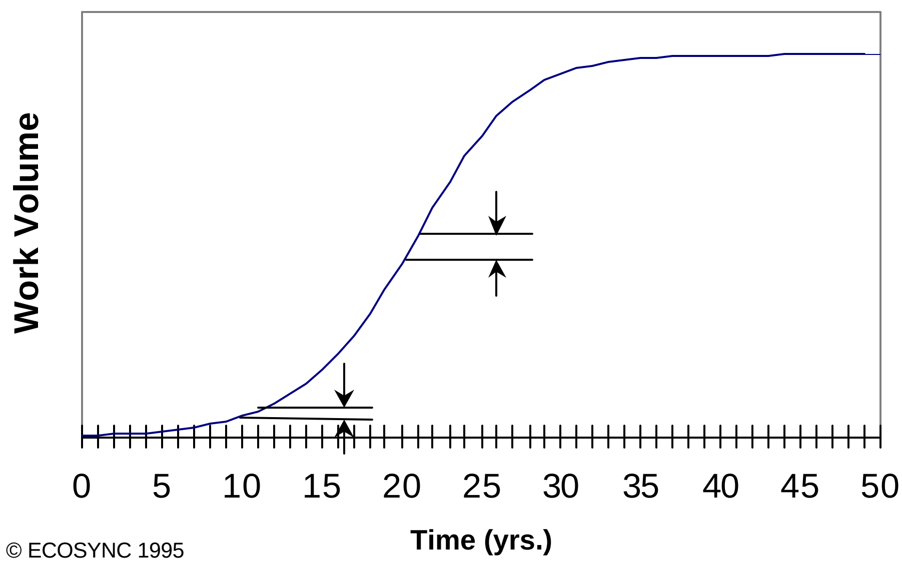
Exhibit 0-3
Tree-caused Distribution Outage Statistics



Source: Western Canadian utility
Note: This work and prediction for future tree-caused outages was performed in early 1997 to show the expected trend to 2000 based on funding below that required to remove the annual workload volume increment.

It is not possible to totally eliminate the tree liability because the ecological process of succession is a constant force for the re-establishment of trees from whence they were removed. The tree liability then is like a debt that can never be completely repaid. Under such circumstances, the best economy is found in maintaining the debt at the minimum level, thereby minimizing the annual accrued interest. However, irrespective of cost, minimizing the size of the tree liability or utility forest is rarely an option for utilities because there are multiple stakeholders with an interest in the trees. What can be achieved, however, is equilibrium. The tree liability can be held at a constant point by annually addressing the workload increment (*Exhibit 0-4*). To continue the debt analogy, a debt is stabilized when the annual payments equal the interest that accrues throughout the year. The interest equivalent in the utility forest is comprised of annual tree growth and mortality. Actions that parallel the reduction in the debt principal are actions that actually decrease the number of trees in the utility forest. Such actions include removal of trees and brush by cutting or through herbicide use.

Exhibit 0-4
Stabilizing Tree Workload
(Illustrative Model)



The graph shows the work volume that must be completed in a year to hold tree work inventory, costs and reliability steady. Performing less than the annual workload-volume increment shifts the total tree work inventory to the right, thus necessitating greater annual vegetation management expenditures to arrest the expansion of tree-related service interruptions.

When the pruning cycle removes the annual growth increment and the hazard tree program removes trees as they become decadent (*Exhibit 0-4*), tree-related outages are stabilized. The residual level of tree-related outages reflects the interaction of several characteristics, including the size of the utility forest, chosen maintenance standards (such as clear width), tree-conductor clearance, and tree-species characteristics (such as mode of failure and decay). An expression of a managed tree liability, one in which the annual workload volume increment is removed, is stable tree-related outages. Reducing tree-related outages below an achieved equilibrium necessitates actions that decrease the size of the utility forest. Actions are not limited to vegetation management. For example, increasing conductor height reduces the size of the utility forest as it reduces the number of trees that are capable of striking the line.

Funding

There are three possible outcomes, which are determined by the level of investment made in vegetation management.

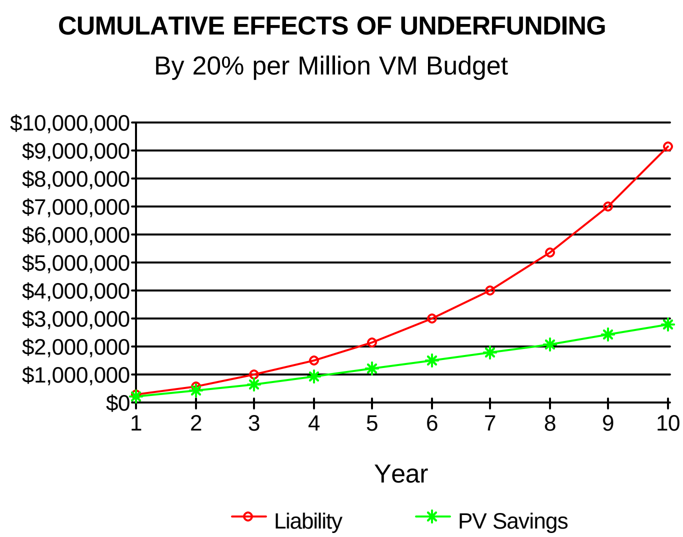
1. The annual workload volume increment is removed, thus keeping the size of the tree liability and next year's workload increment constant.
2. More than the annual workload volume increment is removed, thus decreasing the size of the tree liability and the subsequent year's workload increment.
3. Less than the annual workload volume increment is removed, thus increasing the size of the tree liability. That is because the work not done, expands exponentially, thus increasing the workload increment for the following year.

Tree-related outages are an expression of the tree liability. Hence, changes in the tree liability result in proportional changes in tree-related outages (*Exhibit 0-3, Exhibit 0-5*). Actual outage experience may deviate from the trend based on variance from mean weather conditions.

When less than the annual workload volume increment is removed, the fact that tree liability increases exponentially has two major implications for future costs and reliability. First, the impact of doing less vegetation management work than the annual workload volume increment, as expressed through tree-related outages, may be relatively imperceptible for a few years. Second, the point at which the impact of under-funding is readily observed in deteriorating reliability is where the effect of annual compounding in the workload, and thereby costs, is large (*Exhibit 0-5*). The lack of a significant negative reliability response to reduced vegetation management investment (see 1992 to 1996 *Exhibit 0-3*) may provoke further funding reductions, thereby exacerbating the size of the future re-investment required to contain tree-related outages.

Recognition that the tree workload expands exponentially serves to explain some common utility experience. For many utilities, graphing customer hours lost on tree-caused interruptions over the last ten to twenty years reveals cyclical up and down trends (*Exhibit 0-3*). There are periods when trees are perceived as a problem and funding is increased. Increased funding permits a buying down of the tree liability, reducing tree risks and tree-related outages. Faced with these positive results, spending on vegetation management is reduced. While this tendency is perfectly logical, without the conceptual framework outlined, it is inevitable that funding will be reduced to the point where there is an observable response in tree-related outages. Unfortunately, by the time that tree-related outages are definitively observed to be on an increasing trend, vegetation management investment has been less than what is required to remove the annual workload volume increment for some years. At this point, the power of compounding is well under way and only a very aggressive increase in funding will arrest the trend. The rate of change in the workload liability in *Exhibit 0-5* is approximately equal to a compounding rate of 27% per year. Warmer climates with a longer growing season support higher rates of change. In other words, for distribution systems, the rate of change in the tree workload is substantially higher than the discount rate one would conceivably use to derive the present value benefit of deferred maintenance spending. Taking a short-term financial perspective, any deferred or diverted vegetation management funding that inhibits removal of the annual workload volume increment is poorly allocated unless it provides a better rate of return. The example provided in *Exhibit 0-5* shows that returning the work volume and reliability to the original levels after 10 years of under-funding by 20%, increases costs by 80% over maintenance, which annually removes the workload volume increment.

Exhibit 0-5
Impact of Under-Funding Vegetation Management Revealed Over Time



Notes: Rate of change in liability based on western Canadian utility with a 4-month growing season.
Interest/Discount rate = 6%

It has been shown that under-funding VM has a substantial impact on future reliability and costs to return to the level of reliability enjoyed before under-funding. The increase in workload due to deferred maintenance is not linear. Hence, the impacts of a dollar deferred this year cannot be erased with an investment of a dollar next year. Further, this section has provided the conceptual context that utilities have lacked, which lack has allowed the inefficient, repetitive cycles of under-funding followed by reactive catch-up periods.

Exhibit 0-5 illustrates that failing to make the necessary investment in vegetation management will, in most circumstances, prove imprudent. While utilities are expected to justify their intended vegetation management expenditures, regulators play a role in the effectiveness of the program. Failure to understand the nature of vegetation management workload expansion or skepticism that leads to decisions limiting the ability to remove the annual workload volume increment, will impose the inefficiencies illustrated in *Exhibit 0-5*. By focusing on cost containment, the regulatory process risks supporting such inefficiency. Utilities that are pressured to minimize costs must prove the harm that will result as a consequence of failure to fund and perform proposed work. This burden of proof proves very challenging for maintenance work, where it becomes necessary to prove that an event that did not occur would have occurred but for specific actions and expenditures. By insisting on demonstrable harm, the regulatory structure supports a reactive approach to maintenance with the attendant cyclical inefficiencies.

Managing the Tree Liability for Positive Returns

Trees need to be recognized as a liability in a utility context. While this puts utilities in conflict with community perceptions of trees as assets, the conflict does not change the fact that trees hold only the capacity to impair the safe, reliable operation of the electric system, not to augment it in any way. Recognizing and quantifying the utility forest as a liability provides a measure of the potential for, or risk of, tree-conductor conflicts. Furthermore, it connects and clarifies the influence of design and operating decisions on maintenance costs and reliability risks.

Managing the tree liability necessitates an understanding of how and where tree risks arise, a quantification of the extent of tree exposure, the rate of change in the tree liability, and a commitment to funding that permits, at a minimum, the removal of the annual workload volume increment.

Appropriate investment in vegetation management is one of the best investments a utility can make. It serves to minimize tree-caused interruptions for the chosen clearance standard, thereby avoiding customer complaints, the need for regulator intervention, and in some cases performance penalties. It avoids the inefficiencies that are inherent in the cycle of allowing trees to become a major problem, getting trees under control by buying down the tree liability, and then losing the investment by failing to contain the tree liability. Investment based on the removal of the annual tree workload increment provides the conceptual approach that is needed to deliver a sustainable, least-cost vegetation management program (*Exhibit 0-4*). Simultaneously, such a program provides the lowest incidence of tree-caused service interruptions for community-accepted clearance standards, thereby benefiting ratepayers and shareholders alike.

THE ECONOMIC IMPACTS OF DEFERRING ELECTRIC UTILITY TREE MAINTENANCE

by D. Mark Browning and Harry V. Wiant

Abstract. A study was conducted to examine the economics of deferring line clearance tree pruning. The cost of pruning a tree was found to increase significantly as it grows closer to, and beyond, the conductors. The amount of biomass, and thus disposal cost, also increases with the length of time a tree is allowed to grow. Predictive models were developed for three utilities to provide a means of projecting the total impact of postponing line clearance work on crew time and costs associated with pruning trees. For every routine maintenance dollar deferred, substantially more than one dollar must be spent in subsequent years to re-establish the preferred cycle. The specific amount of this increase is utility dependent and is affected by production costs, tree growth rates, site characteristics (dbh and type of pruning), etc. An additional adjustment would be necessary to allow for an increase in disposal costs resulting from a larger amount of biomass removed. If funding reductions are not offset with larger expenditures in subsequent years, tree maintenance cycles are rapidly extended. Modeling a 20 percent annual funding decrease resulted in extending one utility's cycle from 5 years to 9 years over a 12-year period. These estimates do not take into account the impact that deferred line clearance work has on service reliability, service restoration costs, and the amount of time spent on hotspotting and responding to customer requests for unscheduled maintenance.

Electric utility line clearance programs typically approach tree management through a program of maintenance cycles where trees are pruned at regularly scheduled intervals. Unfortunately, many utilities fund their programs in such a way that trees are not pruned in time and they begin to overgrow the conductors.

The impact of deferring utility tree maintenance is generally evaluated in terms of service reliability. Anecdotal evidence suggests that deferred tree maintenance also impacts a utility's maintenance costs. One implication is that the cost to prune trees on a more frequent basis (i.e., when implementing a shorter pruning cycle) may be offset by reduced per-tree costs. Another implication is that when utilities reduce line clearance funding, there is a disproportionate impact on the cycle. Understanding these relationships would enable utility arborists to better identify and justify the optimum line clearance cycle in their service area.

The International Society of Arboriculture Research Trust provided funding in an effort to better understand the economic impacts of the widespread practice of deferring utility tree maintenance. The study was conducted on three utility properties in the United States by Environmental Consultants, Inc. (ECI). The three utilities that participated in the study are Northern States Power Company (MN), Puget Sound Power & Light Company, and West Penn Power Company.

Study Methodology

Each utility was responsible for selecting 5 areas or circuits last pruned during the dormant season 2, 3, 4, 5, and 6 years prior to the study. The sites were similar in terms of the following criteria:

- Accessibility to a lift truck
- Tree density
- General age of the tree population
- Type of pruning required (e.g., percent top trims)
- Species composition
- Voltage, number of phases, and construction type.

Each site contained between 50 and 80 trees. All of the sites were located in urban/suburban areas on 3-phase circuits accessible to a lift truck. Over 1,000 trees were included in the study.

The utilities began pruning the study trees in the spring of 1996. Pruning was performed in a manner consistent with the utilities' normal line clearance operations. The following data was collected by the crews completing the work:

- Time (years) since last pruned
- Type of work completed
- Tree diameter class
- Time and equipment to complete the work
- Clearance prior to pruning
- Clearance obtained
- Weight of chipped debris.

Study Results

The data collected by the crews were analyzed to determine how deferring line clearance work impacts the cost of tree pruning. The amount of tree-to-conductor clearance prior to pruning, the average branch length removed, diameter at breast height (dbh), and work type (top or side trim) were included in the analysis. The weight of each load of chipped debris was also determined and tracked by study site.

Factors Affecting Maintenance Cost

Years since last pruned. The utilities selected five study areas based on the number of years since the trees at the site were last pruned. Figure 1 illustrates the relationship between the average time required to prune trees for line clearance and the reported number of years since they were last pruned by one of the utilities. A highly significant, positive curvilinear relationship was found to exist between the number of years a tree is allowed to grow and the amount of time required to prune it. As the period of growth is lengthened, the amount of time required for maintenance increases.

Pre-work clearance. Figures 2, 3, and 4 show the average labor time (worker-minutes) required to prune a tree based on the proximity of the trees to the conductors. As shown, an inverse relationship exists between proximity of the branches to the conductors and the average time required to complete line clearance work. As the amount of pre-trim clearance decreases, the average labor time required for tree pruning increases.

The correlation coefficients (r) between pre-work clearance and the time to prune the trees are -0.30 for utility A, -0.51 for utility B, and -0.55 for utility C. In all cases, the relationship is highly significant at the 0.01 level.

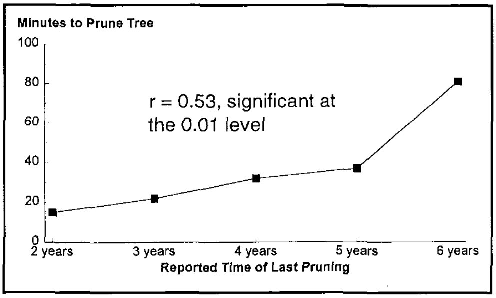


Figure 1. Average worker-minutes to prune trees by the number of years since they were last pruned.

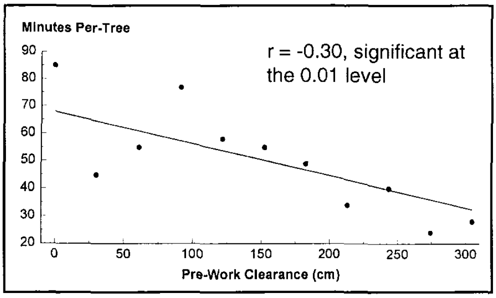


Figure 2. Relatinship between proximity to the conductors and time (worker-minutes) to prune trees at utility A.

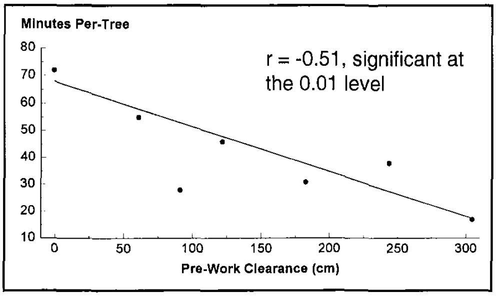


Figure 3. Relationship between proximity to the conductors and time (worker-minutes) to prune trees at utility B.

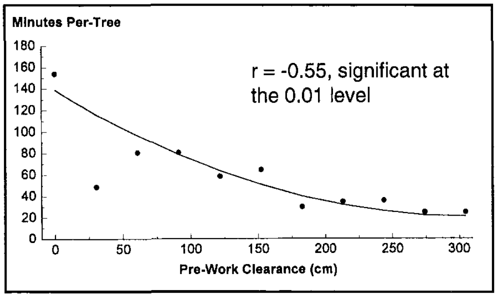


Figure 4. Relationship beetween proximity to the conductors and time (worker-minutes) to prune trees at utility C.

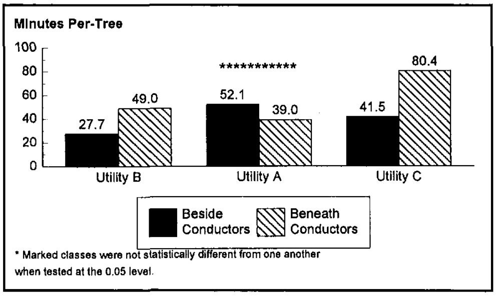


Figure 5. Average time (worker-minutes) to prune trees based on their location.

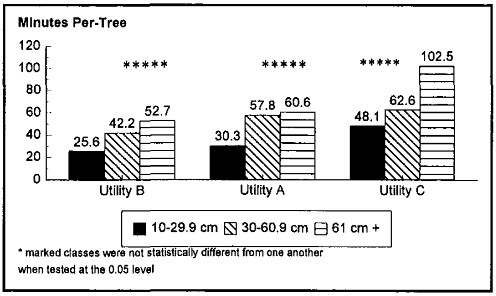


Figure 6. Average per-tree pruning time (worker-minutes) by diameter class.

Branch length. The average branch length removed from a tree is also correlated to the time and cost of line clearance tree pruning. The data from all three utilities showed a strong positive correlation between the average branch length removed and the time required to prune the tree. The correlation coefficients (r) were 0.57 for utility A, 0.47 for utility B, and 0.44 for utility C. All correlations were significant at the .01 level.

Type of pruning. Electric utilities frequently categorize line clearance tree pruning by tree location. Trees located beneath the conductors are typically referred to as requiring "top" pruning while those beside the conductor require "side" pruning. Figure 5 shows the relationship between tree location and the average time needed to complete the work. The time required to prune a tree located beneath the conductors is significantly greater than the time needed for trees beside the conductors at utilities B and C, 1.77 and 1.94 times greater respectively. At utility A, trees beside the conductors took longer, on average, than those beneath the conductor. The difference, however, was not statistically significant at the 0.05 level.

Tree diameter. Three size categories were used to classify the study trees based on their diameter at breast height. The three diameter classes were 10 to 29.9 cm (4 to 11.9 in), 30 to 60.9 cm (12 to 24.3 in), and 61 cm (24.4 in) and larger. The amount of time required to prune trees varied significantly by diameter class at all three utilities (Figure 6).

Impact of Deferred Maintenance on Cost

Pruning costs. Regression analysis was used to develop predictive models for worker-minutes (Y) of pruning time for the participating utilities. Variables (X1, X2 , ..., Xn) and interactions of variables were screened using stepwise regression techniques to determine which significantly contributed to the model. Each variable, each significant interaction, and each variable in the significant interactions were used to develop the final regression models. Regression coefficients and the model correlations are provided in Table 1. The form of the model is as follows:

$$Y = B0 + B1X1 + ... + BnXn$$

These models can be used to project the economic impact of allowing trees to grow longer than the optimum cycle. Since tree diameter, type of pruning, and clearance are each significant factors, it is clear that the impact will vary for different sites. Any specific set of site conditions can be modeled using the data presented in Table 1.

One of the study sites which met this criteria was chosen as a model site. This provided a specific set of conditions for comparing the cost of pruning at different points in time. The results are presented in Table 2, which shows the projected impact of deferring maintenance at each of the utilities.

Table 3 shows the relative impact of deferring maintenance in terms of dollars at each of the utilities. As an example, if utility B's tree population, growth rates and clearance standards indicate that the optimum cycle length is 5 years, deferring pruning past 5 years will have a substantial impact on line clearance costs. Each dollar "saved" by not pruning trees at the appropriate time (year 5) will have to be replaced with $1.21 (plus inflation adjustment) one-year later in order to get back on schedule. If trees are allowed to grow past the conductors for 2 years, it will cost $1.39 for every $1 of pruning which was deferred.

Table 1. Regression coefficients for models to predict average time to prune trees based on significant variables and interactions.

Variable Number	Variable/Interaction	Regression Coefficients (B_n) Utility A	Utility B	Utility C
	Intercept	156.105	95.739	135.044
X_1	Pre-work Clearance	-11.399	-7.928	-14.078
X_2	(Pre-work Clearance)^2	-0.160		0.262
X_3	Length Removed	4.275	-2.431	
X_4	(Length Removed)^2	0.059	-0.052	-0.113
	Tree Diameter*			
X_5	1 if Small, else 0	-84.144	4.234	-68.852
X_6	1 if Medium, else 0	-4.819	5.064	-40.995
	Pruning Type*			
X_7	1 if Side, else 0	-22.220	2.021	2.166
	Interactions			
X_8	$X_1 * X_5$	7.056		8.910
X_9	$X_1 * X_6$			3.803
X_{10}	$X_2 * X_5$			-0.263
X_{11}	$X_2 * X_6$			0.039
X_{12}	$X_2 * X_7$	0.290		
X_{13}	$X_3 * X_5$	-3.628	5.852	
X_{14}	$X_3 * X_6$		3.804	
X_{15}	$X_4 * X_5$	-0.172		
X_{16}	$X_4 * X_6$	-0.222		
X_{17}	$X_4 * X_7$		-0.222	-0.213
Model Degrees of Freedom		12	9	11
Error Degrees of Freedom		327	330	328
Correlation Coefficient		0.63	0.63	0.64

*Categorical data was coded as either a 1 or a zero

Table 2. The impact of deferred maintenance on the average time to prune trees for line clearance as projected by the regression equation.

Utility	Length of Optimum Line Clearance Cycle	Average Time (Worker Minutes) To Prune Trees At A Site That Is: At The Conductor*	1-Yr. Past Optimum	2 Yrs. Past Optimum	3 Yrs. Past Optimum	4 Yrs. Past Optimum
A	5 Years	68.9	84.9	98.7	109.6	116.2
B	5 Years	56.9	68.8	79.2	87.1	93.2
C	6 Years	43.4	50.5	56.3	60.8	64.0

* Optimum time is based on the industry standard of 10-15% maximum tree-to-conductor contact, referenced in this table as "At The Conductor".

Biomass. Chipped debris obtained by tree pruning was collected by utility B to gain insight into the relationship between the age of branch regrowth and the amount of biomass removed from a tree. The weight of chipped debris was not obtained for individual trees. Rather, the total weight of chipped biomass was determined for each site and an average per-tree weight of biomass was calculated. As shown in Table 4, the average weight of chipped biomass rises significantly with time. The average weight of chipped debris increased from about 7.5 kilograms per-tree for the 2-year old site to over 129

Table 3. Projected impact of deferred maintenance on the average cost of pruning trees for line clearance.

			Relative Cost* To Prune Trees At A Site That Is:			
Utility	Length of Optimum Line Clearance Cycle	At The Conductor**	1-Yr. Past Optimum	2 Yrs. Past Optimum	3 Yrs. Past Optimum	4 Yrs. Past Optimum
A	5 Years	$1	$1.23	$1.43	$1.59	$1.69
B	5 Years	$1	$1.21	$1.39	$1.53	$1.64
C	6 Years	$1	$1.16	$1.30	$1.40	$1.47

* Excludes an adjustment for inflation.
** Optimum time is based on the industry standard of 10-15% maximum tree-to-conductor contact, referenced in this table as "At The Conductor".

Table 4. Weight of biomass removed by the number of years since last pruned for trees at Utility B.

Last Pruned	Number of Trees	Total Weight (kg)	Weight Per-Tree (kg)
2 yrs.	63	463	7.4
3 yrs.	73	1,488	20.4
4 yrs.	76	3,892	51.2
5 yrs.	80	4,944	61.8
6 yrs.	65	8,410	129.4

kilograms per-tree for the 6-year old site. Figure 7 illustrates the close relationship found between the average weight of the biomass removed and the average time required to prune a tree.

Discussion

The time and cost associated with pruning a tree to maintain safe and reliable clearance from the electric system increases as it grows toward and beyond the conductors. Every dollar of spending deferred until a later date must be replaced with more than one dollar in order to restore the program to the original cyclical maintenance schedule. How much more depends on the characteristics of the tree (dbh and type of pruning), the specified clearance standards, tree growth rates, and the number of years that pruning is deferred. For Utility B, each dollar withheld from the pruning budget would need to be replaced with $1.21 (plus inflation) the following year in order to get back on schedule. A 2-year delay in pruning would increase this to $1.39. Similar results were obtained from the models developed for utilities A and C.

Postponing maintenance beyond the optimum time also results in increased disposal costs. Data from Utility B showed that the site pruned on cycle (i.e., after 5 years) produced an average of about 62 kilograms of pruning debris per tree. The site which had been allowed to grow 1-year longer produced approximately twice the amount of debris.

Many utilities that reduce their line clearance budget do not replace the funds in subsequent years. Therefore, it is important to know the long-term impact of funding reductions. This can be also assessed using the models presented in Table 1.

For example, assume that Utility B, which has an optimum 5-year cycle, undergoes a 20 percent reduction in its annual budget for tree pruning. Initially, it would appear that the cycle length would merely increase by 20 percent, from 5 years to 6.25 years. The impact, however, would actually be much larger. One year of reduced funding would allow 4 percent of the trees to grow beyond the optimum scheduled maintenance time (5 years). After 4 years of a reduced budget, over 21 percent of the trees will have grown for more than the optimum 5 years.

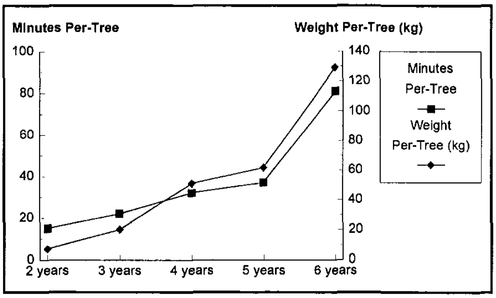


Figure 7. Comparison of time (work-minutes) to prune a tree and the biomass removed by the number of years since trees were last pruned at Utility B.

Some trees will have 7 years of regrowth. After 12 years, nearly one-half of all the trees on the system will have gone more than 5 years without receiving maintenance, and some will not have been pruned in 9 years.

This example, which is illustrated in Figure 8, shows how a 20 percent reduction in funding would result in an 80 percent change in cycle, moving the utility from a 5-year cycle to a 9-year cycle (i.e., 4 years over cycle) in just 12 years. It is important to note that this change is likely to be accelerated as service reliability declines and hotspotting and responding to customer requests becomes more common, further reducing the funds available for scheduled, cyclical maintenance.

A decline in service reliability also results in lost revenue while service is down, and an increase in the amount of time spent on service restoration. Although service restoration is not a vegetation management cost, it can still be directly related to vegetation conditions and should therefore be considered when making decisions on deferring the maintenance of scheduling units.

Deferred maintenance can also alter the vegetation conditions of scheduling units beyond increasing the amount of regrowth on the trees. Longer intervals of maintenance can allow hazardous trees and limbs to develop, further jeopardizing system reliability. In addition, deferring the maintenance of brush allows it to mature and become a more expensive and often permanent part of the workload.

In terms of service reliability and safety, it is imperative to maintain vegetation on a schedule that minimizes the number of trees that have the potential to contact the conductors. Deferring maintenance allows trees to grow into and beyond the conductors, which decreases the reliability of the system and significantly affects future maintenance costs.

Acknowledgments. Thank you to the ISA Research Trust for supporting electric utility vegetation management research projects, and to Northern States Power Company (MN), Puget Sound Power and Light Company, and West Penn Power Company for their support, involvement, and contributions throughout this project.

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(See next page for French and German Abstracts)

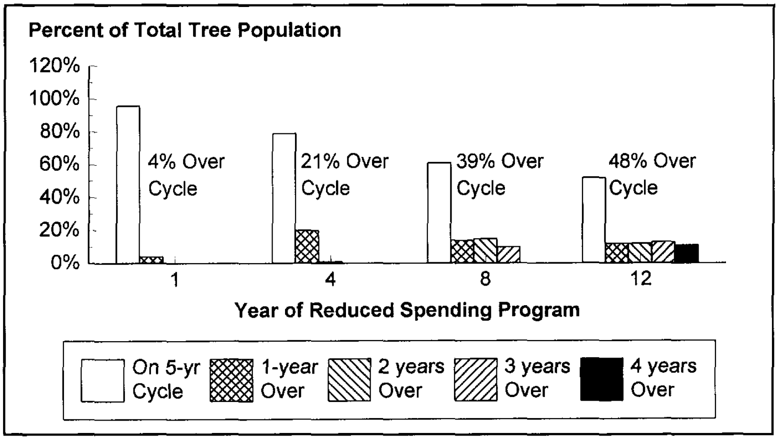


Figure 8. Projected impact on a 5-year cycle of a 20 percent annual funding reduction.

Résumé. Le coût d'élagage de dégagement d'un arbre s'accroît significativement lorsque l'arbre pousse de plus en plus près et au-dessus des fils électriques. Le volume de biomasse, et par conséquent les coûts de disposition, augmentent eux aussi avec la période de temps où il est permis à l'arbre de croître. Des modèles de prédiction ont été développés pour projeter les coûts associés à un report du dégagement des fils électriques. Pour chaque dollar de dépense dans l'entretien cyclique qui est reporté, c'est substantiellement plus d'un dollar qui doit être dépensé au cours des années suivantes pour réétablir le cycle préférentiel de dégagement.

Zussammenfassung. Die Kosten für das Freischneiden von Bäumen steigen deutlich an, wenn die Bäume dicher heran und über die Leitungen hinaus wachsen. Die Menge an Biomasse und die Entsorgungskosten steigen ebenfalls mit der Zeit, in der die Bäume ungestört wachsen können. Es wurden aussagekräftige Modelle entwickelt, um die Kosten für die verzögerten Maßnahmen zum freischneiden der Leitungen zu demonstrieren. Für jeden zurückbehaltenen Dollar für die Routinepflege muß demzufolge mehr als ein Dollar in den Folgejahren aufgegeben werden, um den gewünschten Kreislauf wiederherzustellen.

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Utilities Service

RUS BULLETIN 1730B-121
RD-GD-2013-71

SUBJECT: **Wood Pole Inspection and Maintenance**

TO: All Electric Borrowers

EFFECTIVE DATE: Date of Approval.

OFFICE OF PRIMARY INTEREST: Transmission Branch, Electric Staff Division.

FILING INSTRUCTIONS: This bulletin replaces RUS Bulletin 1730B-121, "Pole Inspection and Maintenance," issued April 15, 1996.

PURPOSE: To furnish information and guidance in establishing a continuing program of pole maintenance.

Nivin Elgohary
Assistant Administrator
Electric Program

August 13, 2013_
Date

TABLE OF CONTENTS

ABBREVIATIONS

ACA - Ammoniacal copper arsenate
ACZA - Ammoniacal copper zinc arsenate
ANSI - American National Standards Institute
AWPA - American Wood Protection Association
CCA - Chromated copper arsenate
EPA - Environmental Protection Agency
NaMDC - N-methyldithiocarbamate
NESC - National Electrical Safety Code
MITC - Methylisothiocyanate
pcf - pounds per cubic foot
RUS - Rural Utilities Service

1 PURPOSE

To furnish information and guidance to electric cooperatives in establishing a continuing program of pole maintenance and to operating personnel in performing inspection and maintenance of standing poles. Included in this bulletin are methods and procedures for determining the minimum permissible groundline circumferences of distribution and transmission poles.

2 GENERAL DISCUSSION OF POLE DECAY

Pole Decay. Decay of treated poles is usually a gradual deterioration caused by fungi and other low forms of plant life. Damage by insect attack (termites, ants and wood borers) is usually considered jointly with decay because preservative treatment of wood protects against both fungi and insects. In most cases, the decay of creosote and penta-treated poles will be just below the groundline where the conditions of moisture, temperature and air are most favorable for growth of the fungi. Factors affecting pole life, such as species of wood, type and thoroughness of treatment, geographical location, and soil conditions are discussed below.

a Pole Species. Of the millions of poles on RUS financed systems, about 85 percent are the thick sapwood southern pines. Untreated, the sapwood is especially vulnerable to attack by wood destroying fungi, termites, and carpenter ants. In the Gulf States, where temperature and moisture are most favorable for growth of these major wood-destroying organisms, the time to pole failure of an untreated pole would be 2 to 3 years. In areas of lower rainfall and few frost-free days, the time to pole failure would increase to 5 to 10 years.

The bulk of the remaining pole population is classified as the western species, comprised of Douglas-fir, western red cedar, red pine, lodgepole pine, ponderosa pine and a small amount of jack pine.

Adequate preservative treatment protects the pole sapwood and the underlying heartwood. Heartwood of these pole species varies not only in decay resistance, but is difficult to treat with preservatives. The heartwood decay resistance for the major pole species is as follows:

Durable - Western red cedar heartwood.

Moderately Durable - Douglas-fir and most of the pines.

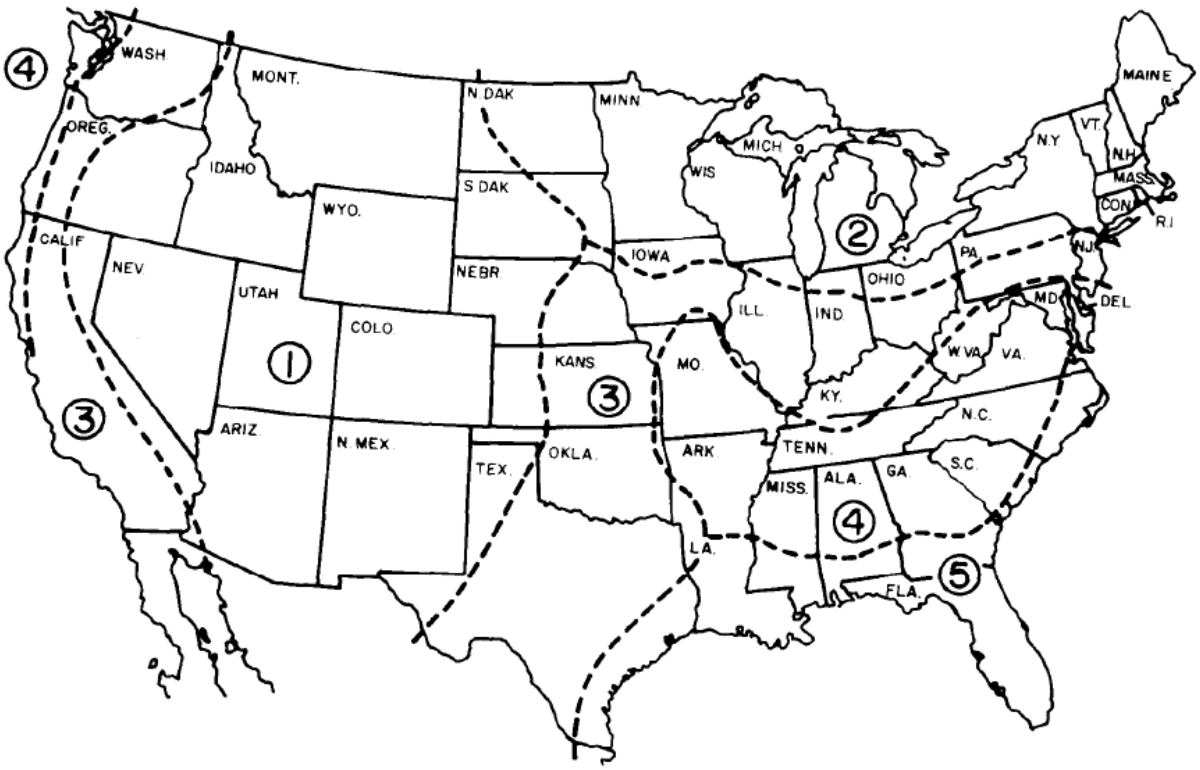
Least Durable - Lodgepole pine. (The use of this species has been limited primarily to the Mountain States areas.)

b Preservative Treatments. There are two general classes of preservative treatment, oilborne (creosote, penta in petroleum, and Copper Naphthenate) and waterborne (arsenates of copper). Creosote was the only preservative for poles on rural systems until 1947, when post-war shortages prompted the introduction of pentachlorophenol (penta) and Copper Naphthenate. Both of these preservatives were dissolved in fuel oils from petroleum or mixtures with creosote.

For many years, penta has been the most widely used preservative for poles. With the increase in cost of petroleum-based products, penta-in-oil treated pole costs have also increased. Presently, both penta and waterborne preservatives are widely used with both preservatives having performed satisfactorily. Where problems have occurred with penta treated poles, the decay can be tied to poor conditioning of the poles, to the loss of solvent carrier due to migration and bleeding or to loss of dissolved penta to retentions below the effective preservative threshold. To overcome these losses, treatments and quality control have been improved.

Standard wood preservatives used in waterborne solutions include ammoniacal copper zinc arsenate (ACZA), and chromated copper arsenate (CCA) (types A, B, and C). These preservatives are often employed when cleanliness and paintability of the treated wood are required. Several formulations involving combinations of copper, chromium, and arsenic have shown high resistance to leaching and very good performance in service. Both ACZA and CCA are included in many product specifications for materials such as building foundations, building poles, utility poles, marine piles, and piles for land and fresh water use. Treatment usually takes place at ambient temperature. Care needs to be taken during treatment to ensure heat sterilization of the pole when treating Douglas-fir with ACZA.

c Decay Zones. The following Decay Severity Zones on a map of the United States was originally based on summer humidity and temperature information and later on a pole performance study conducted by RUS. Decay severity ranges from least severe in Zone 1 to most severe in Zone 5. Service life records and individual experience or a planned sample inspection will indicate if the decay hazard for a system is typical of the zone in which the system is located.



Decay severity zones for wood utility poles as defined by the USDA Rural Utilities Service. Decay is least severe in zone 1, most severe in zone 5.

d <u>Types of Decay</u>. Internal decay may be found in southern pine poles that were not properly conditioned or in which penetration or the amount (retention) of preservative is inadequate. Internal decay of the western species usually involves the heartwood in butt-treated western red cedar, lodgepole pine, and Douglas-fir which have been improperly seasoned prior to treatment. After installation, decay organisms invade the heartwood through the poorly treated sapwood zone checks, or woodpecker holes. Internal decay may also occur in field framed poles when supplementary treatment is neglected.

Insufficient treatment or migration of oil-type preservatives is the principal cause of external decay in southern pine poles. This decay is generally the result of improper seasoning or treatment. Inspection methods should be directed toward discovery of this type of defect and maintenance efforts to supplement the treatment with additional chemicals.

External decay above ground, or better known as "shellrot", may occur in butt-treated western red cedars after 12-15 years of service.

3 PLANNED INSPECTION AND MAINTENANCE PROGRAM

Purpose. The purpose of a planned inspection program is to reveal danger poles and poles which are in early stages of decay so that corrective action can be taken to prolong the service life of the pole. The end result of the inspection program is the establishment of a continuing maintenance program for extending the average service life of all poles on the system. The steps in developing a planned pole inspection and maintenance program are outlined below.

a Spot Checking. Spot checking is the initial step in developing a planned pole inspection and maintenance program. Spot checking is a method of sampling representative groups of poles on a system to determine the extent of pole decay and to establish the priority for a pole maintenance program. A general recommendation is to inspect a 1,000 pole sample made up of continuous pole line groupings of 50 or 100 poles in several areas of the system. The sample should be representative of the poles in place. For instance, all the poles on a line or a map section should be inspected as a unit and not just the poles of a certain age group. The inspection of the sample should be complete, consisting of hammer sounding, boring, and excavation as described in Section 4. Field data should be collected on the sample as to age, supplier, extent of decay, etc.

After the data has been collected, it should be analyzed to determine the areas having the most severe decay conditions and to establish priorities of a pole-by-pole inspection of the entire system. It may be desirable to take additional samples on other portions or areas of the system to determine if the severity of decay is significantly different to warrant the establishment of an accelerated pole inspection and maintenance program for that portion of the system. The results of the spot check will aid in scheduling a continuous pole inspection and maintenance program at a rate commensurate with the incidence of decay.

b Scheduling the Inspection and Maintenance Program. The results of the spot check will aid in determining when the planned program should be started. The suggested timing for initial pole-by-pole inspection and subsequent re-inspection, when supplementary treatment is applied after each inspection, is as follows:

Decay Zone	Initial Inspection	Subsequent Re-inspection	Percent of Total Poles Inspected Each Year
1	12 – 15 Years	12 Years	8.3
2 and 3	10 – 12 Years	10 Years	10
4 and 5	8 - 10 Years	8 Years	12.5

The vulnerability of poles to decay is generally proportionate to the decay zone in which they are located. As a general recommendation, the initial pole-by-pole inspection program should be inaugurated at a yearly rate of 10 percent of the poles on the entire system when the average age of the poles reaches 10 years. If a spot check indicates that decay is advanced in 1 percent of the pole sample, the inspection and maintenance program should be accelerated so that a higher percentage of poles are inspected and treated sooner than the figures shown above. If the decay rate is low for a particular decay zone or area of the system, the pole-by-pole inspection can be postponed accordingly. Historical inspection data indicates that the ratio between the decaying/serviceable poles to reject poles in the 10-15 year age group is about six or more to one. In a 30-year age group, it is about one to one or less. In the latter group, the survivors have more than sufficient residual preservative to protect them indefinitely. The poorly treated poles in the 30-year old group have already decayed and been replaced.

The greatest economic benefit from regular inspection is in locating the decaying/serviceable group. Treatment of poles in this group can extend pole life, thereby saving the cost of emergency replacement. Inspection and proper maintenance can more than pay dividends by extending the serviceable life of the poles. With the costs of replacing poles rising, the economics of extending the service life are more favorable.

c Establishing the Program. The pole-by-pole inspection and maintenance work may be done by system employees or by contracting with an organization specializing in this type of work. The choice should be made on the basis of the amount of work to be done, the trained employees available, and a comparison of the costs. Developing the necessary skills in the system's own crews may require considerable time and be contingent upon the availability of an experienced inspector to train system employees. Therefore, qualified contract crews may be preferable for this work in many instances. An inspector to be qualified should have inspected, as a minimum, 5,000 poles in conjunction with a qualified inspector and another 5,000 on his own, but under close supervision. The inspector's work should be checked every week or two by the system's representative and the inspector's supervisor. To check an inspector’s work select at random about 10 poles, inspected in the previous few weeks, re-excavate, take off paper and treatment, and re-inspect. Check for hollow sounds, take a boring, check soft surface wood, especially adjacent to shaved areas or along checks, re-measure the pole, recheck the calculations, then retreat and backfill. If any serious errors are discovered, all the work between these spot checks should be re-inspected.

The pole inspection and maintenance program may result in a large number of replacements. If the reject rate is high, the system's crews may not be able to replace rejected poles in a reasonable time because of other work. The temporary addition of skilled personnel for inspection or pole replacement may be required. It is generally necessary to use at least one crew full time to keep up with the pole inspector. An average pole inspector can check 150-200 poles per week or 800 poles per month. It is desirable to have one person responsible for supervision and coordination.

d Re-inspections. Information obtained during the first pole-by-pole inspection can serve as the basis for scheduling subsequent inspections. As a guide, it is recommended that a re-inspection be made every 8 to 12 years as shown in paragraph 3c of this Section, according to the decay zone and severity of decay. The recommended re-inspection intervals are based on treating poles during the previous inspection cycle. Shorter re-inspection intervals are recommended if poles were not treated. These recommendations may be modified by experience, but the intervals should not be extended by more than 3 years. It is advisable to recheck some poles which have been groundline treated. At the completion of the inspection of a pole, a small, weatherproof tag should be attached to the pole indicating the organization that performed the inspection and the date of the inspection.

4 INSPECTION METHODS

Inspection Types. There are varying types of inspection, each with a different level of accuracy and cost. Inspection methods with low accuracy require more frequent re-inspection than methods which are detailed and more accurate.

a Visual Inspection. Visual inspection should be considered the first step to inspecting poles but has the lowest accuracy. Since most decay is underground or internal, this method will not detect the majority of defective poles. Obvious data can be collected on each specific structure, such as the condition of the pole above ground, crossarm, and hardware. This method is not recommended for detecting decay.

b Sound and Bore. This method involves striking a pole with a hammer from groundline to as high as the inspector can reach and detecting voids by the hollow sound. An experienced inspector can obtain significant information about a pole by listening to the sounds and noticing the feel of the hammer. The hammer rebounds more from a solid pole than when hitting a section that has an internal decay pocket. The internal pocket also causes a sound that is dull compared to the crisp sound of a solid pole section.

Some contracts require all poles to be bored, while others require boring only when decay is suspected. Boring is usually done with either an incremental borer or power drill with a 3/8" bit. An experienced inspector will notice a change in resistance against the drill when it contacts decayed wood. The shavings or the borings can be examined to determine the condition of the wood, and the borings can be analyzed for preservative penetration and retention.

When voids are discovered a shell thickness indicator can be used to measure them. This information can be used to evaluate the reduction strength by the void.

The effectiveness of the sound and bore method varies by species. For southern yellow pine poles, which represent a majority of the poles in North America, decay normally is established first on the outside shell below ground. The decay moves inward and then upward to sections above ground. By the time sound and bore inspection can detect internal decay pockets above ground, the pole is likely to have extensive deterioration below ground.

Sound and bore method is more effective with Douglas-fir and western red cedar. Decay on these poles is likely to begin internally near the groundline, or in the case of Douglas-fir, above the groundline. Therefore, sounding and boring can identify at least some decay at a stage before the groundline section is severely damaged. All borings should be plugged with a treated wood plug which is properly sized for the respective hole.

c Excavation. The effectiveness of the sound and bore inspection is greatly increased when excavation is added to the process. Excavation exposes the most susceptible section of the pole for inspection. For southern yellow pine this is particularly true, since decay begins externally and below ground.

Poles should be excavated to a depth of 18 inches in most locations. Deep excavation may be required in dry climates. After excavation the exposed pole surface should be scraped clean to detect early surface decay.

Shell rot and external decay pockets should be removed from the pole using a specially designed chipper. Axes or hatchets should not be used for this application. The remaining pole should be measured to determine if the pole has sufficient strength with the reduced circumference. Tables 2, 3, and 4 assist in adjusting circumferences for various size voids.

After complete inspection and application of preservative treatment, the pole is backfilled. The dirt should be tamped firm every 6 to 8 inches. The backfill should mound up around the pole to allow for future settling and drainage away from the pole.

5 ADDITIONAL INSPECTION TOOLS AND METHODS

Additional Methods. Over the past several years there has been a considerable amount of research work done by companies to develop additional products that can be incorporated into the in-line pole inspection process. These products, involving many diverse technologies, are intended to improve both the accuracy and reliability of the in-line inspection programs used by utilities, as well as decrease the time necessary to carry out the inspection process. In developing comprehensive inspection programs, cooperatives are encouraged to examine all potential inspection tools and processes to determine the best system for their particular needs. The data from these testing devices does not always correlate exactly with the actual bending strength determined by full scale testing and, as a result, should be used to establish trends showing changes in strength.

6 RESULTS OF WOOD POLE INSPECTION

a Inspection Results. Inspection results should be used to update pole plant records, evaluate pole condition, plan future inspection and maintenance programs, and provide information for map revisions. The inspection process will result in identifying the condition of each individual distribution or transmission pole.

In general the National Electric Safety Code (NESC) requires that if structure strength deteriorates to the level of the strength reduction factor required at replacement, the structure shall be replaced or rehabilitated. The inspection results should indicate if a pole is "serviceable" or a "reject".

b Serviceable. The characteristics of "serviceable" are based on the following conditions:

(1) Large portion of completely sound wood.

(2) Early stages of decay which have not reduced the pole strength below code requirements.

(3) Pole condition as stated above but a defect in equipment may exist, such as a broken ground or loose guy wire. Equipment defects should be subsequently repaired.

c Rejects. Any poles that do not meet the above conditions should be classified as "rejects". Their characteristics are:

(1) Decay, insect or mechanical damage has reduced pole strength at the groundline below code requirement.

(2) Severe woodpecker hole damage has weakened the pole below safety standards.

(3) Hazardous conditions exist above ground, such as split top.

d Reinforce or Replace. Rejected poles may be classified further depending on the severity of the deterioration and whether they are reinforceable.

(1) A “reinforceable reject” is any reject which is suitable for restoration of the groundline bending capacity with a method of reinforcement.

(2) A “replacement” candidate would be a rejected pole which is not suitable for the necessary rehabilitation.

7 REMEDIAL TREATMENT

Purpose. The purpose of remedial treatment of standing poles is to interrupt the degradation by the addition of chemicals, such as pesticides, insecticides and fungicides, thereby extending the useful life of the structure. Treatment may be external groundline treatment or internal treatment.

a Regulations and Licensing. The majority of states require that applicators or the job supervisor obtain a pesticide applicator license. Testing for this license includes a "basic skills test" to show knowledge of the rules and regulations governing pesticides. Some states also give a "category test" which is specific to wood poles and wood preservation. The uses of every pesticide are classified by the U.S. Environmental Protection Agency (EPA) as either "general" or "restricted".

(1) A "general use" pesticide is not likely to harm humans or the environment when used as directed on the label. These preservatives may be purchased and applied without a pesticide applicator license. However, a manufacturer may choose not to make a product available for purchase by the general public.

(2) A "restricted use" pesticide could cause human injury or environmental damage unless it is applied by competent personnel (certified applicators) who have shown their ability to use these pesticides safely and effectively. These wood preservatives can only be purchased and applied by someone who has a pesticide applicator license or whose immediate supervisor has a pesticide applicator license.

b Groundline Treatment. All treated poles eventually lose resistance to decay. Groundline treatment with effective preservatives provides an economical extension of their physical life. Experience has shown that a well designed and implemented groundline inspection and maintenance program can significantly increase the service life of many poles. Groundline external treatment is recommended under the following conditions:

(1) Whenever a pole is excavated during an inspection, and the pole is sound or decay is not so far advanced that the pole must be replaced or rehabilitated.

(2) Whenever a pole over 5 years old is set.

(3) Whenever a used pole is installed as a replacement.

External preservatives used for groundline treatment typically contain active ingredients that are either water soluble, oil soluble or practically insoluble.

Before application of external preservatives, decayed wood should be stripped from the pole and removed from the excavation. The preservative paste is most commonly brushed onto the pole following label directions. A polyethylene backed paper is then wrapped around the treatment and stapled to the pole. The paper aids the migration of the preservative into the critical outer shell.

c Internal Treatment. The three basic types of preservatives used for internal treatment are liquids, fumigants, and solids.

(1) Liquid Internal Preservative: Liquid internal preservatives should be applied by pressurized injection through a series of borings that lead to internal decay pockets or voids. Adequately saturating the pocket and surrounding wood should arrest existing decay or insect attack and prevent further degradation for an extended time.

Liquid internal preservatives contain water soluble or oil soluble active ingredients. Sodium fluoride, boron and various forms of copper solutions are the principle active ingredients used today. Moisture that is present in the pole will help facilitate diffusion of the active ingredients into the wood beyond a decay pocket.

Oil based internal preservatives most often incorporate Copper Naphthenate as an active ingredient with fuel oil or mineral spirits as the solvents. Since oil-based Copper Naphthenate is not soluble in water, it is likely to migrate into the surrounding wood only as far as the oil will travel.

(2) Fumigants: Most of the fumigants in use for wood poles today were originally developed for agricultural purposes. Applying fumigants to soil will effectively sterilize the ground. Due to high levels of microorganisms and chemical activity in soil, the fumigants will degrade fairly rapidly and dissipate so that new crops can be planted in a short time.

These same fumigants do not degrade rapidly in wood and will remain affixed to sound wood cell structure for many years. Fumigants have also been found to migrate longitudinally in wood, several feet away from the point of application. This helps control decay in a large section of the pole. When the vapors migrate into a decay void, however, they may dissipate through associated checks and cracks. This reduces the long term efficacy and requires more frequent application.

Registered pole fumigants include Sodium N-methyldithiocarbamate (NaMDC), Methylisothiocyanate (MITC),tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (Dazomet) and Chloropicrin. Chloropicrin is a very effective wood fumigant. However, the liquid must be applied from pressurized cylinders, and the applicator must wear a full-face air respirator.

MITC, NaMDC and Dazomet are the most widely used wood pole fumigants. Pure MITC is a solid below 94°F and contains 97 percent active ingredient. Solid MITC sublimes directly into fumigant vapors. Avoiding the liquid stage helps to minimize loss of fumigant during application through checks and cracks. MITC is packaged in aluminum tubes to facilitate installation. Just before placing the tube into a treatment hole, the cap is removed. As with any fumigant, application holes should be plugged with pressure treated wooden or plastic plugs.

NaMDC is soluble in water to a maximum amount of 32.7 percent. Treatment holes drilled in a wood pole are filled with the aqueous solution so the appropriate dosage is applied. Recommended dosages vary according to pole size. The NaMDC solution decomposes and generates MITC as the main fungi-toxic ingredient. The maximum theoretical amount of resultant MITC at ideal conditions is 18.5 percent by weight. After decomposition the MITC vapors then migrate up and down the pole to help control decay.

Dazomet is a very fine granular material that is 98-99% active ingredient. Treatment holes drilled in a wood pole are filled with the granular material so the appropriate dosage is applied. Like NaMDC, Dazomet decomposes and generates MITC as the main fungi-toxic ingredient. The maximum theoretical amount of resultant MITC at ideal conditions is 45.0 percent by weight. The MITC vapors then migrate up and down the pole to help control decay.

(3) Solids: Currently there are several solid diffusible rods available as a supplemental preservative treatment for wood poles. Active ingredients used in these rods include Sodium Fluoride, Boron and Copper. The migration of these ingredients through the wood to control or prevent internal fungal decay is aided by the moisture content present. The zone of effective treatment is determined by the distance the active ingredients move from the point of application at fungi-toxic levels. Studies have shown wood moisture content in excess of the fiber saturation point (approximately 30%) are necessary for significant migration to occur. However, at wood moisture levels typically found at groundline in the internal regions of in-service utility poles, adequate diffusion can be achieved with an appropriate drill pattern in the treatment zone. Active ingredients from rods will tend to move slower than fumigants. Preservative rods should be applied according to the label directions. The rods are typically applied through a pattern of downward angled holes beginning at groundline or below with application rates varying with pole

circumference. Diffusible rods can also be used to sterilize inspection holes and to control or prevent pole top decay.

d Woodpecker Damage. Woodpecker damage is an on-going issue that must be continually addressed. Many preventative methods are available but each typically has a varying degree of success.

It is difficult to predict which poles woodpeckers may select. Frequently the first hole invites further attack by other woodpeckers. For these reasons, it is good maintenance practice to seal up the smaller holes. Various materials are available for plugging the holes, and a wire mesh can be used to cover the plugged hole as well as large areas of a pole. In addition, as a preventative measure, wire mesh can be applied to poles in areas where woodpecker activity is expected. Some of these repairs restore varying degrees of strength to the pole, while others simply plug the hole.

e Pole Reinforcement. Various methods are available to reinforce a deteriorated pole at the ground line. A determination must be made as to whether or not a sufficient cross section of sound wood remains at the ground line if pole reinforcement is to be used. When considering reinforcement options, consult with the pole reinforcement system supplier for design and installation support.

Even though reinforcement may not be economically justified, other factors may need to be considered such as difficulty of access to the pole for replacement or system critical load which would prevent the line from being taken out of service at the time when the pole may be in danger of failing.

8 DETERMINING THE SERVICEABILITY OF DECAYED POLES

Serviceability. The decision to treat or replace a decayed pole depends upon the remaining strength or serviceability of the pole. The permissible reduced circumference of a pole is a good measure of serviceability. The following procedure may be used to assist in determining if a pole should be replaced or reinforced.

a Decay Classifications. Decay at the groundline should be classified as:

(1) General external decay
(2) External pocket
(3) Hollow heart, or
(4) Enclosed pocket.

b Permissible Reduced Circumference. The 2012 edition of the National Electric Safety Code (NESC) requires that wood structures shall be replaced or rehabilitated when deterioration reduces the structure strength to 2/3 of that required when installed for NESC District loading. The NESC 2012 also requires that wood structures shall be replaced or rehabilitated when deterioration reduces the structure strength to 3/4 of that required when installed for NESC extreme wind or extreme ice with concurrent wind loadings.

Computer programs are available that can calculate the remaining capacity of the pole by taking the voids into account when determining the effective remaining section of the pole.

Tables 1 through 4 will assist in determining when replacement or rehabilitation is necessary. If the reduced circumference indicates a pole at or below the minimum reduced circumference, the pole should be replaced, splinted, stubbed immediately, or otherwise rehabilitated.

c General Procedure for Using Table 1, 2, 3 and 4

(1) General External Decay. After removing all the decayed wood, measure the circumference above and below the decayed section to determine the original circumference. Then measure the reduced circumference at the decayed section. Enter Table 1, Column 1, with the original pole circumference. After determining the acceptable level of deterioration as described in paragraph 8c, find the minimum acceptable reduced circumference from the appropriate column - Column 2 for 2/3 of the original circumference, or Column 3 for 3/4 of the original circumference - on the same line as the original circumference. If the actual reduced circumference is larger than the acceptable calculated minimum, from Column 2 or 3, replacement or rehabilitation is not required yet.

(2) External Pockets. Remove decayed wood and take measurements of the depth and width of the pocket. Measure the pole for the original circumference. Refer to Table 2 to determine the circumference reduction. Use the procedure from paragraph 8d(1) to determine the minimum acceptable reduced circumference. If the actual reduced circumference, i.e. the original circumference minus the circumference reduction from Table 2, is larger than the acceptable calculated minimum from Table 1, Column 2 or 3, replacement or rehabilitation is not required yet.

(3) Hollow Heart (Heart Rot). If hollow heart is found, determine the shell thickness and measure the original circumference of the pole. Refer to Table 3 to determine the circumference reduction. Use the procedure from paragraph 8d(1) to determine the minimum acceptable reduced circumference. If the actual reduced circumference, i.e. the original circumference minus the circumference reduction from Table 3, is larger than the acceptable calculated minimum from Column 2 or 3, replacement or rehabilitation is not required yet.

To determine the shell thickness, bore three holes (preferably of 1/4- or 3/8-inch diameter), 120° apart; measure the shell thickness at each hole, add the measurements, and divide by 3. Treat and plug holes with tightly fitting cylindrical wood plugs that have been treated with preservative once shell thickness is determined. A transmission pole with a shell thickness less than 3 inches should be removed from service.

(4) Enclosed Pocket. An enclosed pocket is an off-center void as shown in Table 4 and its diameter should be measured by boring holes as described in paragraph 8d(3). Using the minimum thickness of the shell, refer to Table 4 for the reduction in circumference. Measure the original circumference. Use the procedure from paragraph 8d(1) to determine the minimum acceptable reduced circumference. If the actual reduced circumference, the original circumference minus the circumference reduction from Table 4, is larger than the acceptable calculated minimum from Column 2 or 3, replacement or rehabilitation is not required yet.

Table 1

Reduced circumferences for NESC Rules 250B, 250C, and 250D

	Rule 250B – Combined ice and wind district loading	Rule 250C - Extreme wind and Rule 250D - Extreme ice and concurrent wind
Original Circumference (in)	Minimum Reduced Circumference (in) (Based on 2/3 initial strength)	Minimum Reduced Circumference (in) (Based on 3/4 of initial strength)
30	26.2	27.3
31	27.1	28.2
32	28.0	29.1
33	28.8	30.0
34	29.7	30.9
35	30.6	31.8
36	31.5	32.7
37	32.3	33.6
38	33.2	34.5
39	34.1	35.4
40	35.0	36.3
41	35.8	37.3
42	36.7	38.2
43	37.6	39.1
44	38.4	40.0
45	39.3	40.9
46	40.2	41.8
47	41.1	42.7
48	41.9	43.6
49	42.8	44.5
50	43.7	45.4
51	44.5	46.3
52	45.4	47.3
53	46.3	48.2
54	47.2	49.1
55	48.1	50.0
56	48.9	50.9
57	49.8	51.8
58	50.7	52.7
59	51.5	53.6
60	52.4	54.5

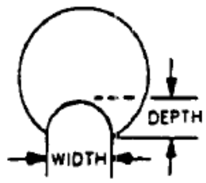


Table 2
Reduction in Measured Circumferences to Compensate for External Pockets

Pocket Width (in)	1					2					3					4					5					6				
Pocket Depth (in)	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
Measured Circumference of Pole (in)	Reduction in Circumferences (in)																													
20 to 30	1	1	2	-	-	2	2	3	-	-	2	3	4	-	-	3	4	5	-	-	4	6	8	-	-	6	8	-	-	-
30 to 40	1	1	1	2	-	1	2	2	3	3	2	3	4	4	4	2	4	5	5	6	3	5	6	7	8	5	7	8	9	-
40 to 50	1	1	1	2	2	1	2	2	3	3	2	3	3	4	4	2	3	4	5	6	3	4	5	6	7	3	5	6	7	8
50 to 60	1	1	1	2	2	1	2	2	3	3	2	3	3	4	4	2	3	3	4	5	3	4	4	5	6	3	4	5	6	7

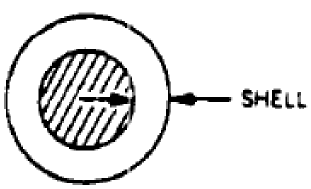


Table 3
Reduction in Measured Circumferences to Compensate For Hollow Heart

Measured Circumference Of Pole (ins)	Minimum Thickness of Shell (ins)					
	2	2.5	3	3.5	4	4.5
20 to 25	1	-	-	-	-	-
25 to 30	2	1	-	-	-	-
30 to 35	3	2	1	-	-	-
35 to 40	4	3	2	1	-	-
40 to 35	5	4	3	2	1	-
40 to 45	7	5	4	3	2	1

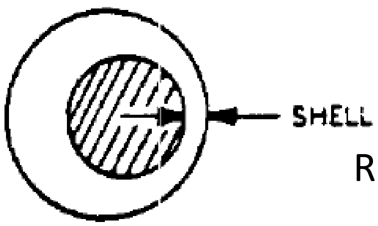


Table 4
Reduction in Measured Circumferences to Compensate For Enclosed Pockets

Diameter of Pocket (in)	3			4			5		
Shell Thickness (in)	1	2	3	1	2	3	1	2	3
Measured Circumferences Of Poles (in)	Reduction in Circumferences (in)								
20 to 30	2	1	-	3	1	-	4	2	-
30 to 40	2	1	1	3	1	1	4	2	1
40 to 50	2	1	1	3	2	1	4	3	1

METRIC CONVERSION FACTORS

To Convert From	To	Multiply by
Foot (ft.)	Meter (m)	0.3048
Inch (in)	Centimeter (cm)	2.54
Degrees Fahrenheit (X°F)	Degrees Celsius (°C)	5/9 (X° - 32)

MPSC Case No: U-21297	
Requester: MNSC	
Question No.: MNSCDE-9.6	
Respondent: S. Hartwick	
Page: 1 of 1	

Question: Referring to S. M. Hartwick's direct testimony, page 17-18. Please explain in detail how the company's ETTP trimming policy meets the industry standard 10% to 15% tree-to-conductor contact level.

Answer: In 2017,The Company had a workload study performed to determine growth rates and optimal trim cycles on the system. The study found that by trimming approximately 10 feet from the conductor, the average contact across the entire system was 12.7 percent after five years.

Attachment: None.

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-21297

PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony and Exhibits of Robert G. Ozar P.E. on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (Exhibit MEC-42 through MEC-49)** was served on the following:

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[signature page to follow]

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: June 13, 2023

Digitally signed by Breanna Thomas
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