



July 26, 2024

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

*Via E-File*

RE: MPSC Case No. U-21534

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Direct Testimony and Exhibits of Paul J. Alvarez on behalf of Attorney General Dana Nessel, Michigan Environmental Council, and Natural Resources Defense Council (Exhibits MEC-1 through MEC-9); and
- Proof of Service.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

A blue ink handwritten signature of Tracy Jane Andrews, consisting of stylized initials "TJA" followed by a horizontal line.

Digitally signed by Tracy Jane Andrews  
DN: cn=Tracy Jane Andrews, o=Troposphere  
Legal, PLC,  
email=tjandrews@tropospherelegal.com,  
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Date: 2024.07.26 16:04:49 -04'00'

Tracy Jane Andrews

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CC: Parties to Case No. U-21534

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-21534

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**DIRECT TESTIMONY OF PAUL J. ALVAREZ**

**ON BEHALF OF**

**ATTORNEY GENERAL DANA NESSEL,  
MICHIGAN ENVIRONMENTAL COUNCIL, AND  
NATURAL RESOURCES DEFENSE COUNCIL**

**July 26, 2024**

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**I. INTRODUCTION, QUALIFICATIONS, AND PREVIEW**

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

2   A.     My name is Paul J. Alvarez. I lead the Wired Group, a small consultancy dedicated to the  
3           needs of consumer, environmental, and business advocates in state utility regulatory  
4           proceedings. My business address is P.O. Box 620756, Littleton, CO 80162.

5   **Q.     On whose behalf is this testimony being offered?**

6   A.     I am testifying on behalf of a group of parties, including the Attorney General (AG),  
7           Michigan Environmental Council (MEC), and Natural Resources Defense Council  
8           (NRDC), collectively referred to as “AG-MN”.

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

10  A.     I have been actively involved in the electric utility industry for 23 years. After a series of  
11          finance, marketing, and product management roles in large corporations operating in  
12          competitive markets, my utility industry experience began in 2001 as a product  
13          development manager with Xcel Energy. At Xcel Energy I oversaw the development of  
14          new demand-side management (“DSM”) programs and became familiar with the various  
15          types of cost-effectiveness tests that are applied to such programs as standard practice. In  
16          2010 and 2011, I led teams that completed the first two independent evaluations of smart  
17          grid investment program benefits as the utility practice leader for a boutique sustainability  
18          consulting firm.<sup>1</sup> I started the Wired Group in 2012 to focus exclusively on distribution

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<sup>1</sup> Colorado PUC 11A-100E, *Smart Grid City Demonstration Project Evaluation Summary*, Xcel Energy report filed as Exhibit MGL-1, Direct Testimony of Michael G. Lamb (December 14, 2011); Ohio PUC 10-2326-GE-RDR, *Duke Energy Ohio Smart Grid Audit and Assessment*, Staff report filed June 30, 2011.

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1 utility planning, investment, performance measurement, and regulation. I wrote “Smart  
2 Grid Hype and Reality: A Systems Approach to Maximizing Customer Return on Utility  
3 Investment” in 2014 and updated it with a 2nd edition in 2018. I occasionally teach a  
4 graduate course at the University of Colorado’s Global Energy Management Program, and  
5 occasionally teach regulators and Staff at Michigan State University’s Institute of Public  
6 Utilities. I also publish papers and present at conferences on distribution utility planning,  
7 investment, performance measurement, and regulation. I received an undergraduate degree  
8 in finance and marketing from Indiana University’s Kelley School of Business in 1983,  
9 and a master’s degree in management from the Kellogg School of Management at  
10 Northwestern University in 1991. My curricula vitae is attached as Ex MEC-1.

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

12 A. Yes. I submitted testimony on behalf of AG-MNS and Citizens Utility Board of Michigan  
13 in the most recent rate application from DTE Electric Company (“DTE” or “Company”).<sup>2</sup>  
14 I am also known to the Michigan Public Service Commission (“Commission”) and Staff  
15 via work with my Wired Group associate Dennis Stephens on behalf of the Association of  
16 Businesses Advocating for Tariff Equity (“ABATE”), for whom we developed several sets  
17 of Commentary in recent years. In U-20147, we helped ABATE develop Comments  
18 regarding (1) The development of five-year distribution plans in Michigan generally  
19 (September 11 and November 18, 2019); (2) Five-year distribution plans and storm  
20 performance (October 1, 2021); (3) Consumers Energy’s Distribution Infrastructure  
21 Investment Plan (June 23, 2021); and (4) DTE Electric Company’s Distribution Grid Plan

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<sup>2</sup> Case No. U-21297, Direct Testimony of Paul J. Alvarez, 6 TR 3311 *et seq.*

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1 (September 29, 2021). We also helped ABATE develop Comments in U-21122, the  
2 August 2021 storm reliability performance and distribution planning docket, (September  
3 24, 2021). Mr. Stephens and I also gave a presentation on distribution planning and utility  
4 proposal cost-effectiveness testing, to include risk-informed benefit-cost analysis and risk-  
5 informed investment decision support, in a Staff-led workshop on distribution plan  
6 development held August 14, 2019.

7 In addition, I have testified on behalf of consumer, business, and environmental  
8 advocates in proceedings related to electric distribution utility planning, investment,  
9 performance, and regulation before 16 other state utility regulators in the past 11 years,  
10 including California, Georgia, Illinois, Indiana, Kansas, Kentucky, Maryland,  
11 Massachusetts, New Hampshire, New Jersey, North Carolina, North Dakota, Ohio,  
12 Oklahoma, Virginia, and Washington. A complete list of proceedings in which I've  
13 submitted testimony to state utility regulators, with proceeding numbers and dates, can be  
14 found in Exhibit MEC-1.

15 **Q. What is the purpose of your testimony?**

16 **A.** I am testifying on behalf of AG-MNS regarding the financial, policy, and regulatory issues  
17 presented by DTE's application as they relate to DTE's electric distribution system. My  
18 testimony was developed in close cooperation with my Wired Group colleague, AG-MNS  
19 witness Dennis Stephens, who covers the technical aspects of the Company's distribution  
20 grid capital spending. Mr. Stephens and I recommend our testimonies be reviewed and  
21 considered together, as the financial, policy, and regulatory issues I cover in this testimony

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are related to what we consider to be unnecessary, premature, or cost ineffective capital spending, which Witness Stephens covers in his testimony.

**Q. Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

Exhibit MEC-1: Curricula Vitae of Paul J. Alvarez

Exhibit MEC-2: Company Response to MNSCDE-2.5 + Attachments 22  
*Monthly Rate Benchmarking, April 2024 and 25 Spring 2023  
Annual*

Exhibit MEC-3: Company Responses to MNSCDE-15.25(c) – (h) + Attachment  
*U-21534 MNSC 15.25g-h PTMM Journal Entry Logic*

Exhibit MEC-4: U-20162, DTE Electric, March 1, 2024, Tree Trim Annual  
Report

Exhibit MEC-5: Company Supplemental Response to MNSCDE-8.5(c) (SI) with  
*Attachments 2022, 2023, and 2024 Budget Appropriations*

Exhibit MEC-6: Company response to MNSCDE-8.16(d)(i)

Exhibit MEC-7: Company response to MNSCDE-7.2(h)

Exhibit MEC-8: Company response to MNSCDE-7.4(a) – (d)

Exhibit MEC-9: Company response to MNSCDE-7.3(a) – (f)

**Q. Please provide a preview of your testimony.**

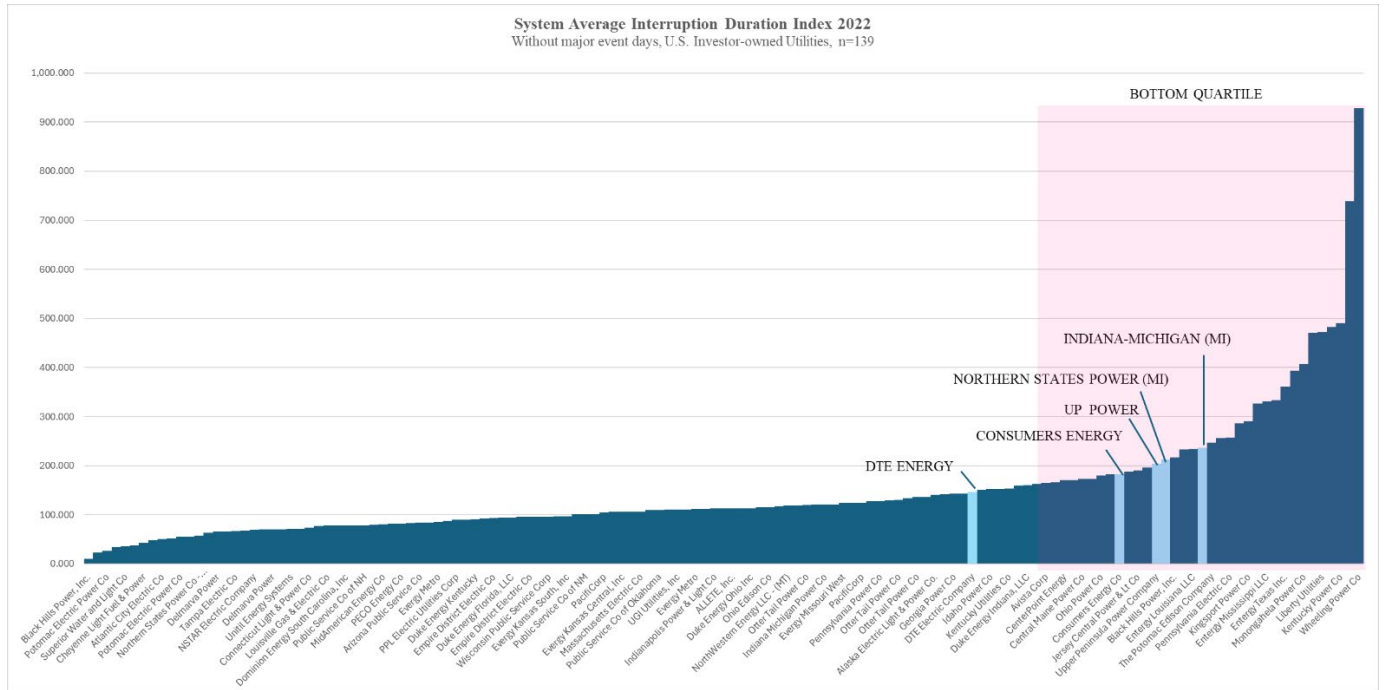
A. DTE's capital spending has skyrocketed in recent years, and the Company's pending rate increase application and 2023 Grid Distribution Plan (Exhibit A-23 Schedule M8) forecast even greater capital spending in the future. While Witness Stephens and I appreciate the

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1 Commission's well-placed concerns about grid safety, reliability and electrification  
2 "readiness" (for electric vehicles and heating), we are also concerned about the adverse  
3 impact of rapidly increasing electricity costs on Michigan's economy generally, and on the  
4 Company's low-income consumers specifically. We are also concerned that rapidly  
5 increasing electric rates will harm consumer and commercial adoption of the very same  
6 electric end-use technologies for which significant electric grid investment is being  
7 contemplated. A simultaneous focus on both reliability and readiness can lead to extreme  
8 rate increases, absent careful capital spending governance and difficult choices.  
9 Unfortunately, it appears to Mr. Stephens and I that such careful governance has not kept  
10 pace in Michigan, and worse, that insufficient controls are in place to optimize capital  
11 spending decisions, or even to monitor the cost-effectiveness of the capital being spent.

12 A consistent theme throughout this testimony is that more rigorous regulatory  
13 controls over the Company's capital spending are necessary. While we observe that many  
14 state utility regulators are being challenged by the need to balance grid investment with  
15 affordability, DTE's poor historical reliability record puts additional pressure on this  
16 Commission. Indeed, DTE barely exceeds bottom-quartile average interruption duration  
17 performance among U.S. investor-owned utilities, and Consumers' Energy, Indiana-  
18 Michigan Power, and Northern States Power are all bottom-quartile performers on this  
19 metric.

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In light of these observations, we encourage the Commission to adopt a more forceful and involved role in regulating the distribution performance and spending of Michigan utilities, beginning with this DTE application. While the Commission’s distribution planning dockets are notable, and a step in the right direction, these efforts appear to have been largely ineffective at improving reliability performance or governing capital spending so far.

This testimony is designed to illuminate multiple regulatory opportunities for improving performance and governing capital spending at DTE by balancing reliability and readiness objectives with affordability. It begins by providing more historical context and perspective, with particular attention paid to DTE spending and performance. It continues with one testimony section each on the policy issues presented by DTE proposals for the Infrastructure Recovery Mechanism (“IRM”) and vegetation management cost

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1 recovery. The testimony continues with a section on the Company's Global (project and  
2 program) Prioritization Model and distribution Reliability Model (used to project reliability  
3 improvements from several strategic capital programs). The final section of this testimony  
4 addresses DTE's fiber optic data communications cable deployment proposal. This  
5 testimony intends to provide perspective, information, and ideas the Commission will find  
6 helpful as it considers the Company's application.

7 **Q. Please summarize your recommendations in this testimony.**

8 A. The primary recommendations I make in this testimony include that the Commission:

- 9 • Require DTE to slow the rate of capital spending and assess the benefits of its  
10 vegetation management program relative to strategic capital spending aimed at  
11 improving reliability.
- 12 • Reject the Company's request to extend and expand the IRM;
- 13 • Regarding DTE's capitalization of vegetation management costs (other than Surge  
14 securitization), require DTE to itemize the costs, assess their impact to ratepayers,  
15 and support its practice in the next rate case;
- 16 • Reject the Company's request to earn a return on the Enhanced Tree Trim Program  
17 (ETTP) Surge regulatory asset;
- 18 • Reject the Company's request to increase ETTP spending in 2026;
- 19 • As the Company approaches the end of the ETTP Surge, require DTE to continue  
20 annual tree trim reporting and order an independent audit of the state of DTE's  
21 overhead line rights of way every five years, commencing in 2025 or 2026;
- 22 • Recognize DTE's Global Prioritization and Reliability Models are unreliable;

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- 1           • Reject the Company’s fiber-optic data communications cable deployment plan and  
2           disallow all proposed bridge and test year spending for Grid Automation  
3           Telecommunications; and
- 4           • Require DTE in its next rate case, if it proposed further spending on the Grid  
5           Automation Telecommunications program, to present a make versus buy analysis  
6           of alternatives and a tool to identify appropriate alternatives.

7       **II. CONTEXT AND PERSPECTIVE**

8       **Q. Please preview this section of testimony.**

9       **A.** This section of testimony provides context and perspective for Commission consideration  
10       as it evaluates DTE’s application, doing so in several steps. It begins with a summary of  
11       DTE’s application, putting the Company’s requests and proposals in this rate case into  
12       perspective with recent rate cases. It also summarizes relevant portions of the Company’s  
13       updated 2023 Distribution Grid Plan, and of Michigan’s Healthy Climate Plan and Clean  
14       Energy Future legislation, with observations and commentary provided.

15       **Q. Please summarize DTE’s instant application.**

16       **A.** DTE’s application describes a strategic imperative “to rebuild, modernize, and automate  
17       our 46,000 miles of electric circuits (the ‘grid’) to achieve reliability that is better than  
18       industry average by 2029.”<sup>3</sup> The Company predicts that \$9 billion in grid investment 2024-  
19       2028 will reduce outage frequency 30% and outage duration 50%, delivering \$15 billion  
20       in benefits to DTE customers.<sup>4</sup> (The Company’s application also refers to \$7 billion in

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<sup>3</sup> Revised Direct Testimony of Neal T. Foley at NTF-4.

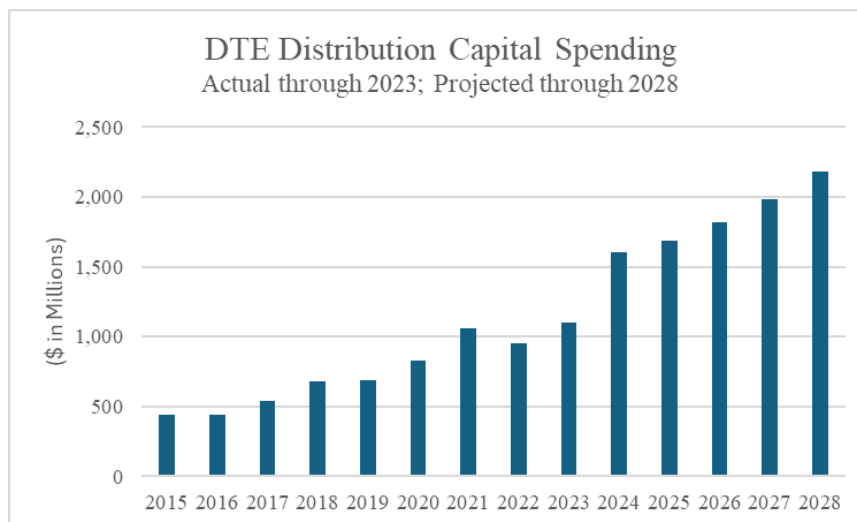
<sup>4</sup> Ibid at NTF-5 to NTF-9.

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clean generation investment over the same time period, though generation is outside the scope of this testimony.) The distribution investments are consistent with those the Company explains in its 2023 Distribution Grid Plan (Exhibit A-23 Schedule M8). In addition to massive increases in capital spending, the Company requests that its IRM rider be extended and expanded.

**Q. Do these proposals concern you?**

A. Yes. Generally, the proposals accrue to shareholders' benefit and increase risks for customers. I will address the IRM later in this testimony, but I am particularly concerned by massive increases in distribution capital spending for improving reliability. Projected distribution capital spending relative to historic capital spending is presented in the chart below.<sup>5</sup> By 2028, DTE's Distribution Grid Plan projects annual distribution spending more than triple the amount it spent in 2018. Capital spending is not necessarily the most reasonable way to improve reliability.



<sup>5</sup> DTE FERC Form 1, line 75, 2015-2023; DTE 2023 Distribution Grid Plan, Ex. 6.6.1, Ex A-23 Sch M8, p. 56 of 264, 2024-2028.

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1     **Q.     What is the relationship between capital spending increases and rate increases?**

2     A.     Rates will not increase as fast as capital spending, because capital cost recovery is spread  
3           out over the depreciation period of the underlying assets. But while capital cost recovery  
4           is spread out over time, associated rate increases will be no less real nor any less significant,  
5           and they will persist for decades (as the typical depreciation period for a distribution asset  
6           is generally 40 years).<sup>6</sup> As every resident and business uses electricity, electric rate  
7           increases act as a drag on Michigan's entire economy. As indicated above, the Commission  
8           must determine the appropriate balance between capital spending and affordability.

9           In doing so, the Commission should be evaluating if DTE is presenting compelling  
10          responses to these difficult questions:

- 11                 •   What are the most appropriate targets for reliability, and over what time  
12                     frames?
- 13                 •   What are the most cost-effective ways to reach the reliability targets?
- 14                 •   What are the most prudent ways to measure grid "readiness" for  
15                     electrification?
- 16                 •   At what speed will electrification proceed (dictating the pace of readiness)?
- 17                 •   How can DTE's Distribution Grid Plan be optimized to provide the biggest  
18                     reliability and readiness benefit per dollar of customer rate increases?

19           Shareholders are best served by massive rate base growth (which increases the  
20          opportunity to earn income) as fast as the Company can possibly manage it (thereby

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<sup>6</sup> DTE applies a depreciation rate of 4.11% to distribution capital that is projected to be in-service. Company response to MNSCDE-15.30.

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1 increasing share prices, which are based largely on earnings, prospects for growth in  
2 earnings, and perceived shareholder risk). In contrast, rate increases are mitigated by  
3 moderating and deferring capital spending, and by prioritizing operations and maintenance  
4 (“O&M”) solutions over capital solutions where appropriate. Regulators often  
5 underestimate the difference in costs to customers between capital and O&M spending.  
6 Customers pay returns on capital and taxes on top of the Company’s capital costs. In the  
7 instant case, for the projected test year, the Company requests a 4.24% interest expense on  
8 debt, a 10.50% return on equity capital,<sup>7</sup> and an additional 35% premium on projected DTE  
9 income to cover taxes.<sup>8</sup> These make DTE capital spending dramatically more costly for  
10 customers than DTE O&M spending. When considering DTE’s capital spending requests,  
11 the Commission cannot ignore the significant premium on DTE capital spending that  
12 customers pay relative to what customers pay on DTE O&M spending.

13 **Q. Has DTE calculated the cost to customers of these large capital spending increases?**

14 A. No. The Company has only estimated revenue requirements through the forward test year  
15 being employed in its application, ending December 31, 2025. The Company requests a  
16 \$456 million increase in the revenue requirement to cover spending through December 31,  
17 2025, driven largely by increases in capital spending and financing costs on that spending  
18 (\$285 million in capital cost recovery and \$36 million in increased financing costs).<sup>9</sup> This

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<sup>7</sup> Ex A-14, Sch D1.

<sup>8</sup> Ex A-13, Sch C2.

<sup>9</sup> Foley Revised Direct at NTF-14.

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amounts to an 8.2% rate increase<sup>10</sup> and does not include any of the capital spending increases described in the Company's 2023 Distribution Grid Plan in 2026, 2027, and 2028.

**Q. Does DTE provide any context for these rate increases?**

A. Yes. The Company reports that its average (residential) bills are below U.S. averages (\$115 vs. \$133).<sup>11</sup> This is a meaningless comparison that should be disregarded entirely. DTE appears to have derived it simply by dividing residential revenues by the count of residential customers. A myriad of differences are masked by this comparison, from customer loads and usage extents (think air conditioning in Florida vs. air conditioning in Michigan), to generation mix and fuel costs (think low-cost coal to higher-cost natural gas or renewables), to differences in the cost of living and the associated impact on the Company's labor rates (Michigan was recently reported as having the 12<sup>th</sup> lowest cost of living among U.S. states,<sup>12</sup> meaning DTE costs are likely lower than the U.S. average), and others. This bill comparison also disregards the fact that DTE's residential rates remain the highest among its Great Lakes peers and in the 4<sup>th</sup> quartile (highest) nationally.<sup>13</sup> The Commission should be unswayed by DTE's meaningless bill comparison.

**Q. What is driving DTE capital spending increases?**

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<sup>10</sup> Ex. A-16, Schedule F2, p. 2.

<sup>11</sup> Foley Revised Direct at NTF-16, Figure 8 and note 5.

<sup>12</sup> Missouri Economic Research and Information Center. Accessed July 23, 2024, available at <https://meric.mo.gov/data/cost-living-data-series>.

<sup>13</sup> Ex MEC-2, Company Response to MNSCDE-2.5-22 Monthly Rate Benchmarking 2024\_4\_AprilvFinal (slide 3); 2.5-25 Spring 2023 Annual (slide 4)

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A. Strategic capital programs amounting to 70% of Distribution Grid Plan spending 2022-2027 are presented in the table below. Note that almost all of the projects within these programs are discretionary as to timing and extent. This means that none are required to address equipment failures or equipment damage; or connect new customers; or accommodate near-term load increases; these costs are budgeted separately as base capital programs. Thus, considerable optionality exists as to the timing of these programs' deployment (and indeed, whether they are truly "needed" at all). Further, it is worth noting that most programs do not consist of individually-identified projects; in general, these are program-wide budgets the Company is asking the Commission to approve without regard to the circuit miles completed or units installed (prompting concerns over both cost control and the Company's reliability improvement estimates). Other than 4.8kV conversions, designed primarily to increase capacity to meet far-off load increases, strategic programs are generally intended to improve reliability. Whether they do so in a cost-effective manner is the issue. My colleague, AG-MNS witness Stephens, addresses in his testimony all the programs listed in the table below, together with a few others:<sup>14</sup>

|                                    | Application Detail |       |       |       | IRM   |       |
|------------------------------------|--------------------|-------|-------|-------|-------|-------|
| Programs (\$ in millions)          | 2022               | 2023  | 2024  | 2025  | 2026  | 2027  |
| 4.8kV Hardening                    | 157.5              | 127.0 | 80.0  | 125.0 | -     | -     |
| Pole & Pole Top Maint & Mod        | 83.9               | 79.1  | 63.5  | 121.0 | 150.0 | 200.0 |
| Subtransmission Redesign & Rebuild | 52.4               | 71.9  | 40.6  | 43.6  | 55.0  | 65.0  |
| 4.8kV Conversions to 13.2 kV       | 104.5              | 161.9 | 199.2 | 78.8  | 190.0 | 240.0 |
| Distribution Automation            | 5.5                | 27.1  | 21.2  | 125.6 | 105.0 | 180.0 |
| Totals                             | 403.8              | 467.1 | 404.4 | 494.0 | 500.0 | 685.0 |

**Q. But clearly, DTE needs to invest in the grid to improve reliability, does it not?**

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<sup>14</sup> Ex A-12 Sch B4.5 pp. 13, 16, 17; Ex A-33 Sch X1 (IRM).

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1     **A.**     Perhaps to some extent, but as noted above, strategic capital investment programs are  
2             discretionary as to amounts, geographic extent, and timing. Further, this question assumes  
3             that more capital investment will deliver reliability improvements of sufficient value to  
4             justify the spending. Neither independent research nor our (Mr. Stephens' and my)  
5             experience validates this assumption.

6             Mr. Stephens and I are particularly concerned about the difference in cost-  
7             effectiveness between vegetation management and capital spending at improving  
8             reliability. DTE's vegetation management "surge" and commitment to a five-year  
9             vegetation management cycle are laudable. But before knowing the system-wide reliability  
10            impact of these efforts, DTE is forging ahead with capital expenditures amounting to  
11            almost \$4 billion dollars in 2023-2027 for discretionary "strategic capital" programs  
12            designed to improve reliability:<sup>15</sup>

| <b>2023</b> | <b>2024</b> |        | <b>2025</b> |         | <b>2026</b> | <b>2027</b> |
|-------------|-------------|--------|-------------|---------|-------------|-------------|
| Rate Base   | Rate Base   | IRM    | Rate Base   | IRM     | IRM         | IRM         |
| 801,026     | 708,777     | 61,865 | 827,280     | 290,134 | 530,000     | 720,000     |

13           And much more on the horizon – the table below is from the 2023 Distribution Grid Plan,  
14           which also not capture the full extent of this spending spree:<sup>16</sup>

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<sup>15</sup> Ex A-12 Sch B5.4 p. 1, line 22 (rate base 2023, 2024, 2025); Ex A-33 Sch X1 line 8 (IRM).

<sup>16</sup> Ex A-12 Sch B5.4, p. 1 (2023 DGP, Ex A-23 Sch M8 p. 162 of 274. As discussed in the 2023 DGP and by Mr. Stephens, DTE aspires to spend many billions more to convert the entire 4.8kV system to 13.2kV, among other programs.

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| Exhibit 11.0.1 Projected Distribution Grid Plan Investments |                                                            |             |         |         |         |         |              |
|-------------------------------------------------------------|------------------------------------------------------------|-------------|---------|---------|---------|---------|--------------|
|                                                             |                                                            | \$ Millions |         |         |         |         |              |
| Category                                                    |                                                            | 2024        | 2025    | 2026    | 2027    | 2028    | 5-Year Total |
| Capital Investments (\$ Millions)                           |                                                            |             |         |         |         |         |              |
| Base Capital                                                | Emergent Replacements (Reactive Trouble and Storm Capital) | \$415       | \$399   | \$368   | \$348   | \$345   | \$1,877      |
|                                                             | Customer Connections, Relocations and Others               | \$282       | \$295   | \$314   | \$334   | \$355   | \$1,580      |
| Strategic Capital Programs (details in Exhibit 11.0.2)      |                                                            | \$906       | \$995   | \$1,134 | \$1,302 | \$1,485 | \$5,821      |
| Total Capital Investments                                   |                                                            | \$1,603     | \$1,689 | \$1,816 | \$1,985 | \$2,185 | \$9,278      |
| Maintenance Programs (\$ Millions)                          |                                                            |             |         |         |         |         |              |
| Tree Trimming                                               |                                                            | \$123       | \$140   | \$101   | \$103   | \$106   | \$573        |
| Preventive Maintenance                                      |                                                            | \$10        | \$10    | \$10    | \$10    | \$10    | \$50         |

We urge the Commission to evaluate the success of the tree trimming modifications before concluding that massive capital spending is required to improve reliability.

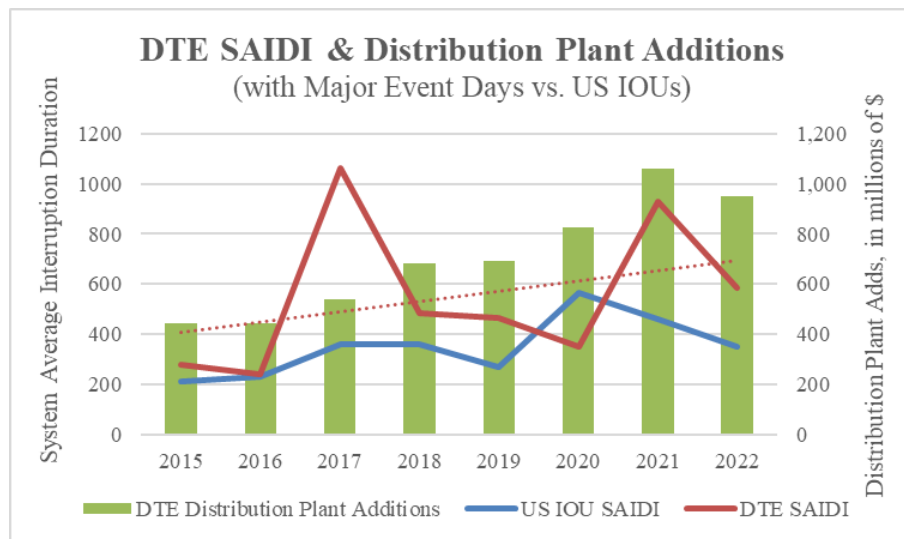
Research completed by Lawrence Berkeley National Laboratory on behalf of the U.S. Department of Energy found no correlation between investor-owned utility distribution capital spending increases and reliability improvement the following year.<sup>17</sup> Regarding DTE’s own experience, DTE admits that more frequent tree trimming – for the most part an O&M expense, not capital spending -- is the most effective thing DTE can do to improve reliability, stating “In areas where tree trimming has been completed,

<sup>17</sup> Larsen PH, LaCommare KH, Eto JH, and Sweeney JL. *Assessing Changes in the Reliability of the U.S. Electric Power System*. Lawrence Berkeley National Laboratory report LBNL-188741 (August 2015), pp. 37-38. Accessed July 22, 2024, available at: <https://emp.lbl.gov/publications/assessing-changes-reliability-us>.

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communities have experienced, on average, 60% fewer outages.”<sup>18</sup> Finally, the chart below indicates that despite a 214% increase in annual distribution grid capital spending from 2015 to 2022, DTE’s service interruption frequency *increased* 58.1%, and is still worse than the average for U.S. investor-owned utilities. To date, DTE has not shown that massive increases in capital spending deliver reliability improvements.

*Figure 1: DTE service interruption duration vs. distribution plant additions over time*



**Q. That result seems counter intuitive. How do you explain it?**

A. The Company tends to describe distribution capital spending as the primary solution for improving reliability. For example, the 2023 Distribution Grid Plan states “much of the current infrastructure is at or beyond expected useful life and susceptible to failure, particularly when exposed to extreme weather.”<sup>19</sup> This statement contains several

<sup>18</sup> *DTE Announces an additional \$70 million investment to combat extreme weather-related power outages.* DTE Energy press release (September 1, 2021). Accessed July 22, 2024, available at <https://ir.dteenergy.com/news/press-release-details/2021/DTE-announces-an-additional-70-million-investment-to-combat-extreme-weather-related-power-outages/default.aspx>.

<sup>19</sup> Ex. A-23 Sch M8 (2023 DGP) at 54 of 274.

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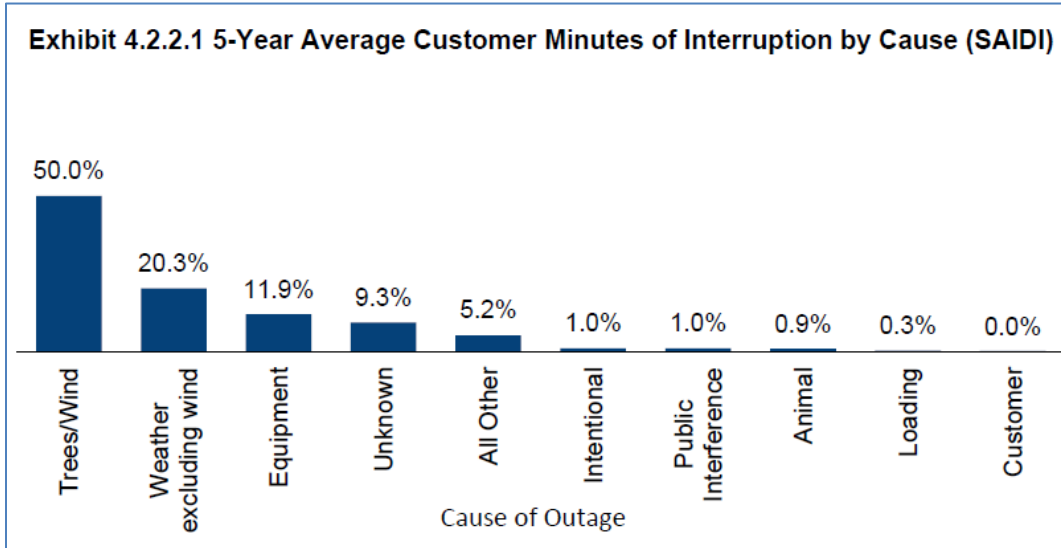
1 misleading statements. First, “expected useful life” is a reference to depreciation periods,  
2 which are based on the average age of assets in service (also known as “survivor curves”).  
3 Distribution equipment is removed from service for many reasons (capacity expansion,  
4 storm damage, facility relocations, and the like), meaning that the average age of  
5 equipment in service – while useful for depreciation period determination – should not be  
6 used as an expectation of an equipment’s design life. For example, utility poles, though  
7 typically depreciated over 40 years, routinely provide safe and reliable service for 80 years  
8 or longer with sound inspection and maintenance practices. To decide that equipment  
9 should be replaced simply because it is fully depreciated, when decades of useful life might  
10 be remaining, serves shareholders at customers’ expense.

11 An analysis of service interruption causes is also illustrative. In its Distribution  
12 Grid Plan, DTE reported that at least 50% of customer minutes of interruption are caused  
13 by vegetation contact, while less than 12% of customer minutes of interruption are  
14 associated with cause “equipment”:<sup>20</sup>

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<sup>20</sup> 2023 DTP, Ex A-23 Sch M8 Exhibit 4.2.2.1 at 41 of 274.

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Further, my colleague Mr. Stephens reports that the equipment cause is overused by field personnel, thereby overstating “equipment” as a cause of service interruptions. In his examination of field notes the Company recorded on a random sample of 100 service interruptions classified as “equipment” related, only 67% of service interruptions with field notes sufficient to determine root cause could be traced to unprompted failures of equipment in service, while 33% were caused by vegetation contact or damage by third parties. Thus, attributing even 12% of the Company’s customer minutes interrupted to “equipment” overstates the equipment condition “problem”.

Finally, I note that some DTE strategic capital programs, like Distribution Automation, are designed to mitigate the impact of service interruptions rather than address the root causes of service interruptions. Given that vegetation contact is the root cause of at least 50% of the interruption minutes customers experience, spending should be focused on root causes, not symptoms. To summarize, tree trimming, and not capital spending, is the most cost-effective way to improve reliability.

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1     **Q.     But what of DTE’s projected reliability improvement benefits?**

2     A.     Later, I will describe fundamental problems with the way DTE has calculated the reliability  
3           improvements attributable to its strategic capital programs. Specifically, the way DTE  
4           defined its control group circuits (used as a baseline for comparison with circuits to which  
5           capital programs have been applied) dramatically overstates the benefits DTE’s Reliability  
6           Model projects. The Commission should not rely upon reliability improvement projections  
7           from DTE’s Model when considering DTE’s strategic capital spending proposals.

8     **Q.     How do you think the Commission should consider Michigan’s Healthy Climate**  
9           **Plan and related legislation when evaluating the Company’s Application?**

10    A.     Michigan’s Healthy Climate Plan does not require large, immediate increases in  
11           distribution spending. With respect to electric vehicles, about 95% of electric vehicle  
12           charging for customers on time-of-use rates is off-peak.<sup>21</sup> (Time-of-use rates offer EV  
13           owners the lowest charging costs.) Therefore, preparing the grid for electrification, for  
14           example through conversion of 4.8kV circuits to 13.2 kV, does not appear to be an urgent  
15           need. The Commission may also be interested to note the Healthy Climate Plan’s focus on  
16           affordability, targeting a maximum 6% energy burden for low-income households.<sup>22</sup>

17                   The Michigan Legislature has taken some action on the Healthy Climate Plan,  
18           including the Clean Energy Future Package. The Package enhanced rooftop solar

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<sup>21</sup> Fitch T, Frost J, and Whited M. *Electric Vehicles Are Driving Electric Rates Down*. Update of a study completed by Synapse Energy Economics for the Natural Resources Defense Council (June, 2020), Fig 3, p. 3. Accessed July 22, 2024, available at [https://www.synapse-energy.com/sites/default/files/EV\\_Impacts\\_June\\_2020\\_18-122.pdf](https://www.synapse-energy.com/sites/default/files/EV_Impacts_June_2020_18-122.pdf).

<sup>22</sup> *MI Healthy Climate Plan*, Michigan Department of Environment, Great Lakes, and Energy (April 2022), p. 36.

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1 deployment in Michigan, though in our (Mr. Stephens' and my) experience rooftop solar  
2 does not typically require much distribution grid investment. Only utility-scale, rurally  
3 located solar systems typically require significant distribution grid investment, and these  
4 cannot typically be forecast in advance of developer applications. Further, many of these  
5 systems are interconnected to the transmission grid, not distribution. The Clean Energy  
6 Jobs Act further facilitated utility-scale wind and solar development, but again, the  
7 opportunities to prepare the distribution grid in advance for these are almost non-existent.  
8 In summary, while the Healthy Climate Plan and clean energy legislation are important  
9 policy changes in Michigan, their impacts on distribution grid investment needs appear  
10 minimal for the near-term.

11 **Q. What do DTE's customers think about ever-increasing DTE rates?**

12 A. Customers obviously dislike rate increases, but comments from DTE customers reveal  
13 specific frustration regarding the lack of value customers are receiving in exchange for  
14 DTE rate increases. Many customers also express frustration with the Commission. We  
15 encourage the Commission to pay particular attention to the following excerpts from  
16 written comments submitted by DTE customers on the Company's instant application:<sup>23</sup>

- 17 • "There is no transparency with DTE"
- 18 • "Do not provide DTE with more money to syphon off to the executives and  
19 shareholders under the false claim of improving the system."
- 20 • "I do not see that an increase will be spent wisely."
- 21 • "They keep asking for more money yet our electricity is always going out and our  
22 bill is higher than ever."
- 23 • "Can you really approve a rate hike for the lack of maintenance shown in these pics?  
24 These dead trees have been risking our power for years."

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<sup>23</sup> Case No. U-21534, Case Comments,

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- 1 • “What do we pay the Public Service Commission to do? We pay you to do your job.  
2 I'm sorry but many of us are feeling neglected!”
- 3 • “This is price gouging and you would be complicit in it if this request is approved.”
- 4 • “Start looking out for the citizens of our state instead of just keep approving rate hikes  
5 so DTE can report larger profits like what has happened the last 2 years.”
- 6 • “Please get realistic when you're considering caving, once again, to DTE.”
- 7 • “They say that they’re doing all this work but where is the proof who’s looking into  
8 where the money is going?”
- 9 • “They are going to raise our rates with the promise of stabilizing the grid, having  
10 fewer and shorter outages, etc. But if/when that doesn't happen, are they going to  
11 lower the rates again and reimburse everyone for the failed attempt? Absolutely not.”
- 12 • “Please reject this proposal and make DTE do better with what they have.”
- 13 • “Michigan electricity utility service quality is in the bottom quarter of all states in  
14 most quality metrics, per the Citizens Utility Board of Michigan.”
- 15 • “When it comes to what DTE says I do not believe what they say any more.”
- 16 • “Why should we pay more for a unreliable service.”
- 17 • “DO NOT grant them another rate increase until they can prove for several years  
18 consecutively that they indeed deserve more of OUR hard earned money.”
- 19 • “I am against the DTE price increase. For years they have neglected the grid and  
20 maintenance of lines for the profit of their investors.”
- 21 • “It is absolutely criminal that DTE can year after year request rate hike after rate hike  
22 and my...our service had not improved whatsoever. Just recently as last month I sat  
23 here with no power trying to report it to DTE and all they did was tell me that my  
24 power was on. It was absolutely infuriating.”<sup>24</sup>
- 25 • “I would urge the commission to fulfill its duty to the public, deny the rate increase,  
26 and remember who they're supposed to serve.”

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<sup>24</sup> This comment indicates that the meter associated with this customer’s premises in DTE records is actually installed on some other customer’s premises (with its power on). This means that this customer is paying for the electricity used at that other customer’s premises, and that some other customer is paying for the electricity used at this customer’s premises. This error probably occurred during DTE’s deployment of smart meters, and causes me concern as to how widespread this problem is among DTE customers.

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1   **Q.   What are your context and perspective conclusions?**

2   A.   While the Commission’s focus on improving the reliability performance of DTE and other  
3       electric distribution utilities is appropriate, capital spending is not necessarily the most  
4       cost-effective way to satisfy reliability objectives. The Commission appears under  
5       pressure to improve reliability, but also to identify the most cost-effective ways to do so.  
6       Given the size of capital spending increases ostensibly proposed to improve reliability,  
7       DTE’s implied assumption that massive investment is required to improve reliability must  
8       be rigorously evaluated. My overall recommendation, consistent with that of my colleague,  
9       Mr. Stephens, is that the Commission require DTE to slow down the capital spending  
10      locomotive that it has become. Further, before speeding up the locomotive again, I  
11      recommend the Commission require DTE to collect and provide more data on the reliability  
12      improvement value of enhanced vegetation management vs. improvements from strategic  
13      capital programs; strengthen its capital spending governance; and practice capital  
14      budgeting restraint. These themes are further developed throughout the rest of this  
15      testimony.

16   **III.   THE COMMISSION SHOULD INCREASE CAPITAL SPENDING**  
17       **GOVERNANCE AND REJECT THE COMPANY’S REQUEST TO EXTEND AND**  
18       **EXPAND THE IRM**

19   **Q.   Please preview this section of testimony.**

20   A.   In this section of testimony, I describe the critical processes of capital spending governance  
21       and identify shortcomings in these components at DTE. I also explain the unintended  
22       consequences associated with rider cost recovery such as DTE’s Infrastructure Recovery  
23       Mechanism (“IRM”), and the increased need for capital spending governance that results.

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1 I conclude with a recommendation that the Commission reject the Company's request to  
2 extend and expand the IRM.

3 **A. Critical Processes for Capital Spending Governance**

4 **Q. What are the critical components of capital spending governance?**

5 A. In my experience there are three processes critical to sound capital spending governance.  
6 To adequately govern capital spending and maximize value per dollar invested, all three  
7 processes must be actively and rigorously managed:

- 8 • Capital project/strategic program selection and capital budget development;
- 9 • Capital project/strategic program planning and cost tracking; and
- 10 • Capital project/strategic program performance evaluation.

11 **Q. Please explain capital project/strategic program selection and capital budget**  
12 **development.**

13 A. Capital project/strategic program selection and capital budget development is all about  
14 decision-making. Though some utility capital spending is not discretionary, all of DTE's  
15 strategic capital programs offer optionality as to geographic extent (which circuits are most  
16 likely to deliver benefits in excess of costs) and speed of deployment. When contemplating  
17 whether to fund a strategic program, for which geographies, and at what deployment speed,  
18 it is important to establish expectations for benefits relative to costs, such as in a benefit-  
19 cost analysis.

20 Companies competing in unregulated markets are extremely good at managing to  
21 capital budget constraints, because market prices for the companies' products and services  
22 restrict the amount of capital such companies can spend. These companies, including

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1 almost all of DTE's commercial and industrial ("C & I") customers, must carefully choose  
2 how to spend their limited capital. For for-profit monopolies regulated by state utility  
3 regulators, regulation represents the only limit to capital spending. Because regulators  
4 offer utilities an opportunity to earn a return on invested capital (earnings, also known as  
5 profits), utilities are motivated to spend as much capital as they can to increase earnings.  
6 This incentive is known as "capital bias".<sup>25</sup> In my experience, utilities are only as good at  
7 restraining the size of capital budgets, and therefore project/program selection, as their  
8 regulators force them to be.

9 **Q. Please explain capital project/strategic program planning and cost tracking.**

10 A. Project/strategic program planning and cost tracking is all about cost control. For projects,  
11 this means establishing a plan and budget for executing each project, managing project  
12 execution in a timely manner, and tracking the capital expended to complete the project.  
13 Most utilities are reasonably good at this. For strategic programs, this means establishing  
14 some type of program expectations, such as the number of circuit miles to be completed,  
15 or units to be installed, for the capital budget established. In my experience utilities are  
16 not good at this.

17 **Q. Please explain capital project/strategic program performance evaluation.**

18 A. Project/strategic program performance evaluation is all about accountability. For projects,  
19 this is generally a post-completion evaluation that examines whether a project was placed  
20 into service by the time indicated and for the costs budgeted in the project plan. Any

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<sup>25</sup> Averch H and Johnson L. *Behavior of the Firm Under Regulatory Constraint*. The American Economic Review, Vol. 52, No. 5 (Dec., 1962), pp. 1052-1069. Accessed July 22, 2024, available at <https://www.jstor.org/stable/1812181>.

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1 deficiencies identified in the post-completion evaluation are tracked back to root causes in  
2 project planning and execution, and improvements in company-wide project planning and  
3 project management processes are sometimes implemented as indicated.

4 For programs, performance valuation constitutes a check-in on the components of  
5 the program as they are completed. This involves, for example, whether miles completed  
6 or units installed for the budget established matched expectations. It also involves a  
7 determination as to whether the benefits delivered by the program are as large as anticipated  
8 by utility management upon program approval. In my experience, utilities are not only  
9 abysmal at this, they have no incentive to validate program performance.

10 **B. Shortcomings in capital spending governance at DTE**

11 **Q. Is DTE deficient in its capital project/strategic program selection and capital budget**  
12 **development?**

13 A. Yes. DTE selects projects and strategic programs for its capital budget using its *Global*  
14 *Prioritization Model*. I provided extensive critique of DTE's Global Prioritization Model  
15 ("GPM") in my testimony in DTE's last rate case and will repeat those critiques later in  
16 this testimony. But for now, the salient point is that the GPM does not determine capital  
17 budget size, or the speed at which strategic programs are implemented. These decisions  
18 are made by DTE management, hired by DTE shareholders to maximize shareholder value.  
19 Due to capital bias, DTE shareholder value is maximized when earnings grow, and  
20 opportunities to grow earnings increase with the size of capital budgets (rate base  
21 increases). As a result, the size of the Company's capital budget, absent regulatory control,  
22 is constrained only by 1) how fast DTE can spend capital; and 2) how much capital DTE

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1 can raise. This is not conducive to sound capital spending governance, and utility  
2 regulation has evolved to serve as constraint on capital spending in the absence of the  
3 capital spending discipline that would normally be instilled through competitive pressure.

4 **Q. Is DTE deficient in its capital project/strategic program planning and cost tracking?**

5 A. For defined capital projects, DTE does not appear to be deficient. It appears to have  
6 processes for planning capital projects, estimating projects costs, securing management  
7 approval, managing project execution, and tracking projects costs. However, for some of  
8 DTE's largest strategic capital programs, DTE planning and cost tracking appear to be  
9 extremely deficient.

10 The Company's Pole and Pole Top Management and Modernization ("PTMM"),  
11 4.8kV circuit hardening, and Distribution Automation (DA) programs appear to be  
12 managed only at the program level as opposed to project level.<sup>26</sup> The annual 4.8kV circuit  
13 conversion budget likewise appear to be a large pot of money from which DTE's  
14 distribution team can use to fund various conversion projects (though better defined) at  
15 will.<sup>27</sup> We could find no established expectations for counts of circuit miles or DA device  
16 installations to be completed for the budgets established for these programs. Apparently,  
17 budgets are established annually for these programs,<sup>28</sup> but there is no telling exactly how  
18 many circuit miles customers can expect will be completed, or DA devices customers can

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<sup>26</sup> See Company responses to MNSCDE 8.15(b) ("The Company budgets and manages the 4.8kV Hardening Program at the program level), 8.16(b) ("The Company budgets and manages the PTMM Program at the program level."); and 8.19(a).

<sup>27</sup> Company response to MNSCDE 8.18(d)(i).

<sup>28</sup> Ex MEC-5, Company response to MNSCDE-8.5c(S1)-02 2023 Budget Appropriation, line 47.

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1 expect will be installed, or the capacity or reliability improvements that will be achieved,  
2 for the established annual budgets for these programs.

3 **Q. Does this present a challenge for the performance evaluation component of capital**  
4 **spending governance?**

5 A. Yes, absolutely. If there is no expectation as to the count of miles or devices installed for  
6 the established budgets, there will be no way to track or manage program spending relative  
7 to expectations. Further, program benefit projections can be over-estimated.

8 Take the PTMM program, for example, which had a program budget of \$127  
9 million in 2023.<sup>29</sup> The Company reports the PTMM budget was for 92 circuits in 2023.<sup>30</sup>  
10 Was PTMM intended to be completed on the entirety of each circuit, or just parts? Did the  
11 amount of PTMM work completed in 2023 for \$127 million meet expectations, or did  
12 customers get less PTMM than the Company expected to deliver for \$127 million? If there  
13 is no expectation, there is no poor performance or good performance relative to budget.  
14 There is only a record of how much money was spent on the program as a whole, which  
15 means nothing without a measurement of units to compare to.

16 Further, the Company's benefit projections for these programs are likely overstated.  
17 If the benefit projected was based on an assumption that the \$127 million budget would  
18 complete 150 miles of PTMM, but only 95 miles of PTMM were actually completed for  
19 \$127 million, customers will clearly not receive the reliability improvements per dollar  
20 anticipated. But as it stands, we cannot even determine how many circuit miles of PTMM

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<sup>29</sup> Ibid, Line 47.

<sup>30</sup> Ex MEC-6, Company response to MNSCDE-8.16(d)(i).

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1           should have been completed for \$127 million, let alone the reliability improvement benefits  
2           customers should have received for \$127 million.

3           **C.     Unintended Consequences of Rider Cost Recovery (such as DTE's IRM).**

4           **Q.     Does the relatively poor capital spending governance at DTE, particularly for large**  
5           **strategic programs, have implications for the use of riders for cost recovery?**

6           A.     Yes. Rider cost recovery increases the need for strong capital spending governance. Rider  
7           cost recovery shifts capital spending risk from shareholders to customers, shifts prudence  
8           responsibilities from utilities to intervenors, and introduces moral hazard into utility  
9           distribution grid investment plan development. I discussed these unintended consequences  
10          at length in my testimony in U-21297,<sup>31</sup> and so I will address them more briefly in this  
11          testimony. But the bottom line is that rider cost recovery (and for the same reasons, even  
12          forward test year ratemaking) marks fundamental changes in the balance of interests  
13          between shareholders and customers that for-profit monopoly utility regulation was  
14          developed to maintain. The Commission should recognize these changes as important  
15          context in evaluating DTE's request to extend and expand rider IRM.

16          **Q.     How does rider cost recovery shift capital spending risk from shareholders to**  
17          **customers?**

18          A.     Once the Commission approves an amount of capital spending for a rider like IRM, the  
19          Commission's practical ability to order a cost disallowance falls to almost zero (for  
20          anything other than gross negligence or malfeasance). This is because any attempt to  
21          identify and then disallow cost recovery after the money was spent would be met with the

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<sup>31</sup> Case No. U-21297, Direct Testimony of Paul J. Alvarez, 6 TR 3332-41.

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1 utility argument that the Commission pre-approved the capital spend, and raises retroactive  
2 ratemaking concerns, which can be difficult for a regulator to reject. Further, if the  
3 Commission were to disallow large costs for recovery, such as the \$127 million DTE spent  
4 in 2023 on the PTMM program, DTE's cost of capital would increase. Customers cover  
5 DTE's cost of capital in rates, countering the impact of a cost disallowance in any event.  
6 To summarize, once the Commission approves a rider of specific dollars in future years,  
7 its practical ability to disallow recovery of the cost of projects included in that spending  
8 falls almost to zero. I suspect that utilities recognize this, and act accordingly by proposing  
9 capital in a rider plan they would not otherwise spend under traditional ratemaking.

10 **Q. How does this impact intervenors?**

11 A. Rider cost recovery (like forward test year ratemaking) shifts the burden of proving  
12 prudence from utilities (in traditional ratemaking, after the capital is spent) to intervenors,  
13 who must now prove imprudence when capital spending projects and programs are initially  
14 proposed. In traditional ratemaking, intervenors could rely on cost disallowance risk to  
15 reduce their prudence burden, because the threat of a disallowance would encourage capital  
16 spending restraint on the part of utilities. In rider (and projected test year) cost recovery,  
17 since regulators' practical ability to order a disallowance post-spending has fallen, utilities  
18 are encouraged to pursue much riskier capital projects and programs than they would  
19 actually spend capital on under traditional ratemaking. Thus, not only has the prudence  
20 burden shifted from utilities to intervenors, the amount of capital spending and the number  
21 of projects and programs intervenors must review and challenge goes up.

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1 Correspondingly, because intervenors have historically been able to rely on cost  
2 disallowance risk to moderate utility capital spending, intervenors' need for technical  
3 expertise to challenge the prudence of capital spending has historically been lower. With  
4 rider cost recovery, intervenors must retain technical experts like myself and Mr. Stephens  
5 to challenge the appropriateness of capital projects and programs proposed for rider cost  
6 recovery in advance of capital spending, and information asymmetry makes it difficult for  
7 intervenors' experts to gather the data needed to evaluate utility spending proposals.

8 **Q. You mentioned that under rider cost recovery, utilities are encouraged to propose**  
9 **much riskier capital projects and programs than they would actually spend capital**  
10 **on under traditional ratemaking. Can you further explain this?**

11 A. Under traditional ratemaking, when utilities face cost disallowance risk, they are careful  
12 not to spend capital on projects or programs at a high risk of cost disallowance, due to the  
13 financial penalties to utilities associated with cost disallowances. Under rider cost  
14 recovery, due to the reduction in regulators' practical ability to order disallowances  
15 described above, utilities have nothing to lose, and everything to gain, by proposing more  
16 capital spending than they would otherwise spend under traditional ratemaking. If a  
17 regulator rejects a capital project or program a utility proposes for rider cost recovery, the  
18 financial penalty to a utility is zero. This is very different from the financial penalties  
19 associated with disallowances of recovery on costs already incurred. Economists call this  
20 *moral hazard*. Rider cost recovery, and the moral hazard it introduces into capital spending  
21 plan development, is the opposite of capital spending constraint.

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1   **Q.   Do you have any evidence that riders like IRM discourage capital spending**  
2       **governance?**

3   A.   An exercise to examine rider cost recovery in every state would be time-prohibitive, but  
4       Michigan- and DTE-specific evidence is available. In his testimony in DTE's current gas  
5       rate case, U-21291, AG Witness Mr. Coppola identifies massive increases in DTE's gas  
6       main replacement program once rider IRM was approved by the Commission. What began  
7       as a \$17.4 million program in 2012 increased to a massive \$350 million program proposed  
8       by 2023.<sup>32</sup> More importantly, DTE's proposal in this proceeding to double the IRM period  
9       and more than quadruple IRM spending relative to what the Commission approved in U-  
10      21297 epitomizes the moral hazard riders introduce into utility investment planning.<sup>33</sup>

11   **Q.   To summarize, capital spending governance is important in for-profit utility**  
12       **regulation, and rider cost recovery is the antithesis of capital spending governance?**

13   A.   Precisely. Rider cost recovery 1) reduces regulators' practical ability to disallow recovery  
14       of capital spending previously approved for a rider; 2) shifts the burden of prudence from  
15       utilities to intervenors; and 3) introduces moral hazard into utility capital budget  
16       development. The end result is a shift in capital spending risk from shareholders to  
17       customers. For these reasons, I recommend the Commission reject DTE's request to extend  
18       and expand rider IRM.

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<sup>32</sup> Case No. U-21291, Direct Testimony of Sebastian Coppola, 4 TR 1453-54.

<sup>33</sup> Revised Foley Direct at NTF-54 Table 1; Ex A-33 Sch X1.

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1   **Q.    Don't the procedural mechanisms the Commission has imposed on DTE's IRM do**  
2       **enough to offset your concerns related to excessive capital spending burden-shifting?**

3    A.   No, they do not. In U-21297, the Commission required DTE to notify Staff and intervenors  
4       about their IRM plans, with an opportunity for questions, and required a contested  
5       reconciliation proceeding.<sup>34</sup> These two procedural mechanism – the preview and  
6       reconciliation – offer little more than lip service to capital spending governance. Since the  
7       Commission set a cap on spending, providing intervenors with a list of planned projects up  
8       to the authorized IRM spending level conceivably *might* allow participating intervenors  
9       with technical expertise to advocate for shifted projects – *e.g.*, start PTMM on a particular  
10      circuit sooner – but changes seem unlikely (DTE is unlikely to shift course so close to start  
11      of the IRM year). Moreover, the preview process still leaves the burden on the intervenors  
12      to counter DTE's plan, not the other way around. The reconciliation contested proceeding  
13      is similarly unredeeming – the money will already have been spent. DTE is asking the  
14      Commission to approve an IRM that adds two more years and another nearly \$1 billion in  
15      distribution capital spending in 2026 and 2027, even before the first IRM year is completed.  
16      Mr. Stephens addresses the weak foundations for the strategic capital programs DTE  
17      proposes for IRM cost recovery, but even if the foundations were solid, the Commission  
18      should reject rider expansion and extension for the reasons discussed above.

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<sup>34</sup> Case No. U-21297, Dec. 1, 2023, Order, pp. 289-90.

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**IV. THE COMMISSION SHOULD REJECT VEGETATION MANAGEMENT COST CAPITALIZATION (EXCEPTING SURGE SECURITIZATION) AND OTHER ETTP PROPOSALS AND ESTABLISH REPORTING AND AUDITING TO ENSURE ETTP BENEFITS ARE RETAINED.**

**Q. Please preview this section of testimony.**

A. This section of testimony addresses the Company's vegetation management proposals. It will begin with some background on vegetation management generally, and briefly cover the history and current state of vegetation management practices at DTE. It will proceed by summarizing DTE's proposals to increase O&M and regulatory asset spending to complete the Enhanced Tree Trimming Program ("ETTP") Surge, and to earn a return on the Surge regulatory asset while it awaits securitization. It will conclude with recommendations regarding DTE's capitalization of vegetation management expenses; recommendations to reject the Company's request to earn a return on the Surge regulatory asset; and a recommendation to order an overhead line right-of-way status audit to be completed every five years, beginning in 2025 or 2026.

**Q. What kind of background on vegetation management would you care to provide?**

A. When vegetation comes into contact with an overhead conductor, it creates a ground fault. As the nearest upstream protective device opens to isolate the fault, an associated service interruption occurs. The need to prevent vegetation from coming into contact with overhead conductor is as old as the industry itself, dating back to the introduction of alternating current, and the lines of conductor required to distribute that current, at the Chicago World's Fair in 1893. Vegetation management has always been one of the largest expenses most utilities must incur. It is characterized by its recurring and incessant nature. It was therefore no surprise that vegetation management was categorized as an operations

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1 and maintenance expense when the Federal Energy Regulatory Commission first  
2 introduced the Uniform System of Accounts.<sup>35</sup>

3 **Q. Does the Uniform System of Accounts permit capitalization of tree trimming expense?**

4 A. Only in the specific circumstance of installing new facilities. (Electric Distribution Plant)  
5 Account 365, Overhead conductors and devices states: “Tree trimming, initial cost,  
6 including the cost of permits therefore.”<sup>36</sup> While the term “initial cost” is somewhat  
7 ambiguous, this ambiguity is cleared by USOA Electric Plant Instruction No. 9, which  
8 states that Plant “*Also include those costs incurred in connection with the first clearing and*  
9 *grading of land and rights-of-way.*”<sup>37</sup>

10 **Q. Has the State of Michigan adopted the federal Uniform System of Accounts?**

11 A. Yes. The Michigan Administrative Code R.460.9002 states “The federal uniform system  
12 of accounts for major and nonmajor electric utilities promulgated by the United States  
13 federal energy regulatory commission and codified at 18 CFR Part 101, as amended  
14 through April 1, 2010, is adopted by reference in these rules as of January 1, 2011. The  
15 rules are prescribed for the use of all electric utilities under the jurisdiction of the Michigan  
16 public service commission . . . unless otherwise ordered by the Michigan public service  
17 commission . . . .” The latter part of the Rule quoted provides the Commission with the  
18 ability to interpret, clarify, or strengthen the Rule as it deems appropriate.

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<sup>35</sup> U.S. CFR Title 18, Chapter I, Subchapter C, Part 101, “UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT. Account 593, Maintenance of overhead lines, Account 593, Part 2.k, “Tree trimming and brush clearing”.

<sup>36</sup> Ibid, Electric Distribution Plant Account 365.

<sup>37</sup> Ibid, Electric Plant Instructions, “9. Equipment”, part A.

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1   **Q.     Has the Commission been asked to interpret the Uniform System of Accounts with**  
2       **respect to vegetation management accounting?**

3   A.    Yes. In the DTE general rate case U-17767, the issue was raised in response to DTE's  
4       request to capitalize its new Enhanced Vegetation Management Program (which has since  
5       been renamed the Enhanced Tree Trimming Program, or "ETTP"). In this former  
6       proceeding, DTE claimed that the more rigorous trimming standard was in effect "a second  
7       initial clearing" of right-of-way because the first clearing was not performed to the new  
8       specification. That interpretation was firmly rejected by the Commission Staff's  
9       engineering specialist Peter Derkos.<sup>38</sup> The ALJ, and subsequently the Commission in its  
10      U-17767 order, agreed with Staff regarding the interpretation of the Michigan USOA, that  
11      the new (ETTP) program is not a first clearing of rights-of-way, and thus is properly an  
12      operation and maintenance expense.<sup>39</sup> Specifically, the Order states "...the Commission is  
13      not persuaded that this cost category is appropriate for capitalization." "The EVMP effort  
14      is not a first clearing, because all of these ROW's have been cleared before, possibly  
15      multiple times.... Having rejected capitalization treatment, the amount of allowed expense  
16      is addressed under net operating income."

17   **Q.     What do you conclude regarding the capitalization of vegetation management**  
18       **spending?**

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<sup>38</sup> Case No. U-17767, Direct Testimony of Peter Derkos, 8 TR 2088.

<sup>39</sup> Case No. U-17767, Oct. 8, 2015, PFD, pp. 86-87, Dec. 11, 2015, Order, pp. 25-27.

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A. I conclude that the only permitted capitalization of vegetation management spending is in the initial construction of a brand-new overhead distribution line. Any other capitalization of tree trimming expense is an unequivocal violation of the Michigan USOA.

**Q. Does DTE capitalize vegetation management spending for reasons other than initial construction of a brand-new overhead distribution line?**

A. Yes. DTE seems to have adopted the policy that if vegetation management is required to complete the work of a capitalized project, the vegetation management spending associated with the project is capitalized as well.<sup>40</sup> Depending on last trim date and the scope of work, extensive if not total trimming of trees is undertaken for projects completed under the 4.8kV hardening, 4.8kV conversion programs, PTMM, and Distribution Automation. As each of these programs involves dozens of miles of circuit work annually, the amount of vegetation management spending the Company is capitalizing annually through these programs is significant:<sup>41</sup>

| <b>Program</b>          | <b>2022 Capital Investment</b> | <b>2023 Capital Investment</b> | <b>Total</b>   |
|-------------------------|--------------------------------|--------------------------------|----------------|
| 4.8kV Hardening         | \$34.6                         | \$18.40                        | <b>\$53.0</b>  |
| 4.8kV Conversions       | \$0.4                          | \$2.10                         | <b>\$2.50</b>  |
| PTMM                    | \$8.8                          | \$9.30                         | <b>\$18.10</b> |
| Distribution Automation | \$0                            | \$0.17                         | <b>\$0.17</b>  |
| <b>Total</b>            | <b>\$43.80</b>                 | <b>\$29.97</b>                 | <b>\$73.77</b> |

**Q. Has the Commission considered DTE's practice of capitalizing tree trimming associated with the hardening, conversion, and PTMM programs?**

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<sup>40</sup> Ex MEC-3, Company response to MNSCDE-15.25d, e, f.

<sup>41</sup> Ex MEC-3, Company Response to MNSCDE-15.25g, h.

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1 Y. Yes. In U-21297, the Commission determined that it would be better to evaluate this issue  
2 after the audit of the company's practice is complete, which is expected later in 2024.<sup>42</sup>  
3 The Commission adopted the ALJ's recommendation on this topic: "While this PFD  
4 recognizes DTE's incentives to capitalize rather than expense tree-trimming, it appears the  
5 company's accounting practice has been ongoing for a while. With the impending audit,  
6 this PFD concludes that it is preferable to await the audit results. In the meantime, DTE  
7 should be reminded that it needs to retain records to establish the legitimacy of its  
8 choices."<sup>43</sup>

9 **Q. What are your recommendations to the Commission regarding DTE's capitalization**  
10 **of vegetation management spending associated with these strategic capital programs?**

11 A. With respect to the tree trimming costs capitalized as part of the PTMM, 4.8kV Hardening,  
12 4.8kV Conversion, and Distribution Automation programs (including spending through the  
13 IRM), I recommend the Commission:

- 14 • Require DTE in its next rate case to identify the extent that it capitalized tree  
15 trimming costs in each program, each year, from 2021 through 2024;
- 16 • Require DTE to present in its next rate case an analysis of the full costs to  
17 ratepayers resulting from its decision to capitalize tree trimming costs compared  
18 to the cost of on-cycle maintenance O&M trimming; and
- 19 • Require DTE in its next rate case to explain the legitimacy of its decision to  
20 capitalize tree trimming expenses for distribution capital programs.

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<sup>42</sup> Case No. U-21297, Order, p. 281; Foley Revised Direct at NTF-60.

<sup>43</sup> Case No. U-21297, Oct. 5, 2023, PFD, p. 701.

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1     **Q.     What are your impressions of DTE’s Enhanced Tree Trimming Program and Surge?**

2     A.     ETTP was clearly necessary, and the Commission rightly required DTE to securitize Surge  
3           costs and deny DTE shareholders a rate of return on those costs. It is clear to Mr. Stephens  
4           and I that DTE’s poor reliability performance in recent decades, including several major  
5           storm incidents accompanied by weeks-long service interruptions for thousands of  
6           customers, has been caused in large part by DTE’s apparently frequent decisions to defer  
7           scheduled and budgeted tree trimming to future years. Given that cost-of-service  
8           ratemaking provides utilities with an economic incentive to reduce Operations and  
9           Maintenance spending between rate cases, and given the large size of annual vegetation  
10          management budgets, the temptation to defer vegetation management spending to hit  
11          earnings targets promised to Wall Street may be difficult for utility executive teams to  
12          resist. But compounded over years, the impact of DTE’s deferrals on the service reliability  
13          customers experience is clearly significant and should not have been tolerated by previous  
14          Commissions.

15                 Notwithstanding those deferrals, the responsibility to remedy the problem, and to  
16                 ensure it does not arise again, is clearly owned by the current DTE executive team and  
17                 Commission. Shareholders have benefitted for so many years at customers’ expense, and  
18                 this Commission should seize every opportunity available to restore the balance between  
19                 shareholder and customer interest that for-profit monopoly regulation is intended to  
20                 maintain.

21     **Q.     Have you reviewed Mr. Lepczyk’s proposal for DTE to earn a return for shareholders**  
22     **on the Company’s ETTP Surge Regulatory Asset?**

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1     A.     Yes. I understand that securitization, like any bond or equity offering, entails significant  
2           fixed costs, and that customer costs can be reduced through the use of fewer, larger-sized  
3           securitization events. I also understand that between securitization events, the associated  
4           regulatory asset used to track Surge costs can get quite large.

5                 On the other hand, it is clear that shareholders have reaped the rewards of increased  
6           earnings as DTE decisions to defer scheduled tree trimming were made year after year. It  
7           is even clearer that customers have paid the price for DTE's decisions to defer scheduled  
8           tree trimming through poor reliability performance, and that DTE is now using its poor  
9           reliability performance to justify massive and growing strategic capital spending.  
10          Customer frustration with the disconnect between large increases and poor reliability  
11          performance, as indicated by the excerpts from customer comments presented earlier, is  
12          palpable.

13    **Q.     What is your recommendation regarding the Company's request to earn a**  
14       **shareholder return on the Surge regulatory asset?**

15    A.     The regulatory compact provides the Commission with guidance on this DTE proposal.  
16           Under the compact, the state awards a monopoly for a defined service area. In exchange,  
17           the utility agrees to provide non-discriminatory service to all customers in that service area  
18           who request it and to make the investments necessary to provide that service in a safe and  
19           reliable manner. To compensate the utility for raising and investing capital and taking risk,  
20           the state offers the utility an opportunity to earn a fair rate of return on used and useful  
21           invested capital. The monopoly award continues at the option of the state, which controls  
22           the utility's rates.

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1           The state of Michigan, in the form of the Commission, has upheld its end of the  
2 compact. The Commission has continued to award DTE an electric distribution monopoly,  
3 and a fair opportunity to earn a rate of return on invested capital, since 1909, when the  
4 Michigan Legislator first authorized the Commission to regulate electric utilities.  
5 However, by continuing to defer scheduled tree trimming year after year, DTE appears to  
6 have taken advantage of the state-awarded monopoly. Shareholders benefitted at customer  
7 expense from deferred tree trimming. By authorizing a rate of return on the Surge  
8 regulatory asset the Commission would be rewarding the Company for the poor and self-  
9 interested tree trimming deferral decisions the Company has made in the past. As the need  
10 for the ETTP Surge was a problem of DTE's own making, providing such a reward would  
11 be inappropriate.

12           Further, the provision of a return for shareholders on the Surge regulatory asset,  
13 when no such return is provided on securitized loans (at present), results in an economic  
14 incentive to make the Surge regulatory asset as large as possible. One way the Company  
15 might increase the size of the regulatory asset would be to delay securitization events. This  
16 would not be in customer's interest, as DTE's weighted average cost of capital (including  
17 profits for shareholders), plus income taxes on regulatory asset profits customers must pay,  
18 results in much higher costs for customers on the regulatory asset relative to the cost of the  
19 securitized loans. My recommendation is that the Commission reject the Company's  
20 request to earn a return for shareholders on the Surge regulatory asset, thereby negating the

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1 Company's incentive to increase the size of the regulatory asset and remaining consistent  
2 with the Commission's treatment of this regulatory asset in prior cases.<sup>44</sup>

3 **Q. Now that the company is reaching the end of its ETTP Surge, what should the**  
4 **Company do to maintain a five-year vegetation management?**

5 A.

6 A. It is critical that the Commission ensure DTE not resume its historic pattern of deferring  
7 tree trimming, and the Commission should institute regulatory guardrails to ensure that  
8 outcome. My first recommendation is that the Commission order DTE to continue its  
9 annual public report of tree trimming that it initiated in U-20162.<sup>45</sup> The annual report  
10 provides valuable public information about spending, miles cleared, and reliability  
11 performance.<sup>46</sup>

12 My second recommendation is that the Commission institute a periodic audit of the  
13 actual state of the Company's overhead rights of way. There are many reasons for the  
14 Commission to institute a periodic audit of the actual state of the Company's overhead  
15 rights of way. First, maintaining the Company's rights of way has been shown to be one  
16 of the most critical drivers of DTE's reliability performance. Second, the Company's  
17 incentive to increase earnings by deferring scheduled vegetation management will remain  
18 once the Surge is complete. Third, the Company has demonstrated an inability to resist  
19 vegetation management deferral in the past. Fourth, the impact of such deferrals is difficult

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<sup>44</sup> See, e.g., Case No. U-21297, Dec. 1, 2023, Order, p. 280.

<sup>45</sup> Case No. U-20162, May 2, 2019, Order, pp. 80-81.

<sup>46</sup> Ex MEC-4, March 1, 2024, DTE Tree Trim Annual Report.

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1 to detect immediately, as reliability deterioration only becomes apparent after years of such  
2 deferrals. Fifth, it is difficult for intervenors to ascertain the state of the Company's  
3 overhead rights of way. Sixth, there can be variation in compliance with right-of-way  
4 distance clearing compliance among various contractors and crews. Seventh, vegetation  
5 management is completed under a variety of Company programs (4.8kV conversions,  
6 4.8kV hardening, and PTMM), and it could be difficult to track the effectiveness of these  
7 relative to routine tree clearing cycle work. Eighth, the Company is proposing new  
8 approaches to vegetation management in the future,<sup>47</sup> and it will be important to make an  
9 objective determination as to how those new approaches fare relative to existing best  
10 practices.

11 **Q. What would such an audit look like?**

12 A. I recommend that a right-of-way audit be conducted once every five years by an  
13 independent expert, preferably retained and managed by Staff, with procurement processes  
14 open to intervenor participation. The audit would be designed around a set of circuits or  
15 circuit miles selected at random. The sample size should be statistically significant relative  
16 to total overhead line miles. The audit would measure the average line clearances along  
17 each circuit or line mile selected for the sample. The first audit would determine whether  
18 the Surge has been completed and could also serve as the baseline result against which  
19 future audit results could be compared. The end of the Surge presents a unique opportunity  
20 to establish such baselines that I recommend the Commission not miss. I therefore  
21 recommend the first audit be completed in 2025, or 2026 at the latest. The expert should

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<sup>47</sup> Direct Testimony of Rachel C. Steudel, RCS-27 through RCS-32.

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1 make recommendations regarding the sufficiency of the width of the rights of way the  
2 Company has defined for its ETTP.

3 **V. DTE'S GLOBAL (PROJECT) PRIORITIZATION AND RELIABILITY**  
4 **(IMPROVEMENT PROJECTION) MODELS ARE UNRELIABLE**

5 **Q. Please preview this section of testimony.**

6 A. This section critiques two models critical to the capital budgets DTE presents for approval  
7 in the instant application. The Global Prioritization Model prioritizes projects and program  
8 spending in the Company's capital budgets, but does so in an unreliable manner. DTE uses  
9 its Reliability Model to project system-wide reliability improvements from several large  
10 strategic capital programs, including ETTP, 4.8kV Hardening, PTMM, 4.8kV circuit  
11 conversions, and Distribution Automation. It uses these projections to justify the levels of  
12 spending proposed for these programs in the instant application. The Commission should  
13 not rely upon these projections to determine the appropriate level of spending for these  
14 programs.

15 **A. DTE's Global Prioritization Model is unreliable as to both outputs and Model**  
16 **application**

17 **Q. What are your concerns regarding DTE's Global Prioritization Model?**

18 A. It is appropriate for DTE to prioritize its capital spending in a way that reduces risks, such  
19 as risks to reliability and safety, from greatest to smallest. Some investments utilities make  
20 are required, such as investments to connect new customers within its defined service area,  
21 or to replace damaged or failed equipment, or to expand capacity when load forecasts  
22 indicate equipment ratings will be exceeded in the near term. There is no need to prioritize

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1       these investments, or to complete benefit-cost analyses on such investments, because there  
2       is no option to avoid or defer such investments. But all other investments utilities make  
3       are discretionary, providing optionality as to whether to spend, how much to spend, where  
4       to spend, and over what time frames (how fast) to spend.

5               DTE's strategic capital programs are all discretionary as to whether to spend, how  
6       much to spend, where to spend, and over what time frames. As Mr. Stephens's testimony  
7       points out, there are important questions to be answered when making decisions about  
8       discretionary investments. These include: 1) Do the benefits to customers from the project  
9       or program exceed the program's costs to customers? 2) For programs, what is the optimum  
10      geographic extent of deployment (i.e., on which circuits or in what circumstances are the  
11      benefits most likely to deliver benefits in excess of costs)? and 3) For programs, what is  
12      the optimum timing/deployment speed? The Company's GPM does not address any of  
13      these questions.

14   **Q.    If DTE's GPM does not answer these questions, what does it do?**

15   **A.**   DTE's GPM model purports to rank capital projects and programs based on their ability to  
16       reduce risk, from highest to lowest. However, in Mr. Stephens's and my estimation, it does  
17       so in a very unreliable manner, for at least three reasons. First, DTE's Global Prioritization  
18       Model (GPM) assigns risk reduction values (scores) to projects and programs that are based  
19       in largest part on inputs subjectively assessed by employees. The model calculates a risk  
20       score for each of ten "impact dimensions" (generally, different types of risk, such as safety,  
21       reliability, etc.). Some impact dimensions seem to overlap, and perhaps double-count a  
22       particular type of risk. For example, two dimensions are "overload relief" and "capacity  
23       relief"; three others are "major event risk", "SAIDI", and "SAIFI".

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1           While multiple inputs are employed to calculate the risk score for each impact  
2           dimension, most of these inputs are not data-driven (i.e., based on historical experience,  
3           research, or pilot results), but based on subjective GPM user assessments. Further, there  
4           are no estimates for current-state risk to serve as a basis of comparison. This means there  
5           are no estimates of the existing likelihood of an adverse event, and no estimate of the size  
6           of such an event's consequences. These attributes are critical to determining the size of  
7           the risk being addressed by a project or program, which in turn indicates whether the risk  
8           is significant enough to warrant attention in the first place. Still further, risk reduction  
9           estimates (such as a projected reduction in customer minutes interrupted) are input with no  
10          indication of the scale of the reduction relative to current-state risk. For example, does a  
11          100,000 minute reduction in customer minutes interrupted represent a 2% reduction from  
12          the baseline, or a 50% reduction from the baseline? In summary, the subjective inputs  
13          outweigh the data-driven inputs, making the model's outputs highly malleable, and even  
14          the data-oriented inputs (largely, risk reduction estimates) are suspect, and difficult to  
15          evaluate or place into context. A model user can get the GPM outputs he or she desires for  
16          a particular project or program simply by manipulating subjectively-assessed model inputs  
17          for the project or program.

18               Once impact dimension scores are calculated from inputs that are mostly subjective,  
19               weightings are applied. As examples, reliability scores are worth 50% more than the  
20               "Regulatory Compliance" scores, and the Regulatory Compliance scores (along with a few  
21               others, such as capacity relief) are worth double the cost avoidance scores (for O&M and  
22               capital). These weightings appear to be entirely subjective.

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**Q. What is your second concern about the GPM and the reliability of its outputs?**

A. My second concern is that risk reduction value associated with projects and programs are scores, not dollars. Failure to express risk reduction value in dollars prohibits the completion of any kind of benefit-cost analysis for the projects and programs DTE recommends. Though the Company does compare the total risk score of a project or program to its costs, and uses this result to rank projects and programs, this is not a benefit-cost analysis. It indicates that project or program “A” might deliver more benefits per dollar than project or program “B”, but the likelihood that either project will deliver greater customer value (in dollars) relative to customer costs (in dollars) is completely unknown. Remember, GPM is used to rank *discretionary* projects and programs. When determining whether to move forward with a discretionary project or program, the ratio of customer value (in dollars) to customer costs (in dollars) is the single most important question to answer.

**Q. What is your third concern about the GPM?**

A. Third, the GPM does not distinguish between discrete “projects” (such as a \$7 million project to replace equipment at the Port Huron substation) and massive “programs” (such as the PTMM program, estimated at \$715 million, or Distribution Automation, estimated at \$1.162 billion, or 4.8kV hardening, at \$259 million). Clearly, within these programs, application to some circuits will deliver greater benefits than application to other circuits. Thus, the GPM does not answer the other two questions critical for discretionary projects and programs: which circuits or circumstances warrant treatment, and over what time frames should these be completed?

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1     **Q.     Do you have any other concerns about the GPM model or its application?**

2     A.     Yes, and it is a big one: DTE does not use the GPM model to score its Enhanced Tree  
3           Trimming Program or the associated Surge spending. If the GPM model were more  
4           reliable, and if the GPM model were to be applied to ETTP, Mr. Stephens and I are  
5           confident that ETTP and the associated Surge would rate a top priority program, far ahead  
6           of all the strategic capital programs.

7     **Q.     How would you summarize your concerns about DTE’s GPM and its application?**

8     A.     I believe AG-MN summarized the GPM and its application succinctly in its Briefs in  
9           DTE’s last rate case, and I note the Administrative Law Judge repeated AG-MNSC’s  
10          summary in her proposal for decision:<sup>48</sup>

11                 “If I have a list of 10 possible purchases and I rank them from #1 through  
12                 #10, that tells me what order to buy them in but it tells me nothing about  
13                 whether to buy the first one of them, or the first three, or the first five, etc.  
14                 Nor does it tell me how many of the purchases I can afford. Nor does it tell  
15                 me which purchases will have more value to me than they will cost. Nor  
16                 does it tell me whether to buy all of them over two years, or five years, or  
17                 ten years. The GPM similarly tells DTE none of these things.”

18    **Q.     What are your recommendations to the Commission regarding DTE’s GPM?**

19    A.     I recommend the Commission avoid relying on the GPM or its outputs, and that the  
20           Commission question the manner in which DTE is applying the GPM. This  
21           recommendation is based on GPM’s failure to adequately answer any of the questions  
22           critical to decision-making on discretionary programs – benefits (in dollars) relative to  
23           costs (in dollars); appropriate geographic extent; and appropriate speed of deployment.

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<sup>48</sup> Case No. U-21297, Oct. 5, 2023, PFD, p. 188.

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**Q. How do you recommend DTE calculate the customer value of discretionary projects and programs?**

A. Mr. Stephens and I recommend risk-informed benefit cost analyses be completed on all discretionary projects over a certain size (measured in capital dollars). The California Public Utilities Commission recently required risk-informed benefit cost analyses to be completed on all projects designed to improve reliability or safety.<sup>49</sup> The calculation for monetizing risk reduction benefits in dollars is presented below. Mr. Stephens and I recommend the reduction in the likelihood of an adverse event risk be estimated through the use of pilots, research, or historical experience, and that the consequences be estimated by circuit (in a reliability example, customer counts and likely service interruption durations associated with the adverse event a project is intended to mitigate.)

$$\begin{array}{ccccc} \text{Value of} & & \text{Reduction in} & & \text{Consequence} \\ \text{Risk} & & \text{the} & & \text{of the} \\ \text{Reduction} & = & \text{Likelihood} & \times & \text{Adverse} \\ \text{(in \$)} & & \text{of an} & & \text{Event (in \$)} \\ & & \text{Adverse} & & \\ & & \text{Event (in \%)} & & \end{array}$$

**Q. How do you recommend DTE determine the appropriate capital budgets and deployment speeds for various capital programs?**

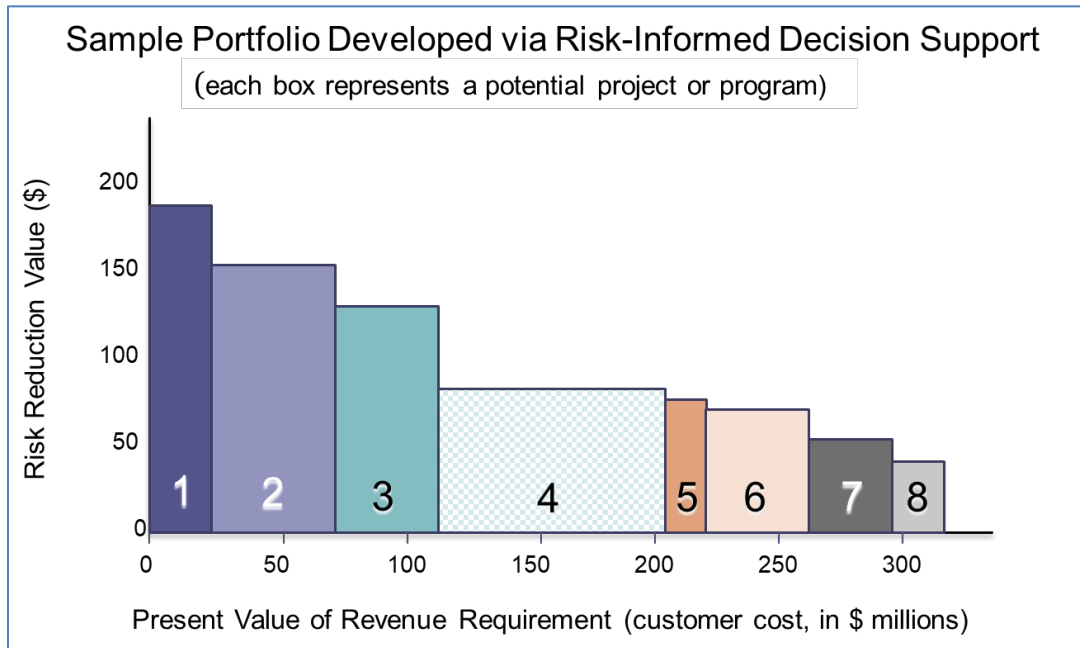
A. I recommend a systematic approach called risk-informed decision-making, or “RIDM” (also known as risk-informed decision support, or “RIDS”). It is ideal for optimizing a capital budget, and for selecting the projects that comprise it, when faced with constraints

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<sup>49</sup> California PUC R20-07-013, Dec. 15, 2022, Decision 22-12-027, Appendix A.

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(such as an interest in maintaining customer affordability). Using individual risk-informed benefit-cost analyses completed on a portfolio of potential projects as a starting point, the approach helps logically identify projects appropriate for deferral to future periods by making informed trade-offs. Ranking programs based on benefits (in dollars) relative to costs informs the trade-offs associated with various capital spending levels. A chart depicting the conceptual application of RIDS to a portfolio of potential projects is presented below.



The chart indicates that project 4 should be eliminated from further consideration, as costs exceed benefits. For the remaining projects, the size of the total capital budget informs the projects that should be deferred to a future period in an order that keeps the most beneficial projects and defers the least beneficial (as measured by benefits relative to costs). A total capital budget of \$115 million looks like a good breakpoint, as it would retain projects 1, 2, and 3 in the budget. An extra \$100 million would permit inclusion of

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1 projects 5 and 6. An additional \$100 million beyond that would include projects 7 and 8,  
2 and so on. With risk-informed decision-making, a utility and its regulator and stakeholders  
3 know the additional benefits they will get by increasing a capital budget, as well as the  
4 benefits that will be foregone by reducing a capital budget. These are the *informed trade-*  
5 *offs* mentioned above.

6 The point is that there are likely much better ways to develop capital budgets than  
7 the approach DTE is using, which appears to be almost entirely subjective with respect to  
8 the Company's strategic capital programs. As indicated earlier in this testimony (using  
9 PTMM as an example), the determination of how much capital should be devoted to  
10 various strategic capital programs – and therefore the number of circuits to be addressed  
11 and speed of deployment – appears to be based on subjective decisions made by senior  
12 management.<sup>50</sup> Also described earlier, senior management decisions about how much  
13 capital to invest, and how soon, are driven by capital bias. As a result, reliance on utility-  
14 proposed capital spending increases is not advised. Another DTE model, the Reliability  
15 Model, might be invoked in considering the optimum size of budgets for various strategic  
16 capital programs. This testimony turns to this subject next.

17 **B. The Reliability Model DTE uses to project system-wide improvements is**  
18 **unreliable.**

19 **Q. Please summarize DTE's Reliability Model**

20 A. DTE's Reliability Model projects system-wide improvements in average service  
21 interruption duration (SAIDI) and frequency (SAIFI) from various strategic capital

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<sup>50</sup> Ex MEC-5, Company Supplemental Response to MNSCDE-8.5c(SI) together with attachments 2022, 2023, and 2024 Budget Appropriations; also Ex MEC-6, Company response to MNSCDE-8.16(d)(i).

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1 programs. These programs include ETP, 4.8kV Hardening, PTMM, 4.8kV circuit  
2 conversions, and Distribution Automation. DTE uses the Reliability Model's improvement  
3 projections to justify the size of its strategic capital program budgets. By implication, the  
4 Model's reliability improvement projects are also intended to justify most of the  
5 Company's request to extend and expand rider IRM.

6 **Q. How does DTE's Reliability Model work?**

7 A. The Reliability Model applies reliability improvements secured historically from these  
8 programs to circuits selected for these programs in the future. Characteristics specific to  
9 each circuit, including customer counts, overhead line miles, and historical reliability  
10 performance, are used to project reliability improvements for each circuit based on units  
11 (generally, line miles) of program to be completed.

12 **Q. Why do you believe DTE's Reliability Model to be unreliable?**

13 A. DTE's Reliability Model is an unreliable predictor of reliability improvements from  
14 strategic capital spending for at least four reasons:

- 15 • Circuits that had been recently tree trimmed were eliminated from the control groups  
16 used to determine historical program reliability improvement performance, inflating  
17 reliability improvement projections;
- 18 • Only one year's pre-program circuit reliability was used to establish baseline  
19 performance against which to compare post-program reliability improvements;
- 20 • Program "units completed" used by the Model to project reliability improvements are  
21 unlikely to be completed for the budgets provided, inflating reliability improvement  
22 projections;
- 23 • DTE refuses to place any of its profits at risk for failing to achieve the all-weather  
24 reliability improvements the Model projects.

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1   **Q.     Please explain how the control group definitions DTE used to determine historical**  
2       **program performance inflate reliability improvements projected by the Model.**

3   A.     The Model attempts to use the historical reliability improvements demonstrated by various  
4       programs to project future reliability improvements from those programs. While this  
5       sounds eminently logical, it relies on accurate historical reliability improvement  
6       performance measurement. DTE's historical reliability improvement performance  
7       measures for various programs (with the exception of ETTP) are not accurate.

8               As explained earlier, multiple strategic capital programs require tree trimming as  
9       part of program implementation. Trees must be completely trimmed to complete PTMM  
10      work and 4.8kV hardening work, and to complete many types of 4.8kV conversion work.  
11      Even the installation of Distribution Automation devices requires a small amount of tree  
12      trimming, as does tie-line capacity expansion for Distribution Automation. This means it  
13      is extremely difficult to isolate the reliability improvements resulting from tree trimming  
14      from the reliability improvements resulting from strategic capital program work.

15             DTE did not attempt to isolate the impact of tree trimming from the impact of  
16      strategic capital program spending when determining historical reliability performance of  
17      the programs. In fact, DTE made matters worse by eliminating circuits that had been tree  
18      trimmed from the control group used to determine historical reliability performance.<sup>51</sup>

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<sup>51</sup> See Company response to MNSCDE-8.1(i)(i) ("Explain, and provide a definition for, how circuits were selected for the 2018, 2019, 2020, and 2021 Control Groups. Provide a list of the circuits selected for each control group, and provide, for each" i. The substation and circuit identification; **Answer:** The control group consists of 4.8kV circuits that were never hardened and excludes those tree-trimmed in recent years. These circuits were selected as the control group for 4.8kV Hardening because they were typically designed and constructed during similar time periods with similar construction standards and are the same voltage class

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DTE appears to have applied the “difference of differences” approach to determine the historical reliability improvements of various strategic capital programs. In this approach, a group of circuits to which a program was applied is used as a test group, and a group of circuits to which a program had not been applied is used as a control group. Reliability statistics are recorded for both groups pre- and post-program application. The change (difference) in reliability pre- to post-program in the test group is compared to the change (difference) in reliability in the control group over the same time periods to determine the improvement in reliability resulting from the program. The table below provides an example.

| <b>(All figures in minutes)</b>                                 | <b>Average SAIDI Before Program</b> | <b>Average SAIDI After Program</b> | <b>Difference, Pre- to Post-Program</b> |
|-----------------------------------------------------------------|-------------------------------------|------------------------------------|-----------------------------------------|
| Test Group Circuits                                             | 100                                 | 90                                 | 10                                      |
| Control Group Circuits                                          | 100                                 | 102                                | 2                                       |
| Difference of differences (improvement attributed from Program) |                                     |                                    | 12                                      |

Circuits that have not had tree trimming will certainly perform much worse than circuits that have had tree trimming. Removing circuits that have had tree trimming creates an unfair control group for comparison. In fact, the proper control group for strategic capital programs that necessarily involve tree trimming is a control group consisting ONLY of circuits that received tree trimming at the same time, but no program spending. This would create an appropriate comparison, as both test and control group circuits had tree trimming, but only the test group had both tree trimming and a program applied. This

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as circuits hardened. As circuits are hardened or tree trimmed, they are removed from the control group in subsequent years.”).

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1 would isolate the impact of the tree trimming from the impact of the program. As it stands,  
2 the reliability improvements the Model applies for programs that involve extensive tree  
3 trimming, including PTMM, 4.8kV hardening, and many if not most 4kV conversions are  
4 dramatically overstated, meaning that the program benefits the Model projects for future  
5 circuits are also dramatically overstated.

6 **Q. Why would using only one year's pre-program reliability performance as a baseline**  
7 **for comparison to post-program reliability be a problem?**

8 A. Weather variation is a big deal in reliability performance measurement. This is true even  
9 in cases where reliability data without major event days (generally, storms) is used to  
10 calculate reliability improvements, as DTE did when developing its Reliability Model.  
11 Consider a year in which a utility's service territory was subjected to an average number  
12 of major thunderstorms that were not classified as major event days. Let us assume that  
13 the average number of major thunderstorms not classified as major event days for our  
14 hypothetical utility is 10 storms. In the following year, assume the utility experiences 20  
15 major thunderstorms that did not qualify as major event days. The reliability results of  
16 these two years, even with major event days excluded, will be very different.

17 Weather variation is the reason why Mr. Stephens and I always recommend using  
18 a minimum of three years' pre-deployment data as a baseline for quantifying reliability  
19 improvements from a program. (We also recommend using a minimum of three years'  
20 post-deployment data for the same reason.) DTE only employed one year of pre-

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deployment reliability data to use as a baseline for calculating reliability improvements from strategic capital programs.<sup>52</sup>

**Q. Please explain why “units completed” used by the Model to project reliability improvements are unlikely to be completed for the capital budgets DTE requests, and how this results in exaggerated reliability improvement projections.**

A. The Model incorporates “units completed” by program to calculate reliability improvements.<sup>53</sup> As the number of units goes up, reliability improvements calculated by the Model increase, just as one would expect. However, this makes the Model sensitive to the counts of units completed. By comparing units completed over time in the Model to program budgets DTE proposes in its application over time, I calculated a cost per unit completed. Surprisingly, the cost per unit completed goes down over time for all five strategic capital programs, in some cases significantly. My calculations are presented in the table below.

|                 | Cost per Unit Completed, 2024 | Cost per Unit Completed, last year data is available <sup>54</sup> | Fall in cost per unit completed over time. |
|-----------------|-------------------------------|--------------------------------------------------------------------|--------------------------------------------|
| ETTP            | \$ 4,689                      | \$ 3,902                                                           | 17%                                        |
| 4.8kV Hardening | 55,172                        | 34,722                                                             | 37%                                        |

<sup>52</sup> Direct Testimony of Allen J. Kryscynski at AJK-71:20.

<sup>53</sup> For most programs, “units” appear to represent circuit miles, but for Distribution Automation the “units” appear to be devices installed. See workpaper WP AJK U-21534 Reliability Model, tab “Program Inputs”.

<sup>54</sup> For ETTP and 4.8kV Hardening programs, the last year data is available is 2025. Budgeted spending for these programs comes from Ex A-12 Sch B5.4, with ETTP from Steudel Direct, RCS-24, Table 7. For PTMM, 4.8kV Conversions, and Distribution Automation programs, the last year data is available is 2027. Budget data for these programs comes from Ex A-33 Sch X1 (IRM).

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|                         |         |         |     |
|-------------------------|---------|---------|-----|
| PTMM                    | 8,416   | 7,547   | 10% |
| 4.8kV Conversion        | 255,982 | 104,348 | 59% |
| Distribution Automation | 9,265   | 7,200   | 22% |

As costs typically go up over time, not down, particularly in these inflationary times, I am concerned that the number of “units completed” in the model are exaggerated relative to the number of units the Company will be able to complete for the capital budgets indicated. If the Company is unable to complete the count of units the Model assumes for the budgets indicate, the reliability benefits the Model projects will be unachievable, and the Model will again be exaggerating the reliability improvements projected. Given that DTE does not appear to employ any measurement standard for dollars per circuit mile completed or devices installed, discussed earlier in this testimony, my observation regarding variability in units completed is particularly concerning.

**Q. Are there any other reasons to question the reliability improvements the Model projects?**

A. Yes. DTE refuses to place any of its profits at risk for failure to achieve the reliability improvements its Model predicts.<sup>55</sup> While the Company cites weather variability as the reason, there are ways to address this concern. If the Company were truly confident in the improvements projected by its Reliability Model, it should be willing to place some of its profits at risk. As it stands, customers bear 100% of the risk that the value of reliability

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<sup>55</sup> Ex MEC-7, Company response to MNSCDE-7.2(h).

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1 improvements DTE delivers from its strategic capital programs will not be enough to cover  
2 the rate increases customers will have to pay for these programs.

3 **VI. THE COMMISSION SHOULD REJECT DTE'S GRID AUTOMATION**  
4 **TELECOMMUNICATIONS PLAN AND DISALLOW COSTS INCURRED TO**  
5 **DATE**

6 **Q. Please provide a preview of this section of testimony.**

7 A. This section of testimony supports my recommendation that the Commission reject DTE's  
8 Grid Automation Telecommunications plan and disallow costs incurred to date. It will  
9 summarize the plan, identify the presumptions DTE makes in justifying its plan, and  
10 explain the deficiencies in these assumptions.

11 **Q. Please summarize DTE's Grid Automation Telecommunications Plan.**

12 A. DTE's Grid Automation Telecommunications Plan consists of expanding the Company's  
13 fiber-optic data communications network (the largest part of the Plan's spending through  
14 2025),<sup>56</sup> largely through connections to substations. The Company then plans to use that  
15 network as a base for a "last mile" wireless communications expansion,<sup>57</sup> which DTE plans  
16 for communications to smart meters, distribution automation and other field devices,  
17 distributed energy resources, autonomous (presumably electric) vehicles, and "mobile  
18 assets".<sup>58</sup> The Company's Plan will cost almost \$107 million 2022-2028.<sup>59</sup>

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<sup>56</sup> Direct Testimony of Shannen M Hartwick at SMH-22:17.

<sup>57</sup> Ibid, at SMH-26:20.

<sup>58</sup> Ibid, at SMH-25:7 and SMH-26:4.

<sup>59</sup> Ex. A-12 Sch B5.4, page 17, line 6 (for 2022-2025); Ex A-23 Sch M8 (2023 DGP), p. 137 of 274, Exhibit 10.1.3 (for 2026-2028).

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1    **Q.     How does the Company communicate with substations and remote devices today?**

2    A.     Like all utilities of which I am aware, the Company communicates with substations and  
3           remote devices today through a variety of technologies, including fiber-optic cable and  
4           wireless technologies such as microwave, cellular, and radio (for smart meters). The  
5           Company owns the equipment that delivers some of these communications services, but  
6           also secures both fiber-optic and wireless communications services through third parties.  
7           As just one example, the Company owns fiber to about 25% of its substations, leases fiber  
8           serving about 1% of its substations, and communicates with the rest of its substations using  
9           both owned wireless equipment and leased wireless communication services.<sup>60</sup>

10   **Q.     What is the total cost of DTE's Grid Automation Telecommunications Plan?**

11   A.     The Company refused to provide details for the plan beyond 2025, citing that details for  
12           the Plan beyond 2025 are beyond the scope of the Company's application.<sup>61</sup> The  
13           Company's 2023 Distribution Grid Plan provides no additional information on the  
14           Telecommunications Plan.<sup>62</sup>

15   **Q.     What do you think of DTE's refusal to provide Plan information beyond 2025?**

16   A.     The fiber-optic cable installations proposed through 2025 are part and parcel of the  
17           Company's larger Plan. One cannot evaluate the appropriateness of the DTE proposal to

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<sup>60</sup> Ex MEC-8, Company response to MNSCDE-7.4(a).

<sup>61</sup> Ex MEC-8, Company response to MNSCDE-7.4(b); *see also* Ex MEC-9, Company response to MNSCDE-7.3.

<sup>62</sup> See Ex A-23 Sch M8 (2023 DGP), pp. 140-42 of 274.

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1 install fiber-optic cable through 2025 without an understanding of DTE's entire Plan, as  
2 the Telecommunications Plan appears to depend on the fiber-optic cable investments.

3 **Q. What presumptions does DTE make in support of its Grid Automation**  
4 **Telecommunications Plan?**

5 A. The Company makes two critical presumptions in support of its Plan. These include: 1)  
6 that many new technologies require real-time communications;<sup>63</sup> and 2) of all available  
7 options, Company-owned options provide the best combination of speed, control, security,  
8 and reliability.<sup>64</sup> The Company has not quantified the cost differences of the options,<sup>65</sup>  
9 and further, neither of the two presumptions are supported by data.

10 **Q. Do the new technologies to which DTE refers require real-time communications?**

11 A. No. The "new technologies" to which DTE refers include distribution automation,  
12 conservation voltage reduction, volt-VAR optimization, advanced metering infrastructure,  
13 demand response, and grid state monitoring (due in large part to distributed energy  
14 resources). All of these technologies and capabilities can perform at a very high level  
15 without real-time communications. In my experience wireless technologies that provide  
16 close to real-time data communications, from microwave to cellular, can deliver almost  
17 100% of the benefit potential available from these capabilities and technologies, and DTE  
18 provides no evidence to the contrary.

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<sup>63</sup> Direct Testimony of Shannen M Hartwick at SMH-22:17.

<sup>64</sup> *Id.*, from SMH-29:1 to SMH-42:17.

<sup>65</sup> *Id.* at SMG-40:4 (Figure 5); also Ex MEC-9, Company response to MNSCDE-7.3(d).

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1   **Q.    Do Company-owned options provide the best combination of speed, control, security,**  
2       **reliability, and cost?**

3    A.    It is difficult to know for certain. There are likely some situations in which Company-  
4       owned options do provide the best combination of speed, control, security, reliability, and  
5       cost. However, in a large number of situations, and likely in a majority of situations, third-  
6       party solutions may offer the best combination of speed, control, security, reliability, and  
7       cost (to customers). Third-party solutions are more flexible, incurring fewer up-front costs  
8       and less risk for customers, than Company-owned solutions. Last but certainly not least,  
9       third-party solutions, as an operating expense, do not incur the Company cost of capital  
10      and income tax reimbursements that customers must pay on top of Company capital  
11      spending.

12   **Q.    Has the Commission asked DTE to analyze a variety of alternatives before advancing**  
13       **its Grid Automaton Telecommunications Plan further?**

14   A.    Yes. In DTE's last rate case, the Commission's Order agreed with the ALJ's  
15      recommendation on this issue, stating "[the ALJ] further found that the company should  
16      be required to provide an analysis of alternatives when requesting further extensions of the  
17      fiber network."<sup>66</sup>

18   **Q.    Has DTE completed such an analysis?**

19   A.    Not in my opinion. DTE Witness Hartwick provides a few pages of testimony describing  
20      a number of telecommunications alternatives, and a "Harvey Ball" type analysis comparing  
21      the relative pros and cons of each option on a scale of one to five, with one (unfavorable)

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<sup>66</sup> Case No. U-21297, Dec. 1, 2023, Order, pp. 120-22.

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1 represented by an open Harvey Ball, and five (favorable) represented by a closed Harvey  
2 Ball.<sup>67</sup> In my opinion, her analysis is not remotely adequate to support \$107 million in  
3 spending, let alone the tens or hundreds of millions of dollars that might comprise the  
4 balance of the Telecommunications Plan (which DTE refused to provide).

5 **Q. What would constitute an appropriate analysis?**

6 A. Before making an investment of \$100 million or more, an unregulated business would  
7 undertake a comprehensive “make vs. buy” study. Such a study would compare the pros  
8 and cons of each technology on technical, operational, cybersecurity, reliability, and other  
9 characteristics, and compare these pros and cons to the risks associated with each  
10 technology (generally, the size of the up-front investment) and the cost of each technology  
11 – not just initially, but over the lifetimes of each alternative’s operation. An unregulated  
12 business might even employ outside experts to complete such a study to ensure objectivity.  
13 DTE has not completed such a study.<sup>68</sup>

14 Assessments of the characteristics of various alternatives should also be supported  
15 by data. For example, it would not be enough for DTE to claim that a public carrier’s  
16 service is insufficiently reliable; DTE must identify the frequency with which commands  
17 issued over DTE’s owned network failed compared to the frequency at which commands  
18 issued through the public carrier’s network failed. Assuming the public carrier’s  
19 performance was worse than the Company’s (which should not be assumed), DTE should  
20 provide the consequence of the difference to customers. For example, of the increased

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<sup>67</sup> Hartwick Direct at SMH-38.

<sup>68</sup> Ex MEC-9, Company response to MNSCDE 7.3(d).

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1 failure rate observed (hypothetically) in commands issued over a public carrier network,  
2 how many resulted in service interruptions to customers, and what were the consequences  
3 to customers (in dollars) of these service interruptions? A precise quantification of  
4 Telecommunication Plan benefits in dollars is needed for comparison to the incremental  
5 costs of the Plan.

6 With an objective understanding of the pros and cons of each alternative relative to  
7 cost and risk, the next step would be to develop a tool to identify which alternative  
8 communications solutions are the most appropriate for application in certain situations and  
9 circumstances. The tool would use defined criteria, informed by the rigorous analyses  
10 described above, to help optimize communications technology choices for various  
11 situations' circumstances. DTE has not developed such a tool,<sup>69</sup> and clearly does not  
12 possess the data needed to inform the development of such a tool.

13 In short, DTE must provide evidence of data-driven decision-making of the sort  
14 described earlier in this testimony, and as described by Mr. Stephens in his testimony. If  
15 the Commission does not establish such expectations for the supporting analysis now, then  
16 DTE will continue to make unsupported proposals for telecommunications network capital  
17 spending in the future.

18 **Q. What are your recommendations on the Company's Grid Automation**  
19 **Telecommunications spending and Plan?**

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<sup>69</sup> Ex MEC-8, Company response to MNSCDE-7.4(c).

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1     A.     I recommend that the Commission disallow Telecommunications Plan costs incurred in  
2           2022 and remove Plan spending from the 2023-2024 bridge period and 2025 test year.<sup>70</sup> I  
3           make this recommendation based on three observations: 1) That DTE has not developed a  
4           benefit-cost or make vs. buy analysis that supports its spending on Plan; 2) That the  
5           Company has not complied with the Commission's Order to analyze alternatives to its Plan;  
6           and 3) That DTE refused to provide the Plan, of which the historical and proposed spending  
7           in its Application constitute a foundational part.

8           I further recommend that the Commission order the Company to solicit an  
9           independent expert to complete a comprehensive analysis of technical, operational,  
10          cybersecurity, and reliability pros and cons of various telecommunications options, and to  
11          compare these options to the risk and total lifecycle costs associated with each option. I  
12          further recommend that the Commission order the Company to complete a tool that  
13          appropriately identifies the best alternative to employ in various situations and  
14          circumstances.

15   **VII.   RECOMMENDATIONS AND CONCLUSION**

16   **Q.   Please summarize your recommendations.**

17   A,   First, in Section II, I recommend that the Commission require DTE to slow the rate of  
18          capital spending, and require DTE to collect and provide more data on the effectiveness of  
19          the Company's vegetation management program relative to its proposed massive capital  
20          spending increases.

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<sup>70</sup> These amounts are reflected in the workpapers and testimony of Mr. Stephens.

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1           In Section III, I recommend the Commission constrain DTE capital spending and  
2           increase capital spending governance at DTE, and specifically that the Commission reject  
3           the Company's proposal to extend and expand rider IRM.

4           Section IV addresses the Company's vegetation management proposals. I discuss  
5           the Company's continued practice of inappropriately capitalizing vegetation management  
6           expenses through 4.8kV hardening, 4.8kV conversion, PTMM programs, and Distribution  
7           Automation, and I recommend that the Commission require DTE to identify costs, assess  
8           ratepayer impacts, and support the claimed propriety of this practice in its next rate case.

9           I further recommend that the Commission reject the Company's request to earn a  
10          return for shareholders on the Surge regulatory asset.

11          Next, I recommend the Commission require DTE to continue its annual tree trim  
12          report ordered in U-20162. Further, due to tree trimming's importance, and due to the  
13          upcoming completion of the Surge, I recommend the Commission order an audit of the  
14          state of the Company's overhead line right of way every five years, to commence in 2025  
15          or 2026.

16          In Section V, I recommend the Commission disregard as unreliable two models the  
17          Company developed to justify its strategic capital spending increases - DTE's Global  
18          Prioritization Model and its Reliability Model.

19          Finally, in Section VI, I recommend the Commission reject the Company's Grid  
20          Automation Telecommunications proposal and disallow costs incurred on the program to  
21          date because the Company has not satisfied the Commission's U-21297 Order to "analyze"

**DIRECT TESTIMONY OF PAUL ALVAREZ FOR AG-MN  
CASE NO. U-21534**

1 various telecommunications technology options, and the Company has not adequately  
2 supported the options it has proposed in the instant application. I also recommend that the  
3 Commission order the Company to complete a make versus buy analysis comparing the  
4 pros and cons of various telecommunications technology alternatives, and a tool to identify  
5 the most appropriate alternative to select for various situations and circumstances.

6 **Q. Does that complete your testimony?**

7 **A. Yes.**

## Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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Wired Group, PO Box 620756, Littleton, CO 80162. palvarez@wiredgroup.net 303-997-0317

### Profile

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After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed conflicts between ratemaking and benefit maximization. Since 2012 Mr. Alvarez has led the Wired Group, a boutique consultancy serving consumer, business, and environmental advocates, and regulators in matters of distribution planning, investment, and performance measurement.

### Appearances and Research Projects in Regulatory Proceedings

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**Evaluate Public Service Oklahoma Application for Rate Increase & Changes in Cost Recovery for Some Expense Types.** Testimony on behalf of Commission Staff in PUD 2023-000086. July 29, 2024.

**Evaluate DTE Energy's Request for Rate Increase, and to Extend and Expand Rider IRM.** Testimony on behalf of a group of environmental and consumer advocates in Michigan PSC U-21534. July 26, 2024.

**Determine If Customer Interest Is Served by Smart Meter Stipulation.** Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 22-0704-EL-UNC. June 11, 2024.

**Evaluate Commonwealth Edison Company's Refiled Grid Plan.** Panel Testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission Case No. 22-0486. May 23, 2024.

**Evaluate Ameren Illinois Company's Refiled Grid Plan.** Panel Testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission Case No. 22-0487. May 13, 2024.

**Evaluate Oklahoma Gas & Electric's historical spending.** Testimony on behalf of Oklahoma Corporation Commission Staff in PUD-2023-000087. April 26, 2024.

**Evaluate National Grid's historical spending and multi-year rate plan.** Panel testimony with Dennis Stephens on behalf of the Attorney General in Massachusetts DPU Case 23-150. March 29, 2024.

**Evaluate Pepco's Second Multi-Year Rate Plan.** Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9702. December 15, 2023.

**Evaluate First Energy's Application to Continue Grid Mod I Program Spending in Grid Mod II.**

Testimony on behalf of the Ohio Consumers' Counsel in Ohio PUC Case No. 22-0704. October 23, 2023

**Evaluate BGE's Second Multi-Year Rate Plan (Electric Distribution Components 2024-2027) and Electric Distribution Spending 2021-2022.**

Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9692. June 20, 2023.

**Evaluate DTE Energy's Request for Strategic Capital Plan Cost Recovery and Infrastructure Recovery Mechanism Rider**

on behalf of the Attorney General and a group of environmental and consumer advocates in Michigan PSC U-21297. June 13, 2023.

**Evaluate Commonwealth Edison's Multi-year Grid Plan.**

Panel testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission 22-0486. May 22, 2023.

**Evaluate Ameren Illinois Corporation's Multi-year Grid Plan.**

Panel testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission 22-0487. May 11, 2023.

**Evaluate Public Service Oklahoma's \$450 million Grid Enhancement and Resilience Plan and Request for Rider Cost Recovery from a Policy Perspective.**

Testimony on behalf of the Attorney General in PUD-2022-000093. March 7, 2023.

**Evaluate Duke Energy's Peak-time Rebate Pilot Results.**

Testimony on behalf of the Attorney General in 2022-00251. November 9, 2022.

**Evaluate Georgia Power's Transmission & Distribution Spending Proposals.**

Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44280. October 20, 2022.

**Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan.**

Panel testimony with Dennis Stephens on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

**Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan.**

Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

**Evaluate Policy Issues and Precedents Associated with Oklahoma Gas & Electric Company's Grid Modernization Factor.**

Testimony on behalf of the Office of Attorney General in PUD 2021000164. April 27, 2022.

**Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities.**

Panel testimonies with Dennis Stephens on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

**Evaluate Dominion's Grid Transformation Plan.**

Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. Virginia SCC PUR-2021-00127. September 13, 2021.

**Investigate Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes.**

Panel testimony with Dennis Stephens on behalf of Public Counsel. WUTC 200900. April 29, 2021.

**Evaluate Kentucky Utilities/Louisville Gas & Electric's CPCN to Install Advanced Meters.**

Testimony on behalf of the Attorney General. Kentucky PSC 2020-00349/00350. March 5, 2021.

**Examine Potomac Electric Power Company's Electric Distribution Spending and Plan.**

Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel. MD PSC 9655. March 3, 2021.

**Determine If Customer Interest Is Served by Smart Meter Stipulation.**

Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 18-1875-EL-GRD. December 17, 2020.

**Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan.**

Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. Aug. 31, 2020.

**Examine Oklahoma Gas and Electric's \$800 million Grid Enhancement Plan.**

Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

**Examine Baltimore Gas and Electric's 2021-2023 Grid Investment and Operations Plan.**

Panel testimony before the Maryland Public Service Commission with Dennis Stephens on behalf of the Office of People's Counsel. MDPSC 9645. August 14, 2020.

**Critique of Duke Energy Carolinas/Duke Energy Progress \$2.3 billion Grid Improvement Plan.**

Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

**Critique of Investment in Traditional Meters (Equipped with AMR).**

Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

**Critique of Smart Meter Benefits Claimed by Puget Sound Energy.**

Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

**Critique of Smart Meter Benefits Claimed by Rockland Electric Company.**

Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

**Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light.**

Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan (\$1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

**Investigation into Distribution Planning Processes.**

Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

**Investigation into Grid Modernization.** Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

**Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric.** Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

**Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase.** Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

**Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement.** Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

**Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding.** Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

**Evaluate Southern California Edison's Request to Invest \$2.3 Billion in its Grid to Accommodate Distributed Energy Resources.** Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

**Evaluate Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan.** Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

**Evaluate National Grid's Massachusetts Smart Meter Deployment Plan.** Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017. Also Unitil in 15-121 and Eversource in 15-122/123, March 10, 2017

**Evaluate Pacific Gas & Electric's Request to Invest \$100 Million in Its Grid to Accommodate Distributed Energy Resources.** Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

**Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case.** Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

**Evaluate Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Ownning Customers.** Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

**Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest.** Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

**Duke Energy Ohio Smart Grid Audit and Assessment.** Primary research and report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

**SmartGridCity™ Demonstration Project Evaluation Summary.** Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

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## Books

**Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment.** Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

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## Noteworthy Publications

**Alternative Ratemaking in the US: A Prerequisite for Grid Modernization, or an Unwarranted Shift of Risk to Customers?** With Kenneth Costello, Sean Ericson and Dennis Stephens. Electricity Journal. Volume 35 (October, 2022).

**Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities.** With Sean Ericson and Dennis Stephens. Electricity Journal. Volume 34 (August, 2021).

**Florida Storm Protection Plans: A Bonanza for Utilities, a Bust for Consumers and the State.** Whitepaper co-authored with Dennis Stephens for AARP-Florida. October 5, 2020.

**Challenging Utility Grid Modernization Proposals.** With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 September, 2020.

**The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement.** With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

**Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers.** Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

**Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders.** Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

**Measuring Distribution Performance? Benchmarking Warrants Your Attention.** With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

**Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked.** With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

**Price Cap Electric Ratemaking: Does it Merit Consideration?** With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

**Integrated Distribution Planning: An Idea Whose Time has Come.** Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3<sup>rd</sup> Ed, March, 2015

**Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs.** Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

**Is This the Future? Simple Methods for Smart Grid Regulation.** Smart Grid News. October 2, 2014.

**A Better Way to Recover Smart Grid Costs.** Smart Grid News. September 3, 2014.

**Why Should We Switch to Performance-based Compensation?** Smart Grid News. August 15, 2014.

**The True Cost of Smart Grid Capabilities.** Intelligent Utility. June 30, 2014.

**Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments.** Public Utilities Fortnightly. January, 2012.

**Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments.** Public Utilities Fortnightly. December, 2009.

### **Notable Presentations**

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**NASUCA Annual Meeting.** *Alternative Ratemaking: Unintended Consequences and Recommendations for Consumer Advocates.* Charlotte, NC. November 7, 2023.

**NASUCA Electricity Committee Meeting.** *Alternative Ratemaking and Grid Modernization: Considerations for Consumer Advocates.* With Dennis Stephens and Ken Costello. December 7, 2022.

**NASUCA Annual Meeting.** *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

**National Council on Electricity Policy Annual Meeting.** Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

**NASUCA Annual Meeting.** *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

**Illinois Commerce Commission, NextGrid Working Group 7.** *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

**NARUC Committee on Electricity.** *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

**Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2.** *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

**NASUCA Mid-Year Meeting.** *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

**NARUC Committee on Energy Resources and the Environment.** *How big data can lead to better decisions for utilities, customers, and regulators.* Washington DC. February 15, 2016.

**National Conference of Regulatory Attorneys 2014 Annual Meeting.** *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

**NASUCA 2013 Annual Conference.** *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

**NARUC Subcommittee on Energy Resources and the Environment.** *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

**IEEE Power and Energy Society, ISGT 2013.** *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

**Great Lakes Smart Grid Symposium.** *What Smart Grid Deployment Evaluations are Telling Us.* Chicago. September 26, 2012.

**Mid-Atlantic Distributed Resource Initiative.** *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

**DistribuTECH 2012.** *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

**DistribuTECH 2012.** *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

**NARUC Subcommittee on Electricity.** *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators.* St. Louis, MO. November 13, 2011.

**Canadian Electric Institute 2013 Annual Distribution Conference.** *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

## Teaching

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**Post-graduate Adjunct Professor.** University of Colorado, Global Energy Management Program.  
Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

**Guest Lecturer.** Michigan State University, Institute for Public Utilities. Courses: Performance  
Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

## Education

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Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University.  
Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University.  
Concentrations: Finance, Marketing.

## Certifications

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New Product Development Professional. Product Development and Management Association. 2007.

**MPSC Case No:** U-21534

**Requester:** MNSC

**Question No.:** MNSCDE-2.5

**Respondent:** A. Willis

**Page:** 1 of 1

**Question:** 5. Produce all analyses prepared by or for DTE Electric within the past three years that compare its present or proposed rates to other electric distribution companies or electric utilities, including all workpapers and source documents. (By way of example and not by way of limitation, see attachments provided with discovery response AGDE-1.13 in Case No. U-20836.)

**Answer:** DTE Electric objects for the reason that the request is unduly burdensome, overly broad, and incapable of answer in its present form since the Company cannot be certain that it is aware of “all” such materials described by the requestor. Subject to and without waiving its objection, the Company would answer as follows:

Please refer to the attached documents

**Attachment:** U-21534 MNSCDE-2.5-01 Monthly Rate Benchmarking - 2022 07\_July vFinal.pdf  
U-21534 MNSCDE-2.5-02 Monthly Rate Benchmarking - 2022 08\_August vFinal.pdf  
U-21534 MNSCDE-2.5-03 Monthly Rate Benchmarking - 2022 09\_September vFinal.pdf  
U-21534 MNSCDE-2.5-04 Monthly Rate Benchmarking - 2022 10\_October vFinal.pdf  
U-21534 MNSCDE-2.5-05 Monthly Rate Benchmarking - 2022 11\_November vFinal.pdf  
U-21534 MNSCDE-2.5-06 Monthly Rate Benchmarking - 2022 12\_December vFinal.pdf  
U-21534 MNSCDE-2.5-07 Monthly Rate Benchmarking - 2023 01\_January vFinal.pdf  
U-21534 MNSCDE-2.5-08 Monthly Rate Benchmarking - 2023 02\_February vFinal.pdf  
U-21534 MNSCDE-2.5-09 Monthly Rate Benchmarking - 2023 03\_March vFinal.pdf  
U-21534 MNSCDE-2.5-10 Monthly Rate Benchmarking - 2023 04\_April vFinal.pdf  
U-21534 MNSCDE-2.5-11 Monthly Rate Benchmarking - 2023 05\_May vFinal.pdf  
U-21534 MNSCDE-2.5-12 Monthly Rate Benchmarking - 2023 06\_June vFinal.pdf  
U-21534 MNSCDE-2.5-13 Monthly Rate Benchmarking - 2023 07\_July vFinal.pdf  
U-21534 MNSCDE-2.5-14 Monthly Rate Benchmarking - 2023 08\_August vFinal.pdf  
U-21534 MNSCDE-2.5-15 Monthly Rate Benchmarking - 2023 09\_September vFinal.pdf  
U-21534 MNSCDE-2.5-16 Monthly Rate Benchmarking - 2023 10\_October vFinal.pdf  
U-21534 MNSCDE-2.5-17 Monthly Rate Benchmarking - 2023 11\_November vFinal.pdf  
U-21534 MNSCDE-2.5-18 Monthly Rate Benchmarking - 2023 12\_December vFinal.pdf  
U-21534 MNSCDE-2.5-19 Monthly Rate Benchmarking - 2024 1\_January vFinal.pdf  
U-21534 MNSCDE-2.5-20 Monthly Rate Benchmarking - 2024 2\_February vFinal.pdf  
U-21534 MNSCDE-2.5-21 Monthly Rate Benchmarking - 2024 3\_March vFinal.pdf  
U-21534 MNSCDE-2.5-22 Monthly Rate Benchmarking - 2024 4\_April vFinal.pdf  
U-21534 MNSCDE-2.5-23 Spring 2024 Annual.pdf  
U-21534 MNSCDE-2.5-24 Spring 2022 Annual.pdf  
U-21534 MNSCDE-2.5-25 Spring 2023 Annual.pdf  
U-21534 MNSCDE-2.5-26 2020 Baseline - EIA Rate Benchmarking Data Monthly Analysis\_2023 December.xlsx  
U-21534 MNSCDE-2.5-27 2021 Baseline - EIA Rate Benchmarking Data Monthly Analysis\_2024 January.xlsx



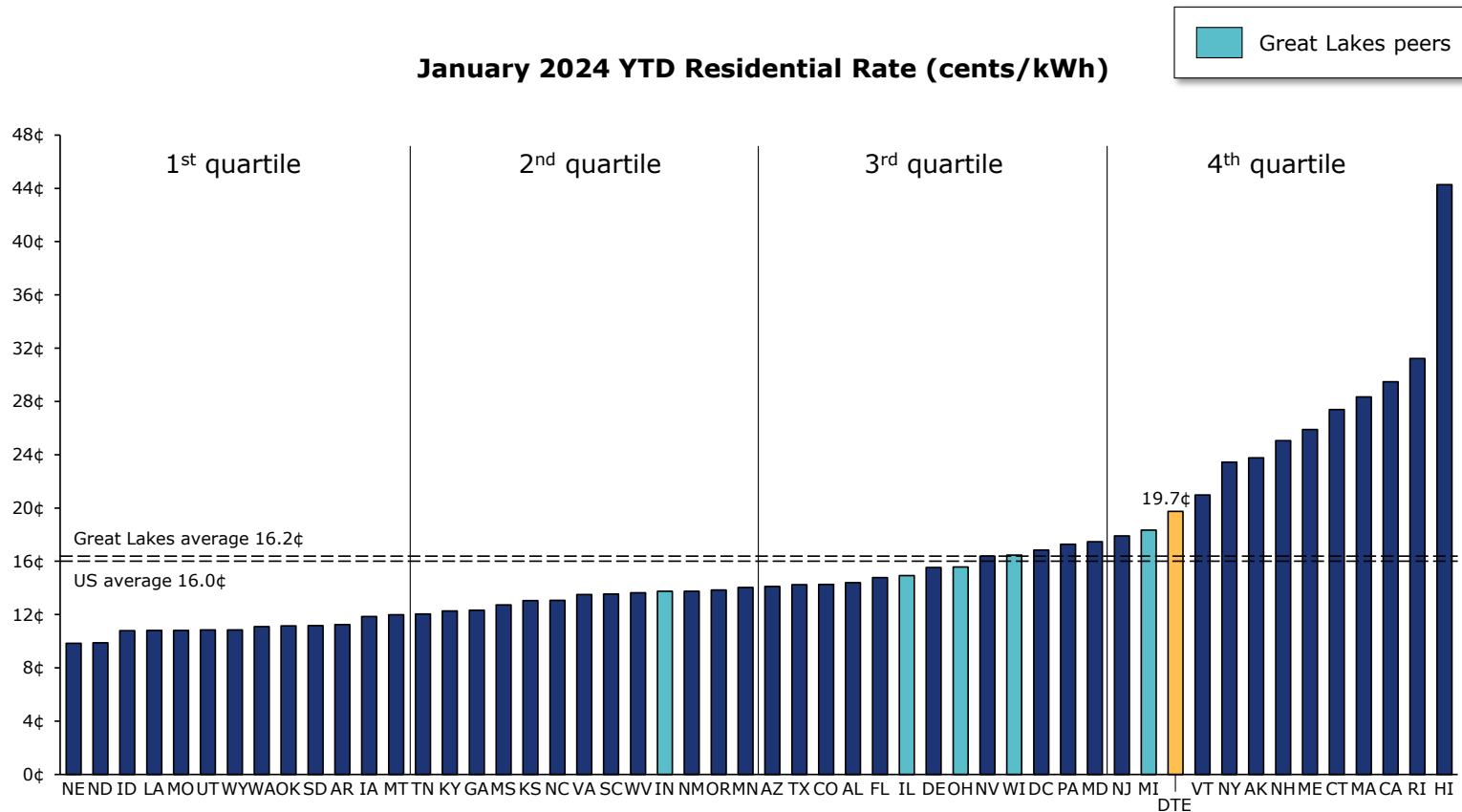
## Monthly Electric Rate Benchmarking

April 12, 2024

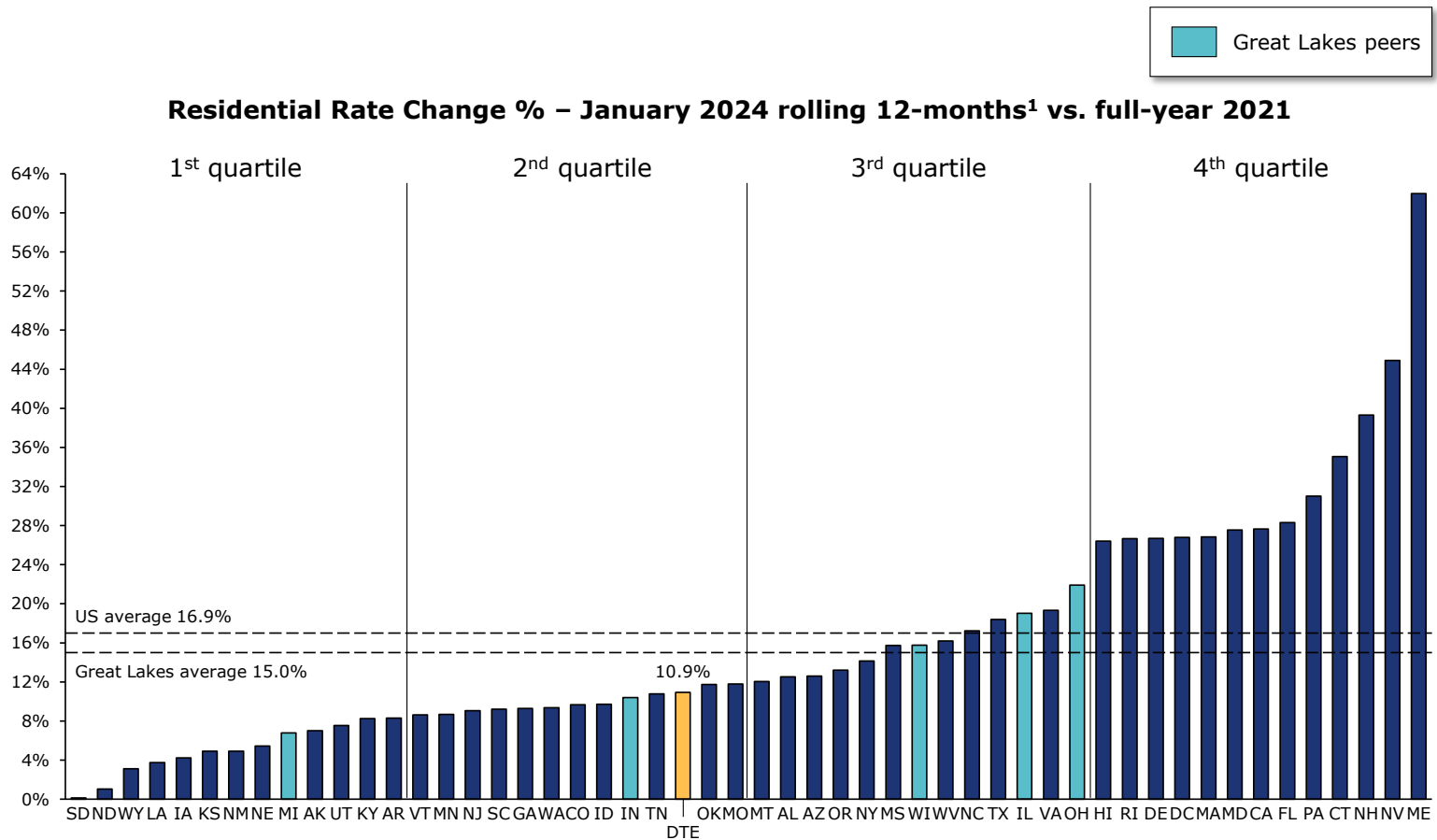
## Agenda

- Electric Rate Benchmarking (EIA data through January 2024)
- National Electric Rate Case Approvals

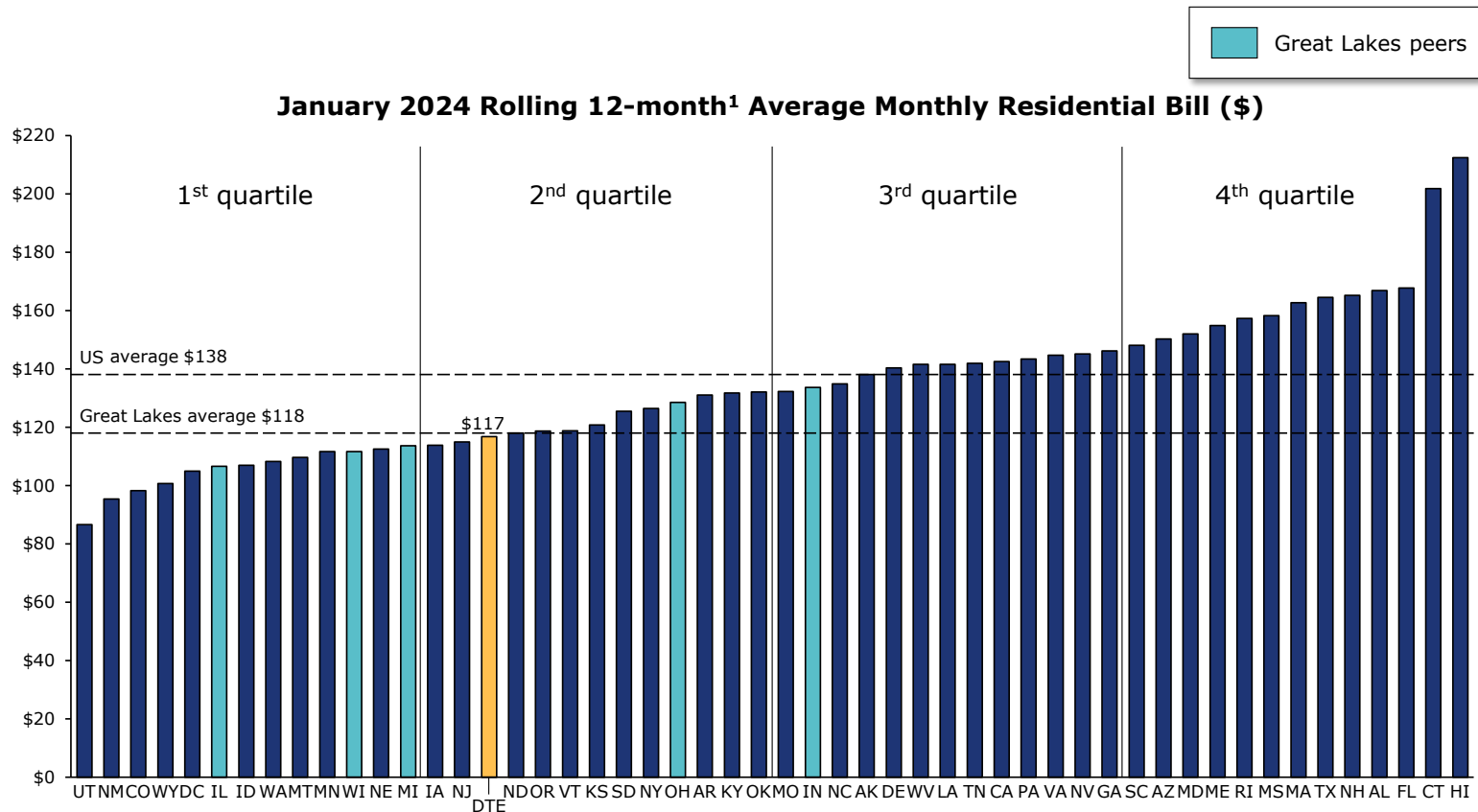
While DTE's residential rates are above the national average...



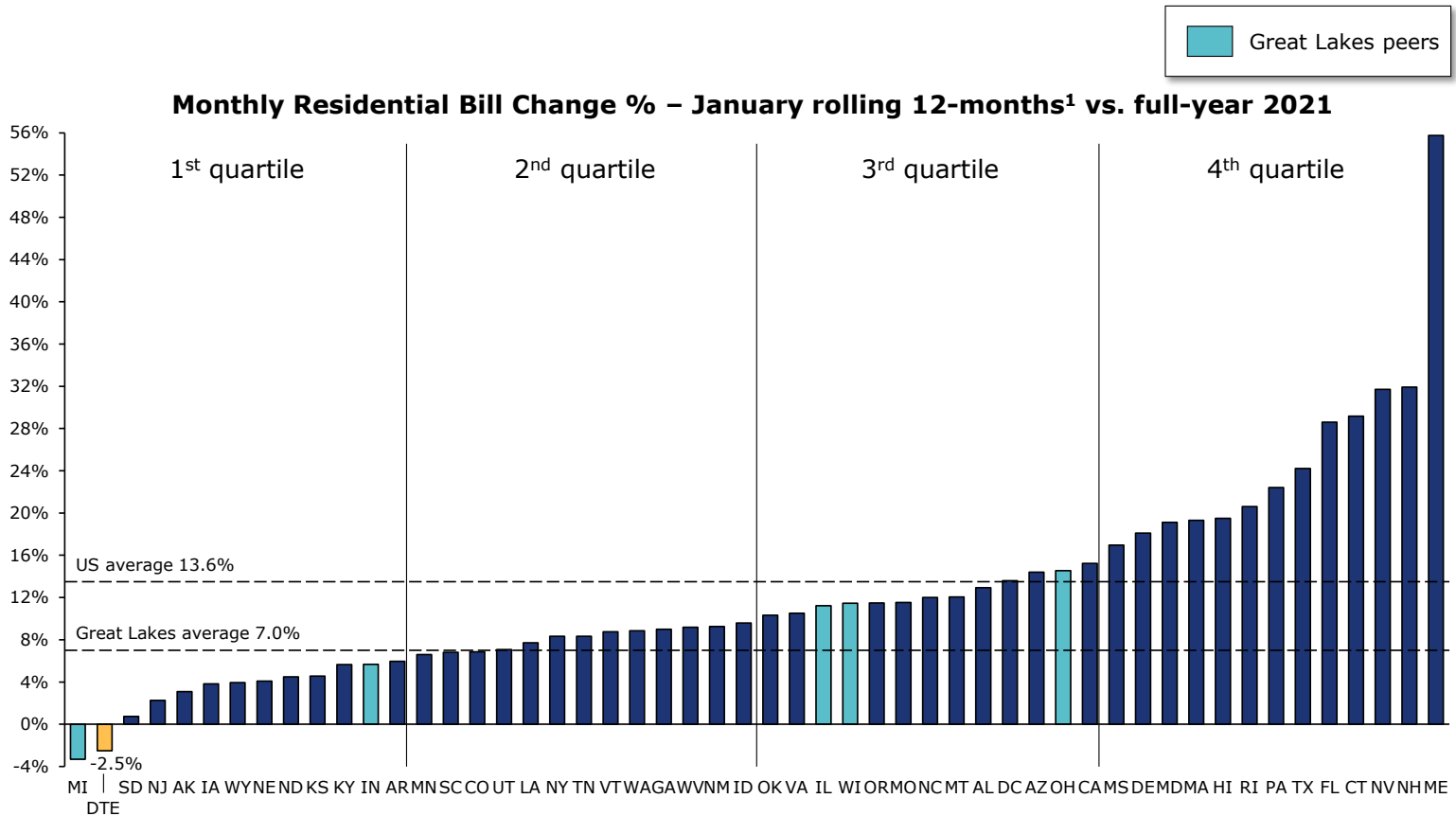
... DTE's rates have been increasing at a slower pace than most other states since 2021



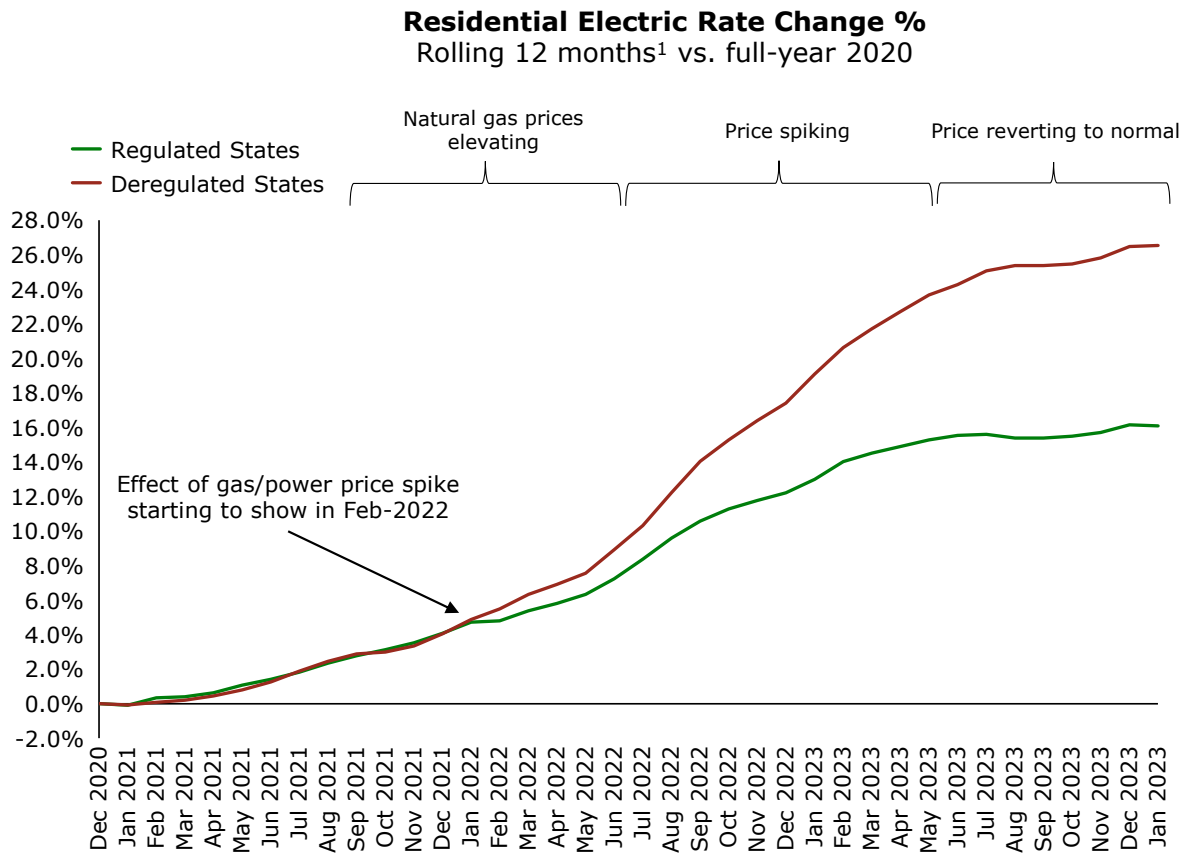
## DTE's residential bills remain in the 2<sup>nd</sup> quartile and below the Great Lakes average



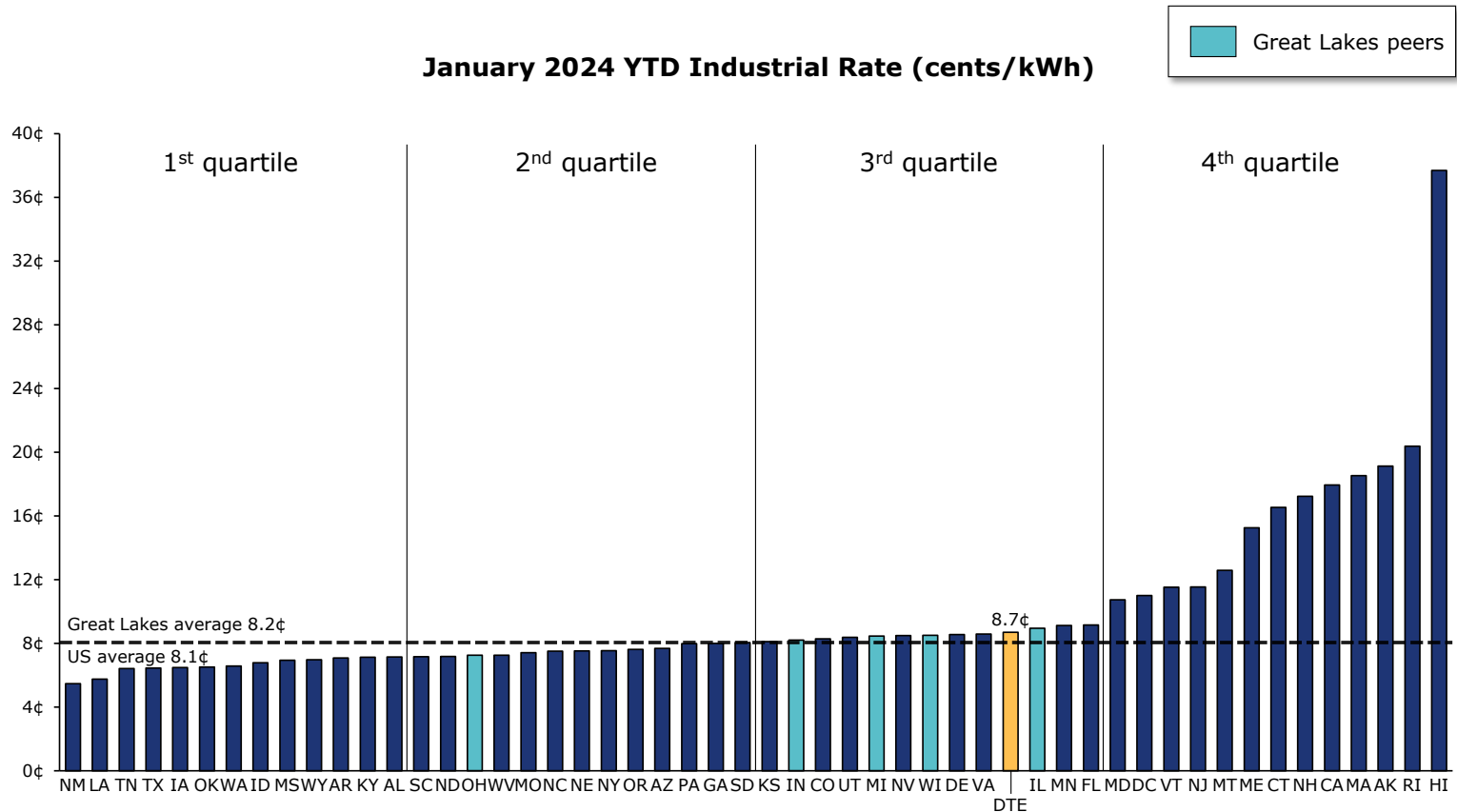
## DTE's residential bill has decreased since 2021 and is first quartile in the nation



## Rate increases in deregulated states have remained elevated from regulated states, despite gas prices reverting to normal



DTE's average industrial rates are ranked 3<sup>rd</sup> quartile and above the national and Great Lakes averages



## Agenda

- Electric Rate Benchmarking (EIA data through January 2024)

- National Electric Rate Case Approvals

## Approved Electric Rate Cases since 2021 through April 12, 2024 – Regulated States<sup>1</sup> (1 of 2)

| Utility                    | State | Auth. Date | Years Since Last Rate Case | Requested Increase (\$M) | Auth. Increase (\$M) | Requested ROE       | Auth. ROE | Increase as % of Revenue <sup>2</sup> |
|----------------------------|-------|------------|----------------------------|--------------------------|----------------------|---------------------|-----------|---------------------------------------|
| PacifiCorp                 | WA    | 03/19/24   | 3.3                        | \$41                     | \$34                 | ROE Not Made Public |           | 0.7%                                  |
| Arizona Public Service Co. | AZ    | 03/05/24   | 2.3                        | \$690                    | \$492 <sup>3</sup>   | 10.25%              | 9.55%     | 12.9%                                 |
| Consumers Energy           | MI    | 03/01/24   | 1.1                        | \$169                    | \$92                 | 10.25%              | 9.90%     | 1.9%                                  |
| Public Service Co. of NM   | NM    | 01/03/24   | 6.0                        | \$64                     | \$15                 | 10.25%              | 9.26%     | 1.5%                                  |
| Idaho Power Co.            | ID    | 12/28/23   | 12.0 <sup>4</sup>          | \$111                    | \$55                 | 10.40%              | 9.60%     | 3.9%                                  |
| Nevada Power               | NV    | 12/26/23   | 3.0                        | \$93                     | \$37                 | 10.26%              | 9.52%     | 1.5%                                  |
| Portland General           | OR    | 12/18/23   | 1.7                        | \$391                    | \$386                | 9.80%               | 9.50%     | 18.0%                                 |
| Entergy Arkansas           | AR    | 12/04/23   | 1.0                        | \$89                     | \$88                 | ROE Not Made Public |           | 4.3%                                  |
| DTE Electric               | MI    | 12/01/23   | 1.0                        | \$583                    | \$368                | 10.25%              | 9.90%     | 6.5%                                  |
| Appalachian Power Co.      | VA    | 11/30/23   | 3.0                        | \$213                    | \$127                | ROE Not Made Public |           | 4.3%                                  |
| Northern States Power      | WI    | 11/09/23   | 2.0                        | \$40                     | \$1                  | 10.25%              | 9.80%     | 0.0%                                  |
| Wisconsin Power & Light    | WI    | 11/09/23   | 2.0                        | \$182                    | \$111                | 10.00%              | 9.80%     | 8.7%                                  |
| Public Service Co. of OK   | OK    | 11/03/23   | 1.8                        | \$294                    | \$131                | 10.40%              | 9.30%     | 7.4%                                  |
| Public Service Co. of CO   | CO    | 09/06/23   | 1.5                        | \$303                    | \$45                 | 10.25%              | 9.30%     | 1.3%                                  |
| NIPSCO                     | IN    | 08/02/23   | 3.7                        | \$279                    | \$262                | 10.40%              | 9.80%     | 15.1%                                 |
| Union Electric             | MO    | 06/14/23   | 1.5                        | \$239                    | \$140                | ROE Not Made Public |           | 4.5%                                  |
| Oklahoma Gas & Electric    | AR    | 03/02/23   | 1.0                        | \$10                     | \$10                 | ROE Not Made Public |           | 0.3%                                  |



Source: S&P Capital IQ Pro

1. Peer set includes utilities with more than 500,000 customers or companies within the Great Lakes peer set
2. Based on electric utility revenue from 2022 and gathered from S&P Capital IQ Pro
3. Large rate increase driven by increase to authorized ROE (8.90% in last rate case) and approval of \$1.5 billion increase to rate base
4. Riders were available to recover investments for the past 12 years prior to this rate case

## Approved Electric Rate Cases since 2021 through April 12, 2024 – Regulated States<sup>1</sup> (2 of 2)

| Utility                      | State | Auth. Date | Years Since Last Rate Case | Requested Increase (\$M) | Auth. Increase (\$M) | Requested ROE       | Auth. ROE | Increase as % of Revenue <sup>2</sup> |
|------------------------------|-------|------------|----------------------------|--------------------------|----------------------|---------------------|-----------|---------------------------------------|
| Southwestern Electric Power  | LA    | 02/17/23   | 10.0 <sup>5</sup>          | \$95                     | \$27                 | 10.35%              | 9.50%     | 1.4%                                  |
| Wisconsin Electric Power     | WI    | 12/29/22   | 1.4                        | \$258                    | \$281                | 10.00%              | 9.80%     | 9.0%                                  |
| Wisconsin Public Service Co. | WI    | 12/22/22   | 3.1                        | \$73                     | \$113                | 10.00%              | 9.80%     | 9.7%                                  |
| Puget Sound                  | WA    | 12/22/22   | 2.5                        | \$347                    | \$223                | 9.90%               | 9.40%     | 8.9%                                  |
| Evergy Metro                 | MO    | 11/21/22   | 4.1                        | \$48                     | \$25                 | ROE Not Made Public |           | 1.5%                                  |
| Indiana Michigan Power       | IN    | 02/23/22   | 2.0                        | \$107                    | (\$95) <sup>4</sup>  | 10.00%              | 9.70%     | (4.6%)                                |
| Dominion Energy SC           | SC    | 07/21/21   | 8.6                        | \$178                    | \$62                 | 10.25%              | 9.50%     | 2.1%                                  |
| Kentucky Utilities           | KY    | 06/30/21   | 2.2                        | \$170                    | \$106                | 10.00%              | 9.43%     | 5.4%                                  |

Source: S&P Capital IQ Pro

1. Peer set includes utilities with more than 500,000 customers or companies within the Great Lakes peer set
2. Based on electric utility revenue from 2022 and gathered from S&P Capital IQ Pro
3. Georgia Power approved rate case to be recovered over three years
4. Rate reduction in IMP's Indiana rate case reflects the removal of \$141 million of annual lease payment attributable to the December 2022 lease termination for unit 2 of the Rockport plant and a lower cost of capital structure (9.7% vs. 10% ROE)

## Approved Electric Rate Cases since 2021 through April 12, 2024 – Deregulated States<sup>1</sup>

| Utility                      | State | Auth. Date | Years Since Last Rate Case | Requested Increase (\$M) | Auth. Increase (\$M) | Requested ROE       | Auth. ROE | Increase as % of Revenue <sup>2</sup> |
|------------------------------|-------|------------|----------------------------|--------------------------|----------------------|---------------------|-----------|---------------------------------------|
| Jersey Central Power & Light | NJ    | 02/14/24   | 3.3                        | \$192                    | \$85                 | 10.40%              | 9.60%     | 4.4%                                  |
| NSTAR Electric               | MA    | 12/26/23   | 1.1                        | \$105                    | \$105                | ROE Not Made Public |           | 3.5%                                  |
| San Diego Gas & Electric     | CA    | 12/22/23   | 1.0                        | \$44                     | \$44                 | 10.65%              | 10.65%    | 1.1%                                  |
| Southern California Edison   | CA    | 12/22/23   | 1.0                        | \$201                    | \$201                | 10.75%              | 10.75%    | 1.3%                                  |
| Pacific Gas and Electric     | CA    | 12/22/23   | 1.0                        | \$158                    | \$158                | 10.70%              | 10.70%    | 1.0%                                  |
| Atlantic City Electric       | NJ    | 11/17/23   | 2.3                        | \$92                     | \$45                 | 10.50%              | 9.60%     | 3.8%                                  |
| Massachusetts Electric       | MA    | 09/28/23   | 1.0                        | \$67                     | \$67                 | ROE Not Made Public |           | 2.5%                                  |
| Central Maine Power          | ME    | 06/06/23   | 3.3                        | \$90                     | \$67                 | 10.20%              | 9.35%     | 8.3%                                  |
| Oncor Electric               | TX    | 03/09/23   | 5.4                        | \$251                    | \$101                | 10.30%              | 9.70%     | 2.2%                                  |
| Duke Energy Ohio             | OH    | 12/14/22   | 4.0                        | \$55                     | \$23                 | 10.30%              | 9.50%     | 2.0%                                  |
| Dayton Power & Light         | OH    | 12/14/22   | 4.2                        | \$121                    | \$76                 | 10.50%              | 10.00%    | 10.3%                                 |
| Duquesne Light               | PA    | 12/16/21   | 3.0                        | \$115                    | \$74                 | ROE Not Made Public |           | 6.9%                                  |
| PECO Energy                  | PA    | 11/18/21   | 2.9                        | \$246                    | \$168                | ROE Not Made Public |           | 6.4%                                  |
| Ohio Power                   | OH    | 11/17/21   | 9.9                        | \$402                    | \$295                | 10.15%              | 9.70%     | 8.8%                                  |



Source: S&P Capital IQ Pro

1. Peer set includes utilities with more than 500,000 customers or companies within the Great Lakes peer set
2. Based on bundled electric utility revenue and bundled electric sales from 2022; gathered from S&P Capital IQ Pro

## Approved Multi-Year Electric Rate Cases since 2021 through April 12, 2024 – All States<sup>1</sup>

| Utility                  | State | Auth. Date | Years Since Last Rate Case | Requested Increase (\$M) | Auth. Increase (\$M) | Requested ROE | Auth. ROE | Years to Recover Increase |
|--------------------------|-------|------------|----------------------------|--------------------------|----------------------|---------------|-----------|---------------------------|
| Duke Energy Carolinas    | NC    | 12/15/23   | 2.7                        | \$833                    | \$769                | 10.40%        | 10.10%    | 3                         |
| Baltimore Gas & Electric | MD    | 12/14/23   | 3.0                        | \$314                    | \$179                | 10.40%        | 9.50%     | 3                         |
| Commonwealth Edison      | IL    | 12/14/23   | 1.1                        | \$1,487                  | \$506                | 10.65%        | 8.91%     | 4                         |
| Ameren Illinois          | IL    | 12/14/23   | 1.0                        | \$465                    | \$142 <sup>2</sup>   | 10.50%        | 8.72%     | 4                         |
| NY State Electric & Gas  | NY    | 10/12/23   | 2.9                        | \$274                    | \$137                | 10.20%        | 9.20%     | 3                         |
| Duke Energy Progress     | NC    | 08/18/23   | 2.3                        | \$227                    | \$148                | 10.40%        | 9.80%     | 3                         |
| ConEd of NY              | NY    | 07/20/23   | 3.5                        | \$1,038                  | \$442                | 10.00%        | 9.25%     | 3                         |
| Georgia Power            | GA    | 12/20/22   | 1.1                        | \$1,004                  | \$996                | 11.00%        | 10.50%    | 3                         |
| Delmarva Power & Light   | MD    | 12/14/22   | 0.8                        | \$37                     | \$29                 | 10.25%        | 9.60%     | 3                         |
| Niagara Mohawk Power     | NY    | 01/20/22   | 3.8                        | \$103                    | \$49                 | 9.50%         | 9.00%     | 3                         |
| Florida Power & Light    | FL    | 10/26/21   | 4.9                        | \$1,680                  | \$1,252              | 11.50%        | 10.60%    | 2 <sup>3</sup>            |
| Tampa Electric Company   | FL    | 10/21/21   | 4.0                        | \$423                    | \$302                | 10.75%        | 9.95%     | 3                         |
| Potomac Electric Power   | MD    | 06/28/21   | 1.9                        | \$104                    | \$52 <sup>3</sup>    | 10.20%        | 9.55%     | 3                         |
| Duke Energy Florida      | FL    | 05/04/21   | 3.5                        | \$195                    | \$195                | 9.85%         | 9.85%     | 3                         |

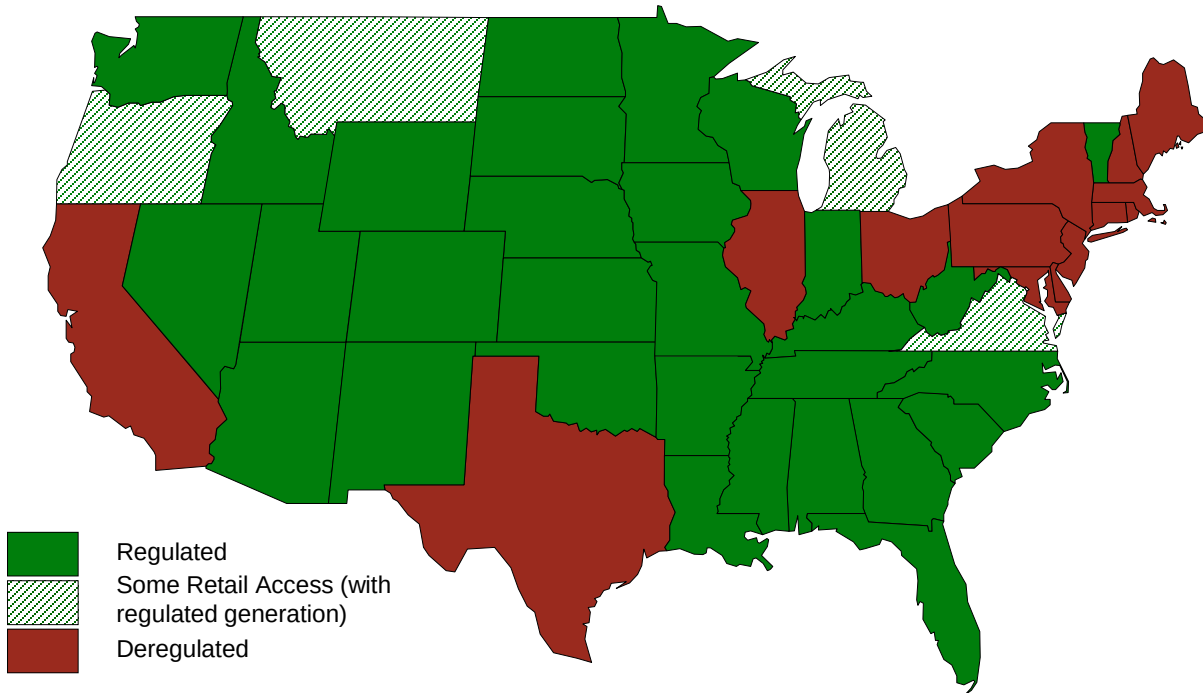
Source: S&P Capital IQ Pro

1. Peer set includes utilities with more than 500,000 customers or companies within the Great Lakes peer set (both regulated and deregulated states included on this page)
2. Ameren Illinois originally was granted a \$58M rate increase but amendatory order increased this to \$142M (this \$142M increase has had a request for rehearing placed by Ameren Illinois that is still pending)
3. Florida Power and Light can recover full authorized increase in 2 years, but has a stay-out clause for 3 years (until 2025)

## Appendix

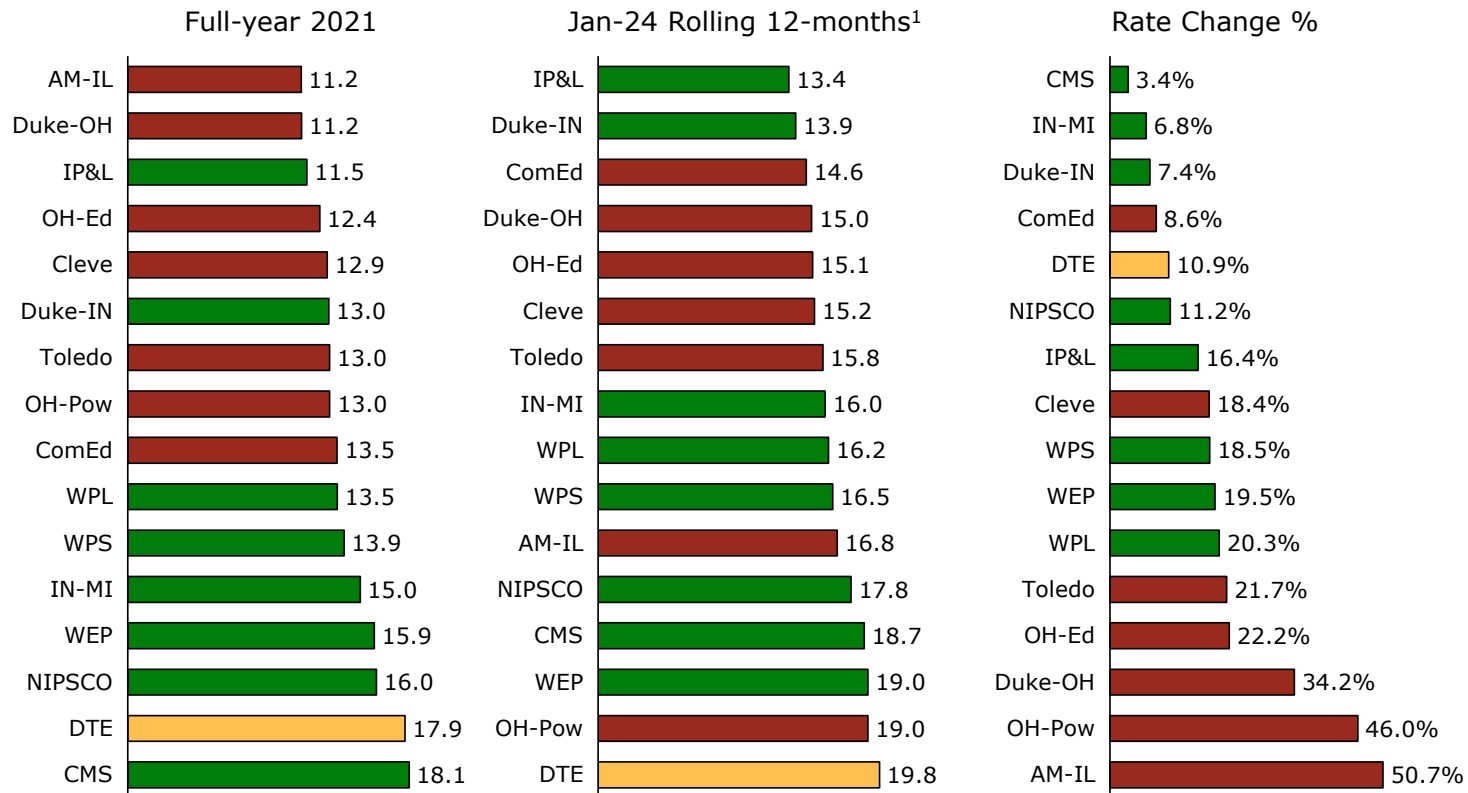
We benchmark state-level data (EIA) with a three-month lag by regulatory models. We track national rate case and multi-year plan approval results

## U.S. Electric Regulatory Models

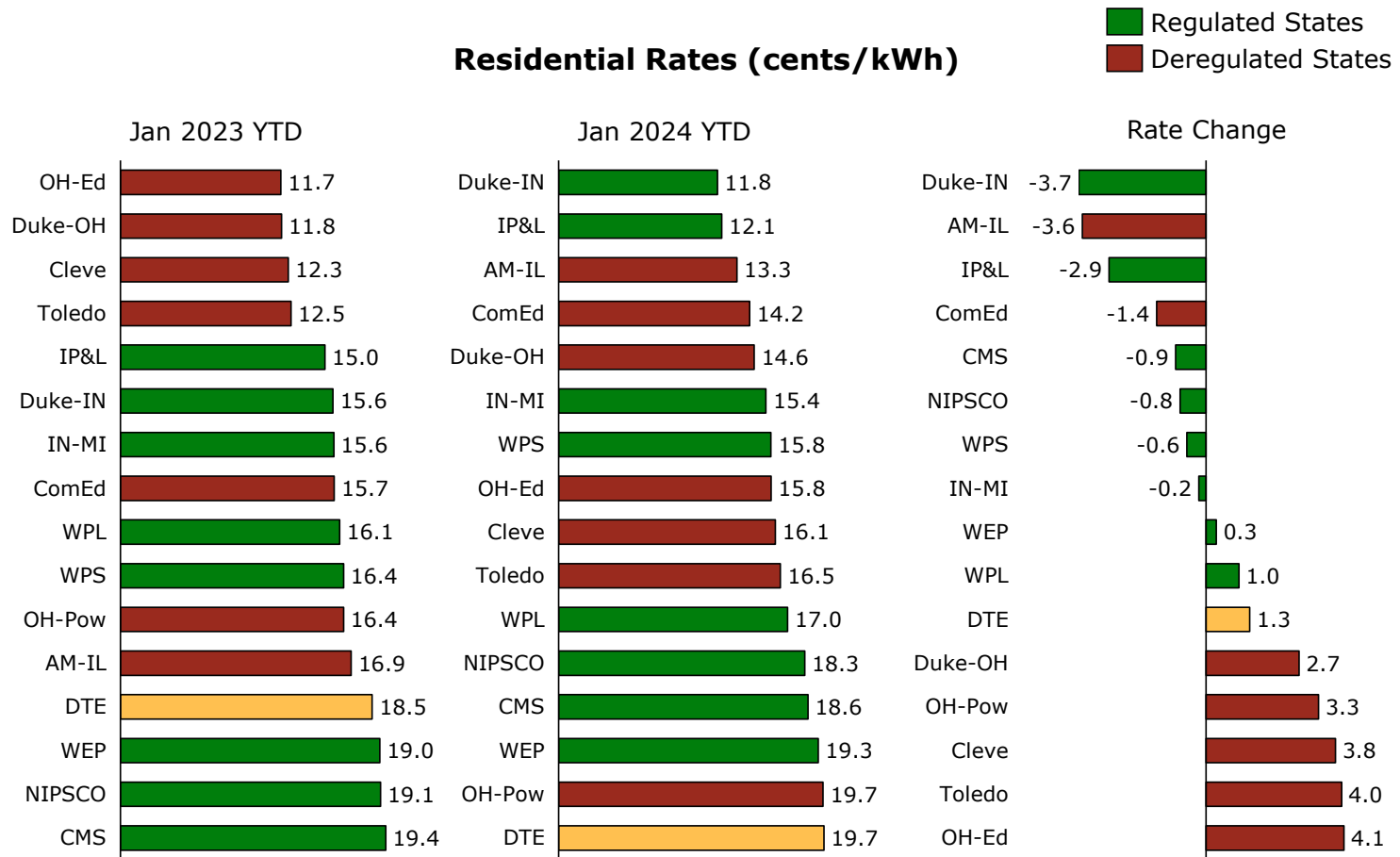


## Great Lakes peer utilities 2021 to January 2024 rate increase

### Residential Rates (cents/kWh unless in %)



## Great Lakes peer utilities year to date rate increase (January 2023 YTD to January 2024 YTD)

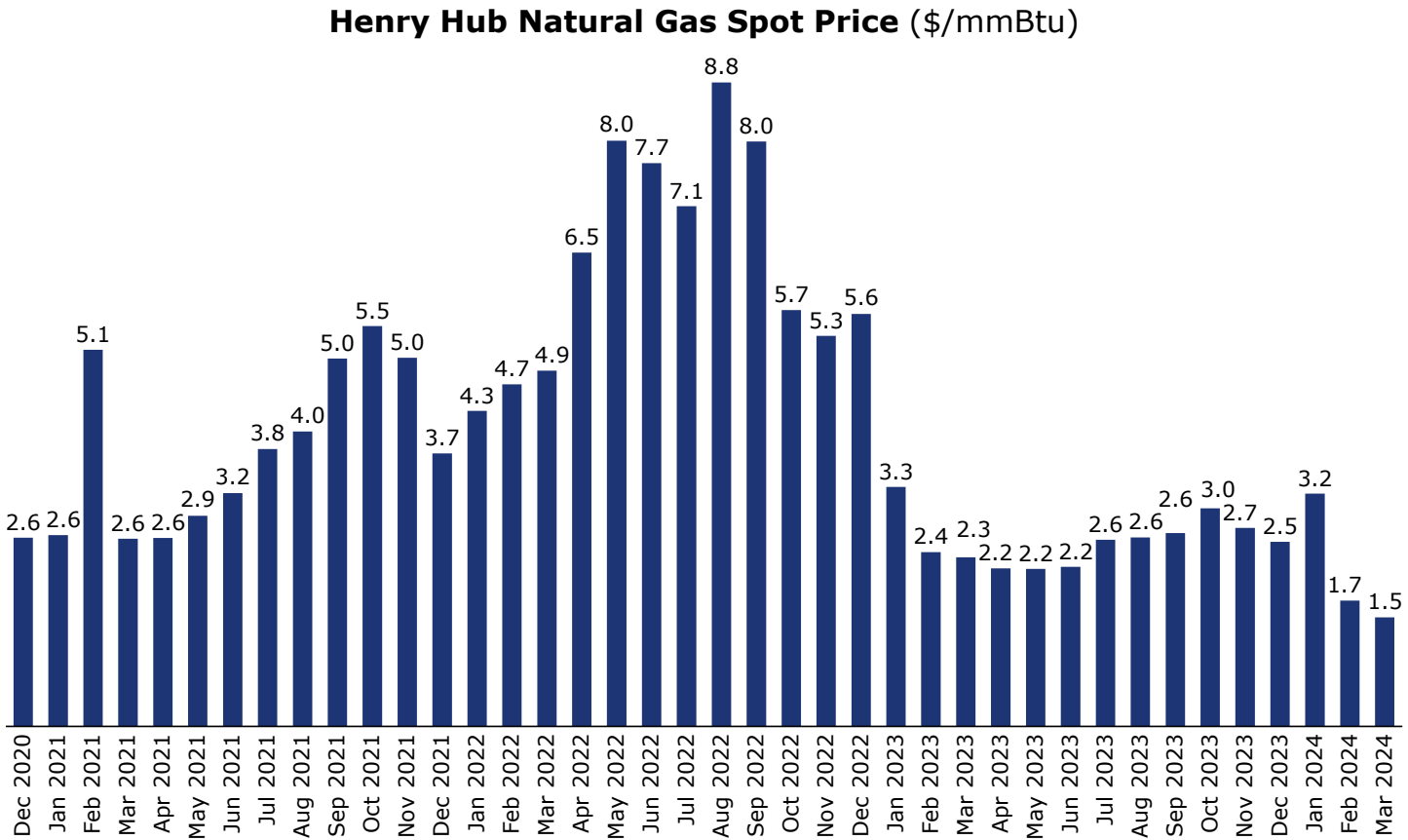


## The rate case benchmarking peer set includes utilities with more than 500,000 customers or are part of DTE's Great Lakes peer group

| Regulated              |                           | Deregulated              |                            |
|------------------------|---------------------------|--------------------------|----------------------------|
| AES Indiana*           | MidAmerican Energy*       | Ameren Illinois          | NY State Electric & Gas    |
| Alabama Power          | Nevada Power              | Atlantic City Electric   | Niagara Mohawk Power       |
| Appalachian Power      | Northern IN Pub. Serv.    | Baltimore Gas & Electric | NSTAR Electric             |
| Arizona Public Service | Northern States Power     | CenterPoint Houston*     | Ohio Edison                |
| Consumers Energy       | Oklahoma Gas & Electric   | Central Maine Power      | Ohio Power                 |
| Dominion Energy SC     | PacifiCorp                | Cleveland Electric*      | Oncor Electric             |
| DTE Electric           | Portland General Electric | Commonwealth Edison      | Pacific Gas & Electric     |
| Duke Energy Carolinas  | Pub. Serv. of CO          | Con. Edison of NY        | PECO Energy                |
| Duke Energy Florida    | Pub. Serv. of NH*         | CT Light & Power*        | Pennsylvania Electric*     |
| Duke Energy Indiana*   | Pub. Serv. of NM          | Dayton Power & Light     | Potomac Electric           |
| Duke Energy Progress   | Pub. Serv. of OK          | Delmarva Power & Light   | PPL Electric*              |
| Entergy Arkansas       | Puget Sound               | Duke Energy Ohio         | Pub. Serv. Electric & Gas* |
| Entergy Louisiana*     | Southwestern Electric     | Duquesne Light           | San Diego Gas & Electric   |
| Evergy Metro           | Tampa Electric            | Jersey Central P&L       | Southern CA Edison         |
| Florida Power & Light  | Union Electric            | Massachusetts Electric   | Toledo Edison*             |
| Georgia Power          | Wisconsin Electric Power  | Metropolitan Edison*     | West Penn Power*           |
| Idaho Power            | Wisconsin Power & Light   |                          |                            |
| Indiana Michigan Power | Wisconsin Pub. Serv.      |                          |                            |
| Kentucky Utilities     |                           |                          |                            |

\*Utility has not had an electric rate case approved since 2021 (as of April 12, 2024)

## Natural gas prices have been volatile since 2020



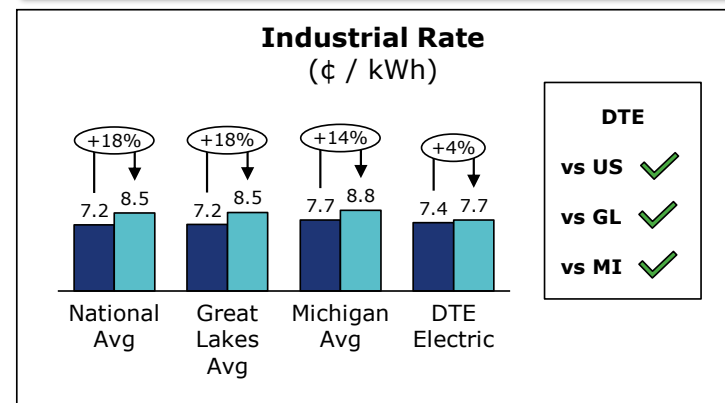
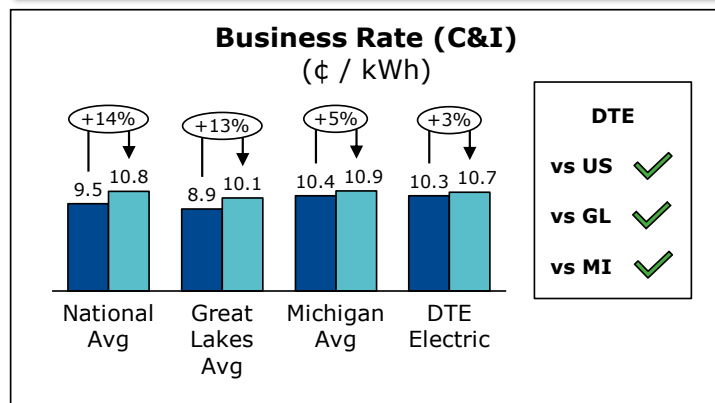
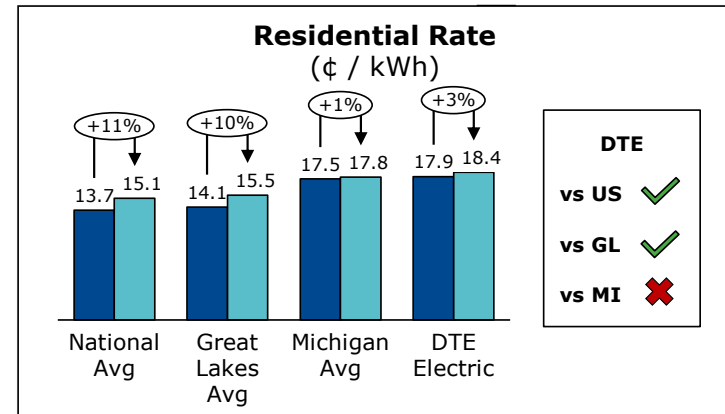
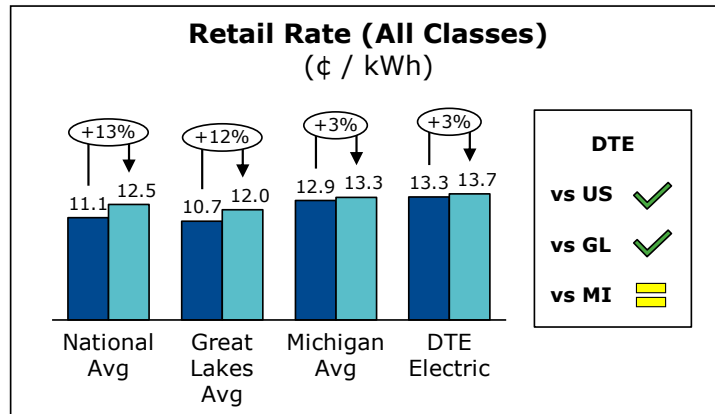


## Annual Rate Benchmarking

April 18, 2023

From 2021 to 2022, DTE's electric rates grew at a slower pace than its Great Lakes and national peers across all rate classes

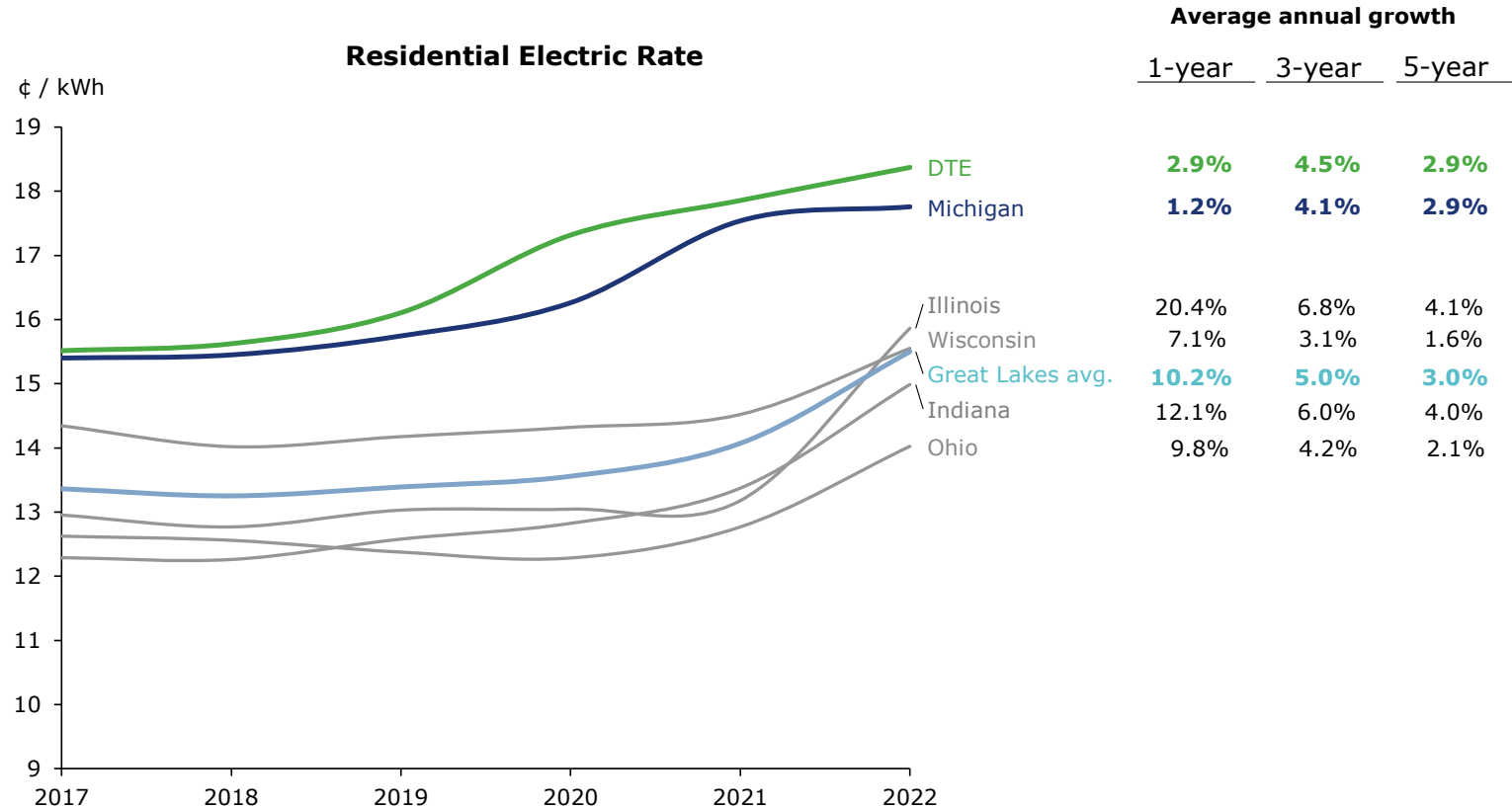
2021



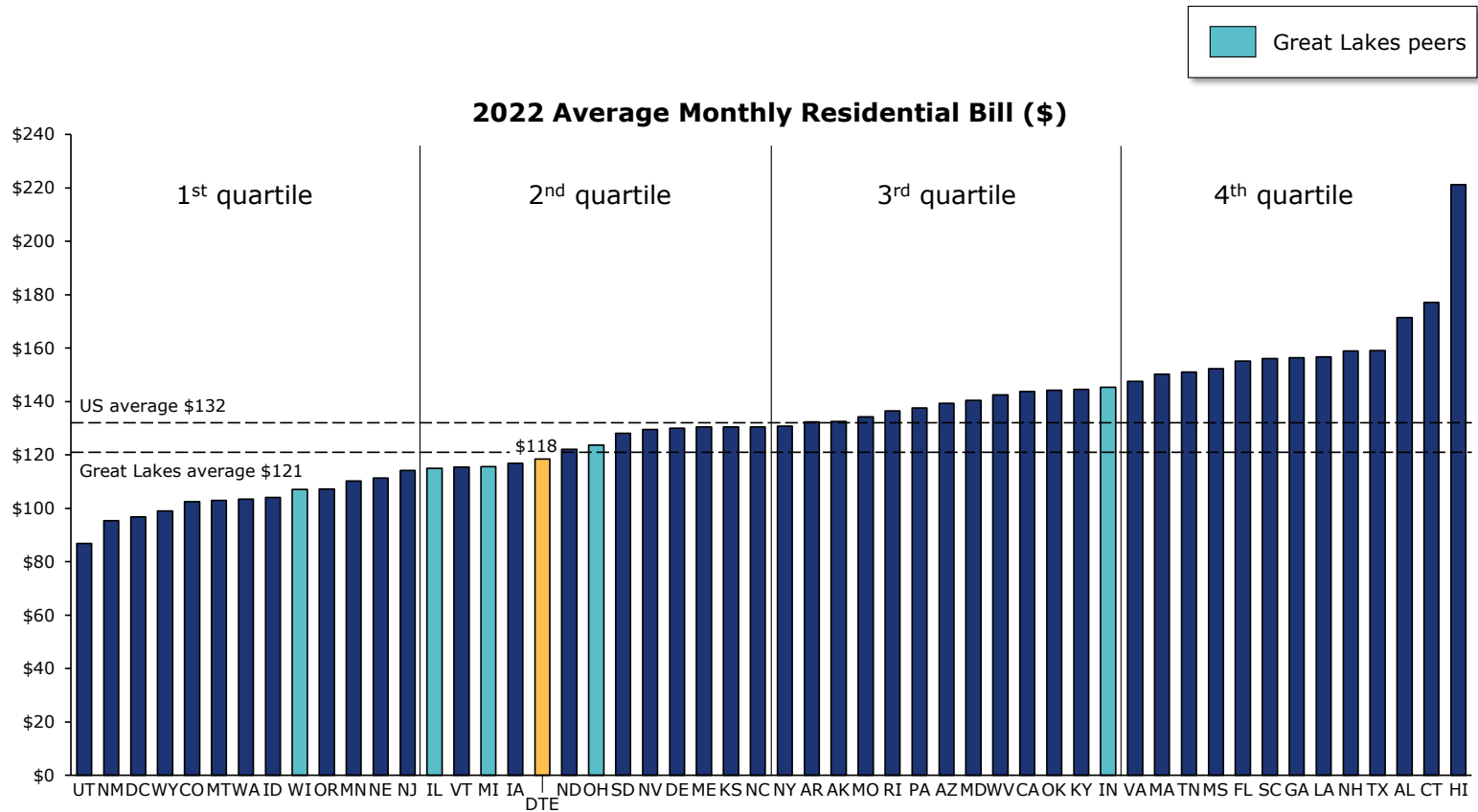
While DTE's residential rates are above the national average...



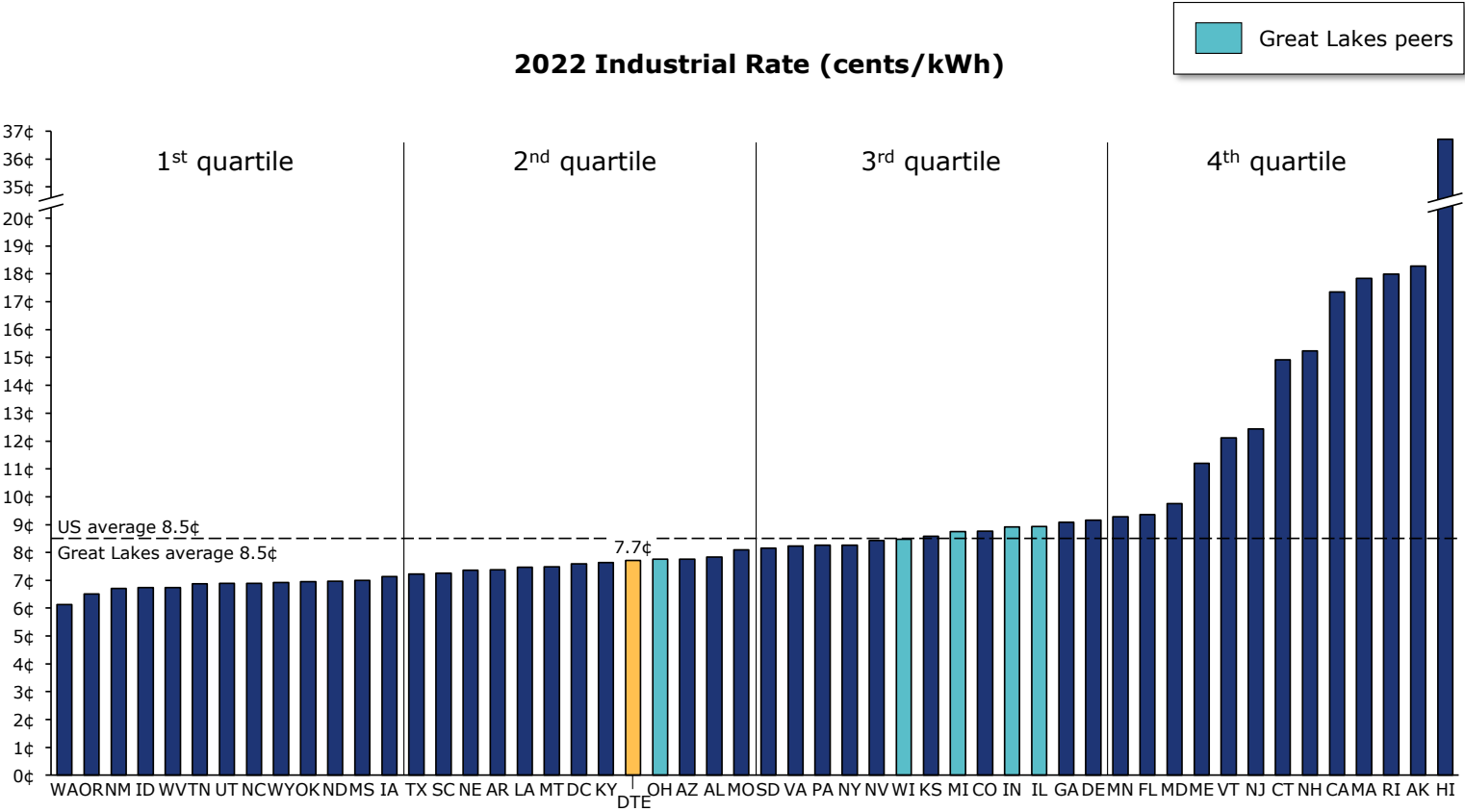
DTE and Michigan had the lowest one-year growth rates and are below the Great Lakes average for five-year growth rates



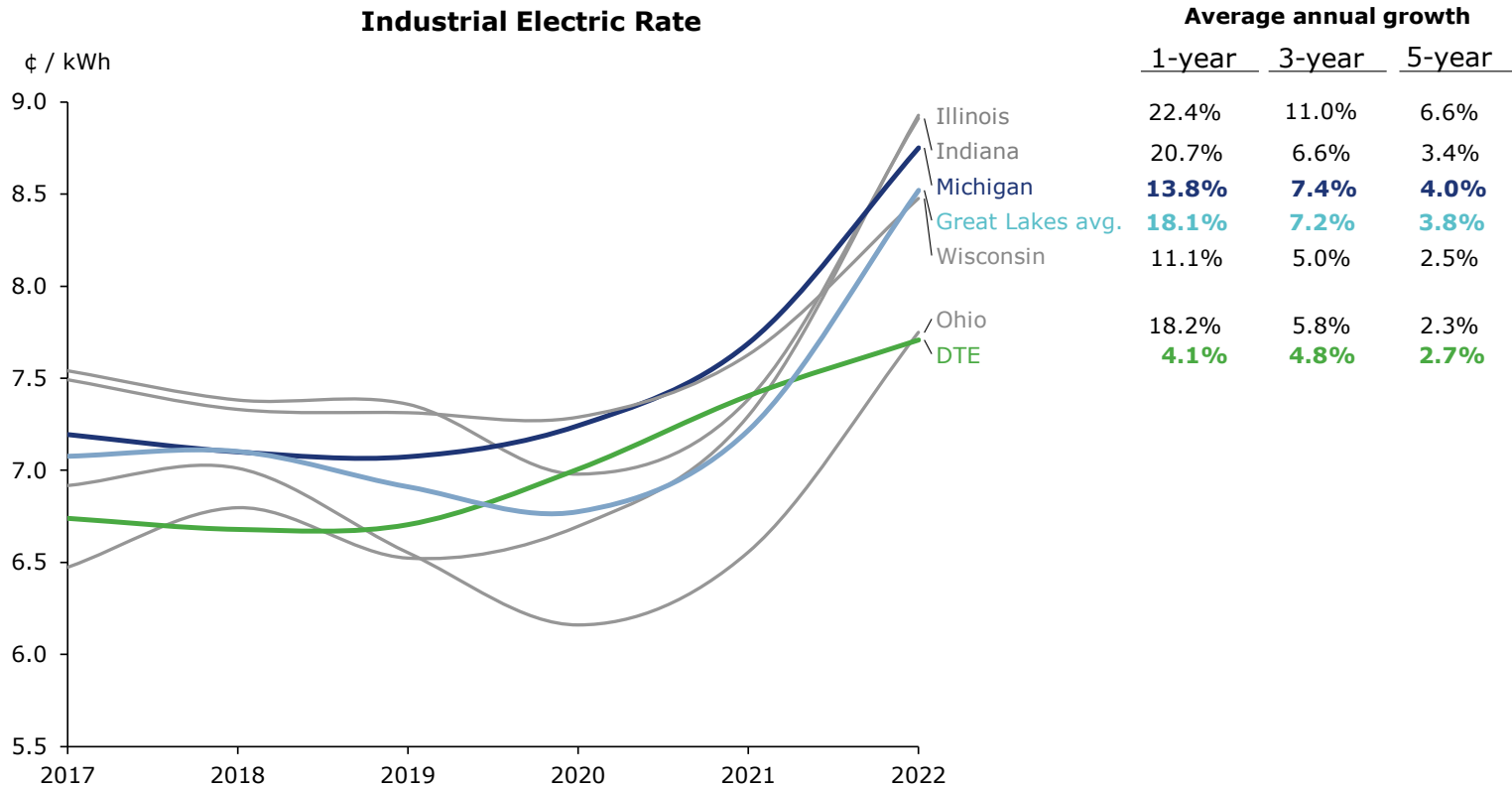
## Residential bills remain in the 2<sup>nd</sup> quartile



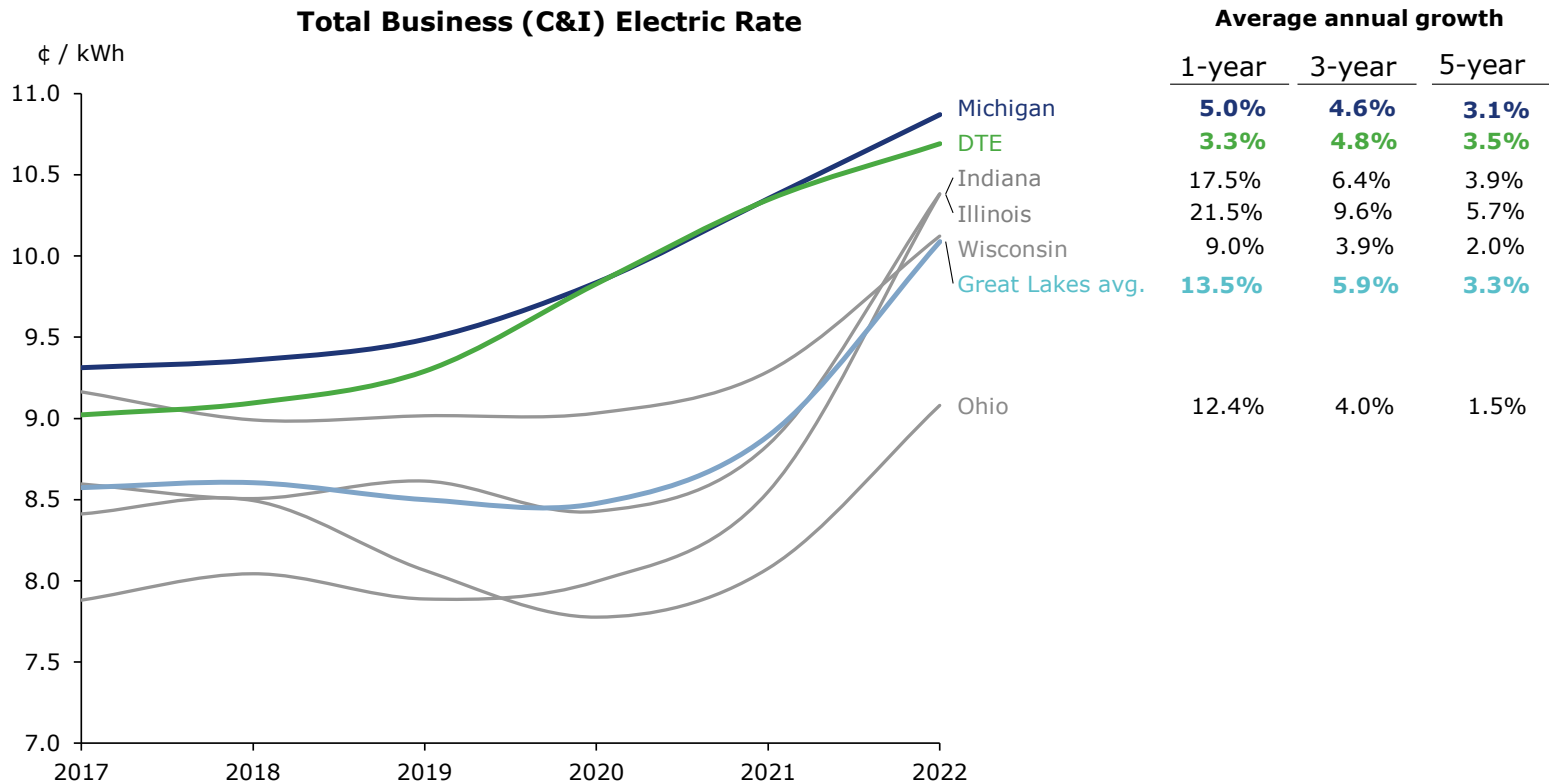
DTE industrial rates were below the national and Great Lakes averages



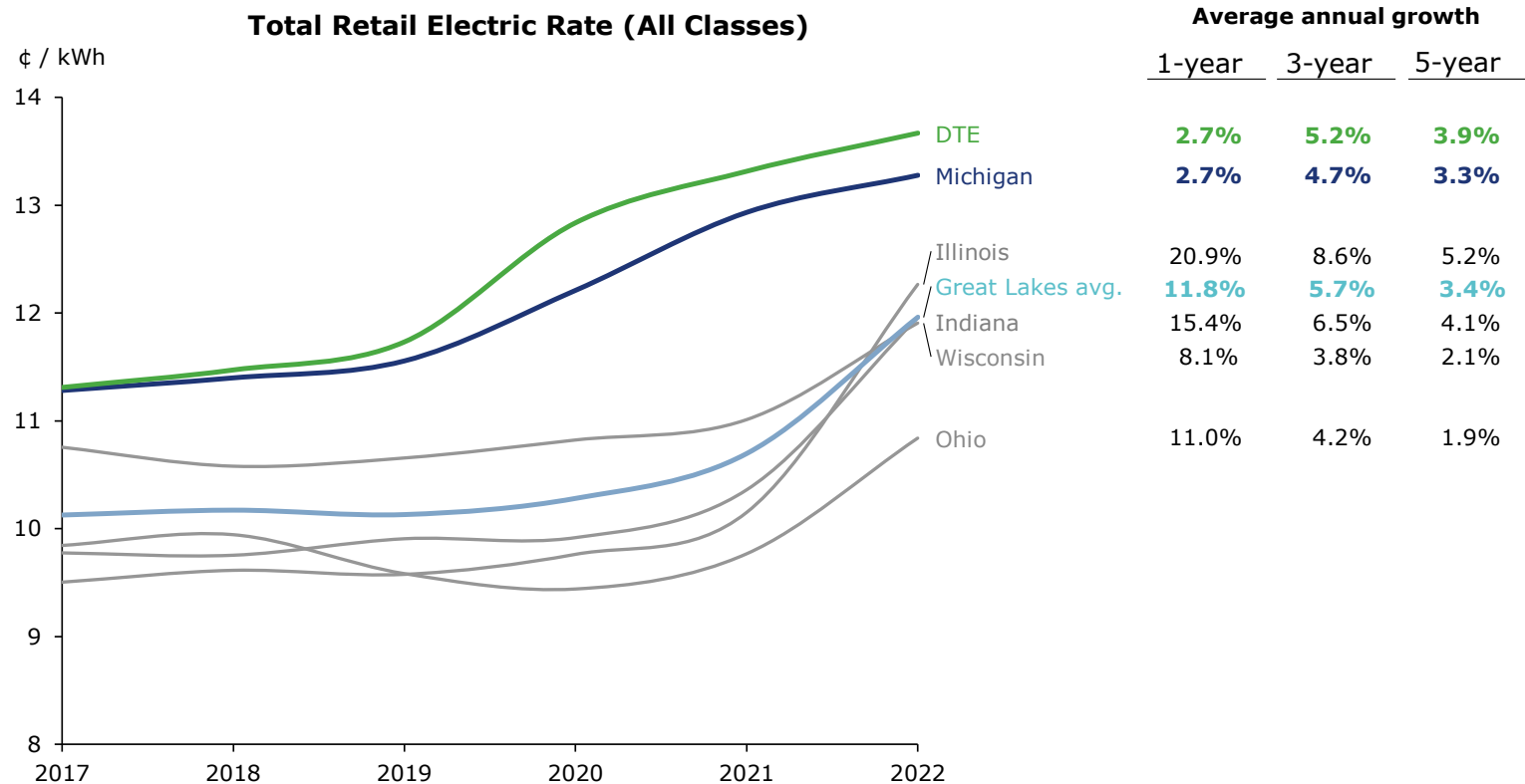
DTE had by far the lowest year-over-year growth in Industrial rates and is now lower than any of the states in the region



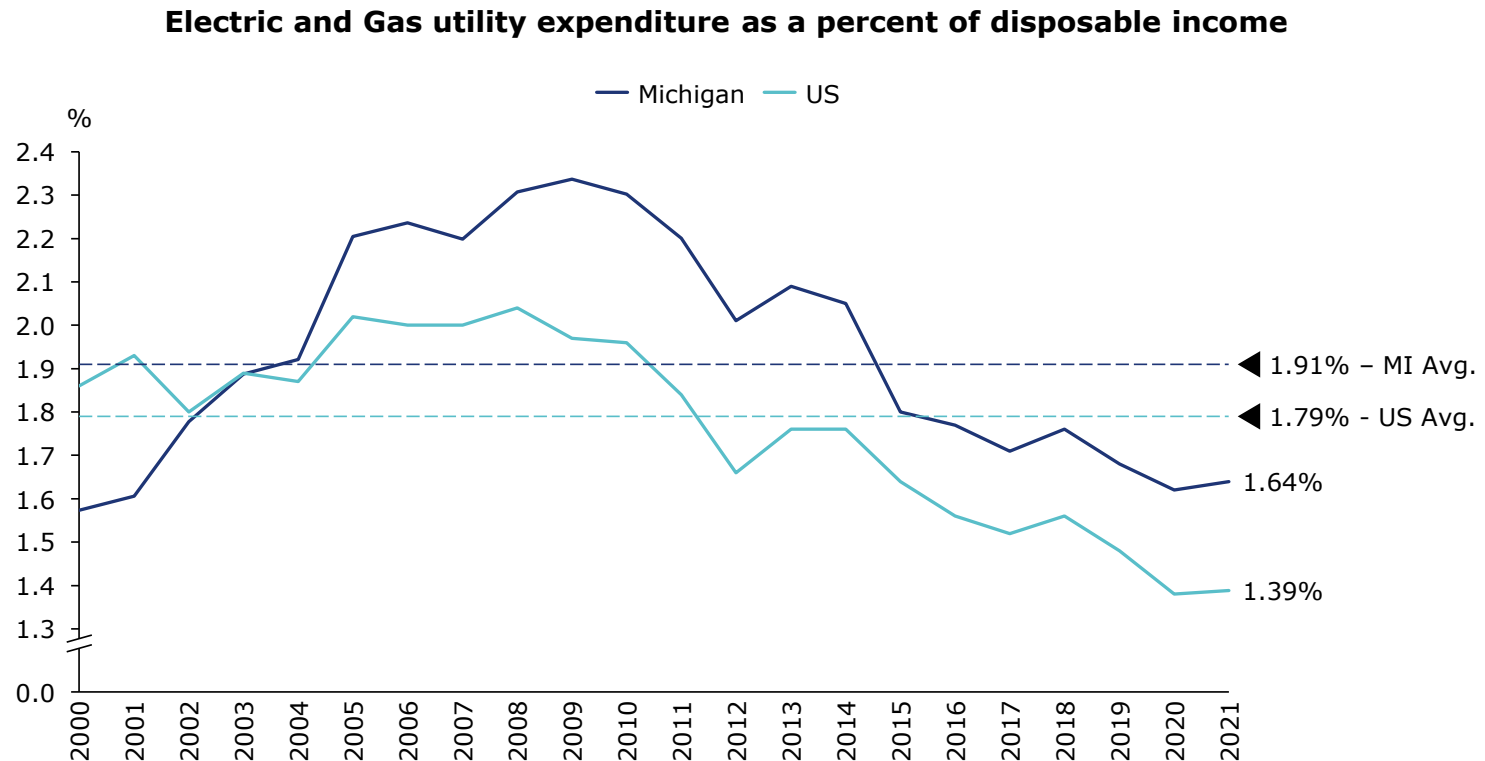
## DTE total business rate changes compare unfavorably to the regional average over one-, three-, and five-year periods



## The changes in DTE Electric retail rates compare favorably to our regional average over one- and three-year periods

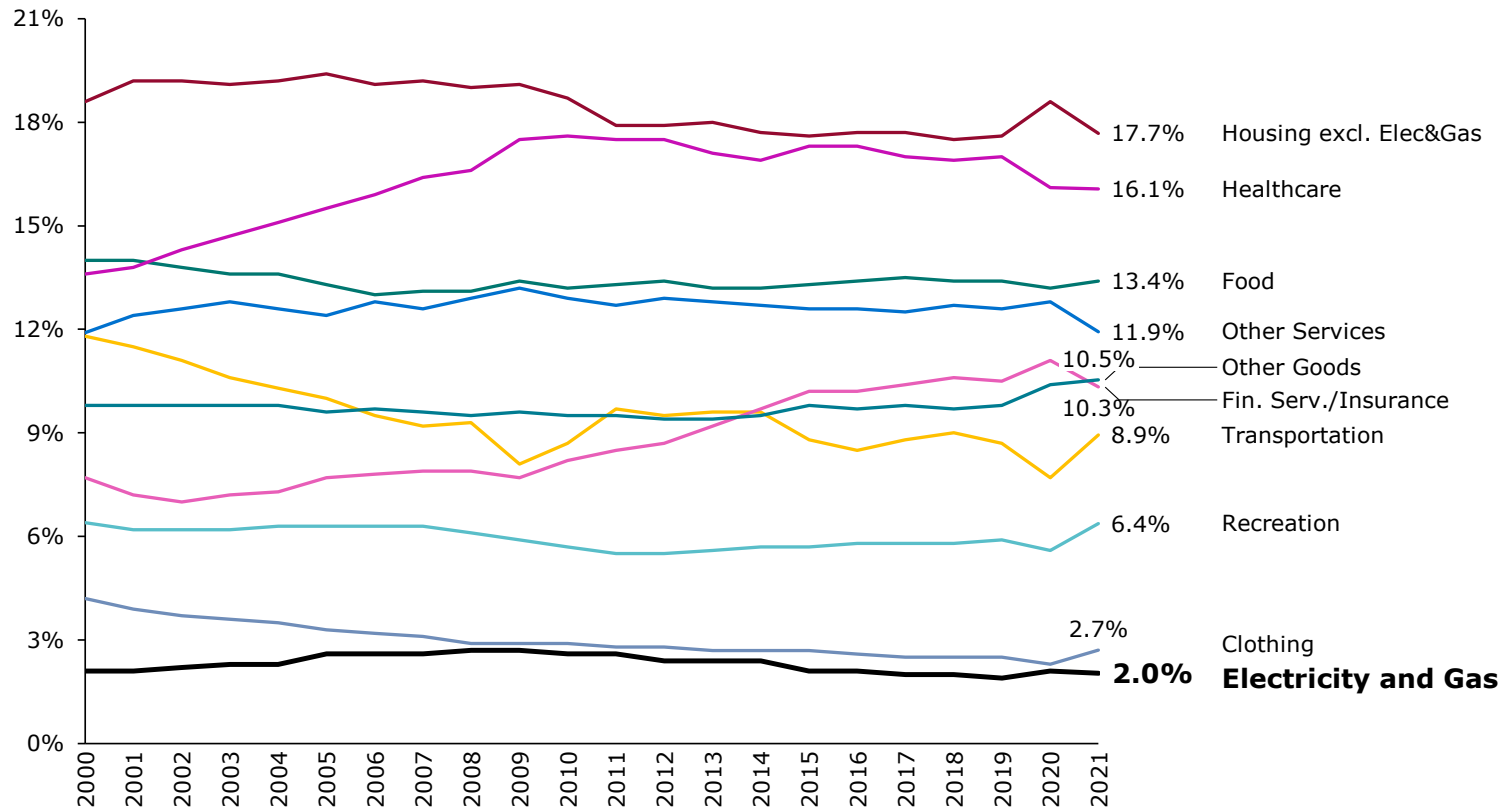


The share of disposable income for residential electric and gas utility expense in Michigan has been trending lower over the past decade

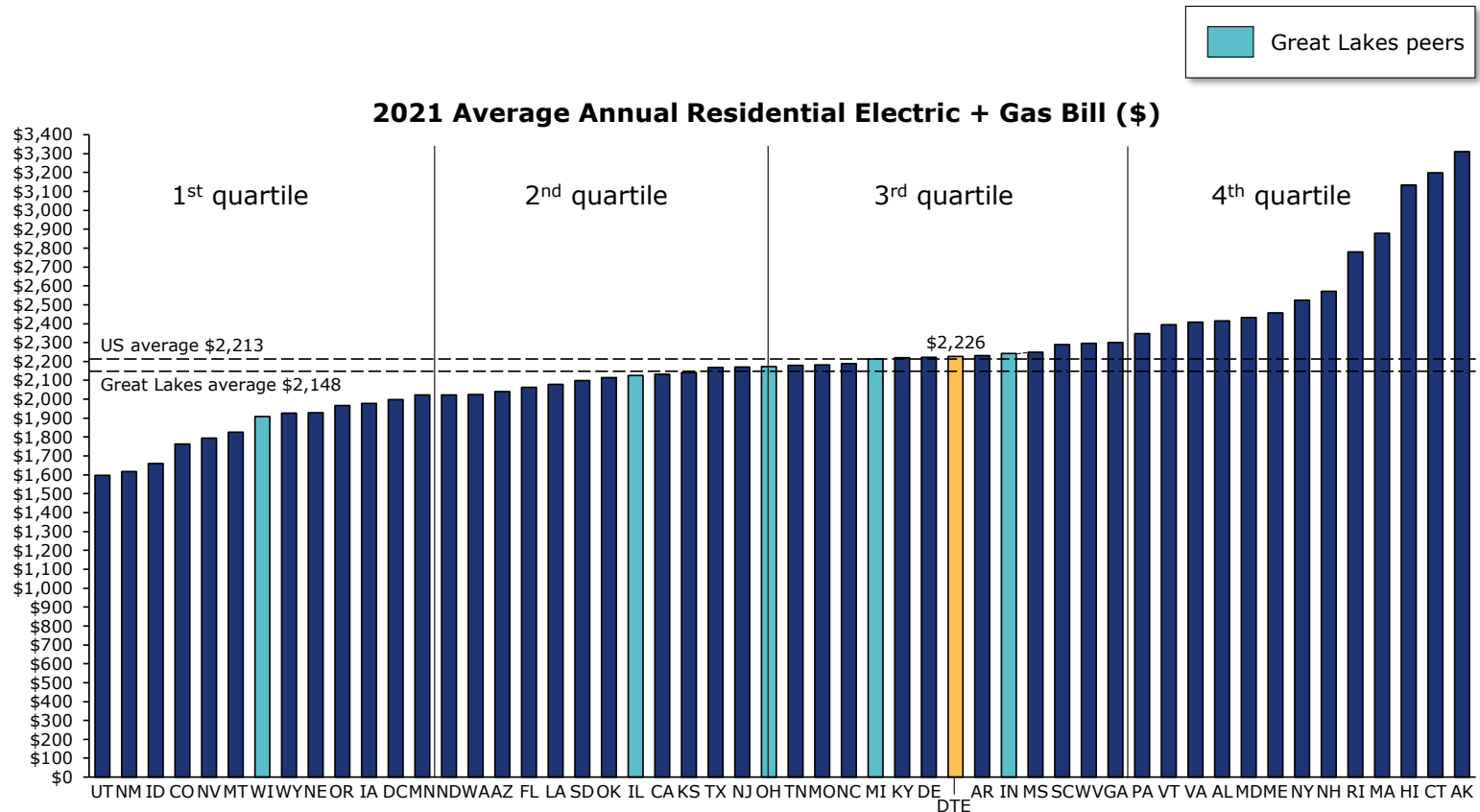


The share of spend on residential electric and gas utility bills in Michigan has also remained small relative to other typical categories of household spend

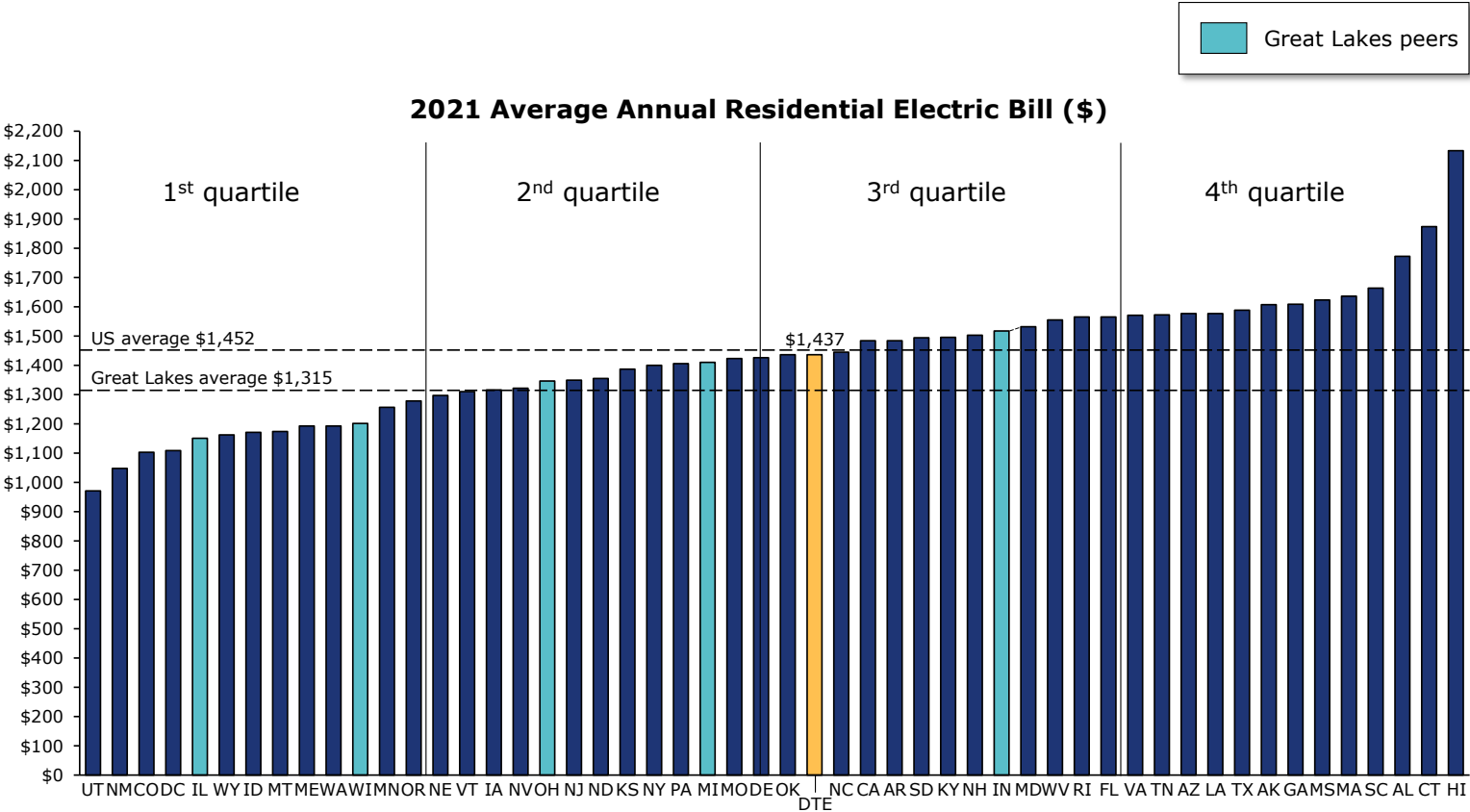
**Michigan percentage of personal consumption expenditures over time**



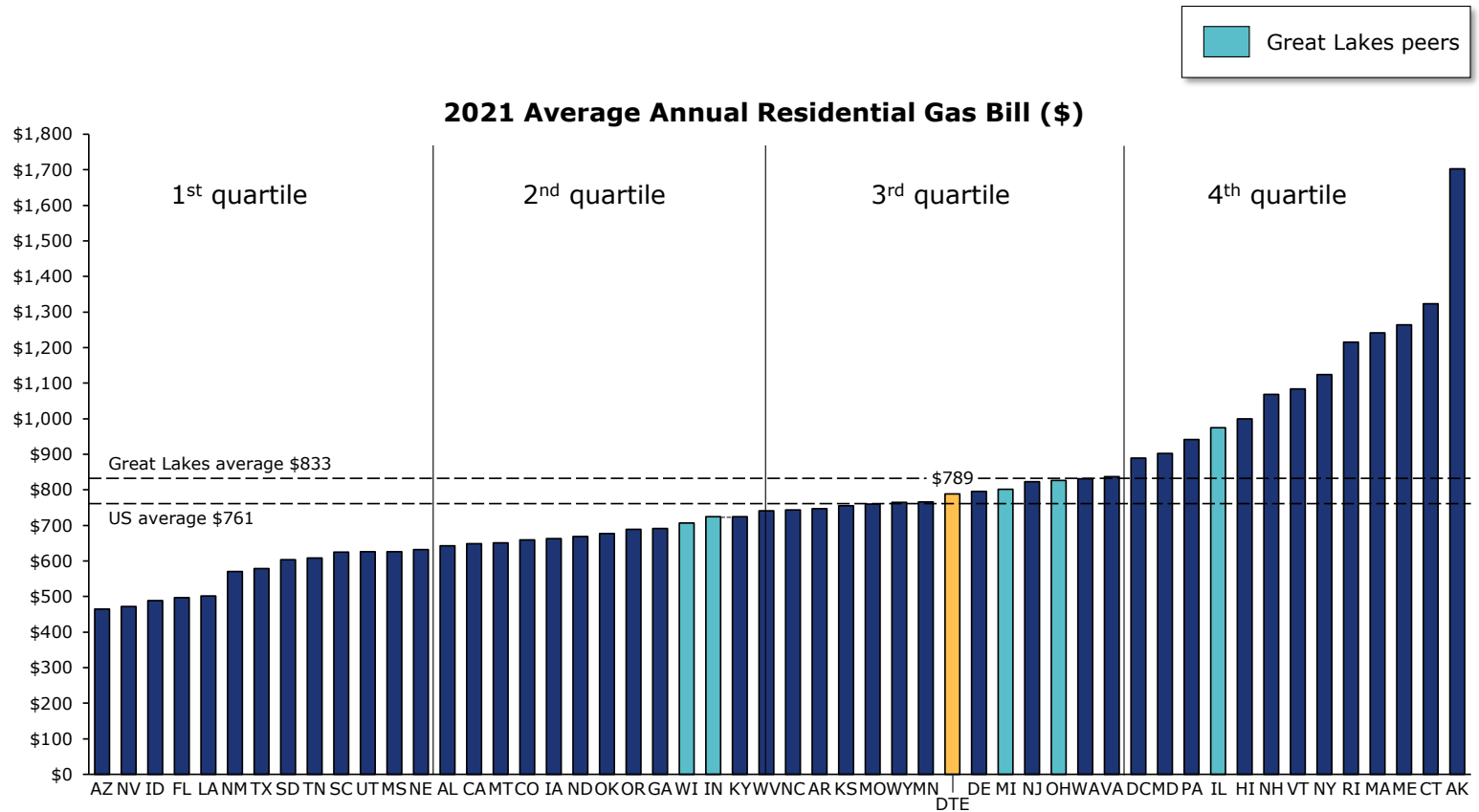
## Full Year 2021 Combined Electric and Gas Bills



# Full Year 2021 Electric Bills



## Full Year 2021 Gas Bills



**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-15.25c

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**Respondent:** M. Elliott Andahazy

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**Page:** 1 of 1

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- Question:** 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.
- c. Refer to the response to sub-part (b). For each program/analysis provided, confirm that vegetation management circuits were removed from the control group. If this cannot be confirmed, please explain.

**Answer:** The Company confirms that tree trim circuits were removed from the control group for the 4.8kV Hardening Program effectiveness analysis.

The control group for the Tree Trim analysis includes circuits that have not been trimmed to the Enhanced Tree Trimming Program (ETTP) specification.

**Attachment:** N/A

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-15.25d

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**Respondent:** M. Elliott Andahazy

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**Page:** 1 of 1

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**Question:** 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.

d. For each of the following programs, identify whether tree trimming is completed as part of the program work (or not): 4.8kV Hardening; 4.8kV circuit conversion; PTMM; and distribution automation.

**Answer:** For all the programs referenced, tree trimming is completed as part of the program. Trimming under these programs is executed to provide the Company safe and efficient access to complete the work – the scope and extent of trimming varies by program and project.

**Attachment:** N/A

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-15.25e

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**Respondent:** M. Elliott Andahazy

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**Page:** 1 of 1

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- Question:** 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.
- e. Refer to the response to subpart (d). For each program in which tree trimming is completed as part of program work, confirm that tree trimming is capitalized as part of overall project costs and depreciated over the same time frame as the expected useful life of the project. If not confirmed, please explain.

**Answer:** Tree trimming is associated with all programs referenced and is capitalized as part of the overall project investments and depreciated at the same rate as the capitalized assets.

**Attachment:** N/A

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-15.25f

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**Respondent:** T. Uzenski

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**Page:** 1 of 1

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- Question:** 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.
- f. Please provide the expected useful life used to depreciate each program's capital spending: Tree trimming if capitalized; 4.8kv Hardening; 4.8kV circuit conversion; PTMM; and distribution automation.

**Answer:** To forecast projected depreciation expense for rate case purposes, a depreciation rate of 4.11% is applied to distribution capital that is projected to be in-service.

**Attachment:** None.

**MPSC Case No:** U-21534

**Requester:** MNSC

**Question No.:** MNSCDE-15.25g

**Respondent:** R. Steudle

**Page:** 1 of 1

- Question:** 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.
- g. For 2022, estimate the dollar amount of program capital spending associated with tree trimming for each program: 4.8kv Hardening; 4.8kV circuit conversion; PTMM; and distribution automation. Provide workpapers used to complete each estimate, including data employed and identifying sources of data employed.

**Answer:** See the below table, there was no tree trim associated with distribution automation in 2022:

| Program                 | 2022 Investment | Methodology for Estimate                          |
|-------------------------|-----------------|---------------------------------------------------|
| 4.8 Hardening           | \$34.6          | Direct charged to project                         |
| 4.8 Conversions         | \$0.4           | Direct charged to project                         |
| PTMM                    | \$8.8           | Journal Entry (Logic Attached) and Direct charges |
| Distribution Automation | \$0.0           | Direct charged to project                         |

**Attachment:** U-21534 MNSC 15.25g-h PTMM Journal Entry Logic

**MPSC Case No:** U-21534

**Requester:** MNSC

**Question No.:** MNSCDE-15.25h

**Respondent:** R. Steudle

**Page:** 1 of 1

- Question:** 25. Refer to the Company's response to MNSC 8.1.f(i), which indicates that circuits with vegetation management were eliminated from the control group used to compare circuits on which 4.8kV hardening was completed to secure estimates of reliability improvement benefits.
- h. For 2023, estimate the dollar amount of program capital spending associated with tree trimming for each program: 4.8kv Hardening; 4.8kV circuit conversion; PTMM; and distribution automation. Provide workpapers used to complete each estimate, including data employed and identifying sources of data employed.

**Answer:**

| Program                 | 2023 Investment (\$M) | Methodology for Estimate                          |
|-------------------------|-----------------------|---------------------------------------------------|
| 4.8 Hardening           | \$18.40               | Direct charged to project                         |
| 4.8 Conversions         | \$2.10                | Direct charged to project                         |
| PTMM                    | \$9.30                | Journal Entry (Logic Attached) and Direct charges |
| Distribution Automation | \$0.17                | Direct charged to project                         |

**Attachment:** U-21534 MNSC 15.25g-h PTMM Journal Entry Logic

|                                        |    |             |
|----------------------------------------|----|-------------|
| Illustrative Data                      |    |             |
| PTMM Budget                            | \$ | 60,000,000  |
| PTMM Miles                             |    | 1300        |
| Tree Trim Budget (Line Clearance Only) | \$ | 100,000,000 |
| Tree Trim Miles                        |    | 5000        |
| Coincidence Factor (B6/B3)             |    | 26%         |
| Capitalization Factor                  |    | 18.89%      |
| Journal Entry (B5*B8*B10)              | \$ | 4,911,400   |

The journal entry related to tree trimming and the PTMM program is based on the annual miles that undergo PTMM and the annual miles trimmed. *Annual budgets and miles are illustrative*

DTE Electric Company  
One Energy Plaza, 1635 WCB  
Detroit, MI 48226-1279



Andrea E. Hayden  
(313) 235-9449  
andrea.hayden@dteenergy.com

March 1, 2024

Ms. Lisa Felice  
Executive Secretary  
Michigan Public Service Commission  
7109 West Saginaw Highway  
Lansing, Michigan 48917

Re: In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.  
MPSC Case No. U-20162

Dear Ms. Felice:

Pursuant to the Commission's final Order in MPSC Case No. U-20162, please find attached DTE Electric Company's March 1, 2024 Tree Trim Annual Report. If you have any questions, please feel free to contact me.

Very truly yours,

Andrea E.  
Hayden

Digitally signed by Andrea  
E. Hayden  
Date: 2024.03.01 09:18:18  
-05'00'

Andrea E. Hayden

AEH/cdm  
Encl.



### **March 1, 2024 Tree Trim Annual Report**

In Case U-20162, on May 2, 2019, the Commission directed DTE Electric (DTEE) to file an annual report to detail the progress of the Surge program and Enhanced Tree Trim Program (ETTP) performance. From the U-20162 Order:

Thus, the annual report shall also break out all activity, costs, and miles trimmed under any and all tree trimming programs (including hardening) in the city of Detroit, to provide information on the progress made in the city of Detroit with each program. The reporting shall include measurable data for the efforts, including miles completed by service center, performance of ETTP circuits compared to non-ETTP circuits, the costs of the efforts, number of employees directly involved in the efforts, tree-related outage reductions, SAIDI reductions, and whether the funding for the efforts is a capital expense or O&M cost. Further, the report shall track ETTP circuit performance, comparing average outages for the three years prior to the enhanced trimming with outages in the years after the trimming has been performed. The first report is due in this docket March 1, 2020, and an annual report is due on March 1 of each year thereafter.

Per Case U-20162 order and Case U-20561 order, this report covers the requested information. The report is split into six sections:

- 1) Miles Completed to ETTP Standard – Annual ETTP maintenance miles are reported by Service Center over the 2015-2023 time period. City of Detroit miles are broken out separately.
- 2) O&M and Capital Spend on Tree Trimming Activities – Annual tree trim spend are reported by Service Center over the 2016-2023 time period. City of Detroit spend is broken out separately. Costs from 2015 are not included because the ETTP specification makes up a relatively small portion of the overall tree trim spend in that year.
- 3) ETTP Circuit Performance – ETTP circuit performance comparing average outage events, customer interruptions, outage minutes, and wire downs before and after ETTP work. The performance will cover ETTP circuits trimmed in 2015 through 2022 with reliability data that ranges from 2012 to 2023. Performance of ETTP circuits trimmed in 2023 will be measured starting in 2024.
- 4) Spot Tree Trimming – Description of spot-trimming work done on the 10 worst performing circuits.
- 5) Tree Trim Workforce – A 2023 summary of the tree trim workforce is broken down by DTEE employees and contractors.

- 6) Incremental Funding for Tree Trim Program – Description of the additional work completed in 2023 from the increased funding from Case No. U-21128, in which the Company committed an incremental \$90M to the tree trim program.

### **Section 1 – Miles Completed to ETP Standard**

Since the inception of the ETP standard, the Company has trimmed 38,550 miles. 5,299 ETP miles were trimmed in 2023 as part of the Surge program. Below, **Table 1** breaks out ETP miles trimmed by distribution and subtransmission, **Table 2** details miles trimmed by service center and year. **Table 3** shows total miles trimmed to ETP, which may include second and third cycle ETP trimming. It has a breakdown of only unique miles trimmed to ETP, which does not count the second or third cycle of ETP trimming. It also shows miles in backlog (off-cycle), average density and work location by service center. Previous filings from the Company also included manual/climbing trimming data by service center, which was from a onetime study performed by a third-party consultant. The Company does not collect climbing data for each circuit trimmed, however, backlog work is strongly correlated with manual/climbing trimming. **Table 4** shows ETP miles trimmed in the City of Detroit, and **Table 5** covers miles trimmed as part of the 4.8kV Hardening Program.

**Table 1 – ETP Miles Trimmed by Circuit Type**

| <b>Circuit Type</b>          | <b>2015</b> | <b>2016</b>  | <b>2017</b>  | <b>2018</b>  | <b>2019</b>  | <b>2020</b>  | <b>2021</b>  | <b>2022</b>  | <b>2023</b>  | <b>Total</b>  | <b>% of System</b>     |
|------------------------------|-------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|---------------|------------------------|
| Distribution <sup>1</sup>    | 257         | 2,270        | 2,733        | 3,128        | 3,181        | 4,583        | 5,021        | 5,991        | 4,566        | 31,730        | 81%                    |
| Subtransmission <sup>2</sup> | 188         | 1,030        | 868          | 540          | 1,006        | 1,006        | 726          | 723          | 733          | 6,820         | 100%                   |
| <b>Total Miles</b>           | <b>445</b>  | <b>3,300</b> | <b>3,601</b> | <b>3,668</b> | <b>4,187</b> | <b>5,589</b> | <b>5,747</b> | <b>6,714</b> | <b>5,299</b> | <b>38,550</b> | <b>83%<sup>3</sup></b> |

<sup>1</sup> Some of these distribution miles are on their second cycle of ETP trimming and show up in the numbers more than once.

<sup>2</sup> Some of these subtransmission miles are on their second or third cycle of ETP trimming and show up in the numbers more than once.

<sup>3</sup> Numerator only includes unique miles – it only counts the miles once even if the miles are on their second or third cycle of ETP trimming.

**Table 2 – ETP Miles Trimmed by Service Center**

| Service Center     | 2015       | 2016         | 2017         | 2018         | 2019         | 2020         | 2021         | 2022         | 2023         | Total         |
|--------------------|------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|---------------|
| ANN                | 5          | 143          | 566          | 309          | 246          | 537          | 285          | 585          | 423          | 3,099         |
| CAN                | 40         | 60           | 62           | 271          | 307          | 335          | 360          | 375          | 244          | 2,054         |
| HWL                | 192        | 272          | 445          | 262          | 264          | 603          | 659          | 719          | 320          | 3,736         |
| LAP                | 13         | 341          | 390          | 423          | 378          | 653          | 584          | 555          | 616          | 3,953         |
| MAR                | 70         | 351          | 419          | 432          | 303          | 334          | 395          | 776          | 781          | 3,861         |
| MTC                | 23         | 250          | 259          | 115          | 321          | 430          | 274          | 335          | 79           | 2,086         |
| NAE                | 42         | 693          | 470          | 533          | 557          | 463          | 826          | 793          | 605          | 4,982         |
| NPT                | 5          | 159          | 263          | 342          | 254          | 536          | 561          | 196          | 437          | 2,753         |
| PON                | 6          | 426          | 230          | 237          | 424          | 567          | 618          | 551          | 443          | 3,502         |
| RFD                | 24         | 219          | 112          | 381          | 670          | 444          | 300          | 922          | 466          | 3,538         |
| SBY                | 8          | 111          | 102          | 207          | 129          | 114          | 181          | 377          | 453          | 1,682         |
| WWS                | 17         | 275          | 283          | 156          | 334          | 573          | 704          | 531          | 433          | 3,306         |
| <b>Total Miles</b> | <b>445</b> | <b>3,300</b> | <b>3,601</b> | <b>3,668</b> | <b>4,187</b> | <b>5,589</b> | <b>5,747</b> | <b>6,714</b> | <b>5,299</b> | <b>38,550</b> |

**Table 3 – ETP Miles Trimmed, Miles of Backlog, Average Tree Density and Mix of Work by Service Center**

| Service Center     | Cumulative Miles Trimmed ETP <sup>4</sup> | Total System Miles                       |                                                | For the 2023 Plan Only                        |                          |                                             |                                        |
|--------------------|-------------------------------------------|------------------------------------------|------------------------------------------------|-----------------------------------------------|--------------------------|---------------------------------------------|----------------------------------------|
|                    |                                           | Unique Miles Trimmed to ETP <sup>5</sup> | Remaining Miles of Backlog to ETP <sup>6</sup> | 2023 Unique Miles Trimmed to ETP <sup>5</sup> | Total 2023 Miles Trimmed | Avg. Tree Density <sup>7</sup> (trees/mile) | Work Location <sup>7</sup> (% Backlot) |
| ANN                | 3,099                                     | 2,090                                    | 146                                            | 184                                           | 423                      | 575                                         | 73%                                    |
| CAN                | 2,054                                     | 1,387                                    | 40                                             | 1                                             | 244                      | 408                                         | 93%                                    |
| HWL                | 3,736                                     | 2,404                                    | 25                                             | 38                                            | 320                      | 301                                         | 74%                                    |
| LAP                | 3,953                                     | 2,645                                    | 24                                             | 115                                           | 616                      | 276                                         | 65%                                    |
| MAR                | 3,861                                     | 2,449                                    | 534                                            | 370                                           | 781                      | 201                                         | 61%                                    |
| MTC                | 2,086                                     | 1,365                                    | 1,206                                          | 0                                             | 79                       | 108                                         | 80%                                    |
| NAE                | 4,982                                     | 2,887                                    | 895                                            | 140                                           | 605                      | 157                                         | 84%                                    |
| NPT                | 2,753                                     | 1,943                                    | 10                                             | 46                                            | 437                      | 125                                         | 75%                                    |
| PON                | 3,502                                     | 2,614                                    | 238                                            | 294                                           | 443                      | 476                                         | 68%                                    |
| RFD                | 3,538                                     | 2,994                                    | 423                                            | 226                                           | 466                      | 315                                         | 84%                                    |
| SBY                | 1,682                                     | 1,239                                    | 71                                             | 260                                           | 453                      | 286                                         | 60%                                    |
| WWS                | 3,306                                     | 2,343                                    | 1,006                                          | 95                                            | 433                      | 290                                         | 82%                                    |
| <b>Total Miles</b> | <b>38,551</b>                             | <b>26,359</b>                            | <b>4,615</b>                                   | <b>1,768</b>                                  | <b>5,299</b>             | <b>290</b>                                  | <b>73%</b>                             |

<sup>4</sup> Includes second or third cycle ETP trim.

<sup>5</sup> Does not include second or third cycle ETP trim.

<sup>6</sup> Remaining miles in backlog after 2023 trimming.

<sup>7</sup> Density and work location are calculated based on task points identified by the planners during planning – includes brush.

**Table 4 – ETTP Miles Trimmed in the City of Detroit by Service Center**

| Service Center                         | 2015      | 2016       | 2017      | 2018       | 2019       | 2020       | 2021       | 2022       | 2023       | Total        | % of City              |
|----------------------------------------|-----------|------------|-----------|------------|------------|------------|------------|------------|------------|--------------|------------------------|
| CAN                                    | 40        | 42         | 60        | 234        | 293        | 291        | 326        | 246        | 240        | 1,772        | -                      |
| MTC                                    | -         | -          | 6         | -          | -          | 6          | -          | -          | 5          | 17           | -                      |
| RFD                                    | 5         | 87         | 27        | 251        | 464        | 90         | 129        | 259        | 192        | 1,504        | -                      |
| <b>Total Detroit Miles<sup>8</sup></b> | <b>45</b> | <b>129</b> | <b>93</b> | <b>485</b> | <b>757</b> | <b>387</b> | <b>455</b> | <b>505</b> | <b>438</b> | <b>3,293</b> | <b>97%<sup>9</sup></b> |

**Table 5 – ETTP Miles Trimmed as Part of the 4.8kV Hardening Program<sup>10</sup>**

| Service Center           | 2015     | 2016     | 2017     | 2018       | 2019       | 2020       | 2021       | 2022       | 2023       | Total        |
|--------------------------|----------|----------|----------|------------|------------|------------|------------|------------|------------|--------------|
| CAN                      | -        | -        | -        | 20         | 0          | 106        | 198        | 199        | 143        | 666          |
| RFD                      | -        | -        | -        | 127        | 158        | 161        | 129        | 325        | 100        | 1,000        |
| <b>Total 4.8kV Miles</b> | <b>-</b> | <b>-</b> | <b>-</b> | <b>147</b> | <b>158</b> | <b>267</b> | <b>327</b> | <b>524</b> | <b>243</b> | <b>1,666</b> |

## **Section 2 – O&M and Capital Spend on Tree Trimming Activities**

The Company spent \$169,669,666 in O&M for its tree trim program in 2023 as detailed in **Table 6**; years 2016 through 2022 are also included for reference. **Table 6** groups costs into five categories:

- 1) Line Clearance Maintenance – Comprises costs needed for maintenance activities such as contractor labor and equipment, general foreman cost, per diems, and overtime premiums.
- 2) Trouble – Spend on non-storm unplanned reactive tree trim work related to outage or non-outage problems on the electric system.
- 3) Tree Trim Program/Other – Includes customer request work, auditing, software maintenance, the herbicide program, training, safety, and other cost miscellaneous costs associated with Tree Trim.
- 4) DTE Staff Cost – DTE staff costs related to the tree trim program.
- 5) COVID Expenses – Includes costs associated with the additional safety measures that were taken due to the COVID-19 Pandemic.

<sup>8</sup> Some of these miles are on their second cycle of ETTP trimming and show up in the number more than once.

<sup>9</sup> Numerator only includes unique miles trimmed to ETTP, therefore does not double count miles on second- cycle or beyond.

<sup>10</sup> Program began in 2018 and miles in Table 5 are a subset of miles in Tables 1-3.

**Table 6 – Annual O&M Tree Trim Spend by Category<sup>11</sup>**

| O&M Spend                  | 2016                | 2017                | 2018                | 2019                 | 2020                 | 2021                 | 2022                 | 2023                 |
|----------------------------|---------------------|---------------------|---------------------|----------------------|----------------------|----------------------|----------------------|----------------------|
| Line Clearance Maintenance | \$59,155,543        | \$69,344,451        | \$71,757,936        | \$116,748,952        | \$151,021,453        | \$140,202,546        | \$209,270,442        | \$149,227,403        |
| Trouble                    | \$10,738,172        | \$11,395,011        | \$12,966,909        | \$16,556,969         | \$12,237,821         | \$10,667,520         | \$12,682,979         | \$9,535,799          |
| Tree Trim Program/Other    | \$2,771,660         | \$1,812,622         | \$2,500,756         | \$10,229,182         | \$6,839,979          | \$15,670,339         | \$13,013,567         | \$6,483,393          |
| DTE Staff Cost             | \$1,496,789         | \$1,704,325         | \$1,883,630         | \$2,667,190          | \$3,722,732          | \$4,372,897          | \$4,603,174          | \$4,423,070          |
| COVID-19 <sup>12</sup>     |                     |                     |                     |                      | \$1,340,624          | \$746,118            |                      |                      |
| <b>O&amp;M Total</b>       | <b>\$74,162,165</b> | <b>\$84,256,409</b> | <b>\$89,109,232</b> | <b>\$146,202,293</b> | <b>\$175,162,609</b> | <b>\$171,659,420</b> | <b>\$239,570,162</b> | <b>\$169,669,666</b> |

**Table 7** further breaks down the “Line Clearance Maintenance” costs in **Table 6** by service center.

**Table 7 – Annual Maintenance Tree Trim Spend by Service Center (O&M Only)**

| Service Center | 2016                | 2017                | 2018                | 2019                 | 2020                 | 2021                 | 2022                 | 2023                 |
|----------------|---------------------|---------------------|---------------------|----------------------|----------------------|----------------------|----------------------|----------------------|
| ANN            | \$4,081,462         | \$12,103,989        | \$9,489,387         | \$6,699,698          | \$18,811,275         | \$11,077,345         | \$19,663,782         | \$17,458,180         |
| CAN            | \$3,312,191         | \$1,200,014         | \$8,851,085         | \$18,827,931         | \$11,253,759         | \$6,701,520          | \$14,189,914         | \$4,913,541          |
| HWL            | \$4,838,162         | \$12,561,698        | \$6,269,100         | \$6,523,040          | \$19,744,784         | \$23,573,175         | \$20,366,427         | \$10,942,721         |
| LAP            | \$5,145,835         | \$5,820,146         | \$4,385,310         | \$5,306,986          | \$12,866,142         | \$8,215,356          | \$6,297,393          | \$9,272,157          |
| MAR            | \$3,679,637         | \$4,450,068         | \$5,021,951         | \$2,757,355          | \$5,087,650          | \$3,444,947          | \$8,968,144          | \$11,316,545         |
| MTC            | \$3,868,638         | \$4,093,991         | \$1,961,451         | \$3,770,923          | \$9,913,687          | \$3,727,800          | \$4,874,212          | \$2,258,725          |
| NAE            | \$3,100,279         | \$2,242,086         | \$2,615,529         | \$3,137,335          | \$5,336,176          | \$3,858,290          | \$5,567,071          | \$4,196,993          |
| NPT            | \$1,990,418         | \$4,844,204         | \$5,288,021         | \$3,400,257          | \$9,634,726          | \$12,826,082         | \$6,520,390          | \$11,730,643         |
| PON            | \$12,293,540        | \$8,619,875         | \$8,167,988         | \$24,883,843         | \$27,768,967         | \$29,346,468         | \$31,445,874         | \$19,290,761         |
| RFD            | \$5,929,162         | \$3,762,082         | \$11,025,927        | \$28,999,125         | \$12,309,855         | \$6,816,756          | \$42,187,521         | \$27,138,327         |
| SBY            | \$3,351,803         | \$3,078,400         | \$4,338,480         | \$2,656,440          | \$3,982,452          | \$2,863,698          | \$15,143,984         | \$13,380,970         |
| WWS            | \$7,564,417         | \$6,567,898         | \$4,343,707         | \$9,786,018          | \$14,311,980         | \$27,751,110         | \$34,045,729         | \$17,327,840         |
| <b>Total</b>   | <b>\$59,155,544</b> | <b>\$69,344,451</b> | <b>\$71,757,936</b> | <b>\$116,748,951</b> | <b>\$151,021,453</b> | <b>\$140,202,546</b> | <b>\$209,270,442</b> | <b>\$149,227,403</b> |

<sup>11</sup> Table does not include any spot trimming expenses from other programs because they are not part of the tree trim maintenance costs. This table does not include tree trimming cost related to storm, those costs are charged outside the tree trim budget.

<sup>12</sup> These expenses were mainly for the one-person per vehicle policy, and PPE for DTEE employees and contractors.

**Table 8** details the 4.8kV Hardening capital spend in 2018-2023.

**Table 8 – Annual 4.8kV Hardening Tree Trim Capital Spend by Service Center**

| Service Center | 2018                | 2019                 | 2020                | 2021                | 2022                | 2023                |
|----------------|---------------------|----------------------|---------------------|---------------------|---------------------|---------------------|
| CAN            | \$ 2,136,156        | -                    | \$5,878,864         | \$11,757,474        | \$10,675,606        | \$7,819,132         |
| RFD            | \$ 7,858,107        | \$ 10,081,771        | \$12,025,855        | \$10,274,963        | \$25,313,553        | \$10,955,464        |
| <b>Total</b>   | <b>\$ 9,994,263</b> | <b>\$ 10,081,771</b> | <b>\$17,904,719</b> | <b>\$22,032,437</b> | <b>\$35,989,159</b> | <b>\$18,774,596</b> |

**Table 9** highlights the \$25,903,156 tree trim spend in the City of Detroit for the year 2023, which includes \$16,148,871 of Capital spend. City spend in 2016 through 2023 is included for reference.

**Table 9 – Annual Detroit O&M and 4.8kV Hardening Capital Tree Trim Spend**

|                                   | 2018                | 2019                | 2020                | 2021                | 2022                | 2023                |
|-----------------------------------|---------------------|---------------------|---------------------|---------------------|---------------------|---------------------|
| Detroit - O&M                     | \$14,071,122        | \$40,513,330        | \$7,333,594         | \$3,875,167         | \$8,468,206         | \$9,754,285         |
| Detroit – 4.8kV Hardening Capital | \$9,326,363         | \$10,081,771        | \$11,888,408        | \$21,408,206        | \$28,865,840        | \$16,148,871        |
| <b>Detroit Total</b>              | <b>\$23,397,485</b> | <b>\$50,595,101</b> | <b>\$19,222,002</b> | <b>\$25,283,373</b> | <b>\$37,334,046</b> | <b>\$25,903,156</b> |

### **Section 3 – ETPP Circuit Performance**

#### **Methodology Used to Calculate ETPP Performance**

The methodology used to calculate ETPP Performance for all distribution circuits uses the average of three years of pre-trim ETPP tree-related outage events and compares it to each year post-trimming. All post-trim year results of the same year were then summed to increase the sample size (as an example, all post-trim year 1 results are included collectively as a sum). The difference between the before trimming performance and the post trimming performance was used to create the “% Change in Outage Event Reduction for ETPP circuits”. To create a control group for comparison, the same methodology was used for the remainder of circuits not trimmed ETPP<sup>13</sup> (Non-ETPP circuits), which are identified as “% Change in Outage Event Reduction for Non-ETPP circuits”. To account for natural weather variation, the performance of the control group is subtracted from the ETPP circuit performance to provide an accurate representation of the true impact of the ETPP. This is the same methodology outlined in Case U-20561, U-20836, and U-21297.

<sup>13</sup> This group consists of circuits that have not been trimmed to the ETPP specification and are considered off-cycle.

**Table 10 – Methodology for ETP Performance Analysis**

| 2012                                   | 2103                                   | 2014                                   | 2015                                   | 2016             | 2017             | 2018             | 2019             | # of ETP Circuits |
|----------------------------------------|----------------------------------------|----------------------------------------|----------------------------------------|------------------|------------------|------------------|------------------|-------------------|
|                                        |                                        |                                        | Three Year Average Pre-ETP Performance |                  |                  | Year of Trim     | Post Trim Year 1 | 321               |
|                                        |                                        | Three Year Average Pre-ETP Performance |                                        |                  | Year of Trim     | Post Trim Year 1 | Post Trim Year 2 | 128               |
|                                        | Three Year Average Pre-ETP Performance |                                        |                                        | Year of Trim     | Post Trim Year 1 | Post Trim Year 2 | Post Trim Year 3 | 171               |
| Three Year Average Pre-ETP Performance |                                        |                                        | Year of Trim                           | Post Trim Year 1 | Post Trim Year 2 | Post Trim Year 3 | Post Trim Year 4 | 20                |

**Table 11 – Methodology for Control Group Non-ETP Performance Analysis**

| 2012                                       | 2103                                       | 2014                                       | 2015                                       | 2016             | 2017             | 2018             | 2019             | # of ETP Circuits |
|--------------------------------------------|--------------------------------------------|--------------------------------------------|--------------------------------------------|------------------|------------------|------------------|------------------|-------------------|
|                                            |                                            |                                            | Three Year Average Pre-Non-ETP Performance |                  |                  | Year of Trim     | Post Trim Year 1 | N/A               |
|                                            |                                            | Three Year Average Pre-Non-ETP Performance |                                            |                  | Year of Trim     | Post Trim Year 1 | Post Trim Year 2 | N/A               |
|                                            | Three Year Average Pre-Non-ETP Performance |                                            |                                            | Year of Trim     | Post Trim Year 1 | Post Trim Year 2 | Post Trim Year 3 | N/A               |
| Three Year Average Pre-Non-ETP Performance |                                            |                                            | Year of Trim                               | Post Trim Year 1 | Post Trim Year 2 | Post Trim Year 3 | Post Trim Year 4 | N/A               |

The control group of non-ETP circuits and the ETP circuits are compared against each other to account for non-tree trim related variations. This methodology normalizes reliability performance from variations that occur year-to-year, such as weather and storms. This approach provides a more accurate measure of the ETP effectiveness since we are comparing circuits over the course of years.

### ETP Outage Event Performance

The actual difference of outage events on ETP circuits compared to the balance of the system not trimmed ETP is 54.0% in post-trim year 1, 36.8% in the second year, 43.8% in the third year,

and 11.1% in the fourth year. The actual reduction for Years 1-4 post ETPP trim is depicted in **Table 12**.

**Table 12 – ETPP Tree-Related Outage Event Difference Compared to Non ETPP Circuits**

|                   | Number of<br>Dist. Circuits<br>ETPP<br>Trimmed | % Change in<br>Outage Event<br>Reduction for<br>ETPP circuits | % Change in<br>Outage Event<br>Reduction for<br>Non-ETPP<br>circuits | <b>Difference in %<br/>Change in<br/>Event<br/>Reduction<br/>ETPP vs Non-<br/>ETPP circuits</b> | U-20162<br>Surge<br>Model<br>Projected<br>Reduction |
|-------------------|------------------------------------------------|---------------------------------------------------------------|----------------------------------------------------------------------|-------------------------------------------------------------------------------------------------|-----------------------------------------------------|
| 1 Year Post Trim  | 2,063                                          | -22.0%                                                        | 32.0%                                                                | <b>-54.0%</b>                                                                                   | -57.0%                                              |
| 2 Years Post Trim | 1,442                                          | -12.8%                                                        | 49.6%                                                                | <b>-36.8%</b>                                                                                   | -57.0%                                              |
| 3 Years Post Trim | 974                                            | 9.94%                                                         | 53.7%                                                                | <b>-43.8%</b>                                                                                   | -50.0%                                              |
| 4 Years Post Trim | 491                                            | 58.1%                                                         | 69.2%                                                                | <b>-11.1%</b>                                                                                   | -37.0%                                              |

#### **ETPP Customer Interruptions Performance**

Using the same methodology discussed above, the Company has determined that actual customer interruptions on ETPP circuits vs. Non-ETPP circuits show a 57.9% difference in Year 1, 59.3% difference in Year 2, 48.6% difference in Year 3, and 40.7% difference in Year 4. These results are shown in Table 13.

**Table 13 – ETPP Tree-Related Customer Interruption Difference Compared to  
Non ETPP Circuits**

|                   | Number of<br>Dist. Circuits<br>ETPP<br>Trimmed | % Change in<br>Outage<br>Interruption<br>Reduction for<br>ETPP circuits | % Change in<br>Outage<br>Interruption<br>Reduction for<br>Non-ETPP<br>circuits | <b>Difference in %<br/>Change in Event<br/>Reduction<br/>ETPP vs Non-<br/>ETPP circuits</b> | U-20162<br>Surge<br>Model<br>Projected<br>Reduction |
|-------------------|------------------------------------------------|-------------------------------------------------------------------------|--------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------|-----------------------------------------------------|
| 1 Year Post Trim  | 2,063                                          | -38.8%                                                                  | 19.1%                                                                          | <b>-57.9%</b>                                                                               | -57.0%                                              |
| 2 Years Post Trim | 1,442                                          | -28.0%                                                                  | 31.2%                                                                          | <b>-59.3%</b>                                                                               | -57.0%                                              |
| 3 Years Post Trim | 974                                            | -24.1%                                                                  | 24.6%                                                                          | <b>-48.6%</b>                                                                               | -50.0%                                              |
| 4 Years Post Trim | 491                                            | -14.3%                                                                  | 26.4%                                                                          | <b>-40.7%</b>                                                                               | -37.0%                                              |

#### **ETPP Customer Outage Minute Performance**

Customer minutes of interruption, shown in **Table 14**, also shows significant improvements from the ETPP program. Actual minutes of customer interruption on ETPP circuits vs. Non-ETTP circuits show a 32.4% difference in Year 1, 8.1% difference in Year 2, -22.4% difference in Year 3, and -6.4% difference in Year

**Table 14 – ETPP Tree-Related Customer Outage Minutes of Interruption Difference Compared to Non ETPP Circuits**

|                   | Number of Dist. Circuits ETPP Trimmed | % Change in Outage Minutes Reduction for ETPP circuits | % Change in Outage Minutes Reduction for Non-ETTP circuits | Difference in % Change in Event Reduction ETPP vs Non-ETTP circuits | U-20162 Surge Model Projected Reduction |
|-------------------|---------------------------------------|--------------------------------------------------------|------------------------------------------------------------|---------------------------------------------------------------------|-----------------------------------------|
| 1 Year Post Trim  | 2,063                                 | -27.0%                                                 | 5.3%                                                       | <b>-32.4%</b>                                                       | -57.0%                                  |
| 2 Years Post Trim | 1,442                                 | 16.4%                                                  | 24.5%                                                      | <b>-8.1%</b>                                                        | -57.0%                                  |
| 3 Years Post Trim | 974                                   | 10.5%                                                  | -11.9%                                                     | <b>22.4%</b>                                                        | -50.0%                                  |
| 4 Years Post Trim | 491                                   | 1.3%                                                   | -5.2%                                                      | <b>6.4%</b>                                                         | -37.0%                                  |

Table 15 shows the 2023 outage minutes avoided due to ETPP trimming and the impact to overall system SAIDI, which reflects a net reduction of 226 SAIDI minutes. If only ETPP circuits are considered, the SAIDI reduction is 313 minutes.

**Table 15 – 2023 ETPP Outage Minute Reduction and SAIDI Impact**

|                                                   | ETPP Outage Minutes |
|---------------------------------------------------|---------------------|
| 3 Years Before Trim Avg. Outage Minutes           | 603,540,803         |
| 2023 Outage Minutes                               | 900,537,209         |
| Minutes Saved                                     | -296,996,406        |
| Minutes Avoided – Non ETPP System Deterioration   | 947,747,698         |
| Total Minute Reduction                            | 650,751,293         |
| <b>ETPP Overall System SAIDI Minute Reduction</b> | <b>300</b>          |

|                                                      |            |
|------------------------------------------------------|------------|
| <b>SAIDI Minute Reduction for ETPP Circuits ONLY</b> | <b>390</b> |
|------------------------------------------------------|------------|

### **ETTP Wire-Down Performance**

Using the same methodology discussed above, the Company has determined that actual wire-down events for ETPP circuits vs. Non-ETTP circuits show a 55.4% difference in Year 1, 56.8% difference in Year 2, 39.8% difference in Year 3, and 15.3% difference in Year 4. These results are shown in **Table 16**.

**Table 16 – Post-ETTP Wire-Down Difference Compared to Non-ETTP Circuits**

|                   | Number of Dist. Circuits ETPP Trimmed | % Change Wire-Down Events for ETPP circuits | % Change for Wire-Down Events for Non-ETTP circuits | <b>Difference in % Change in Wire-Down Events ETPP vs. Non-ETTP circuits</b> |
|-------------------|---------------------------------------|---------------------------------------------|-----------------------------------------------------|------------------------------------------------------------------------------|
| 1 Year Post Trim  | 2,063                                 | -65.5%                                      | -10.1%                                              | <b>-55.4%</b>                                                                |
| 2 Years Post Trim | 1,442                                 | -64.8%                                      | -8.0%                                               | <b>-56.8%</b>                                                                |
| 3 Years Post Trim | 974                                   | -58.3%                                      | -18.5%                                              | <b>-39.8%</b>                                                                |
| 4 Years Post Trim | 491                                   | -52.7%                                      | -37.4%                                              | <b>-15.3%</b>                                                                |

### **Section 4 – Spot Trimming on Worst Performing Circuits**

DTE Electric provides an annual power quality investigation report which contains data on all primary customer power quality investigations conducted in the past year for end-use customers, derived from their power quality meters, and the outcome of each investigation. This report contains the DTE Electric January 1, 2023 through December 31, 2023 results and identifies a list of 10 worst performing circuits based on SAIFI outages compared to the rest of the system (based on all cause codes, not just tree related events). Table 17 lists these circuits and the spot trimming that took place in 2023, or planned maintenance trimming.

**Table 17 – Tree Trimming on 2023 Ten Worst Performing Circuits**

| Circuit   | sysSAIFI <sup>14</sup> | sysSAIFI ex MED <sup>15</sup> | Spot Trimming      |                         | Last Maintenance Trimming Year |
|-----------|------------------------|-------------------------------|--------------------|-------------------------|--------------------------------|
|           |                        |                               | Performed in 2023? | Number of Poles Trimmed |                                |
| MOTT9789  | 0.01031                | 0.00451                       | No                 |                         | 2020                           |
| NIXON8932 | 0.00905                | 0.00339                       | No                 |                         | 2023                           |
| CROWN9832 | 0.00853                | 0.00581                       | Yes                | 4                       | 2022                           |
| GODSN8134 | 0.00792                | 0.00390                       | Yes                | 110                     | 2018                           |
| PERU9432  | 0.00765                | 0.00508                       | No                 |                         | 2022                           |
| KENSL9858 | 0.00719                | 0.00436                       | No                 |                         | 2022                           |
| STATE8137 | 0.00657                | 0.00308                       | No                 |                         | 2014                           |
| DUBLN8195 | 0.00617                | 0.00093                       | Yes                | 12                      | 2020                           |
| CODY9537  | 0.00606                | 0.00187                       | Yes                | 125                     | 2015                           |
| DUBLN8205 | 0.00595                | 0.00126                       | Yes                | 21                      | 2020                           |

### **Section 5 – Tree Trim Workforce**

The internal employees directly involved in Tree Trimming are detailed in **Table 18**. In 2023, the average number for contractors on property were 1,282. Contractor headcount fluctuation over the course of 2023 is seen in **Chart 1**.

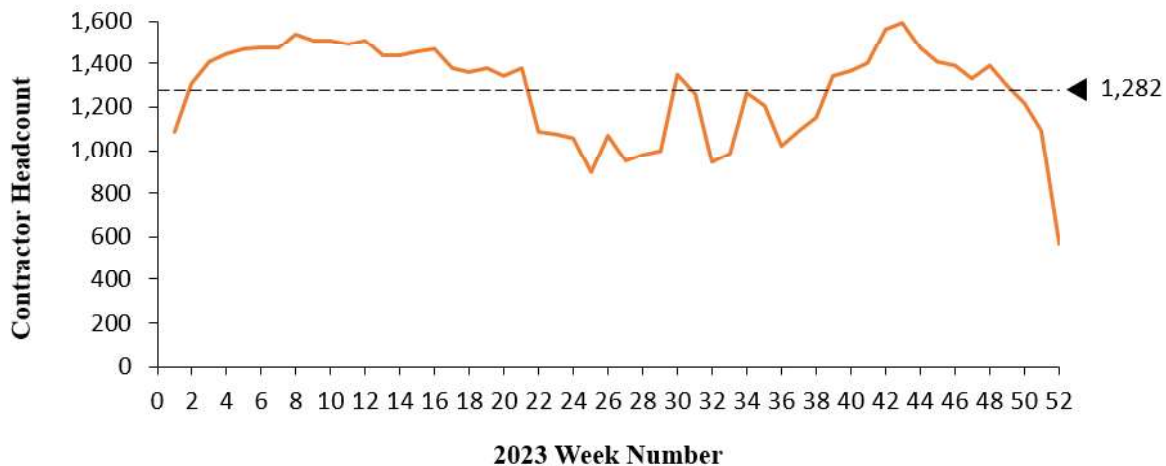
**Table 18 – 2023 DTE and Contractor Tree Trim Headcount**

|                                             |              |
|---------------------------------------------|--------------|
| Facilitator – Arborists                     | 13           |
| Supervision                                 | 8            |
| Regional Foresters                          | 5            |
| Strategy and Planning                       | 9            |
| <b>Internal Employees involved with ETP</b> | <b>35</b>    |
|                                             |              |
| <b>2023 Average # of Contractors</b>        | <b>1,282</b> |

<sup>14</sup> sysSAIFI is the number of customer interruptions on a specific circuit divided by the number of system customer interruptions.

<sup>15</sup> MED stands for Major Event Days.

**Chart 1 – 2023 Contract Tree Trim Headcount by Week**



The 2023 average local journeymen trimmers were 641, and the number of local apprentices were 229. Outsourced journeymen trimmers averaged 412 for 2023. It is typical for the workforce numbers to fluctuate over the year, especially in the late fall when many outsource trimmers return to their home states for the holidays. The outsource trimmers then slowly return through the first quarter of the year based on the Company's capacity needs.

The Company is participating in three programs in an effort to increase the number of local trimmers. The three programs are the Parnall Correctional Facility Vocational Village Training Program, the City of Detroit Tree Trim Academy, and the IBEW Local 17 Traditional Boot Camp. Below is an update on each of the programs:

1. Parnall Correctional Facility The Parnall Tree Trimming program is designed to provide returning citizens the skills needed to start as an apprentice tree trimmer. DTE has partnered with the Michigan Department of Corrections to provide qualified instructors and the required training support within the prison facility before participants are released. The company has paired 30 graduates with jobs.
2. Tree Trim Academy – The Company has partnered with the City of Detroit, IBEW Local 17, and its tree-trimming contractors to develop and implement a pre-woodsman training pilot program to satisfy the demand for qualified tree trimmers. The pilot tree trimming academy is located within the City of Detroit and facilitates training that is aimed at preparing local resident candidates to work as woodsmen. Once candidates complete the pre-woodsman program, graduates enter the nine-day boot camp that was previously designed in partnership with the Company, IBEW Local 17, and the Company's tree-trimming contractors.

To date the tree trimming academy has trained and graduated 202 individuals. Graduates leave the program with sought after climbing experience, a Class B CDL, and a federally required pesticide Applicator certification.

3. Traditional Boot Camp – IBEW continues to hold regular scheduled boot camp training for apprentices. Current camps are conducted at their training facility in Wales, MI.

## **Section 6 – Incremental Funding for Tree Trim Program**

On August 31, 2021, the Company proposed additional funding for the Tree Trim program in Case No. U-21128. Per the application, the Company would invest incremental funding into the Tree Trim Surge during the remainder of 2021 through 2023, beyond the authorized regulatory asset amounts, and would not seek recovery of the additional expenditures. This has the effect of advancing the Company's tree trimming efforts while avoiding future customer expense for those investments, thus providing an affordability benefit to customers. The Company's application was approved on November 4th, 2021, and the Company committed to \$90 million of incremental funding for the Tree Trimming program.

In 2022, the Company spent \$85.8 million of the incremental \$90 million investment. The annual maintenance plan was developed based on the total budget, including the incremental \$85.8 million. The Company did not distinguish specific circuits trimmed as part of the base budget compared to the incremental funding. However, the Company can calculate the incremental work the additional funding enabled us to complete. The additional \$85.8 million allowed the Company to complete an extra 1,700 off-cycle miles in 2022 and lead the system to be 79% on-cycle at year end. These miles were focused in poor reliability areas and trimming was completed prior to the 2022 storm season.

In 2023, the remaining \$4.2 million of the incremental funding was spent to support the Company's spot trimming program to address high-risk areas that were not on the 2023 maintenance plan. The spot trimming program and circuit impact are reviewed in Section 4.

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-8.5c

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**Respondent:** J. Kryscynski

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**Page:** 1 of 1

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- Question:** 5. Refer to Mr. Kryscynski's testimony at page 56, which states "The engineering team evaluates alternatives to meet the system needs and selects the best project or program to move forward. If necessary, a BCA takes place as part of the engineering process to select the best option. The solution which is selected to move forward is scored in the GPM for prioritization." Refer also to NDA U-21534 MNSCDE-1.8a GPM CONFIDENTIAL, which provides GPM scores for 138 different projects in tab "GPM Results".
- c. Provide the approved capital project authorizations on every one of these 138 projects with an expected total capital cost exceeding \$10 million. Include all supporting documentation presented to management with each capital project authorization.

**Answer:** DTE Electric objects to providing the capital project authorizations and supporting documentation for the reason that the request is unduly burdensome and overly broad. Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:

The approved capital project authorizations to the extent they are available will be provided in a supplemental response as soon as the information can be collected.

**Attachment:** None.

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-8.5c (S1)

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**Respondent:** J. Kryscynski

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- Question:** 5. Refer to Mr. Kryscynski's testimony at page 56, which states "The engineering team evaluates alternatives to meet the system needs and selects the best project or program to move forward. If necessary, a BCA takes place as part of the engineering process to select the best option. The solution which is selected to move forward is scored in the GPM for prioritization." Refer also to NDA U-21534 MNSCDE-1.8a GPM CONFIDENTIAL, which provides GPM scores for 138 different projects in tab "GPM Results".
- c. Provide the approved capital project authorizations on every one of these 138 projects with an expected total capital cost exceeding \$10 million. Include all supporting documentation presented to management with each capital project authorization.

**Answer:** Duplicative capital authorizations were requested in MNSCDE-8.5c, MNSCDE-8.6, MNSCDE-8.9d, MNSCDE-8.14a, MNSCDE-8.15a, MNSCDE-8.16a, MNSCDE-8.17a, MNSCDE-8.18a, MNSCDE-8.19a, MNSCDE-8.20a, MNSCDE-8.21a, MNSCDE-8.22b, MNSCDE-9.3b, MNSCDE-12.2j, MNSCDE-12.11, and MNSCDE-12.12. To the extent available, the requested authorizations are attached.

The Distribution Grid Plans (DGP), filed with the Commission, include a 5-year investment plan which constitutes the initial capital investment plan that is reviewed and approved by management. For the 2023 DGP which includes the 5-year investments for capital projects and programs, please see Exhibit A-23 Schedule M8.

The DGP 5-year investment plan is a key input to the annual management review. For 2023 capital investments, the 2021 DGP was the supportive grid planning reference. For 2024 to 2027 investments, the 2023 DGP is the grid planning reference. Below is an example from section 11 of the 2023 DGP, showing planned future investments that were reviewed by management.

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**Requester:** MNSC

**Question No.:** MNSCDE-8.5c (S1)

**Respondent:** J. Kryscynski

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| Programs                                        | \$ Millions |       |       |       |       |              |
|-------------------------------------------------|-------------|-------|-------|-------|-------|--------------|
|                                                 | 2024        | 2025  | 2026  | 2027  | 2028  | 5-Year Total |
| Infrastructure Resilience & Hardening           |             |       |       |       |       |              |
| Pole and Pole Top Maintenance and Modernization | \$121       | \$121 | \$151 | \$192 | \$188 | \$773        |

The Company considers this annual management review, which includes the President of DTE Electric and which subsequently leads to the request contained in the rate case, to be the authorization for projects under \$10 million and for programs that are composed of many individual projects that are below that threshold (e.g. PTMM, 4.8kV Hardening).

Supporting this discovery request, in addition to the 2023 DGP and the rate case budget submitted in Exhibit A-12, Schedule B5.4, the Company is providing two types of capital project authorizations, depending on whether they are authorizations for projects above \$10MM, such as a conversion, or for programs, such as PTMM.

First, in addition to the management reviews and approvals as noted, individual projects greater than \$10 million require specific management approval and must be authorized by a Capital Appropriations Request Form (CARF). Approved CARFs for projects associated with projects in tab "GPM Results" have been collected and attached. Some large projects in the engineering and design phase may not have yet reached the threshold to require a CARF.

Second, capital programs (e.g., PTMM) and projects smaller than \$10MM that are authorized during the annual management review process receive further confirmed immediately prior to the year in which they are to be executed. The relevant forms for 2022, 2023, and 2024 are attached.

**Attachment:** U-21534 MNSCDE-8.5c(S1)-01 2022 Budget Appropriation  
U-21534 MNSCDE-8.5c(S1)-02 2023 Budget Appropriation

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U-21534 MNSCDE-8.5c(S1)-03 2024 Budget Appropriation

U-21534 MNSCDE-8.5c(S1)-04 4.8 kV CC Almont Relief and Circuit Conversion (Midas)

U-21534 MNSCDE-8.5c(S1)-05 4.8 kV CC Ariel Substation and Circuit Conversion

U-21534 MNSCDE-8.5c(S1)-06 4.8 kV CC Buckler Circuit Conversion

U-21534 MNSCDE-8.5c(S1)-07 4.8 kV CC Cortland - Oakman - Linwood Consolidation

U-21534 MNSCDE-8.5c(S1)-08 4.8 kV CC Cortland - Oakman - Linwood Consolidation

U-21534 MNSCDE-8.5c(S1)-09 4.8 kV CC GRFIN & WMSTN Conversions

U-21534 MNSCDE-8.5c(S1)-10 4.8 kV CC Hilton Substation and Circuit Conversion

U-21534 MNSCDE-8.5c(S1)-11 4.8 kV CC I-94 Substation and Circuit Conversion (Promenade) - Below Grade

U-21534 MNSCDE-8.5c(S1)-12 4.8 kV CC Pinegrove Substation Relocation and Conversion

U-21534 MNSCDE-8.5c(S1)-13 4.8 kV CC Pinegrove Substation Relocation and Conversion

U-21534 MNSCDE-8.5c(S1)-14 4.8 kV CC Zenon Substation and Circuit Conversion

U-21534 MNSCDE-8.5c(S1)-15 4.8 kV CC Zenon Substation and Circuit Conversion

U-21534 MNSCDE-8.5c(S1)-16 8.3 kV CC Pontiac Overhead Conversion

U-21534 MNSCDE-8.5c(S1)-17 ADMS DMS-OMS

U-21534 MNSCDE-8.5c(S1)-18 ADMS DMS-OMS

U-21534 MNSCDE-8.5c(S1)-19 Ann Arbor System Improvements

U-21534 MNSCDE-8.5c(S1)-20 Ann Arbor System Improvements

U-21534 MNSCDE-8.5c(S1)-21 Buffalo-Charles OH to UG pilot

U-21534 MNSCDE-8.5c(S1)-22 CODI Alfred Substation Expansion

U-21534 MNSCDE-8.5c(S1)-23 CODI CATO Substation Expansion

U-21534 MNSCDE-8.5c(S1)-24 CODI Charlotte Network Upgrade

U-21534 MNSCDE-8.5c(S1)-25 CODI Charlotte Network Upgrade

U-21534 MNSCDE-8.5c(S1)-26 CODI Corktown Substation

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**Respondent:** J. Kryscynski

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U-21534 MNSCDE-8.5c(S1)-27 CODI Garfield Network Upgrade  
U-21534 MNSCDE-8.5c(S1)-28 CODI Garfield Network Upgrade  
U-21534 MNSCDE-8.5c(S1)-29 CODI Garfield Radial (Midtown Circuits)  
U-21534 MNSCDE-8.5c(S1)-30 CODI Garfield Radial (Midtown Circuits)  
U-21534 MNSCDE-8.5c(S1)-31 CODI Howard Conversion  
U-21534 MNSCDE-8.5c(S1)-32 CODI Howard Conversion  
U-21534 MNSCDE-8.5c(S1)-33 CODI Islandview Substation - Phase 1  
U-21534 MNSCDE-8.5c(S1)-34 CODI Islandview Substation - Phase 2  
U-21534 MNSCDE-8.5c(S1)-35 CODI Islandview Substation - Phase 2  
U-21534 MNSCDE-8.5c(S1)-36 CODI Kent-Gibson Conversion - Phase 1  
U-21534 MNSCDE-8.5c(S1)-37 CODI Kent-Gibson Conversion - Phase 1  
U-21534 MNSCDE-8.5c(S1)-38 CODI Midtown Substation Expansion  
U-21534 MNSCDE-8.5c(S1)-39 Station Upgrade Northeast (Relay Replacement)  
U-21534 MNSCDE-8.5c(S1)-40 Station Upgrade Warren (Relay Replacement)  
U-21534 MNSCDE-8.5c(S1)-41 Substation Risk Apache  
U-21534 MNSCDE-8.5c(S1)-42 Substation Risk Apache  
U-21534 MNSCDE-8.5c(S1)-43 Substation Risk Chestnut  
U-21534 MNSCDE-8.5c(S1)-44 Substation Risk Chestnut  
U-21534 MNSCDE-8.5c(S1)-45 Substation Risk McGraw  
U-21534 MNSCDE-8.5c(S1)-46 Subtransmission Redesign & Rebuild Boyne  
U-21534 MNSCDE-8.5c(S1)-47 Subtransmission Redesign & Rebuild Tie 4105 Phase 1  
U-21534 MNSCDE-8.5c(S1)-48 Subtransmission Redesign & Rebuild Tie 4105 Phase 3  
U-21534 MNSCDE-8.5c(S1)-49 Subtransmission Redesign & Rebuild Tie 4105 Phase 3  
U-21534 MNSCDE-8.5c(S1)-50 Subtransmission Redesign & Rebuild Tie 810  
U-21534 MNSCDE-8.5c(S1)-51 Subtransmission Redesign & Rebuild Tie 810  
U-21534 MNSCDE-8.5c(S1)-52 Subtransmission Redesign & Rebuild Trunk 2308  
U-21534 MNSCDE-8.5c(S1)-53 Subtransmission Redesign & Rebuild Trunk 4911  
U-21534 MNSCDE-8.5c(S1)-54 System Loading Richmond-Armada  
U-21534 MNSCDE-8.5c(S1)-55 System Loading Richmond-Armada  
U-21534 MNSCDE-8.5c(S1)-56 Clerical Corrections

10/28/2021

|                                       |                         | Project Type | 2022                  |
|---------------------------------------|-------------------------|--------------|-----------------------|
| Emergent Replacements                 | 371,753,014             | Blanket      | 106,680,976           |
| Customer Attachments                  | 136,566,464             | Blanket      | 18,140,794            |
| Equipment, Relocation & Other         | 115,303,129             | Blanket      | 1,675,246             |
| Infrastructure Redesign               | 215,018,042             | Blanket      | 13,699,096            |
| Infrastructure Resilience & Hardening | 320,615,975             | Blanket      | 15,223,917            |
| Technology Enhancement                | 74,971,134              | Blanket      | 8,322,561             |
|                                       | <u>\$ 1,234,227,757</u> | Blanket      | <u>1,061,418</u>      |
|                                       |                         |              | <u>\$ 164,804,009</u> |
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Sign Off covers all items that do not need FC-20 approval.  
\* Any individual project over \$10M will still need to go through the FC-20 process.

## Hope L Allen

---

**From:** Case R Lancaster  
**Sent:** Monday, November 15, 2021 12:13 PM  
**To:** Brian R VanJaarsveld  
**Subject:** FW: 2022 DO Capital Budget CARF

FYI

---

**From:** Trevor F Lauer <[trevor.lauer@dteenergy.com](mailto:trevor.lauer@dteenergy.com)>  
**Sent:** Monday, November 15, 2021 12:12 PM  
**To:** Case R Lancaster <[case.lancaster@dteenergy.com](mailto:case.lancaster@dteenergy.com)>  
**Cc:** Karen Vucinaj <[karen.vucinaj@dteenergy.com](mailto:karen.vucinaj@dteenergy.com)>  
**Subject:** Re: 2022 DO Capital Budget CARF

Approved

Trevor F Lauer  
DTE Energy  
(313) 605 7275 (M)  
(313) 235 8104 (O)

He/Him/His

---

**From:** Case R Lancaster <[case.lancaster@dteenergy.com](mailto:case.lancaster@dteenergy.com)>  
**Sent:** Monday, November 15, 2021 11:55:36 AM  
**To:** Trevor F Lauer <[trevor.lauer@dteenergy.com](mailto:trevor.lauer@dteenergy.com)>  
**Cc:** Karen Vucinaj <[karen.vucinaj@dteenergy.com](mailto:karen.vucinaj@dteenergy.com)>  
**Subject:** FW: 2022 DO Capital Budget CARF

Trevor – please let me know if you approve this CARF for DO capital budget for 2022. An email approval will suffice. Please let me know if you have any questions or concerns.

Case

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**From:** Case R Lancaster  
**Sent:** Wednesday, November 3, 2021 3:00 PM  
**To:** Trevor F Lauer <[Trevor.Lauer@dteenergy.com](mailto:Trevor.Lauer@dteenergy.com)>  
**Cc:** Karen Vucinaj <[Karen.Vucinaj@dteenergy.com](mailto:Karen.Vucinaj@dteenergy.com)>; Brian R VanJaarsveld <[Brian.VanJaarsveld@dteenergy.com](mailto:Brian.VanJaarsveld@dteenergy.com)>  
**Subject:** 2022 DO Capital Budget CARF

Trevor,

Attached is the 2022 DO Capital CARF for your review and signature. We ask for approval now to be able to set up the required work orders. Note that this capital request ties to the 2022 capital targets and the capital to be filed in the upcoming rate case. Please let me know if you have any questions.

Please sign and return, or reply all with your approval

Case

Case Lancaster

DTE Electric Controller

DTE Energy

o: 313-235-3973

m: 248-930-4189

\* Any individual project over \$10M will still need to go through the FC-20 process.

## Hope L Allen

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**From:** Trevor F Lauer  
**Sent:** Wednesday, November 16, 2022 7:47 AM  
**To:** Case R Lancaster; Karen Vucinaj  
**Cc:** Brian R VanJaarsveld; Michael L Wood  
**Subject:** Re: DO Capital Budget for Trevor's signature

approved

Trevor F Lauer  
DTE Energy  
(313) 605 7275 (M)  
(313) 235 8104 (O)

He/Him/His

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**From:** Case R Lancaster <case.lancaster@dteenergy.com>  
**Sent:** Tuesday, November 15, 2022 9:48:59 AM  
**To:** Karen Vucinaj <karen.vucinaj@dteenergy.com>  
**Cc:** Brian R VanJaarsveld <brian.vanjaarsveld@dteenergy.com>; Trevor F Lauer <trevor.lauer@dteenergy.com>; Michael L Wood <michael.l.wood@dteenergy.com>  
**Subject:** DO Capital Budget for Trevor's signature

Karen,

Can you please have Trevor sign the attached document for 2023 DO Capital budget. Contact me, Brian VanJaarsveld or Mike Wood with any questions or concerns.

Case

Case Lancaster  
DTE Energy  
O: 313.235.3973  
M: 248.930.4189

|                                                         |                         | Project Type                                 | 2024                    |
|---------------------------------------------------------|-------------------------|----------------------------------------------|-------------------------|
| <b>ERUC- Trouble</b>                                    |                         |                                              |                         |
| Emergent Replacements                                   | 423,420,001             | Blanket                                      | 105,537,289             |
| Customer Attachments                                    | 199,514,249             | Blanket                                      | 6,925,736               |
| Equipment, Relocation & Other                           | 82,235,239              | Blanket                                      | 7,842,301               |
| Infrastructure Redesign and Modernization               | 359,882,229             | Blanket                                      | 42,244,180              |
| Infrastructure Resilience and Hardening                 | 380,893,092             | Blanket                                      | 3,463,265               |
| Technology and Automation                               | 169,297,305             | Blanket                                      | 4,464,912               |
|                                                         | <b>\$ 1,615,242,115</b> |                                              | 1,910,361               |
|                                                         |                         |                                              | 18,745                  |
|                                                         |                         |                                              | <b>\$ 172,406,790</b>   |
| <b>ERUC- Storm</b>                                      |                         |                                              |                         |
| 10 Storm                                                |                         | Blanket                                      | 157,906,531             |
| 11 Storm - SO Follow Up                                 |                         | Blanket                                      | 44,571,823              |
| 12 Capital Completions & Removals                       |                         | Blanket                                      | 5,244,630               |
| 13 Total ERUC - Storm                                   |                         |                                              | <b>\$ 207,722,984</b>   |
| <b>Substation Improvements - Failures</b>               |                         |                                              |                         |
| 14 Z Budget Failures Major Equipment                    |                         | Blanket                                      | 12,704,319              |
| 15 Z Budget Failures Minor Equipment                    |                         | Blanket                                      | 15,738,180              |
| 16 Z Budget Failures Trfs/Regs                          |                         | Blanket                                      | 10,489,522              |
| 17 Z Budget Non-Electrical                              |                         | Blanket                                      | 3,816,098               |
| 18 Z Budget- Minor System/ Circuits                     |                         | Blanket                                      | 542,108                 |
| 19 Total ERUC - Storm_subs                              |                         |                                              | <b>\$ 43,290,226</b>    |
|                                                         |                         |                                              | <b>\$ 423,420,001</b>   |
| 20 Total Trouble/ Storm/ Substn CM                      |                         |                                              |                         |
| <b>Customer Attachments</b>                             |                         |                                              |                         |
| 21 New Business & Load Growth Projects                  |                         | * See note below                             | 71,127,673              |
| 22 Customer Connections                                 |                         | Blanket                                      | 104,320,760             |
| 23 Small Load Growth Blanket                            |                         | Blanket                                      | 19,365,816              |
| 24 TEP (transportation electrification)                 |                         |                                              | 4,700,000               |
| 25 Total Customer Attachments                           |                         |                                              | <b>\$ 199,514,249</b>   |
| <b>Equipment, Relocation &amp; Other</b>                |                         |                                              |                         |
| 26 Cuts & Restores                                      |                         | Blanket                                      | 8,320,011               |
| 27 Electric System ( Transformers, Regulators & Meters) |                         | Blanket                                      | 22,462,260              |
| 28 General Plant, Tools & Equipment and Miscellaneous   |                         | Blanket                                      | 7,909,141               |
| 29 NRUC, Improvement Blankets                           |                         | Blanket & individual project less than \$10M | 15,977,655              |
| 30 Small Relocation Blanket                             |                         | Blanket                                      | 8,961,298               |
| 31 Relocation Project                                   |                         | Individual projects, each less than \$10M    | 12,678,704              |
| 32 Other                                                |                         | Individual projects, each less than \$10M    | 5,926,171               |
| 33 Total Equipment, Relocation & Other                  |                         |                                              | <b>\$ 82,235,239</b>    |
| <b>Infrastructure Redesign and Modernization</b>        |                         |                                              |                         |
| 34 Subtransmission Redesign & Rebuild                   |                         |                                              | 100,287,058             |
| 35 CODI                                                 |                         |                                              | 99,842,781              |
| 36 4.8kV CC/ 8.3kV CC                                   |                         |                                              | 98,440,779              |
| 37 System Loading                                       |                         |                                              | 46,667,772              |
| 38 Strategic Undergrounding Pilot                       |                         |                                              | 14,643,840              |
| 39 Total Infrastructure Resilience and Hardening        |                         |                                              | <b>\$ 359,882,229</b>   |
| <b>Infrastructure Resilience and Hardening</b>          |                         |                                              |                         |
| 40 4.8 kV Hardening                                     |                         |                                              | 80,000,000              |
| 41 Pole and Pole Top Hardware                           |                         |                                              | 121,000,000             |
| 42 Frequent Outage                                      |                         |                                              | 48,049,745              |
| 43 40 kV Automatic Pole Top Switch                      |                         |                                              | 4,995,000               |
| 44 Substation Risk                                      |                         |                                              | 50,798,110              |
| 45 Station Upgrades                                     |                         |                                              | 5,314,241               |
| 46 Breaker Replacement                                  |                         |                                              | 14,278,548              |
| 47 Disconnect and Switcher Replacement                  |                         |                                              | 4,900,000               |
| 48 Cable Replacement Program                            |                         |                                              | 21,391,919              |
| 49 URD Replacement Program                              |                         |                                              | 15,041,398              |
| 50 Mobile Fleet Program                                 |                         |                                              | 5,000,000               |
| 51 SCADA Pole Top Device Replacement                    |                         |                                              | 1,808,034               |
| 52 Substation Regulator Replacement                     |                         |                                              | 816,097                 |
| 53 Steel Pole Highway Crossings                         |                         |                                              | 5,000,000               |
| 54 Batteries and Chargers Replacement                   |                         |                                              | 2,500,000               |
| 55 Total Infrastructure Redesign and Modernization      |                         |                                              | <b>\$ 380,893,092</b>   |
| <b>Technology and Automation</b>                        |                         |                                              |                         |
| 56 Grid Automation                                      |                         |                                              | 111,397,305             |
| 57 Grid Management                                      |                         |                                              | 26,300,000              |
| 58 Distribution Planning                                |                         |                                              | 12,000,000              |
| 59 Work Management                                      |                         |                                              | 10,000,000              |
| 60 Asset Management                                     |                         |                                              | 1,400,000               |
| 61 Mobile Technology                                    |                         |                                              | 8,200,000               |
| 62 Total Technology and Automation                      |                         |                                              | <b>\$ 169,297,305</b>   |
| 63 TOTAL DO INVESTMENT PLAN                             |                         |                                              | <b>\$ 1,615,242,115</b> |

Sign Off covers all items that do not need FC-20 approval.

\* Any individual project over \$10M will still need to go through the FC-20 process.

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-8.16di

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**Respondent:** J. Kryscynski

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- Question:** 16. Refer to Exhibit A-12, Schedule B5.4, page 13, and to line 13, the PTMM program. Refer also to Exhibit A-33, Schedule X1, line 7, and to the PPTM budgets proposed for the IRM in 2026 and 2027.
- d. Refer to the responses to subparts (a) and (b) above. Explain how the PTMM program budget was established for each of the following years, and provide a list of circuits and capital dollars budgeted for each project each year:
- i. 2023

**Answer:** The Company develops the long-term vision for the grid and 5-year investment plans for distribution programs and projects using the process described in the 2021 and 2023 Distribution Grid Plans (DGP). The DGP investments address aging infrastructure, improvements to reliability, resiliency, and safety, and current and projected future capacity constraints. Investments are prioritized using the GPM as well as other considerations, as discussed in Witness Kryscynski's testimony.

The 5-year investment plan is a key reference when developing the annual distribution budgets. The annual budget planning process includes the 5-year DGP plan, updated information on grid needs including reliability data, and regulatory feedback obtained through rate cases. For 2023 investments, the 2021 DGP is the supportive grid planning reference.

The capital investment associated with PTMM for 2023 where the Company is seeking recovery through the current case can be found in Exhibit A-12, Schedule B5.4, page 13, line 13, column c. No investment associated with the PTMM Program has been authorized for IRM treatment in 2023.

**PTMM Circuits Completed in 2023:**

- ALGON0307
- ARNLD1653
- ARNLD2730
- AUBRN8866
- BEMIS9871
- BIDDLE1677

**Co-Respondent(s):** N. Foley, M. Elliott Andahazy

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-8.16di

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**Respondent:** J. Kryscynski

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- BISHP1755
- BREWR9229
- BRITN0332
- BRITN0333
- BURTN0386
- BVRLY0357
- BVRLY1579
- BVRLY1865
- CALMT0344
- CHIPW0346
- CHIPW0348
- COLFX9873
- COMLK9538
- DRAKE8969
- ELGIN1433
- FINLY1550
- FLTRK0303
- FOWLR0302
- FRLDG8042
- GARCY0580
- GARCY1604
- GAY 1747
- GAY 1762
- GRENA9813
- HINES9378
- HINES9459
- HOWEL0980
- HOWEL0981
- HOWEL2931
- HOWEL2933
- HOWEL2934
- IDA 0311
- JEFSN9338
- JEFSN9409

**Co-Respondent(s):** N. Foley, M. Elliott Andahazy

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-8.16di

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**Respondent:** J. Kryscynski

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- KELOG9864
- KENEY0486
- KENEY2697
- KERN 8898
- KOPNK9437
- KOPNK9463
- LIBER1056
- LYNCH2260
- MALTA8469
- MALTA8543
- MEDNA8692
- MTMRA0302
- NINMI0252
- NINMI0560
- NINMI0825
- NINMI0860
- ORION9071
- PHENX9833
- PINGV2607
- PROSP0305
- PROSP0306
- PROTR2601
- PTAUS0312
- QTNRD0326
- QUAIL0311
- RAISN0305
- RAISN0306
- REMER8796
- ROCHR1814
- ROCHR1838
- RUSH 8089
- SHERW0321
- SHERW0322
- STEPH8669

**Co-Respondent(s):** N. Foley, M. Elliott Andahazy

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-8.16di

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**Respondent:** J. Kryscynski

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- SYRAC1901
- SYRAC1903
- TAMRK9096
- TFANY8024
- TFANY8038
- TFANY8038
- TIE 4708
- TIE 9205
- TINKN8933
- TRK 3536
- TRK 7115
- TRK 7756
- UTICA2558
- UTICA2583
- VENOEY9383
- WCHTR1618
- WCHTR1937
- WCHTR2687

**Attachment:** N/A

**Co-Respondent(s):** N. Foley, M. Elliott Andahazy

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-7.2h

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**Respondent:** S. Hartwick

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**Page:** 1 of 1

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- Question:** 2. Refer to Exhibit A-23, Schedule M7 (S. Hartwick) at page 48, which states, regarding Distribution Automation, “The planned Distribution Automation work for 2024 is expected to address ground detection and isolation for 63 circuits at 18 substations that is part of the IRM, and an additional 32 circuits at 11 substations. It is also expected to reduce SAIDI on impacted circuits by 45%, reducing system SAIDI by 9 minutes, based on the circuit level benefits modeling discussed earlier. The planned work for 2025 is expected to address ground detection and isolation for 281 circuits at 73 substations and is expected to reduce SAIDI on impacted circuits by 47% reducing system SAIDI by 45 minutes.”
- h. Describe any assurances the Company is willing to provide that system SAIDI will fall 54 minutes in 2026 from the baseline provided in response to subpart (g) above as a result of distribution automation installed in 2024 and 2025. Provide the amount of cost recovery the Company is willing to place at risk for failing to deliver 54 minutes’ reduction from system SAIDI in 2026. If the Company is not willing to place any amount of cost recovery at risk based on the results of its distribution automation spending, please explain why not.

**Answer:** DTE Electric objects for the reason that the information requested is not relevant, nor is it reasonably calculated to lead to the discovery of relevant evidence. The Company's revenue requirement in this case is determined based upon the capital investments projected to go into service by the end of the test year. Therefore, assurances and recovery reductions based upon performance beyond the test year are not relevant to this proceeding. The Company also objects as it is unclear what is meant by “place at risk”. Without waiving these objections, but subject to them, the Company responds as follows:

The Company has confidence that the investments will yield reliability improvements, however the Company can’t predict the specific outcome in a specific year based on the impacts of weather or storm.

**Attachment:** None

Co-respondent: J. Kryscynski, Legal

**MPSC Case No:** U-21534

**Requester:** MNSC

**Question No.:** MNSCDE-7.4a

**Respondent:** S. Hartwick

**Page:** 1 of 1

- Question:** 4. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, pages SMH 21-48, and specifically to the proposal to continue deploying fiber to substations through 2028, and to the statement "In 2026 and through the end of the program, fiber routes will be run through a cost benefit analysis to determine the appropriate future technology to be used that will support the telecommunications needs of all other DTEE investments and programs."
- a. Provide a count of substations the Company operates today. Of these, provide counts of i) substations served by Company-owned fiber; ii) substations served by leased fiber; and iii) substations served by microwave or other wireless communications.

**Answer:** Refer to Table 1 in Witness Kryscynski's direct testimony for the total number of substations.

| Request                                                               | Number of Substations |
|-----------------------------------------------------------------------|-----------------------|
| i) substations served by Company-owned fiber                          | 17                    |
| ii) substations served by leased fiber                                | 6                     |
| iii) substations served by microwave or other wireless communications | 589                   |

Additionally, 181 number of substations have Company owned fiber up to the substation premise as part of the fiber program.

**Attachment:** None

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-7.4b

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**Respondent:** S. Hartwick

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**Page:** 1 of 1

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- Question:** 4. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, pages SMH 21-48, and specifically to the proposal to continue deploying fiber to substations through 2028, and to the statement "In 2026 and through the end of the program, fiber routes will be run through a cost benefit analysis to determine the appropriate future technology to be used that will support the telecommunications needs of all other DTEE investments and programs."
- b. Provide a list of substations to which the Company plans to extend fiber from January 1, 2024 through December 31, 2028. Provide the capital cost estimate for each deployment.

**Answer:** DTE Electric objects to the request for the reason that the request seeks confidential and proprietary, commercially sensitive and/or customer sensitive personal information that the disclosure of which will result in harm to the company or its customers. Subject to this objection and without waiver thereof, the Company would answer as follows:

The Company estimated investments for 2024 and 2025 are provided in the attachment. The investment timing for specific stations may change based on permitting, constructability and coordination with other DTE, utility, municipality, county, or state construction. Deployments in 2026 and beyond are outside of the instant case.

**Attachment:** NDA\_U-21534 MNSCDE-7.4b 2024-2025 Fiber Deployment.xlsx

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-7.4c

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**Respondent:** S. Hartwick

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**Page:** 1 of 1

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- Question:** 4. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, pages SMH 21-48, and specifically to the proposal to continue deploying fiber to substations through 2028, and to the statement "In 2026 and through the end of the program, fiber routes will be run through a cost benefit analysis to determine the appropriate future technology to be used that will support the telecommunications needs of all other DTEE investments and programs."
- c. Provide the template or model of the cost benefit analysis tool to be used to determine the appropriate future technologies to deploy, including all identified inputs and assumptions. If the tool is already in use, please provide the results of all analyses for fiber deployments installed since 2020, including all data used, sources of data and calculations, and all fiber deployments currently planned. If the tool is not already in use, please explain why not, and provide an example of how the cost benefit analysis will be applied including examples of input data, the sources of the data, and all calculations, workpapers and spreadsheets.

**Answer:** The cost benefit analysis tool does not currently exist.

The fiber deployments through 2025 are focused on completing the critical rings for the fiber backhaul network that connects the key infrastructure sites such as substations and other critical facilities to the various data centers. These investments are critical for enabling secure and reliable communications that directly support improved resiliency and improved speed of restoration. See questions 43-46 of Witness Hartwick's testimony discuss how fiber deployment was evaluated for the critical rings for the fiber backhaul network.

Beyond 2025, DTE Electric will need to continue to expand the telecommunications network investments to the next tier of locations that are prioritized from a resiliency perspective. The company is currently developing the cost benefit analysis tool for determining fiber deployments beyond 2025, but it is not yet completed.

**Attachment:** None

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-7.4d

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**Respondent:** S. Hartwick

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**Page:** 1 of 1

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**Question:** 4. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, pages SMH 21-48, and specifically to the proposal to continue deploying fiber to substations through 2028, and to the statement "In 2026 and through the end of the program, fiber routes will be run through a cost benefit analysis to determine the appropriate future technology to be used that will support the telecommunications needs of all other DTEE investments and programs."

d. Explain how the Company has identified the fiber deployments which are likely to deliver benefits in excess of costs to date.

**Answer:** Not all benefits are definable on a strict cost basis. See A42 of Witness Hartwick's testimony for customer benefits.

**Attachment:** None

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-7.3a

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**Respondent:** S. Hartwick

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**Page:** 1 of 1

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**Question:** 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

- a. An estimated timeline for the plan through completion (as depicted in the future technology landscape diagram);

**Answer:** The future technology landscape diagram 10.1.5.2 in Exhibit A-23 Schedule M8, page 141 of 274 is an overview. However, a simplified layered structure of the Grid Telecommunication Network is presented in Figure 2 of Witness Hartwick's testimony. As described in testimony, the Fiber Backhaul network will be the singular focus of Grid Automation Telecommunications investment through 2025. Fiber installations will continue through 2028. The advanced mesh is beyond the scope of the current case but will utilize the fiber backbone built with this investment to connect the last mile network.

**Attachment:** None

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-7.3b

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**Respondent:** S. Hartwick

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**Page:** 1 of 1

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**Question:** 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

b. The most significant (by cost) components of the plan;

**Answer:** The most significant component of the plan is the installation of fiber between locations followed by the electronics and routers needed to utilize the fiber.

**Attachment:** None

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-7.3c

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**Respondent:** S. Hartwick

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**Question:** 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

c. The estimated capital cost of the plan by year, by component through completion;

**Answer:** Please see Exhibit A-12, Schedule B5.4, page 17, line 6 for the capital investment by year and Exhibit A-23, Schedule M7, page 77 for a breakdown by material, labor and other. The Company does not have the breakdown by component.

**Attachment:** None

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-7.3d

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**Respondent:** S. Hartwick

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**Page:** 1 of 1

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**Question:** 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

d. Any benefit-cost analysis the Company has completed on the plan;

**Answer:** Secure and reliable telecommunications are foundational for distribution automation. Without this base capability, the modern infrastructure of the grid would be unable to function at its full capability and provide benefits to customers including integrating new technology such as distributed generation and storage. The Company has not completed a benefit-cost analysis for the Grid Automation Telecommunications program; however, a qualitative analysis for the fiber backhaul component of the plan is presented in Figure 3, 4, and 5 of Witness Hartwick's testimony.

**Attachment:** None

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-7.3e

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**Respondent:** S. Hartwick

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**Page:** 1 of 1

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**Question:** 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

e. All approved capital expenditure requests approved for the plan so far; and

**Answer:** Please refer to the Exhibit A-12, Schedule B.5.4, page 17, line 6. Grid Automation Telecommunications disallowances from U-21297 have been provided in STDE3.4.

**Attachment:** None

**MPSC Case No:** U-21534

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**Requester:** MNSC

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**Question No.:** MNSCDE-7.3f

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**Respondent:** S. Hartwick

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**Page:** 1 of 1

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**Question:** 3. Refer to Ms. Hartwick's Direct Testimony regarding Grid Automation Telecommunications generally, SMH pages 21-48, and to the DTE Electric Distribution Grid Plan, page 140, diagrams 10.1.5.1 (current technology landscape) and 10.1.5.2 (future technology landscape) (Exhibit A-23 Schedule M8, page 141 of 274). Provide a complete description of the Grid Automation Telecommunications plan the Company proposes to deploy to move from the current to the future technology landscape, including but not limited to:

f. A description of the portions of the plan completed through December 31, 2023 and the capital spent on each portion through that date.

**Answer:** Fiber deployments completed in 2022 and 2023 are discussed in Q47 of Witness Hartwick's direct testimony. Yearly capital investments are detailed in Exhibit A-12, Schedule B.5.4, page 17, line 6.

**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.

Case No. U-21534

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**Proof of Service**

On the date below, an electronic copy of **Direct Testimony and Exhibits of Paul J. Alvarez on behalf of Attorney General Dana Nessel, Michigan Environmental Council, and Natural Resources Defense Council (Exhibits MEC-1 through MEC-9)** was served on the following:

| <b>Name/Party</b>                                                                                                                                       | <b>E-mail Address</b>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
|---------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Administrative Law Judge</b><br>Hon. Sally Wallace                                                                                                   | <a href="mailto:wallaces2@michigan.gov">wallaces2@michigan.gov</a>                                                                                                                                                                                                                                                                                                                                                                                                                                     |
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The statements above are true to the best of my knowledge, information and belief.

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Date: July 26, 2024

By:



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