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

Jon P. Christinidis
(313) 235-7706
jon.christinidis@dteenergy.com

August 16, 2022

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

RE: In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority
MPSC Case No. U-20836

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter is DTE Electric Company's Reply Brief. Also attached is the Proof of Service.

Very truly yours,

Jon Christinidis
Digitally signed by Jon Christinidis
Date: 2022.08.16 15:07:43 -04'00'

Jon P. Christinidis

JPC/cdm
Attachments

cc: Service List

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-20836

DTE ELECTRIC COMPANY'S

REPLY BRIEF

Dated: August 16, 2022

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I. INTRODUCTION

DTE Electric Company (DTE Electric or the Company) filed its Initial Brief on July 26, 2022. Initial briefs were also filed by the Staff, Michigan Attorney General (AG); the Association of Businesses Advocating Tariff Equity (ABATE); Bloom Energy Corp (Bloom); ChargePoint, Inc. (ChargePoint); Energy Michigan, Inc. (Energy Michigan or EM); the Environmental Law & Policy Center, Ecology Center, and Vote Solar (collectively the Clean Energy Organizations or CEO); EVgo Services, LLC (EVgo); Gerdau MacSteel, Inc. (Gerdau); Great Lakes Renewable Energy Association (GLREA); International Transmission Company (ITC); the Kroger Company (Kroger); Michigan Energy Innovation Business Council (MEIBC) and Institute for Energy Innovation (collectively MEIBC/IEI); Local 223, Utility Workers Union of America, AFL-CIO (UWUA, Local 223, or UWL 223); the Michigan Environmental Council (MEC), Natural Resource Defense Council (NRDC), the Sierra Club (SC) and the Citizens Utility Board of Michigan (CUB) (collectively MNSC); Michigan Municipal Association for Utility Issues (MI-MAUI) and City of Ann Arbor (Ann Arbor); Soulardarity and We Want Green, Too (collectively the Detroit Area Advocacy Organizations or DAAO); Wal-Mart, Inc. (Wal-Mart); and Zeco Systems, Inc. (Zeco).

This reply will focus on Staff's Initial Brief because that brief sets forth the most comprehensive discussion of the issues in this proceeding. DTE Electric will collectively address the other parties' related arguments in the context of replying to Staff except where otherwise noted. To avoid repetition and for efficiency, and in accordance with the July 7, 2022 e-mail providing the Administrative Law Judge's (ALJ) briefing requests, DTE Electric will also generally follow the order of its Initial Brief, noting matters that appear resolved, and including some discussion for

context. DTE Electric relies on the content of its Initial Brief and Attachments,[1] along with its testimony and exhibits, and incorporates the same as if restated herein. DTE Electric will attempt to be thorough, but of course cannot respond (other than noting this general objection) to the extent any party's Initial Brief does not articulate or explain a position.[2] Some issues also depend on the resolution of other issues, as numbers flow through calculations. Lack of a discussion by DTE Electric to separately address every issue or position suggested or inferred by any party should not be deemed to constitute an agreement by DTE Electric.[3]

II. SUMMARY OF MAJOR ISSUES

DTE Electric's Initial Brief explained that the Company initially requested a jurisdictional rate increase of approximately $388.2 million; however, after reviewing Staff's and other intervenors' positions, DTE Electric reduced its projected revenue deficiency to $367.9 million to account for five adjustments (listed as items a – e on page 1 of DTE Electric's Initial Brief, and further detailed in Attachments A and B to that Brief). See also the Summary of Major issues at DTE Electric's Initial Brief, p 8.

[1] Unless otherwise indicated, references to Attachments are to the Attachments accompanying this Reply Brief.

[2] There is similarly no requirement for this ALJ or the Commission to attempt to unravel and consider such matters. Courts have repeatedly recognized, for example: "It is not sufficient for a party 'simply to announce a position or assert a claim of error and then leave it up to this Court to discover and rationalize the basis for his claims, or unravel and elaborate for him his arguments, and then search for authority to sustain or reject his position.'" *Wilson v Taylor*, 457 Mich 232, 243; 577 NW2d 100 (1998), quoting *Mitcham v Detroit*, 355 Mich 182, 203; 94 NW2d 388 (1959). *See also*, *Gross v General Motors Corp*, 448 Mich 147, 161-62, n 8; 528 NW2d 707 (1995) ("Failure to properly brief an issue on appeal constitutes abandonment of the question"); *Isagholian v Transmerica*, 208 Mich App 9, 14; 527 NW2d 13 (1994).

[3] For example, but without limitation, some suggestions are beyond the scope of this case, but might be the subject of some other case(s) or proceeding(s). DTE Electric reserves all rights to address issues elsewhere and/or on appeal.

DTE Electric continues to support a revenue deficiency of approximately $367.9 million for the projected test year as set forth in this Reply Brief and Reply Brief Attachments A and B.[4]

III. JURISDICTION, STANDARD OF REVIEW AND RATE SETTING LAW

DTE Electric's Initial Brief, pp 8-15, discussed the Commission's jurisdiction over this case, as well as the applicable standard of review and rate setting law. Despite the well-established and controlling legal requirements, some parties suggest that the Commission should rule otherwise.

First, the AG's Initial Brief, p 11, suggests that DTE Electric's requested relief should be diminished because the Company had an "excessive level of earnings above the authorized ROE and high revenue sufficiency amounts in the historical periods." This and similar suggestions (*e.g.*, ABATE Initial Brief, pp 1, 6) neglect what the Commission is undoubtedly well aware, that (1) revenue depends on volumetric rates, (2) electricity consumption shifted due to the COVID pandemic and resulting directives, [5] and (3) the Company is using $70 million of the unexpected resulting revenue to fund additional tree trim surge investments to continue to improve customer service, without impacting rates (See, for example, the November 4, 2021 Order in Case Nos. U-21128 and U-20162). The AG and ABATE's suggestions are also contrary to established law.

Rates for utility service are set prospectively so that the utility provides service, and its customers receive service at established rates. Those rates are based on the estimated costs of providing that service, plus a reasonable return on the utility's investment. *ABATE v Public Service*

[4] See Reply Brief Attachments A and B. [5] Mitigation strategies to reduce the spread of COVID-19 caused a shift in electricity consumption in DTE Electric's service territory, with a general increase in Residential sales and decrease in C&I sales (Leuker, 7T 2623)

[5] Mitigation strategies to reduce the spread of COVID-19 caused a shift in electricity consumption in DTE Electric's service territory, with a general increase in Residential sales and decrease in C&I sales (Leuker, 7T 2623)

Comm, 208 Mich App 248, 257-258; 527 NW2d 533 (1994). This is part of the "regulatory compact," under which the utility dedicates its private property to serve the public, and correspondingly receives a reasonable return on the value of its private property. In *Board of Public Utility Comm'rs v New York Telephone Co*, 271 US 23; 46 S Ct 363; 70 L Ed 808 (1926), the United States Supreme Court explained that the just compensation safeguarded to the utility by the Fourteenth Amendment is a reasonable return on the value of the property used at the time that the property is being used for the public service. Rates that are not sufficient to yield that present return are confiscatory. 271 US at 31. To the extent that the utility might have earned sufficient revenue in the past, such past revenue cannot be used to sustain confiscatory rates in the future. *Id*. at 32. Thus, it would be unconstitutional for the Commission to use hindsight or otherwise base DTE Electric's rates on past events.

There are also various proposals that DTE Electric should provide new or expanded programs, without acknowledging the necessary funding. As indicated previously and above, rates are set to recover the revenue that a utility needs for a return "of" and "on" its investment in providing service. If the Commission were to order additional funding for something, then that funding must be recovered though a corresponding rate increase. DTE Electric has constitutional protections against "takings" and confiscatory rates,[6] and is entitled to rates that provide a

[6] DTE Electric has constitutional protections against "takings" and confiscatory rates under the Fifth Amendment to the US Constitution, which is applicable to the states through the Fourteenth Amendment. Similarly, Const 1963, art 10, § 2 provides in part, "Private property shall not be taken for public use without just compensation therefore being first made or secured in a manner prescribed by law." These constitutional protections have been recognized and applied to public utility rates in well-established case law. *See generally, Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm of Missouri*, 262 US 276; 43 S Ct 544; 67 L Ed 981 (1923); *Federal Power Comm v Natural Gas Pipeline*, 315 US 575; 62 S Ct 736; 86 L Ed 1037 (1942); *Duquesne Light Co v Barasch*, 488 US 299; 109 S Ct 609; 102 L Ed 2d 646 (1989). *See also, Northern Michigan Water Co v Public Service Comm*, 381 Mich 340; 161 NW2d 584 (1968); *Consumers Power Co v Public Service Comm*, 415 Mich 134; 327 NW2d 875 (1982); *ABATE v Public Service Comm*, 430 Mich 33; 420 NW2d 81 (1988).

corresponding recovery for investments that provide service to its customers.[7] DTE Electric's revenue recovery cannot be diminished by a requirement that the Company use some of that money to fund additional (uncompensated) services.

There are also suggestions that the Commission should shift costs among customers based on the proponents' views regarding what would be good social policy (but effectively constituting some monetary benefit for some customers that would need to be paid by other customers). Such suggestions are contrary to the abolished prior regulatory practice of subsidized residential rates and law requiring that the Commission set cost-based rates. MCL 460.11 states in part:

> Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of service to each customer class."

The statute's plain language must be applied as written - cost causers shall pay their costs.[8] It is also axiomatic that "agencies cannot exercise legislative power by creating law or changing the laws enacted by the Legislature*."*[9]

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[7] As a matter of fundamental ratemaking law, DTE Electric is entitled to a commensurate return of and on its investment in providing utility service. *See, Bluefield Waterworks Improvement Co v Public Service Commission of West Virginia*, 262 US 679, 690-694; 43 S Ct 675; 67 L Ed 1176 (1923); *Federal Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944). *See also, Permian Basin Area Rate Cases*, 390 US 747, 769-70; 88 S Ct 1344; 20 L Ed 2d 312 (1968); *FPC v Memphis Light, Gas and Water Division*, 411 US 458; 43 S Ct 1723; 36 L Ed 2d 426 (1973); *General Telephone Co v Public Service Comm*, 341 Mich 620; 67 NW2d 882 (1954); *Michigan Consolidated Gas Co v Public Service Comm*, 389 Mich 624; 209 NW2d 210 (1973).

[8] *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("we presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"); *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); and *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003) ("where the language of a statute is clear, it is not the role of the judiciary to second-guess a legislative policy choice; a court's constitutional obligation is to interpret, not rewrite, the law").

[9] *In re Complaint of Rovas Against SBC Michigan*, 482 Mich 90, 98; 754 NW2d 259 (2008).

There is similarly no legal basis for suggestions that the Commission should otherwise function as an agency to advance what certain intervenors may consider to be appropriate policy changes that are beyond the scope of this case, and the Commission's jurisdiction generally.[10]

The Commission is an "administrative body created by statute and the warrant for the exercise of all its power and authority must be found in statutory enactments."[11] The Commission's authority must be conferred by clear and unmistakable statutory language, and a doubtful power does not exist.[12] The Commission cannot expand its jurisdiction through its own acts or assumption of authority.[13] The Commission cannot re-write the Legislature's language to include new or different provisions. [14] If a Commission order conflicts with a statute, the order is void.[15]

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[10] See, for example, *In re Complaint of Consumers Energy Co*, 255 Mich App 496, 501; 660 NW2d 785 (2002), where the Court of Appeals reversed the Commission for misinterpreting and misapplying its own rule, explaining in part: "We agree with the dissenting commissioner that the majority ignored the clear language of the administrative rule to foster customer choice."

See also *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002), where the Court of Appeals vacated the Commission's decision to follow an unlawful path as a matter of policy. The Court explained in part:

> "Invoking the public interest and the need for policy that is responsive to a changing industry, the PSC eschewed the procedural mandates of the APA in favor of its own course of action . . . While we do not doubt the PSC's legitimate concerns . . . the process utilized by the PSC constituted a rather heavy-handed rebuke of established APA procedures, and, accordingly, we are compelled to invalidate that process" (252 Mich App at 267-68).

[11] *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm,* 269 Mich App 473; 713NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.)

[12] *Mason Co Civil Research Council v Mason Co,* 343 Mich 313, 326-27; 72 NW2d 292 (1955).

[13] *Ram Broadcasting v Public Service Comm,* 113 Mich App 79, 92; 317 NW2d 295 (1982).

[14] *Hanson v Mecosta Co Rd Comm,* 465 Mich 492, 501-503; 638 NW2d 396 (2002).

[15] *Manufacturers Nat'l Bank v DNR*, 420 Mich 128, 146; 362 NW2d 572 (1984).

Finally, for purposes of this general discussion, Michigan's Constitution requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, Art 6, § 28. Substantial evidence is evidence "that a reasoning mind would accept as sufficient to support a conclusion." [16] Expert testimony is "substantial" only if it is offered by a qualified expert who has an informed and rational basis for his or her view.[17]

"There are many different kinds of experts, and many different kinds of expertise."[18] The "real question is, what is he an expert about?" [19] Our Supreme Court explained: "Where the subject of the proffered testimony is far beyond the scope of an individual's expertise – for example, where a party offers an expert in economics to testify about biochemistry – that testimony is *inadmissible* under MRE 702." [20]

Testimony cannot support a decision by the Commission if it is beyond the witness's expertise or lacks foundation. In addition to the discussion above, expert testimony may not be

[16] *Monroe v State Employees' Retirement Sys*, 293 Mich App 594, 607; 809 NW2d 453 (2011).

[17] *Great Lakes Steel v Public Service Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983).

[18] *Kumho Tire Co v Carmichael*, 526 US 137, 150; 119 S Ct 1167; 143 L Ed 2d (1999) (expert testimony properly excluded despite witness' general qualifications in engineering).

[19] *Wheeling Pittsburgh Steel Corp v Beelman River Terminals, Inc*, 254 F3d 706, 715 (CA 8, 2001) (trial court reversibly erred in allowing expert to testify beyond the scope of his expertise). See also, *Berry v City of Detroit*, 25 F3d 1342, 1351 (CA 6, 1994), *cert denied*, 513 US 1111; 115 S Ct 902; 130 L Ed 2d 786 (1995) ("The issue with regard to expert testimony is not the qualifications of a witness in the abstract, but whether those qualifications provide a basis for a witness to answer a specific question").

[20] *Gilbert, supra*, 470 Mich at 789 (emphasis in original).

considered where it is "connected to existing data only by the *ipse dixit* of the expert."[21] What matters is "not what the experts say, but what basis they have for saying it."[22]

IV. TEST YEAR

DTE Electric's Initial Brief, pp 15-17, discussed the Company's projected test year of November 1, 2022 through October 31, 2023. ABATE's Initial Brief, pp 2-7, suggests policy arguments against projected test years, and that the Commission should instead use an historical test year. The AG's Initial Brief, pp 10-12, agrees with ABATE.

The Company incorporates its prior discussion and emphasizes that MCL 460.6a(1) plainly states: "A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges." And the November 1, 2022 – October 31, 2023 test year in this case is plainly a "consecutive 12-month period." Regardless of ABATE's disagreement with the Legislature's choice to reduce regulatory lag, the plain statutory language must be applied as discussed above, and as the Commission recognized in DTE Electric's last two rate cases (U-20162 and U-20561).

ABATE's Initial Brief, p 3, quotes two Court of Appeals opinions suggesting that a projected test year set too far in the future could be problematic (ABATE) but neglects to recognize that the suggestion is entirely hypothetical, and that the Court has affirmed, and our Supreme Court has declined to review, the use of projected test years in every appeal. This case uses the same type of projected test year that DTE Electric used (and the Commission adopted, and the Courts

[21] *General Electric Co v Joiner*, 522 US 136, 146; 118 S Ct 512; 139 L Ed 2d 508 (1997), quoted with approval in *Gilbert v DaimlerChrysler Corp*, 470 Mich749, 783; 685 NW2d 391 (2004) (holding that social worker was not qualified to offer expert medical testimony).

[22] *Daubert v Merrell Dow Pharmaceuticals, Inc*, 43 F3d 1311, 1316 (CA 9, 1995).

affirmed) in Case Nos. U-20162[23] and U-20561,[24] which is designed to begin approximately when the Commission's order is expected, which makes sense because new rates cannot be implemented until a final order is issued.

ABATE's Initial Brief, p 6, further suggests that the use of a projected test year allows the Company to recover investments and expenses that are not "truly supported by evidence." To the contrary, the Company supported its projected costs, for example, with over 1,600 pages of direct testimony, over 2,700 pages of exhibits, and responses to over 5,600 audit and discovery requests. (Crozier, 7T 2388-2389). Thus, ABATE's suggestion violates the requirement that the Commission must base its decision on the record. Const 1963, art 6, § 28; MCL 24.285. ABATE's proposal to use an historical test year and/or selective adjustments (ABATE Initial Brief, pp 2-3) also threatens fundamental due process.[25]

Moreover, the use of projected test years is a well-established factor that already has been used to reduce ROEs. See, for example, the October 20, 2011 Order in Case No. U-16472, p 39. Thus, even assuming for argument's sake that the Commission could increase utility risk as ABATE

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[23] The Court of Appeals affirmed and denied rehearing, and our Supreme Court similarly denied RCG's application for leave to appeal and reconsideration. *In re Application of DTE Electric Company to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued February 25, 2021 (Docket Nos. 349924 and 350008), *recon den* (April 19, 2021) *lv den* (November 2, 2021), *recon den* (January 31, 2022).

[24] The Court of Appeals affirmed, and our Supreme Court declined to hear the case. *In re Application of DTE Electric Co*, unpublished per curiam opinion of the Court of Appeals, issued December 21, 2021 (Docket No. U-353767), *lv den* 974 NW2d 192 (May 31, 2022).

[25] The Michigan Supreme Court cited with approval the conclusions of a circuit court judge granting an injunction against such unlawful rates:

> Certainly at first blush it would appear to anyone steeped in 'due process' considerations that it is grossly unfair to include certain items of decreased cost in rate determination while at the same time to exclude items of increased cost." Michigan Consolidated Gas Company v Public Service Comm, 389 Mich 624, 633; 209 NW2d 210 (1973).

See also most recently, *Bauserman v Unemployment Ins Agency*, ___ Mich ___ ; ___ NW2d ___ (July 26, 2022) (2022 WL 2965921) (broadly discussing judicial enforcement of constitutional rights, particularly for fundamental rights such as due process).

suggests (contrary to what our Legislature has provided), there would have to be a corresponding increase in DTE Electric's ROE.

Therefore, ABATE's argument against projected test years should be rejected because it (1) is contrary to plain statutory language, (2) simply rehashes policy arguments that have been repeatedly rejected, and (3) is refuted by the massive record in this case (along with DTE Electric's additional thousands of responses to audit and discovery requests) verifying the Company's projected costs.

V. RATE BASE

DTE Electric's Initial Brief, p 17, discussed the Company's initially filed ($21.268 billion) and adjusted ($21.243 billion) rate base. Staff recommends a rate base of $20,631,922,000, consisting of $19,229,736,000 of Net Plant and $1,249,327,000 of Working Capital (Staff Initial Brief, pp 1, 4-7; and Appendix B). The Attorney General suggests a $679.9 million reduction in rate base, based on various recommendations reflected on Exhibit AG-1.26 (AG Initial Brief, p 79). The Staff's and AG's proposals are based on matters that are discussed separately below.

A. Working Capital

DTE Electric's Initial Brief, pp 17-18, discussed the Company's agreement with Staff's $8,055,000 million working capital adjustment, resulting in agreement with Staff's $1.249 billion working capital projection. There is no other issue, accordingly the $1.249 billion working capital projection should be accepted.

B. Capital Expenditures

DTE Electric's Initial Brief, p 18, introduced approximately $6.6 billion of capital expenditures that the Company has made, or will make, from the end of the historical test year to

the end of the projected test year to maintain its safe and reliable system for generating and distributing electricity to its customers.

1. Energy Supply

DTE Electric's Initial Brief, pp 19-41, explained and supported total Energy Supply[26] capital expenditures of $636.5 million for 2020, $489.6 million for 2021, $398.6 million for the 10 months ending October 31, 2022, and $427.0 million for the projected test year (Exhibit A-12, Schedule B5.1, page 1, line 13, columns (b), (c), (d) and (f)).

DTE Electric's Initial Brief, pp 19-23, explained that the AG's proposal to disallow $166 million of capital expenditures for 13 routine and non-routine projects should be rejected because, among other things, the AG's proposal was based on an incorrect understanding of the projects' approval status. Mr. Coppola based his proposed disallowance only on a discovery response indicating when several of the projects were scheduled to receive additional internal management approvals. But follow-up discovery response STDE-12.5 (Exhibit A-40, Schedule EE1) updated the approval status, reflecting that at that time (on April 13, 2022, which was over a month before Mr. Coppola's testimony was filed) several projects had additionally received executed capital appropriation request forms (CARFs) for the funds being requested in this case.

The AG responds by contending that she asked about this further in discovery, and the "response to AGDE-11.392 [Exhibit AG-1.69] contradicts witness Morren's rebuttal testimony" that the projects received corporate approval (AG Initial Brief, p 57). To the contrary, Exhibit AG-1.69 consists of a table summarizing the approved projects and attached approval documents, which confirm Mr. Morren's rebuttal testimony.

[26] In July 2021, the Company restructured some of its business units and combined Renewables Operations with the Fossil Generation business unit into a new integrated business unit called Energy Supply (Morren, 5T 630).

The AG then acknowledges this approval and changes her position to criticize that the "date of approval for each project in the discovery response predates the expected approval date" (AG Initial Brief, p 57). This does not support any disallowance. The projects are approved, and it makes no difference that they were approved sooner than expected. The remainder of the AG's discussion lacks coherence and support, so the Company simply objects. See footnote 2.

ABATE's proposed disallowances associated with the decommissioning of the River Rouge, St. Clair, and Trenton Channel Power Plants (ABATE Initial Brief, pp 46- 48) should similarly be rejected because Company management has approved $9.5 million, $9.5 million, and $9.7 million for their respective decommissioning projects. The removal of steam generating units involves three sequenced primary activities: decommissioning, decontamination, and demolition. The Company currently needs to and is completing make-safe decommissioning work to protect both personnel and the environment. Additional funding approvals will be made to complete the work as scheduled. The proposal to defund the decommissioning projects should also be rejected because the Company has already started this work and continuing the work uninterrupted is necessary and well-supported (Morren, 5T 655-656, 734-735; Exhibit A-40, Schedule EE1).[27]

The AG simply incorporates her witness's testimony and maintains her proposal for a full ($47.6 million) disallowance of the Company's BlackStart[28] infrastructure improvements (AG Initial Brief, pp 62-63). The Company incorporates its prior discussion explaining why the AG's

[27] ABATE's witness also attempted to justify her proposed disallowances utilizing small early capital project data, which she did not recognize as being related to an early phase of the work that predominately occurred while each plant was still operating. This data is irrelevant and therefore cannot support a decision (Morren, 5T 749).

[28] BlackStart infrastructure includes assets utilized to restart the electrical grid after a blackout. Recovery from a blackout can only be accomplished if certain specifically-located generating units have the ability to self-start without the support of an external electrical power source. BlackStart units are specifically designated to offer that ability any time it is required (Morren, 5T 739).

proposal should be rejected (DTE Electric's Initial Brief, pp 22-23). Staff recommends BlackStart disallowances based solely on the cadence and status of the internal Company approval process, a position that inappropriately elevates administrative matters over the reality that these improvements are required to support grid reliability and are key elements in the FERC-required transmission owner system restoration plan. (Staff Brief, pp. 15-16) There is no material or substantial basis to justify any disallowance of the incremental expenses the Company is incurring for this grid reliability work. [29]

MNSC witness Comings proposed $48.8 million of capital expenditure disallowances associated with four routine capital projects at Monroe Power Plant (8T 4078), but "MNSC has decided to no longer pursue the recommended Monroe disallowances in this proceeding" (MNSC Initial Brief, p 8, n 16). Thus, the expenditures should be approved as undisputed, as well as fully supported (discussed at DTE Electric's Initial Brief, pp 23-24).

DTE Electric's Initial Brief, pp 25-27, discussed the Company's disagreement with Staff's recommendation for a combined disallowance of approximately $76 million for removal projects that are above the amounts previously approved for inclusion in depreciation rates, [30] and that any reasonably and prudently incurred removal costs be deferred with a full return of and on the deferred amount. As an alternative, the Company proposes to include the costs in rates in this case, but subject to a reconciliation. Specifically, should any actual expenditures ultimately be found to be imprudent and permanently disallowed for these specific projects, the Company will write-off the

[29] The Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. Substantial evidence is evidence "that a reasoning mind would accept as sufficient to support a conclusion." *Monroe v State Employees' Retirement Sys,* 293 Mich App 594, 607; 809 NW2d 453 (2011).

[30] The proposed adjustments are $6.7 million, $10.2 million, $24.7 million, and $34.9 million for the Monroe Bottom Ash Basin Closure (CCR), Conners Creek Decommissioning / Sea Wall, River Rouge Decommissioning, and Trenton Channel Decommissioning projects.

disallowed costs and record a regulatory liability for the "return on" the costs included in base rates for refund to customers (Crozier, 7T 2379-2380; Uzenski, 2789).

Staff responds by stating that it finds the Company's counterproposal reasonable with the following additional condition:

> The Company will provide detailed cost information in its next depreciation case comparing the actual project scope and costs to the previously approved project scope and costs. Any actual costs found to be unreasonable or imprudent shall be written-off and a regulatory liability for the return on the costs shall be included in base rates for refund to customers. [Staff Initial Brief, p 14.]

The Company agrees, so this matter is resolved for purposes of this case.

In summary, the projected capital projects and associated expenditures for the Company's Energy Supply units are required to support safety, regulatory compliance, environmental compliance, and reliability. Therefore, the Company's capital expense recovery should be fully approved, subject to the agreement on removal costs discussed above. Further details are presented below in the context of specific topics.

i. Actions in Response to Steam Electric Effluent Limit Guidelines (ELG) Rule Changes

DTE Electric's Initial Brief, pp 27-31, discussed ELGs (national wastewater discharge standards that are developed by the Environmental Protection Agency (EPA)), and the EPA's ELG Reconsideration Rule, which contains time-based options for complying with the updated rules for Bottom Ash Transport Water (BATW) and Flue Gas Desulfurization (FGD) wastewater. On October 13, 2021, DTE Electric submitted Notices of Planned Participation (NOPP) to the Michigan Department of Environment, Great Lakes, and Energy (EGLE) for (1) cessation of coal burning at the Belle River Power Plant to achieve compliance with BATW discharge requirements, and (2) the Voluntary Incentive Plan (VIP) at the Monroe Power Plant for FGD wastewater compliance. (Morren, 5T 633-635; Lee, 7T 1591-1593). DTE Electric's NOPP for the Belle River

Power Plant indicated a commitment to cease coal-fired operations by the end of 2028, with the option to evaluate a conversion to an alternative fuel source. This decision allows the Company to avoid installing $55 million of new ELG-compliant bottom ash technology by the end of 2025 (Morren, 5T 645, 711-712).

ABATE's Initial Brief, pp 41-42, proposes to disallow the Belle River Power Plant natural gas preliminary engineering study, reasoning that there is uncertainty whether the $2.5 million effort will be completed before the end of the test year. To the contrary, multiple documents in this case show that ABATE's postulated uncertainty is unfounded, as previously discussed at DTE Electric's Initial Brief, p 29.[31] Therefore, ABATE's proposed disallowance should be rejected.

The Monroe Power Plant provides essential support to the local and regional electrical grids because of its size, location, and operating characteristics.[32] Therefore, the Company is proceeding with Fly Ash Transport Water (FATW), BATW, and FGD wastewater projects to meet the fast-approaching ELG compliance deadlines (Morren, 5T 645-646). In summary, the Company is currently implementing projects for FATW ELG compliance according to the 2015 Rule, which will allow the plant to continue operating beyond 2023.[33] The Company will achieve BATW

[31] In summary: (1) PAT Form 18325 (Exhibit AB-10, p 16) shows that that the effort is to be completed in 2022; (2) Exhibit A-40, Schedule EE5 states that the engineering work is to be completed in time to support the Company's 2022 IRP filing; (3) Exhibit A-40, Schedule EE6 indicates the work is to be completed in the third quarter of 2022, and (4) Exhibit A-40, Schedule EE7 indicates that the contract to complete the work has been executed (Morren, 5T 744).

[32] The Monroe Power Plant has a capacity of over 3,000 MW, making it the largest power plant in Michigan, the second largest in the Midwest, and the fourth largest in the United States (Morren, 5T 645).

[33] The FATW portion of the ELG Rule requires companies to cease water discharges related to the transport of fly ash by the end of 2023. The project to install piping, silos, and other infrastructure for the dry transport of fly ash from Monroe Power Plant boilers to a storage area was approved by the Company's Board of directors in 2020 and is fully underway (Morren, 5T 646, 651-652).

wastewater ELG compliance by the end of 2025.[34] The Company will achieve FGD wastewater compliance based on one of the options described above. If a BAT is selected, compliance must be achieved by December 31, 2025. If a technology that qualifies for the VIP is selected, compliance must be achieved by December 31, 2028 (Morren, 5T 647; Lee, 7T 1593).

ABATE's Initial Brief, pp 42-43, proposes a $23.614 million disallowance ($16.947 million in the bridge period, and $6.667 million in the test year) for the Monroe Bottom Ash Conversion (ELG) project, based on witness York's opinion that it was unclear whether the Company would incur costs during the bridge period or projected test year. The Company disagrees based on the record, incorporating its prior discussion (DTE Electric Initial Brief, pp 30).[35]

ABATE's Initial Brief, p 43, further asserts that "[b]ecause the project will not be used or useful within the period implicated by this case the Commission should reject recovery here." To the contrary, the Court of Appeals previously rejected ABATE's argument that the Commission is required to use the "used and useful" test in setting rates. *ABATE v Public Service Comm*, 208 Mich App 248, 258-59; 527 NW2d 533 (1994). This is controlling precedent that must be followed. MCR 7.215(C)(2) and (J)(1). Therefore, based on the law and the record, ABATE's proposed disallowance should be rejected

[34] The Company plans to terminate the use of water for transport of bottom ash at the Monroe Power Plant, and replace it by installing a dry drag chain conveyor system. The project is currently approved for engineering, design, and initial work, with additional approvals scheduled in 2022 (Morren, 5T 646, 652).

[35] Mr. Morren highlighted the importance of timing to meet compliance requirements, the complexity associated with making major modifications to four of the largest coal-fired generating units in the country, and the major project work that began in 2020 (Morren, 5T 652, 745; Exhibit A-40, Schedule EE8; Exhibit AB-10, p 22). Also, each unit is effectively its own Bottom Ash Conversion (ELG) project. While the fourth and final unit does not need to be completed until the end of 2025, the other units need to have 100% of their work completed well ahead of time to meet regulation deadlines (Morren, 5T 745-746).

ii. Belle River Power Plant NPVRR Analysis, and the Company's Decision to Cease its Coal-fired Operations.

DTE Electric's Initial Brief, pp 31-38, discussed Company's net present value revenue requirement analysis (NPVRR) for its Belle River Power Plant,[36] and resource adequacy concerns for MISO Zone 7, which demonstrate the importance of continuing to operate the Belle River Power Plant.[37] The most favorable outcome in the NPVRR analysis (Table 6 at Burgdorf, 4T 139) at a capacity price of CONE is ceasing Belle River's coal-fired operations in 2028. Based on the resource adequacy risks, NPVRR analysis, and the ability to avoid the $55 million bottom ash ELG-related costs discussed above and in DTE Electric's Initial Brief, the Company decided that it would be in its customers' best interest for the Belle River Power Plant to cease coal-fired operations by the end of 2028 (Morren, 5T 712-713).

MNSC's Initial Brief, pp 26-29, proposes a $2.4 million disallowance for the Belle River Fuel Conversion Engineering project based on the Company not having made a decision to convert the plant from coal to natural gas-fired operations. The Company previously explained that MNSC's proposal should be rejected because it was apparently based on a misunderstanding that the project is for engineering to convert the plant to natural gas. Instead, the project is to provide

[36] The results are summarized on Exhibit A-12, Schedules B6.1 – B6.3, and show a range of outcomes consistent with the range of capacity prices (Burgdorf, 4T 135-139; 5T 709).

[37] The plant provides approximately 1,200 MWs of UCAP towards meeting the MISO Zone 7 LCR in PY 2025/26. The ability to reliably serve load in Zone 7 could be compromised if the Belle River units were retired, and therefore not available. If Zone 7 (where DTE Electric serves) does not meet the LCR, then the MISO clearing price for Zone 7 would be set at the CONE, and the probability of a loss of load event (available capacity is insufficient to serve demand) would exceed the federal reliability standards that govern the resource adequacy planning process (Burgdorf, 4T 135; Morren, 5T 712). The Commission also recently recognized this concern in the July 2, 2021 Order in Case Nos. U-20886 and U-21099, p 10, which "emphasizes that the shortfall in LRZ 7 should serve as an important signal to LSEs of the severe economic consequences that could occur in the event of a loss of load event."

the information necessary to decide whether the plant should be converted to natural gas (DTE Electric Initial Brief, pp 43-35).[38]

MSNC's Initial Brief, pp 14-25, similarly attempts to cast doubt on the Company's assessment of resource adequacy in Zone 7. The Company disagrees, incorporating its prior discussion (DTE Electric Initial Brief, pp 35-38). MNSC's position boils down to: (1) remember when capacity resources were not so tight, and (2) now let's speculate that the situation might somehow get better. Capacity resources have been tightening over the years with the advancing retirements of coal fired plants. The Commission discussed its concerns regarding the tightening of capacity resources in its recent Order in capacity demonstration Case Nos. U-21099 *et al*, explaining in part:

> [The Staff report filed on March 25, 2022] also notes concerns regarding tightening capacity availability throughout the MISO zones and slimming margins for LRZ 7. *See*, Staff Report, pp. iii, 8, 17. The ***Commission shares these concerns regarding the tightening of capacity resources given the implications for resource adequacy and the economic and human impacts of capacity shortfalls. As described in last year's capacity demonstration docket,*** Case Nos. U-20866 *et al*., ***LRZ7 experienced a capacity shortfall that led to the PRA for that zone being set to CONE***. *Capacity Demonstration Results: Planning Year 2024/2025* in Case No. U-20886, filing #U-20886-0075, p. 4. While not included in this year's Staff report due to the MISO 2022/2023 PRA being conducted after the Staff Report was issued, the results were released on April 14, 2022. ***The MISO 2022/2023 PRA showed that all zones within the MISO footprint met their LCR, but LRZs 1-7 cleared at CONE, which for 2022/2023 is set at $236.66 per MW-day.*** [June 23, 2022 Order in Case Nos. U-21099 *et al*., pp 13-14; emphasis added.]

[38] Mr. Morren, who was previously the director of the Belle River Power Plant and therefore familiar with its operations, explained that the Company utilized the original equipment manufacturer (OEM) to perform boiler modeling, which determined that converting the plant from coal to natural gas is feasible from an engineering perspective focusing on the boiler. The Company then hired the OEM to complete a more in-depth broader project engineering study and detailed cost estimate for a natural gas conversion. The Company believes that a fuel conversion would be a minor and relatively low-cost alteration to the plant (*e.g*., it would be a fraction of the cost of building a new power plant). The conversion would provide an expeditious means to address potential resource adequacy and other grid reliability considerations given widespread power plant retirements across MISO Zone 7. A fuel conversion would retain Belle River's ability to supply 1,300 MWs of 24/7 dispatchable capacity and energy that currently benefits customers across Michigan (Morren, 5T 651, 769-771, 774, 782, 784, 787-788). The project is also appropriate and timely to determine the scope, schedule, and potential cost of a potential plant conversion. This information will form important inputs to the Company's upcoming IRP (Morren, 5T 752).

MNSC's Initial Brief, p 18, further asserts that it is unrealistic to assume that the Company would retire Belle River without replacing its capacity because, for example, Belle River could be converted to natural gas. The Company agrees that Belle River's conversion might be a viable alternative, but in that case Belle River would continue operating rather than retire. [39]

Thus, and as the Company explained previously, Belle River's capacity remains important to Zone 7 reliability, and a hypothetical early retirement would risk a capacity shortfall (4T 146-148). MNSC's criticisms and speculation provide no sound basis to support a decision regarding Belle River's retirement (Burgdorf, 4T 148-149).

MNSC's Initial Brief, pp 8-14, also asserts that five projects (totaling $12.8 million) should be disallowed as allegedly avoidable because the Belle River Power plant might retire in 2026 ($15.248 million with the engineering study discussed previously). The Company disagrees because it has committed to ceasing coal-fired operations at the plant by the end of 2028, but it has not decided to retire the plant in 2026. As discussed in DTE Electric's Initial Brief and above, the plant's economic operation is justified in the near term, and the plant has value for resource adequacy. The Company's upcoming integrated resource plan (IRP) will evaluate the long-term plan for the plant, including its conversion to operate on natural gas. The capital expenditures in this rate case are required to continue the plant's safe and reliable operation while it continues to

[39] The Company maintains its disagreement with MNSC's discussion about other potential options to replace Belle River's capacity because any "new resources" would have to be above the current forecast. Plus, there are risks of bringing on new renewable resources and the potential for MISO changes in renewable capacity accreditation with greater renewable penetration. Supply chain bottlenecks and other risks have grown since this case was filed and would likely result in delays for any new project (Exhibit A-033, Schedule X2 reflects some recent DTE Electric experiences with renewable project). Moreover, Mr. Comings ignored the risk that other resources in MISO might retire causing a regional capacity shortfall, as was the case in PY 2022/23 for the MISO North-Central region (Burgdorf, 4T 144-145, 148; Exhibit A-33, Schedules X1 and X3, slide 7).

provide energy for customers. Therefore, MNSC's proposed disallowance should be rejected (Morren, 5T 750-751).

iii. Coal Combustion Residuals (CCR) Expenditures

DTE Electric's Initial Brief, pp 38-39, explained and supported the historic and projected capital and O&M expenditures required to comply with CCR regulations at the Company's ten (10) CCR sites (the bottom ash basins at Belle River, Monroe, River Rouge, and St. Clair Power Plants, the St. Clair Scrubber Basin, the Belle River diversion basin, the Monroe Fly Ash Impoundment, and the landfills at Range Road, Sibley Quarry, and Monroe) (Lee, 7T 1596-1598 Exhibit A-12, Schedule B5.1.1).[40]

ABATE's Initial Brief, pp 43-44, proposes a $24.073 million disallowance ($21.765 million in the bridge period, and $2.308 million in the test year) for the Sibley Quarry Landfill Modifications (CCR), asserting that "the project will not be used or useful within the period implicated by this case." As indicated above, the Court of Appeals rejected ABATE's argument that the Commission is required to use the "used and useful" test in setting rates.[41] The project is also supported by the record as the Company explained previously. Therefore, ABATE's proposed disallowance should be rejected.

ABATE's Initial Brief, pp 45-46, proposes a disallowance of all funding ($57.3 million total) for the Monroe Bottom Ash Basin Closure (CCR) project, asserting that it is uncertain if the Company is completing the work as scheduled, and that a major portion of the work occurs after

[40] Forecasted capital expenditures are best estimates of site modifications required to meet currently known State and Federal regulations. O&M expenditures are based on current costs to operate CCR sites and engineering judgment of future site preservation and monitoring costs (Lee, 7T 1598). *See also* Uzenski, 7T 2770-2772; Exhibit A-30 Revised, Schedule U-1 regarding the recovery of CCR-related costs through rates).

[41] *ABATE v Public Service Comm*, 208 Mich App 248, 258-59; 527 NW2d 533 (1994).

the test year. The Company disagrees, incorporating its prior discussion explaining why ABATE's proposed disallowance should be rejected.

iv. Hydrogen Fuel System Pilot and Slocum BESS Pilot

DTE Electric's Initial Brief, pp 39-43, explained and supported two pilot projects that will introduce emerging technologies—hydrogen-fueled generation[42] and a grid-scale Battery Energy Storage System (BESS)[43]—into the Company's generation portfolio, and support the Company's advancement in the decarbonization arena.

ABATE's Initial Brief, pp 40-41, proposes a full disallowance of the Hydrogen Fuel System Pilot because "the project will not be used or useful within the period implicated by this case" Again, the Court of Appeals rejected ABATE's argument that the Commission is required to use the "used and useful" test in setting rates.[44] Beyond that, ABATE simply speculates that "DTE's timeline may be too aggressive," without support or explanation (See footnote 2). [45] ABATE does not dispute the Company's previous explanation that ABATE's witness confused two different

[42] The Hydrogen Fuel System Pilot (Exhibit A-12, Schedule B5.1, page 2, line 30) is a project to produce and utilize green hydrogen as a fuel source at the Blue Water Energy Center (BWEC) to aid in future carbon reduction. The project includes the construction of an 11 MW electrolyzer plant with storage capacity, and a fuel blending station that can support up to 5% of the BWEC's fuel requirement. Exhibit A-12, Schedule B5.1.2 details the need, goals, design, expected pilot costs, stakeholder engagement process, and public interest benefits (Morren, 5T 659). Mr. Morren also provided additional testimony on these topics and supporting the pilot (5T 659-667).

[43] The Slocum Battery Pilot (Exhibit A-12, Schedule B5.1, page 2, line 31) is a pilot to replace the diesel-fueled peakers at the Company's Slocum peaker site located in the City of Trenton with a 14MW / 56 MWhr lithium-ion (Li-ion) BESS that will store excess energy that is generated on the grid during off-peak hours. This energy will then be available for dispatch during higher-priced peak hours. Exhibit A-12, Schedule B5.1.3 details the need, goals, design, expected pilot costs, stakeholder engagement process, and how the project is in the best interest of the public (Morren, 5T 667-668). Mr. Morren also provided additional testimony on these topics and supporting the pilot (5T 668-671).

[44] *ABATE v Public Service Comm*, 208 Mich App 248, 258-59; 527 NW2d 533 (1994).

[45] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

engineering projects, Therefore, ABATE's proposed disallowance should be rejected as unfounded (Morren, 5T 741-742).

Staff (Initial Brief, pp 16-19), the AG (Initial Brief, pp 58-60), GLREA (Initial Brief, pp 10-12), and MNSC (Initial Brief, pp 136-141), oppose the hydrogen pilot as allegedly too costly in comparison to its benefits. The Company maintains that it is unreasonable to give little weight to numerous factors favoring the pilot (Morren, 5T 743).

The AG's Initial Brief, pp 60-62, proposes that the Commission reject the Slocum BESS Pilot (disallow $33.7 million) based on Mr. Coppola's opinion that the Company did not make a convincing case that it can create sufficient value for customers relative to the investment required. The Company disagrees, incorporating its prior discussion. Mr. Morren explained in part that a BESS is a storage system for energy and not a generation unit, which Mr. Coppola incorrectly attempted to use as a comparison.

The AG responds by suggesting that Mr. Morren "fails to acknowledge" that they both serve the same function of providing energy and capacity (AG Initial Brief, p 62). To the contrary, it is the AG who neglects a crucial difference – a BESS is able to release energy into the grid without any new emissions. The AG also makes an inapt comparison in arriving at a faulty conclusion – a BESS does not "provide the same function" as a combustion turbine generator (which is the assumed technology underpinning CONE) and a BESS does not provide power "at a cost that is 25 times higher than using a combustion turbine." (AG Initial Brief pp. 60-62: See Exhibit MEC- 81 the MISO Resource Adequacy Business Practice Manual) The AG's conclusion assumes that a single CONE payment is equal to the total project cost for building a combustion turbine generation unit, which is not the case. A single CONE payment is not the total project construction cost. Instead, CONE spreads the installed cost of a combustion turbine over a 20-year payment

schedule.[46] Thus, the AG's comparison between a one-time CONE payment and the Company's Slocum BESS project construction cost substantially understates the cost of a combustion turbine, rendering the AG's "25 times" conclusion massively inaccurate.

There are also several additional factors that make a BESS a reasonable and useful addition to DTE Electric's energy supply options, including the expanding need for the electric grid to have additional energy storage levels due to the growth of intermittent generation, and Company management's full support and approval of more funding ($38.0 million) than the Company requests in this case (Morren, 5T 736-737; Exhibit A-40, Schedules EE3 and EE4).

Moreover, "Staff is supportive of this pilot, as the Company has shown it will provide a value to ratepayers" (DeCooman, 8T 5319), MEIBC/IEI witness Sherman acknowledged the valuable learnings and experience that the Company can gain from this pilot (8T 4399), and MEIBC/IEI's Initial Brief, pp 22-26, generally supports the pilot. Therefore, the Commission should reject the AG's proposed disallowance (Morren, 5T 737-738).

Staff's Initial Brief, pp 19-21, proposes a $1,767,000 disallowance in the bridge period, and a $26,430,490 disallowance in the projected test year. Staff initially proposed a full disallowance of requested capital expenditures for the projected test year ($26,430,490), reasoning that the pilot did not have internal budgetary approval (DeCooman, 8T 5317-5318). As indicated above, however, the pilot has received management approval for $38 million (Exhibit A-40, Schedule EE3 and EE4), so Staff's concern has been addressed (see also 5T Morren, 761-762).

Staff's Initial Brief, pp 20-21, responds:

[46] MISO defines CONE as being an *annualized* NPV value as opposed to a *total* NPV value. Page 197 of Exhibit MEC-81 (MISO Resource Adequacy Business Practice Manual 11) states, "In order to produce the *annualized* CONE value for each LRZ from these cost numbers, MISO assumes: (i) a 55/45 debt to equity ratio; (ii) a 20-year project life and loan term;…" (emphasis added)

> While Staff is generally supportive of this project, the information provided in rebuttal has not assuaged its concerns with the test year capital expenditures requested in this case. Specifically, while Exhibit A-40, Schedule EE4 includes the full internal budgetary approval, it also includes an updated scoping document with updated costs that align with the amounts identified for budgetary approval. . . . Given the fluidity of these costs, Staff's position to align the bridge period costs with the Company's forecasted amounts included as Exhibit S-10.4 and disallow capital expenditures in the test year until a future case when the costs have more certainty and can be fully reviewed is the most reasonable position and should be adopted.

The Company disagrees because Staff generally supports the project and acknowledges that it has full internal budgetary approval. The project involves substantial costs, as most recently and accurately reflected by the approved numbers. Staff's concerns are overstated, and do not provide a sound basis for Staff's proposed 100% disallowance in the projected test year.

2. Fuel Supply and Midwest Energy Resources Company

DTE Electric's Initial Brief, p 42, explained and supported the Company's Fuel Supply and Midwest Energy Resources Company (MERC) capital expenditures. There is no disagreement, so the expenditures should be approved.

3. Nuclear - Fermi 2

DTE Electric's Initial Brief, pp 42-45, explained and supported the capital expenditures for the Fermi 2 Nuclear Power Plant (Fermi 2).

The AG's Initial Brief, pp 64-66, proposes to remove approximately $38.4 million of capital expenditures ($391,000 for 2020, $4,234,000 for 2021, $14,608,000 for the 10 months ending October 31, 2022, and $19,236,000 for the projected test year) associated with three projects: (1) Plant Radio System, (2) Security System Computer, and (3) Plant Wireless (8T 4797-4800; Exhibit A-12, Schedule B5.3, page 2, line 28; page 3, line 41; and page 3, line 50). The Company incorporates its prior discussion, which explained that the AG's proposal should be rejected because it would unjustifiably reduce the recovery of capital expenditures that DTE Electric has already

reasonably and prudently incurred, and that the Company reasonably and prudently projects to incur to replace and install systems that are critical to safely operating Fermi 2.

The AG responds by complaining about answers she received in response to discovery requests on Mr. Davis' rebuttal testimony,[47] and suggests that the Company's capital expenditures "remain unsupported" (AG Initial Brief, p 65). To the contrary, the expenditures are supported by the evidence summarized in DTE Electric's Initial Brief. The AG's characterization of the discovery responses is also inaccurate. The Company appropriately answered the AG's questions, particularly considering this case's short response deadlines and massive discovery (the Company responded to over 5,600 audit and discovery requests). The remainder of the AG's discussion is unfounded rhetoric that cannot support a decision. [48] Therefore, the AG's proposed disallowance should be rejected.

The Company also notes a continuing objection to the AG's briefing approach, including without limitation the general methodology of: (1) starting discussions by incorporating her

[47] Mr. Davis explained that Witness Coppola's proposal was based on the apparent misconception that the Plant Radio System and Security System Computer are just ordinary business equipment, when instead they are critical to DTE Electric remaining compliant with its Nuclear Regulatory Commission (NRC) operating license and safe operations of Fermi 2. The Plant Radio System provides the necessary communications network for the safe operation of Fermi 2 and must remain operable during all postulated scenarios of plant operations because the system is credited in the Fermi 2 Emergency Response Plan. The Security System Computer provides necessary surveillance and perimeter intrusion detection capabilities for safe operation of Fermi 2 and must remain operable during a wide variety of challenging conditions to meet the plant's obligations under NRC regulations. Furthermore, replacing the existing plant equipment with a wireless system requires design changes to the plant and strict plant configuration controls and cyber security protocols. (Davis, 7T 2547, 2578-2579, 2580, 2583).

Mr. Davis also disagreed with witness Coppola's suggestion that the capital expenditures were not adequately supported, recounting his direct testimony, which was further augmented with project details in Attachment 9 of the Part III submission, and responses to the AG's discovery requests (Davis, 7T 2538, 2541, 2553, 2580-2852).

[48] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

witness's testimony "in its entirety," and without any specific transcript cites (*e.g.*, Initial Brief, p 64); then disregarding or misconstruing rebuttal; (3) then vaguely pointing to discovery responses as allegedly somehow undermining the rebuttal. The Company attempts to respond for the ALJ's convenience but maintains that there is no requirement to unravel the AG's arguments for her. See footnote 2.

4. Distribution Operations (DO)

DTE Electric's Initial Brief, pp 45-50, explained and supported Distribution Operations (DO) capital expenditures, which totaled $905 million in 2020, and are projected to be $2.3 billion for the 22-month bridge period ending October 31, 2022, and $1.4 billion for the projected test year (Pfeuffer, 4T 230; Exhibit A-12, Schedule B5.4, page 1, line 23, columns (b), (e), and (f)).[49]

In response to the Staff and ABATE's arguments that the Company should continue to use a five-year average to forecast emergent replacements rather than a three-year average (Staff's Initial Brief, pp 22-24; ABATE Initial Brief, pp 49-50), the Company incorporates the arguments it previously made on this topic in its Initial Brief, at pages 46-47, which explain in detail that due largely to an increasing trend of stronger and more frequent storms, a three-year average is most appropriate. (See also Pfeuffer, 4T 248, 250, 489-92; Exhibit A-41, Schedule FF15).

In its brief, Staff took issue with the Company's explanation that if emergent expenditures do not materialize as forecast, then the Company would be able to shift those resources to exceed its planned strategic capital investments to improve the reliability of its system for customers more quickly than planned. Staff responds by pointing to the May 8, 2020 Order in Case No. U-20561, at

[49] Pages 1 and 2 of Exhibit A-12, Schedule B5.4 provide a high-level overview of base and strategic capital investments. Pages 3 to 11 provide additional support including forecasting methodology and project lists. Exhibit A-23, Schedules M-3 through M-6 provide detailed descriptions of each project or program listed in Exhibit A-12, Schedule B5.4 (4T 378). Ms. Pfeuffer also provided detailed explanations of Exhibit A-12, Schedule B5.4 (Pfeuffer, 4T 378-386), and Exhibit A-23 (4T 386-387).

page 91, where the Commission stated that it "disagrees with DTE Electric's view that DO capital expenditures should be treated as a single entity, putting, for all practical purposes, strategic capital and emergent replacements in the same bucket" (Staff's Initial Brief, p 24). Staff neglects the Commission's further guidance that it would like more accurate forecasting and an increased emphasis on strategic capital – which is exactly what the Company is doing. The Company is not suggesting the Commission consider emergent and strategic capital as the "same bucket" as Staff suggests. Rather, the Company's comment about using any potential overage to fund strategic capital was in response to Staff's indicated concern that the funds might not be spent, and in accordance with the Commission's emphasis on strategic capital. Staff indicates that "the Commission has been clear with its expectation that the Company will not shift spending" however, this is a gross oversimplification of the Commission's statements in its order. (Staff Initial Brief, p 24). The Commission was clear that its expectation was that the Company would "use the dollars approved in rates tied to improving reliability for their intended purpose (i.e., strategic capital investments category), and not shift them to other categories such as emergent replacement and other reactive spending." May 8, 2020 Order in Case No. U-20561, p 91. This was not a blanket admonition that the Company may not shift investments in other ways to benefit customers as situations arise. In fact, the Commission stated "[E]vidence shows that strategic capital was underspent in 2019, while emergent replacements capital was overspent in 2019. The Commission would like to see these results reversed…" *Id.* Thus, Staff's "same bucket" argument misses the point, which is that if there are unused dollars earmarked for emergent that do not need to be spent on emergent expenses, the Company will not merely retain the funds. There is no risk that customers would pay for investment dollars that are not spent. The Company would redirect those dollars to strategic capital projects that will improve overall reliability for its customers, a scenario well within the Commission's stated expectations. *Id.*

In response to ABATE's Initial Brief, pp 50-51, which asserts that the Company "improperly and unreasonably adjusted the relevant historical values for inflation through 2020" the Company incorporates the arguments it previously made on this topic in its Initial Brief, at page 47, which explains in detail that prior years' expenditures must be expressed in a constant-dollar denomination (in this case, 2020 dollars) in order to make an apples to apples comparison because the value of a dollar changes over time due to inflation. The Commission approved the Company's normalization practice its most recent rate case. (See May 8, 2020 Order in Case No. U-20561, p 86.) Therefore, the ALJ and the Commission should reject ABATE's proposed methodology (rejecting normalization) (Pfeuffer, 4T 492-493).

The AG's Initial Brief, p 54, vaguely reflects that her witness Coppola proposed a $9.08 million reduction in emergent capital based on the success of the tree trimming surge in reducing power outages caused by trees. As explained more fully in the Company's Initial Brief at page 47, the AG's proposal is duplicative of cost savings associated with reduced equipment failures from the tree trimming surge already included in Exhibit A-12, Schedule B5.4, page 1, line 6.

Staff's Initial Brief, pp 273-76, suggests that the Commission order the Company to re-classify certain emergent replacement capital costs, including a proposal that the Company "begin tracking equipment identified as imminent failure (near failure but has not failed) and exclude those costs from the emergent replacements capital program" (*Id*, p 274, quoting Becker 8T 5404).[50] The Company previously explained in its Initial Brief, at pages 47-48, that it disagrees because these items are necessary, reactive, unplanned work to prevent customer outages, prevent hazards and/or prevent any additional damage to the electrical system. When field personnel discover these items,

[50] Staff further states that, by design, it did not specify where it thinks the costs should be assigned, and: "The Company should determine the appropriate program in the next electric case after its review" (*Id*, p 275).

they initiate emergent replacements to the latest construction standard, but without the full planning and engineering that would go into strategic replacement. There is a similar need to immediately replace equipment whether it has failed, or failure is imminent. Staff's proposal to track a separate imminent-failure category is unnecessary and would require significant time and other resources to implement. (Pfeuffer, 4T 497).

Moreover, what Staff suggests is impractical and may be impossible for the Company to achieve. In a situation where there is a power outage, much of what a lineman does in the field is a judgment call based on the site-specific circumstances. Adding an additional step whereby a worker must stop work and document his or her thought process in determining whether damaged or degraded equipment should be replaced immediately will take precious time that should be spent restoring power to our customers. As the Commission is aware, the Company brings in linemen from all over the country when needed to restore service to customers as quickly as possible. These linemen are often unfamiliar with the Company's software, and it is not practical to document their thought processes and decisions on this level. They may not even have access to equipment in the field that would allow them to upload reports. The goal of customer restoration and safety is paramount, and the addition of unnecessary documentation and reporting processes should not hinder or delay restoration. In addition, creating new programs to allow additional reports of a kind not currently on the Company's system will require investment in additional IT work and additional training expenses. (Pfeuffer, 4T 497)

Finally, it is unclear what benefit the new data would provide. If a worker responds to a trouble ticket and sees a line down, but also sees that another component has been damaged so badly that even if the line is reattached, failure of the other component is imminent and would require a return to the same address to repair the other component, what value is gained by

documenting separately the replacement of the damaged component? It is unclear to the Company what valuable information Staff would glean by requiring separate reporting of replacement of equipment in imminent risk of failure from replacement of equipment that has already failed during the conduct of a restoration. The Staff's request for separate reporting should be denied.

The AG's Initial Brief, pp 43-48, reflects that her witness Coppola proposed disallowances in select other base capital programs (Major Equipment; Normal Retirement Unit Change-Out (NRUC) & Improvement Blankets; and General plant, Tools & equipment and Miscellaneous) based on his belief that the Company should estimate these investments using a five-year average of past expenditures. The Company incorporates its discussion on page 48 of its Initial Brief, which explains in more detail that a five-year average of expenditures is not the most accurate representation of future expenditures in these categories and why the ALJ and the Commission should reject the AG's approach. If the Commission decides to change the methodology for this case, which it should not, then the Company recommends a three-year historical average (2019-2021) plus inflation as shown in Exhibit A-41, Schedule FF16, and as explained more fully in the Company's Initial Brief at page 48.

Staff's Initial Brief, pp 26-27, proposes disallowances ($1.667 million in the bridge period; $2 million in the projected test year) for NRUC & Improvement Blankets. The Company incorporates its response at page 49 of its Initial Brief, which explains that the additional $2.11 million was requested by regional planning engineers to address very real needs of our customers, including reliability and power quality concerns. The Company will use this funding to be more quickly and locally responsive to customer concerns and complaints (Pfeuffer, 4T 502-503). Staff's Initial Brief, p 27, responds by suggesting that the Company did not adequately support its request

with evidence, citing MCL 460.6a(1). Staff's reliance on the statute[51] is overstated. While Staff raised its lack of evidence concern in its direct testimony, Staff ignores Witness Pfeuffer's rebuttal testimony, which properly responded to Staff's indicated concern and constitutes additional evidence supporting the Company's requested recovery. The Staff argues that "Higher costs of projects are not equivalent to increased reliability concerns and customer complaints." (Staff Initial Brief, p 27. (4T 375, Staff Initial Brief at 27). However, Staff does not dispute that the projects included in this category are reasonable and prudent investments. Witness Pfeuffer explained that:

> [T]he additional $2.11 million was requested by regional planning engineers, who are often supporting specific customer reliability and power quality concerns, to support doing more small projects locally to improve customer reliability concerns in a quick and efficient manner. Increased funding to the regional planning engineers, typically the front facing employees closest to our customers, ensures that they have the flexibility to quickly resolve smaller in scope reliability equipment issues. [4T 502.]

Thus, the Company is not requesting the additional $2.11 million merely because costs are higher, as Staff suggests. The Company provided evidence that it needs the additional funding to *increase* the number of small projects. Staff does not disagree with the necessity of investments in this category as a whole and seems to assume that the addition of inflation to historical actuals should be sufficient. This would be a valid argument if the quantity of small projects was to stay the same, year over year. However, Witness Pfeuffer clarified that the number of projects would be higher than in previous years. Adding inflation to historic actuals accounts for rising costs but does not account for additional projects. The ALJ and the Commission should reject the Staff's recommended disallowance.

[51] MCL 460.6a(1) states in part "[t]he utility shall place in evidence facts relied upon to support the utility's petition or application to increase its rates and charges, or to alter, change, or amend any rate or rate schedules."

i. 2020 Actual Expenditures versus U-20561 Forecast

DTE Electric's Initial Brief, pp 50-53, reflects that overall, the Company invested $44.0 million more in 2020 than what was forecasted in Case No. U-20561 (approximately 5%, primarily due to higher-than-projected Emergent Replacements),[52] and explained that the Company tracks Emergent capital expenditures in three major categories: (1) Storm, (2) Non-Storm (tracked in four subcategories: Emergent, Reactive, Corrective, and Environmental), and (3) Substation Reactive (tracked in four subcategories: Major Equipment, Minor Equipment, Transformers & Regulators, and Non-Electrical Equipment) (Pfeuffer, 4T 253).[53]

ii. The Company's Projected DO Capital Expenditures

DTE Electric's Initial Brief, pp 53-60, explained and supported the Company's projected DO capital expenditures, including a discussion of DTE Electric's final 2021 Distribution Grid Plan (DGP; Exhibit A-23, Schedule M1), the Company's Global Prioritization Model (GPM, which is a benefit-cost analysis (BCA)), and the three key objectives that the Company is pursuing on behalf of its customers: (1) safety; (2) improving reliability; and (3) avoiding emergent costs. DTE Electric's planned Strategic Capital investments are focused in three areas: (1) Infrastructure

[52] Partly in response to the greater than projected spending in Emergent Replacements, there was a reduction in spending for Strategic Capital programs. The COVID-19 pandemic also had a significant impact on the Company's ability to perform strategic work in 2020, and the delay in filing this case (Crozier, 7 T 2348) makes a comparison to forecasted 2020 investments from Case No. U-20561 less relevant or useful than it might be under ordinary circumstances (Pfeuffer, 4T 243-245).

[53] Table 7 (at Pfeuffer, 4T 254-255) provides the details of each category. Table 8 (at Pfeuffer, 4T 255-256) shows 2020 Emergent capital expenditures by investment category. Expenditures in Storm and Non-Storm Emergent are incurred to support field activities under eight work types (Critical Infrastructure Customer, Emergency Job, Hazards, Multiple Customer Outage, Police/Fire, Public Safety Concern, Single Customer Outage, and Single Customer Problem) (Pfeuffer, 4T 256). Table 9 (Pfeuffer, at 4T 256-257) provides examples for each category.

Resilience & Hardening,[54] (2) Infrastructure Redesign and Modernization,[55] and (3) Technology and Automation.[56]

Staff's Initial Brief, pp 28-34, proposes a $91,768,000 disallowance ($39.854 million in the bridge period; $51.914 million in the test year) in infrastructure resilience and hardening capital expenditures, which is a calculated (and rounded up) "average percent underspend in the infrastructure resilience and hardening subprogram each year from 2020 and 2021" (*Id*, p 29). The AG's reference to this issue borders on the indiscernible and does not improve by misconstruing the Company's rebuttal (AG Initial Brief, pp 48-49). The Company objects to the AG's approach (as discussed above in the Introduction) and incorporates its response to Mr. Coppola at DTE Electric Initial Brief, pp 56-58.

In its Initial Brief, the Company explained that it fundamentally disagrees with the "average of percentages" methodology that Staff uses because it is prone to inaccuracy and gives an outsized effect to small projects.[57] Rather, if an average percentage is to be used at all, it should be a weighted average, which is a far more accurate methodology. The Company has provided an illustrative example, Exhibit A-41 Schedule FF1 of how averaging percentages can lead to vastly different results when comparing the same dollar values and can state an overinvestment when an

[54] These projects and programs focus on hardening the system, addressing frequent outage circuits, and replacing aging infrastructure. Exhibit A-12, Schedule B5.4, page 8 provides details, with additional details at Exhibit A-23, Schedule M4 (Pfeuffer, 4T 277, 289).

[55] This area focuses on major projects that generally involve the construction of substations and the rebuilding of large portions of circuits. Exhibit A-12, Schedule B5.4, pages 9-10 provide details, with additional details at Exhibit A-23, Schedule M5 (Pfeuffer, 4T 277, 313).

[56] These projects and programs are tightly linked to the grid modernization process and include investments that develop capabilities in observability, analytics and computing, controls, and communications. They meet current grid need and provide immediate benefits to customers, lay the foundation for grid modernization, and will support increased adoption of DERs and EVs. Exhibit A-12, Schedule B5.4, page 11 provides details, with additional details at Exhibit A-23, Schedule M6 (Pfeuffer, 4T 277, 347-348).

[57] Reif, Roberto "Why you should be careful when averaging percentages" accessed 8/15/22 at https://www.robertoreif.com/blog/2018/1/7/why-you-should-be-careful-when-averaging-percentages.

underinvestment actually occurred. In the example the Company shows how investing $910 million against a forecast of $1,100 across two years can provide an under-investment of 50% in one case and an over-investment of 40% in the other case, with the same total true investment of $910/$1,100=83% in both cases. (Pfeuffer, 4T 407-409).

Staff's Initial Brief, pp 31-32, recounts the Company's reasons for opposing the calculated disallowances, but offers no substantive response. Instead, Staff asserts that "[g]iven the consistent underspend, it is difficult to trust the Company will spend at projected levels for 2022 and 2023 especially considering the level of increase compared to 2021 spend" (*Id*, p 32). The Company maintains that it properly supported its projected expenditures with evidence.

Staff's Initial Brief, p 33, further asserts that "[t]he pandemic did not cause statewide shutdowns for significantly long periods of time in 2020 and the risk of severe storms causing a high volume of statewide outages is still a real risk that exists in 2022 and beyond, making 2020 and 2021 reliable measures." Staff's reasoning is overstated at best, since pandemic shutdowns and 2021 storms are major, well-known events that are further reflected on the record as indicated above. And while the Staff finds that statewide shutdowns were not for "significantly long periods" a loss of ability to do strategic work for more than a month is certainly significant. Moreover, Staff's newly-asserted reasoning is inconsistent with Staff's opposition to the Company's use of a three-year average for emergent replacements. It is inconsistent for Staff to assert that 2020 and 2021 are "reliable measures" in one context, but almost in the same breath assert that they are not reliable measures in another context, both in support of a resulting proposed disallowance. Company witness Pfeuffer explained the Company's consistent and appropriately cautious approach to dealing with the COVID-19 pandemic:

> As the COVID-19 pandemic impacted Michigan, the Company took immediate action to protect the health and wellbeing of its employees. Due to the limited knowledge regarding the impacts of the virus, the Company sequestered its employees doing critical job roles and used a home reserve program for all other field employees from mid-March 2020 to early May 2020. During this time, only emergent and system critical work was performed to ensure reliability. Because only emergent and system critical work was performed, all strategic work was paused. This action protected our employee's health but resulted in lost labor hours and not completing as much strategic work compared to the original plan. [4T 245.]

ABATE's Initial Brief, pp 51-52, proposes that the Commission limit additions to rate base attributable to Strategic Capital programs to those that will be "used and useful" by the end of the projected test year. The Company incorporates its arguments made more fully at pages 58-60 of its Initial Brief. The Company disagrees with ABATE because project costs can be included in rate base if they are deemed reasonable and prudent, regardless of whether they will be in service in the projected test year.[58] The capital expended on these multi-year projects receive a different accounting treatment (construction work in progress, or CWIP) under Commission orders going back to 1976.[59] Accordingly, ABATE's proposal should be rejected as contrary to decades of Michigan utility ratemaking and accounting treatment. Project completion dates are often based on the final steps of a project, and customers receive the benefits of the work done before these final

[58] The Court of Appeals rejected ABATE's contention that the Commission has no authority to apply anything other than the "used and useful" test in setting rates. *ABATE v Public Service Comm*, 208 Mich App 248, 258-59; 527 NW2d 533 (1994). The Commission is not bound to apply any particular formula or use any specific method in setting rates. *Id*; *Detroit Edison Co v Public Service Comm*, 127 Mich App 499, 524; 342 NW2d 273 (1983); *Residential Ratepayer Consortium v Public Service Comm*, 239 Mich App 1, 6; 607 NW2d 391 (1999).

[59] Company witness Uzenski explained that CWIP is forecasted, in part, based on the expected in-service date for large projects, when they are reclassified from CWIP to Plant in Service. Generally, these projects include Allowance for Funds Used During Construction (AFUDC), which is credited on the income statement, reducing the revenue deficiency, and offsetting the impact of the assets in rate base. AFUDC is applied to projects greater than $50,000 and lasting more than six months, with some exceptions for environmental and other specifically ordered projects. For example, in Case No. U-5281, the Commission required that pollution control related to CWIP should not accrue AFUDC but instead be included in rate base (March 14, 1980 Order in Case No. U-5281, pp. 114-117, 127).

steps (*e.g.*, improved reliability where the final step is to decommission an old substation) (Pfeuffer, 4T 415-416; Uzenski, 7T 2391, 2743).[60]

ABATE's proposal should also be rejected because it is based on the subjective proposition that the "Company has not provided adequate information to justify recovering the capital expenditures described above" (ABATE Initial Brief, p 52). To the contrary, the Company's DO witnesses provided over 500 pages of testimony, over 1,281 pages of exhibits, and responded to nearly 2,000 audit and discovery questions in this case providing details regarding each of these programs including in-service dates (Crozier, 7T 2392).

iii. Specific Strategic Capital Investment Programs

DTE Electric's Initial Brief, pp 60-94, discussed specific programs grouped within investment pillars.

a. Infrastructure resilience & hardening pillar.

DTE Electric's Initial Brief, p 61, explained that the Company projects capital investments associated with Infrastructure Resilience & Hardening projects of $455.5 million for 22 months ending October 31, 2022, and $346.1 million for 12 months ending October 31, 2023 (Pfeuffer, 4T 289; Exhibit A-12, Schedule B5.4, page 8; Exhibit A-23, Schedule M4).

Supporting our and our customers' goals of a more reliable, weather-resilient grid, the Company plans to invest in 28 different programs in this category. Four warrant particular discussion: (1) 4.8 kV Hardening, (2) Pole and Pole Top Hardware (Pole Top Maintenance and

[60] Many of these multi-year projects include components that will be used and useful during the test year. For example, "when the Company performs conversion work, the circuits are converted over multiple years and the final step is to decommission the old substation." (Pfeuffer, 4T 416) The CODI: Garfield Network Upgrade is a perfect example; while the old substation will not be decommissioned until after 2025, cutover of circuits will take place over the next several years. Witness Pfeuffer explained that "Customers will benefit from reduced trouble events, wire downs, and improved reliability from the construction and cutover work on the circuits, long before the Garfield substation is decommissioned, and the project is finally closed out." (Pfeuffer, 4T 415-416).

Modernization, or PTMM), (3) Cable Replacement, and (4) Underground Residential Distribution (URD) Replacement, as discussed previously and below.

1. 4.8 kV Hardening.

DTE Electric's Initial Brief, pp 61-64, discussed the purpose, history (including approvals in Case Nos. U-20162 and U-20561), success, and continuing appropriateness of this program, which was developed as a cost-effective way of providing improvements in safety and reliability at a faster pace than simply converting the entire 4.8 kV system in the city of Detroit.[61] It is also important to recall that 4.8 kV Hardening includes the removal of extremely hazardous legacy arc wire, left in place by the Detroit Public Lighting Department (DPLD).

The Company has successfully hardened over 600 line-miles and expects to harden close to 1,600 miles over the next five years. This is appropriate because the program has proven very effective in improving the safety and reliability of one of the oldest parts of the Company's electrical grid (Pfeuffer, 4T 293-297, 426). Moreover, the 4.8 kV hardening will deliver safety and reliability improvements faster than 13.2 kV conversion alone could (Pfeuffer, 4T 295).

MNSC's Initial Brief, pp 33-52, presents a variety of arguments that boil down to the proposition that the Commission should adopt witness Ozar's suggestion to maintain the same level of annual spending as in 2021 (8T 3984). The Company disagrees. The discussion at DTE Electric's Initial Brief, pp 61-63, largely addressed Mr. Ozar's indicated misperceptions. He also suggested that "an effective tree trimming program targeting the worst-performing 4.8kV lines would achieve significant reliability improvements, at a lower cost to ratepayers" (Ozar, 8T 3978). The Company

[61] Primary components of the 4.8kV Hardening program include replacing or reinforcing poles as necessary, replacing wooden cross-arms with fiberglass cross-arms, removing Detroit Public Lighting Department (DPLD) arc wire (consistent with the Commission's Order in Case No. U-18484) and DPLD distribution wire from DTE Electric-owned equipment, removing service lines to abandoned properties, and trimming trees to support construction activities (Pfeuffer, 4T 291, 423-424).

disagrees because tree trimming alone will not remove the DPLD-owned arc wire or address the aged pole and pole top equipment in Detroit circuits.

Mr. Ozar also incorrectly assumed that the 4.8kV Hardening program only targets the worst-performing substation areas in Detroit. Instead, as discussed previously, the prioritization methodology targets safety (wire downs and foot traffic) (Pfeuffer, 4T 292, 427). The Company also cannot just remove arc wire without other pole top work because that would leave cross arms dangerously unbalanced. When line workers remove arc wire, they must also rebalance and properly support the remaining wires. The 4.8kV Hardening program is fully developed, well supported in past cases, efficient, and providing immediate safety and reliability benefits for 4.8kV customers in Detroit. Therefore, MNSC's proposal to cap the 4.8kV Hardening program at the 2021 investment level should be rejected (Pfeuffer, 4T 423-428).

MNSC's briefing adds additional layers of complexity and contentiousness, but ultimately makes no meritorious point. For example, regardless of the nuances of arc wire, the Commission has indicated its expectation that DTE Electric remove the old DPLD arc wire,[62] and the Company is doing just that, expeditiously and safely. MNSC's similar attempts to dissect the 4.8kV Hardening program and attempt to raise doubts about individual parts (or suggest that the parts should be pursued individually instead of coordinated in the program) neglects that the program is a well-designed and approved multi-part program that has achieved success and continues to be appropriate, as discussed previously.

DAAO's Initial Brief, pp 11-33, takes a different approach to assessing the 4.8kV Hardening program. Instead of attempting to restrict it as MNSC suggests, DAAO proposes to abandon it in favor of 13kV conversion, ultimately acknowledging that the "capital cost of conversion is

[6262] MPSC Case No. U-18484, December 7, 2017 Order, p 5; March 15, 2018 Order, p 6.

daunting, to be sure" (*Id*, p 33). DAAO member Soulardarity essentially made the same argument in Case Nos. U-20162 and U-20561. The Commission previously agreed with the ALJ, who "agreed with DTE Electric that the 4.8 kV hardening proposal is economically efficient" and that a "more complete conversion of the system to 13.2 kV would be expensive and provide limited incremental benefit" in the short term (May 2, 2019 Order in Case No. U-20162, pp 31, 33). Conversion will take many years; 4.8kV hardening provides many of the safety and reliability benefits of conversion much more quickly. In the Company's last general rate case, the Commission stated that it "concurs with the ALJ that Soulardarity's concerns were largely addressed in Case No. U-20162" (May 8, 2020 Order in Case No. U-20561, p 110).

Therefore, rather than re-argue Soulardarity's redundant issues, the Company relies on the Commission's past decisions,[63] as well as the additional record evidence on the 4.8kV Hardening program discussed in DTE Electric's Initial Brief and above. Ms. Pfeuffer also provided a broad discussion of Energy Justice (Pfeuffer, 4T 505-21), including corrections to various apparent misperceptions regarding the 4.8kV system (reflected for example at DAAO Initial Brief, pp 17-19), explaining for example that most areas of the system have sufficient capacity to incorporate some EVs and DERs, and that hardening does not in itself delay the conversion to 13.2kV (Pfeuffer, 4T 508-509, 119). Also, while approximately 14% of the Company's customers are located in the City of Detroit, the Company is investing approximately 29% of its 2021-2023 Strategic Capital in the City of Detroit to address aging infrastructure and improve safety and reliability, and these significant investments will continue in future years (Pfeuffer, 4T 298-299).

[63] Issues fully decided in earlier MPSC proceedings need not be relitigated in later proceedings unless a party presents new evidence or shows by changed circumstances that the earlier result is unreasonable. *Application of Consumers Energy Co*, 291 Mich App 106, 122; 804 NW2d 574 (2010); *Pennwalt Corp v Public Service Comm*, 166 Mich App 1, 420 NW2d 156 (1988).

Therefore, the Company maintains that the 4.8kV Hardening program is appropriate, fully supported by data-driven results, and should be approved as proposed.

2. Pole and Pole Top Maintenance and Modernization (PTMM).

DTE Electric's Initial Brief, pp 64-66, explained that it will increase the numbers of inspections conducted under this program, which proactively identifies and replaces damaged or defective pole and pole top equipment before unexpected failures occur (Pfeuffer, 4T 301-302).[64]

MNSC's Initial Brief, pp 53-59, reflects that its witness Ozar proposed to cap the Pole/PTMM program at the 2021 investment level (disallowances of approximately $15.7 million for the 10 months ending October 31, 2022; $54.3 million for the test year), indicating disagreements with the Company's reasons for increasing investments (8T 3989-3997). The Company maintains that its reasons are valid and fully support its proposed level of funding, as indicated in DTE Electric's Initial Brief and further discussed below.

First, the Company has a goal of achieving a 10-year inspection cycle using only the Pole/PTMM program because (1) inspections under the Pole/PTMM program are now performed to an updated, more robust standard; (2) benchmarking showed that a 10-year inspection cycle (or less) was industry best practice; and (3) the Pole/PTMM program will efficiently meet the Staff's 10- to 12-year cycle recommendation (Pfeuffer, 4T 430).

Second, the Company changed its pole inspection process to specify pole testing (instead of visual inspection alone) for poles 20 years or older. Thus, more poles are now inspected for below-

[64] The Company inspects poles on a 10- to 12-year cycle. Results from these patrols have typically shown that approximately 8% of the total poles inspected have reduced strength and need remediation (Pfeuffer, 4T 302). The Company is increasing its investments in this area due to enhancements made to the program specifications based on benchmarking and learnings from other key programs. The enhanced pole inspection specification and process align with industry best practices and will reduce the risk of pole failures, improve customer reliability, and reduce reactive costs during trouble or storm events. Customers will benefit because overhead-equipment related outages account for almost 25% of all events. As a result of the planned improvements to the Pole/PTMM program, the Company expects a reduction in equipment-related outage events, which will drive reliability improvements, reduce reactive costs, and improve safety by reducing downed wires (Pfeuffer, 4T 303, 124-125).

grade decay that is not visible in above ground visual inspections. This results in the identification of more poles requiring replacement or remediation, and a corresponding increase in capital to replace or reinforce these poles (Pfeuffer, 4T 431).

Third, a change in pole specifications has increased the strength of new poles by a factor of more than 2.5. Only about 12% of the Company's current poles are higher-class poles called for in the updated specification. Customers will receive safety and reliability benefits from stronger poles that are more resilient to storms and wind (Pfeuffer, 4T 251, 432).

MNSC responds by attempting to undermine each point in the Company's support for its PTMM program investment, but its arguments lack merit particularly when viewed collectively. First, MNSC suggests that a shorter inspection cycle does not justify spending increases because it should be an "even shorter" 5-year inspection cycle (MNSC Initial Brief, p 54). But MNSC neglects the Company's additional evidence, including additional testing and increased pole specifications. Second, MNSC suggests that the new inspection standard does not justify increased costs, since it will result in more remediation, which "should lead to avoided replacements" (MNSC's Initial Brief, p 55). In addition to being speculative, MNSC neglects the present cost of additional remediation. Third, MNSC does not dispute the higher pole specifications, but instead suggests that "there is no demonstration that poles are failing and requiring replacement at a higher rate than historically" (MNSC Initial Brief, p 57). But MNSC neglects that, as the Company said when introducing this topic, the program proactively identifies and replaces damaged or defective equipment before *unexpected failures occur* (Pfeuffer, 4T 301). Nearly 30% of the Company's poles are now more than 60 years old, with an industry life expectancy of 40-60 years (Exhibit A-23, Schedule M1, DGP p. 176). The Company disagrees with MNSC to the extent they suggest that the Company should wait for pole failures before acting. Failing poles put customers and linemen

at risk when they break; discovery of below grade decay (and subsequent replacement) prevents poles from failing (Pfeuffer, 4T 256, 301, 305). There is simply no merit in MNSC's overall theme that the Company is being overly "proactive" (*e.g.*, MNSC Initial Brief, pp 31, 58).[65]

Therefore, and as further discussed on the record, MNSC's proposed investment cap should be rejected, and the Pole/PTMM program should be fully funded.

Staff's Initial Brief, pp 276-79, reflects that its witness (Becker 8T 5412-5413) and MNSC witness Ozar (*e.g.*, 8T 3968, 3999-4016) questioned whether certain items relating to the 4.8kV Hardening and PTMM programs should be recorded to expense instead of capital. Company witness Uzenski explained that the Company's capitalization policies are appropriate under the USOA and otherwise reasonable and based on actual work performed. The Company also agrees to file reports explaining/documenting the capitalization policies relating to inspection costs questioned by Staff and MNSC (Uzenski, 7T 2775, 2790-2792). Thus, there is no need for Staff's suggestion that the Commission should order the Company, Staff and potentially other stakeholders to meet, or the Company to provide additional information, regarding capitalization policy.

3. Cable Replacement.

There appears to be no dispute about the merits of this program, which prioritizes and replaces system cable based on multiple factors including cable type, vintage, failure history, system impacts, and cable loading.[66]

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[65] In addition to the prior discussion, and in response to MNSC's inaccurate suggestion that the Company changed its emergent replacement policy to require replacements rather than perform lower-cost repairs (Ozar, 8T 3962-3963), Ms. Pfeuffer further explained that the Company has placed a greater emphasis on replacing outdated equipment rather than repairing it but does not require replacement. The decision to repair or replace is often made in the field by line workers, depending on factors including the amount and type of damage, and field conditions that affect the difficulty of a repair or replacement during storm or emergent conditions (Pfeuffer, 4T 250-251, 498).

[66] There are approximately 3,100 miles of underground system cable on the Company's distribution and subtransmission systems. The Company is ramping up its cable replacement efforts, which will benefit customers through reduced risk of lengthy outages, improved reliability, and lower reactive costs (Pfeuffer, 4T 305-310).

4. Underground Residential Distribution (URD) Replacement.

There appears to be no dispute about the merits of this program, which prioritizes and replaces URD cable based on multiple factors including vintage, number of failures, and number of customers affected by those failures.[67]

b. Infrastructure redesign and modernization.

DTE Electric's Initial Brief, pp 66-67, explained that the Company projects capital investments associated with these projects of $307.5 million for 22 months ending October 31, 2022, and $314.3 million for 12 months ending October 31, 2023 (Pfeuffer, 4T 313; Exhibit A-12 Schedule B5.4, page 9, line 89, columns (f) and (g); Exhibit A-23, Schedule M5). Significant programs include Subtransmission Redesign & Rebuild, City of Detroit Infrastructure (CODI), 4.8kV Conversion, Strategic Undergrounding Pilots, System Loading, and 8.3kV Pontiac Conversion, as discussed below.

Staff's Initial Brief, pp 37-40, proposes a 40% disallowance ($70.958 million in the bridge period; $86.034 million in the test year) based on underinvestment in 2020 and 2021 compared to the forecast from Case No. U-20561, similar to Staff's proposed percent disallowance for Infrastructure Resilience and Hardening (discussed at the beginning of section V. B. 4). The Company disagrees because the Company fully supported the reasonableness and prudence of the projects, and Staff did not contend that any of the projects are not reasonable or prudent, or that

[67] There are approximately 11,000 miles of URD cable on the system, with approximately 2,800 miles (25%) being pre-1985 (non-tree-retardant). "Treeing" refers to the tree-like pattern of insulation breakdown. The breakdown typically originates at an impurity or defect in the solid insulation and grows gradually over time to resemble the branches of a tree, ultimately leading to a cable failure (Pfeuffer, 4T 310). The Company has successfully ramped up its underground replacement program in recent years and is confident that it will be able to execute the URD Replacement program presented in this case (21 miles in 2021; 28 miles in 2022; and 45 miles in 2023). Customers will benefit from improved reliability because the program will reduce the number and length of customer interruptions due to URD cable failures. Fewer URD cable failures will also result in a reduction in reactive costs (Pfeuffer, 4T 310-313).

they will not provide customer benefits. Staff simply relied on a methodology that is flawed for four reasons discussed above (in summary: (1) historic spending should not be used to forecast future strategic capital need; (2) the "average of percentages" methodology is flawed; (3) 2020 and 2021 had unique circumstances, and (4) the Company has instituted changes that will improve its planning and project execution) (Pfeuffer, 4T 433-434).[68]

Staff does not offer any specific response, but instead "responds to these arguments in the way it responded to the Company's arguments regarding structure [sic] resilience and hardening capital expenditures" (Staff Initial Brief, p 40). Accordingly, the Company incorporates its prior discussion in section V. B. 4, and the discussion in its Initial Brief at pages 55-56.

1. Subtransmission Redesign & Rebuild.

DTE Electric's Initial Brief, p 67, explained that the Company's Subtransmission system is operated at a mid-level voltage of 24 kV, 40 kV, or 120 kV, and is used to step down transmission voltage to serve distribution and industrial substations. The Subtransmission Redesign & Rebuild program focuses on installing new station equipment and rebuilding both the overhead and underground portions of the subtransmission system. The program is needed to increase capacity for loads from existing and new customers, support DER interconnections, and improve reliability due to aging equipment. Benefits include safety improvements, improved reliability and operability, and increased capacity (Pfeuffer, 4T 315-323).

While they don't make any specific arguments against the overall subtransmission redesign and rebuild program at a high level, Staff's Initial Brief, pp 34-36, proposes a complete ($2.917 million in the test year) disallowance for one part of the program, Small Projects & Reserve (Exhibit

[68] If an average method is adopted (which it should not be), then it should be based on the Company's analysis, which in this category would result in disallowances slightly less than Staff suggests (Pfeuffer, 4T 434; Exhibit A-41, Schedule FF4).

A-12, Schedule B5.4, page 9, line 36), characterizing it as "premature and unsupported" (*Id*, p 35). The Company disagrees because it has identified and supported actual projects that are needed to support grid reliability for 2023, as stated in response to discovery (Exhibit A-41, Schedule FF5) and Exhibit A-23, Schedule M5, pages 140-43 (Pfeuffer, 4T 435-436).

Staff's Initial Brief, p 36, responds that "[a]lthough there are actual projects, they continue to be inconsistent," reasoning Exhibit A-23, Schedule M5 refers to four projects, but STDE-25.16, Exhibit A-41, Schedule FF5 refers to six projects. Staff neglects Ms. Pfeuffer's testimony that "STDE-25.16, Exhibit A-41 Schedule FF5, was the final and correct response that meant to correct the record" (4T 436). Therefore, the projects are supported, and their costs should be approved.

2. CODI.

There appears to be no dispute about this program, which is needed to address the significant portions of the electrical infrastructure in the downtown area of the City of Detroit including hospitals, stadiums, and universities, which were placed in service in the early part of the 20th century.[69]

3. 4.8 kV Conversion.

There appears to be no dispute about this program, which is aimed at upgrading the aged 4.8 kV system to higher grid voltage and other higher standards by building new substations and upgrading the associated circuits to add capacity to serve growing load, and to address deteriorating reliability performance due to aging electrical infrastructure.[70]

[69] Development in the City of Detroit is stressing this aging infrastructure, and the Company cannot serve new customer load with existing capacity. The Company is focusing on ten CODI projects between 2021 and 2023, as shown on Table 15 of Ms. Pfeuffer's direct testimony (Pfeuffer, 4T 324-327. See Exhibit A-23, Schedule M5 for more detail).

[70] This will be a significant investment that the Company expects to occur over several decades (Pfeuffer, 4T 328-332). The investments presented in this case reflect investments that address current loading constraints on the system (Pfeuffer, 4T 331; See Exhibit A-23, Schedule M5 for details). Ms. Pfeuffer provided additional details on two

4. Strategic Undergrounding Pilots.

DTE Electric's Initial Brief, pp 69-72, explained and supported the Company's strategic undergrounding pilots, which seek to understand the viability of undergrounding in a number of different technical scenarios to address grid resiliency challenges.[71] In addition to completing the currently ongoing Appoline DC 1346 pilot, the Company is developing a balanced set of pilots with two approaches to undergrounding: (1) Replacing overhead services with underground services; this pilot will begin in 2022 (see Exhibit A-12, Schedule B5.4.2 for details), and (2) replacing both overhead laterals and services with URD.[72]

Staff's Initial Brief, pp 41-45, proposes disallowances ($15,100,000 (of $17,248,000) for the ten months ending October 31, 2022; and the entire $36,783,000 for the test year) "primarily because the Company is proposing to begin multiple new undergrounding pilots without having

representative projects for a deeper understanding of the drivers, scope, and benefits of 4.8kV conversion: (2) Buckler Circuit Conversion (4T 332-333), and (2) Lapeer – Elba Expansion and Circuit Conversion (Apollo) (4T 333-334). The Company also operates some circuits at 4.8kV that are fed from a 13.2 kV substation, which are known as isolation down areas (ISO down). The portion of the program for converting ISO down areas is aimed at upgrading portions of the circuits to a higher voltage, thus adding capacity to serve existing load, and to address deteriorating reliability performance due to aging electrical infrastructure. The ISO Down portion of the project may span multiple decades due to the extensive scope of work, but in this case the Company is targeting two ISO Down locations for conversion: Camden substation, and Gilbert Substation (Pfeuffer, 4T 334-336; See Exhibit A-23, Schedule M5, pp 264-271 for details).

[71] The Company received feedback from customers and the Commission following 2021's historic storm season to determine whether undergrounding might provide a solution to alleviate weather-related outages. In addition, and as explained more fully in the Company's DGP (Exhibit A23, Schedule M1), one of the planning scenarios contemplates the anticipated long-term effects of climate change (increasing temperatures and frequency of catastrophic storms) on the distribution grid. One option for addressing this scenario is undergrounding to improve reliability as compared to overhead construction. The pilots seek to test whether undergrounding is a viable solution to current weather-related outage frequency, and a potential solution in the event of even greater increases in catastrophic storm frequency in the future, since underground infrastructure is less susceptible to surface conditions than overhead. On the other hand, underground construction cost is higher, undergrounding does not completely eliminate the potential for outages, and outages in underground systems might take longer and be more costly to locate and repair. Thus, the Company must thoughtfully implement Strategic Undergrounding to balance the benefits with the challenges. Pilots will help develop and refine analysis of overall life cycle costs and criteria for Strategic Undergrounding (Pfeuffer, 4T 336-340).

[72] For this second pilot, the Company plans to relocate rear-lot overhead assets to front-lot URD on a portion of a Fairmount circuit in Detroit (Pfeuffer, 4T 341-343). Replacing laterals has the additional benefits of preventing overhead primary wires down and preparing for eventual conversions to higher voltages for the areas. Focusing on both lateral and service pilots provides a balanced approach that will provide information that is necessary to identify the most benefits for customers while also considering the cost of the work (Pfeuffer, 4T 343-344).

completed an ongoing undergrounding pilot on Appoline DC 1346 in Detroit …capital expenditures for new undergrounding pilots should not be put into rates until the Appoline DC 1346 pilot is completed, and the results known and analyzed" (*Id*, p 41). The Company disagrees because the Appoline DC 1346 pilot is essentially complete, and the Company has gained key learnings that it is using for the new Strategic Undergrounding pilots (Pfeuffer, 4T 339, 438-440, 449).

The AG's Initial Brief, p 50, reflects that her witness Coppola proposed a complete disallowance ($17.3 million in the bridge period; $36.8 million in the projected test year) in the alternative to his recommended reduction in overall capital spending for strategic capital. In addition to the discussion above, the Company disagrees with the three reasons that Mr. Coppola suggested for his proposal. First, he suggested that the same process used on the Appoline pilot will be repeated on the proposed pilots. To the contrary, there is a major difference in scope and approach between assets being relocated from rear-lot overhead to rear-lot underground (Appoline pilot) versus rear-lot overhead to front-lot underground (Fairmount DC1593 pilot) (Pfeuffer, 4T 444; Exhibit A-23, Schedule M1, pp 344, 350). Another significant difference is a greater level of effort and proactiveness for customer engagement that will support the efficiency and success of the proposed pilots (Pfeuffer, 4T 444-445, 447; Exhibit A-23, Schedule M1, p 346). Finally, the pilot for undergrounding services[73] differs from the previous pilot because it is focused strictly on undergrounding customer service feeds, a key driver to improving reduced outage duration for single customer outages (Pfeuffer, 4T 445; Exhibit A-23, Schedule M1, pp 349-51).

Mr. Coppola further suggested that DTE Electric has not considered what other utilities have done, and not identified new lessons to be learned (8T 4763). To the contrary, the Company has learned from continued benchmarking as well as the Appoline pilot to test more cost-effective

[73] "Services" refers to individual service drops that connect a single customer location to a nearby distribution line.

methods and customer-engagement approaches, which will enable further learnings regarding scalability and cost efficiency. The Company is also interested in assessing the improvement potential that undergrounding services has on overall storm restoration times. Finally, if the results of the services pilot show that it is cost effective and results in enhanced reliability for customers, then the pilots might be expanded, or be suitable for widespread adoption (Pfeuffer, 4T 342, 445-447, 349; Exhibit A-23, Schedule M1, pp 346, 349, 356).

The AG's Initial Brief, pp 50-51, responds by suggesting that the additional learnings are "basic, unhelpful, and do not require a pilot project to determine the impact on the cost of such a project." Instead, the AG inaccurately describes the record and misconstrues a discovery response (Exhibit AG-1.64, pp 3-5), which actually provides *more* support for the Company's position.

Staff further reasons that "[u]ndergrounding is far more expensive than building overhead lines: (Staff Initial Brief, p 43), and its witness suggested that the potential for undergrounding being a cost-effective solution for DTE Electric's service territory is likely quite limited" (Evans, 8T 5431). The Company disagrees that the potential for undergrounding is this "limited." While the Company's initial foray into undergrounding shows higher costs, the Company can obtain cost advantages of larger scale by increasing the volume of its Strategic Undergrounding work. There are also safety and reliability considerations beyond cost (Pfeuffer, 4T 343, 440-443).

Staff responds by "point[ing] out that even if DTE Electric were to reduce undergrounding costs by 30%, these savings would be small compared to the difference in cost between installing overhead lines and burying existing overhead lines" (Staff Initial Brief, p 44). Staff neglects to acknowledge that cost is not the only relevant factor. There are also safety and reliability considerations, as indicated above, and undergrounding is worth pursuing in addition to the Company's other efforts (for example, the 4.8kV Hardening program, discussed above).

Local 223, the workforce that helps to address customer outages today and which will be involved with rebuilding parts of the grid underground in the future, agrees with the Company and supports the undergrounding pilots, explaining in part:

> [T]he Union submits that undergrounding will also protect the lives and safety of the public and utility workers . . .
>
> The benefits of undergrounding warrant further exploration. This can be accomplished through the Company's pilots. Undergrounding programs must be further developed to safeguard the safety and welfare of the public and the Company's workforce. [Local 223 Initial Brief, pp 1-2.]

The discussion above also essentially applies to MNSC's Initial Brief, pp 141-44, which reflects its witness Ozar's proposal for a complete disallowance of Strategic Undergrounding pilots (4T 448-449). He further proposed that the Commission approve up to $1 million to support assessments of lifecycle costs of underground and overhead systems (Ozar, 8T 4016). The Company agrees that lifecycle cost analysis is important, but it is important to keep in mind that this lifecycle work can only be informative when supported by the actual experience that the Company will gain from the Strategic Undergrounding pilots (Pfeuffer, 4T 449).

In summary, the Commission has expressed its interest in improving reliability in Detroit and other parts of the Company's service territory, and we continue to hear customer questions and strong feedback supporting the undergrounding of parts of the distribution grid. Moreover, in its August 25, 2021 Order in MPSC Case No. U-21122, at page 10, the Commission specifically asked utilities to consider undergrounding, asking "Are there potential utility pilots or industry best practices that can improve customer safety and reliability by moving overhead lines on specific circuits or in segments of the electric distribution system underground at reasonable costs?" The pilots proposed here will allow the Company to fully answer the Commission's inquiry. Understanding the potential for Strategic Undergrounding is an important part of the Company's

plan to achieve its reliability goals. In the pilots, the Company expects to reduce the cost by increasing the volume of work and utilizing the lessons learned from the Appoline pilot and benchmarking, allowing strategic undergrounding to become another important reliability tool. Therefore, the Commission should fully approve the requested funding (Pfeuffer, 4T 450).

5. System Loading.

There appears to be no dispute about these projects.[74]

6. 8.3kV Pontiac Conversion.

There appears to be no dispute about this program, which concerns the 8.3kV system that serves the city of Pontiac.[75]

c. Technology & Automation.

DTE Electric's Initial Brief, pp 73-77, explained that Technology & Automation projects and programs are tightly linked to the grid modernization process, and include investments that develop capabilities in observability, analytics and computing, controls, and communications. They meet current grid needs and provide immediate benefits to customers. They also lay the foundation for grid modernization and will support increased adoption of DERs and EVs. Exhibit A-12, Schedule B5.4, page 11 provides details, with additional details at Exhibit A-23, Schedule M6 (Pfeuffer, 4T 277, 347-348, 451). Significant investments include Grid Automation

[74] These projects add capacity to the distribution system, and typically include construction of new substations, expansion of current substations by installing additional transformers or replacing existing transformers, installing new switchgear lineups, creating new distribution circuits, reconductoring circuits, converting circuits to 13.2kV, and transferring load once additional capacity has been created. Many areas identified in the priority ranking for system load relief are addressed as part of CODI, 4.8kV Conversion, or 8.3kV Pontiac Conversion programs. Load relief needs that are not included in those programs are part of the System Loading projects category (Pfeuffer, 4T 344-345).

[75] The Company acquired the system from CMS Energy in the 1980's, and it is the only 8.3kV in the Company's distribution system. As an island surrounded by the 13.2kV system, there is a high risk for stranded load in the event of a substation outage. Plus, the 8.3kV system is aged, replacement parts are often unavailable due to obsolescence, and Pontiac has increased its load in recent years. Therefore, the Company has developed a plan to upgrade and convert the Pontiac system to 13.2KV as part of grid modernization, starting with upgrading the system vaults as outlined in previous rate cases and section 8.19 of the DGP (Pfeuffer, 4T 346-347).

Telecommunications, Distribution Automation, Conservation Voltage Reduction (CVR)/Volt-Var Optimization (VVO), and Non-Wire Alternatives (NWA), as discussed previously and below. Like DTE Electric's Initial Brief, the discussion first addresses generic proposed disallowances before moving on to the specific investments.

Staff's Initial Brief, pp 80-81, proposes a generic 20% disallowance across eleven projects (disallowances of $3.623 million in the bridge period; $4.258 million in the projected test year) by comparing them to a forecast of 2020 historical spending that Staff calculated. The Company previously explained that it disagrees for three primary reasons.

First, it was improper for the Staff to calculate a forecast for 2020, ignoring the forecast that the Company provided in Case No. U-20561 (Exhibit A-12, Schedule B5.4, page 9, column (d); Exhibit A-41, Schedule FF6). Staff also materially changed the forecast by "adding four months of the forecasted bridge period… and eight months of the projected test year" (Wang, 8T 5223). Staff's use of its own unique calculation method resulted in forecasted amounts different than those that the Company actually presented in Case No. U-20561 (Pfeuffer, 4T 455-457).

Second, Staff performed its analysis based on only a select number of projects in the Technology and Automation category. This category (excluding ESOC and ASOC because they include major building construction) should be viewed as a whole. Excluding approximately half of the projects in this category results in misleading analysis. The Company is particularly concerned that Staff did not consider four projects (reflected on the chart at 4T 457) with investments that exceeded their 2020 forecasts (Pfeuffer, 4T 457-458). Selecting only those projects with underspend, leads to misleading and inaccurate results.

Third, Staff's methodology (calculating a percentage of overinvestment/underinvestment per project, and then averaging the percentages to derive an overall percentage) is flawed as

discussed in section V. B. 4. If one were to use this type of analysis, however, then it should be correctly performed using all the projects/programs in the Technology and Automation category, excluding ESOC and ASOC. The Company did so, reflecting a "% Projected Cost Actually Spent" of 137% (Pfeuffer, 4T 458-459; Exhibit A-41, Schedule FF8).

Moreover, it is improper for Staff to use its own analysis selectively, applying it to investments when doing so would support proposed disallowances, but then not applying that same analysis to investments when doing so would not support a disallowance. For example, Staff calculated that the ADMS: Network Management System had a "% Projected Cost Actually Spent" of 133.8%, yet instead of applying that 133.8% factor, Staff proposed a 20% disallowance based on Staff's calculated average (Pfeuffer, 4T 460). Applying a disallowance, based on questioning the Company's ability to spend to forecast, to a category where the Company over-invested its forecast, lacks logical support.

In summary, Staff's analysis has numerous flaws, and it applied its analysis inconsistently across the projects analyzed. While the Company asserts that the Commission should not apply a disallowance based upon historical spending in 2020 (or 2021) on technology and automation capital investments, if it chooses to do so, the Commission should at least apply a complete analysis including all like projects in the category.[76] The Company's analysis, applying Staff's methodology to all applicable projects in the category, produces a "% Projected Cost Actually Spent" of 137%. This result highlights the flawed nature of using an average of percentages, as discussed more fully above. When comparing actual dollars spent to actual dollars forecast, the Company was able to invest 92% of its forecast even in the pandemic-impacted year analyzed.

[76] ESOC and ASOC are rightly excluded because, as major building construction projects, they are different in kind from all other technology and automation investments.

Therefore, the ALJ and the Commission should reject the Staff's proposed 20% disallowance (Pfeuffer, 4T 461).

Staff's Initial Brief, p 81, responds: "The Company's arguments in opposition to this position are incorrect and, therefore, should not be given much weight, if any." Staff does not offer any reasoning, let alone proof, to redeem its disproven position (see footnote 2). Therefore, Staff's proposed 20% disallowance should be rejected.

Staff also later acknowledges that the Company is correct on the first point summarized above, resulting in changes to Staff's recommendations:

> The Company is correct that Staff's calculated forecast amounts for 2020 led to different amounts than the Company's forecast. Staff, therefore, revises its recommended disallowances by using the Company's U-20561 projections and the new level percentage of projected cost that was actually spent. This results in the changes detailed in Table 1 below and a revised projected bridge period recommended capital disallowance of $14,695,000 and projected test year recommended capital disallowances of $9,980,801 across eight projects. [Staff's Initial Brief, pp 85-86. See also, p 87, reflecting that Staff's change is not included in its proposed revenue requirement.]

In her direct testimony witness Wang states:

> Of the projects examined, Staff finds an average of 73.3% of projected costs were actually spent. One project spent only 0.36% of the projected spend. Given that an average of 73.3% of projected costs were actually spent in 2020 for the projects analyzed by Staff, Staff finds a downward adjustment of 20% to be reasonable and prudent. [8T 5221.]

This statement contradicts the claim in Staff Initial Brief on page 87:

> Though Staff provided the average percent of projected funds that were unspent, this was provided for general understanding. For projects with recommended disallowances, Staff only recommends adjustments based on the percent of projected costs that was actually not spent in 2020 for that particular project.

Staff, as noted in testimony, relied on the analysis to propose disallowances as "reasonable and prudent" to several projects, including: ADMS: Network Management System, Distribution Sensing and Monitoring (including Line Sensors), SCADA/AMI Enhancements, DERMS, DER

Control, Mobile Technology, Substation Design Tool Upgrades, Microwave End of Life, SCADA Remote Access and Configuration Platform, Sensor, Network and Algorithm Development (Solar Deployment) and Substation Cybersecurity; as noted in Staff Exhibit S-7.42 (any line in Exhibit S-7.42 that has a line for 20% disallowance).

Additionally, it is unclear why Staff relied on 2020 data when the Company provided 2021 data in discovery and rebuttal for Technology and Automation. This is especially confounding where Staff did include 2021 information provided for Infrastructure Resilience and Hardening and Infrastructure Redesign and Modernization categories. In Staff's Initial Brief on page 86, Staff proposes new disallowances for ADMS: DMS/OMS, Distribution Automation, and Non-Wires Alternatives based solely on 2020 investments. When looking at ADMS: DMS/OMS, Distribution Automation, and Pilot: Non-Wires Alternatives in 2021 it becomes clear that in two of the programs, the Company actually overspent the 2021 forecast for these strategic programs – yet Staff still recommends a disallowance, for underspending in the previous year.

Projects ($000s)	U-20561 2021 Forecast Exhibit A-2 Sch B 5.4	2021 Actuals Exhibit A-41 Schedule FF9	% Projected Cost Actually Spent
ADMS: DMS/OMS	9,900	22,390	226%
Distribution Automation	10,000	111	1.11%
Pilot: Non-Wires Alternatives[77]	2,500	7,698	308%

Again, Staff does not look at every project in this category to determine the Company's overall ability to invest in Technology and Automation nor does Staff consider all available information including the most recent year's investments. The Company finds it perplexing that Staff would consider all available information for Infrastructure Resilience and Hardening and

[77] Non-Wires Alternative project list for 2021 includes: O'Shea Energy Storage, Omega Load Relief, Fisher Load Relief, Small Solar and Storage Testbed, and EV Charging Demonstration at ACM.

Infrastructure Redesign and Modernization, including reviewing all projects in each category together as a whole and including the most recent year investment profile; but in Technology and Automation, Staff appears to only utilize data that best supports its position. (Wang, 8T 5224; Pfeuffer, 4T 457-458).

Staff's Initial Brief, pp 81-83, also proposes disallowances ($6,927,699 in the bridge period; $3,698,781 in the projected test year) that represent a reduction in assumed "Other" costs to 5.17% of total project cost across 22 projects. The Company previously explained that it disagrees because it allocates many different overhead costs, on a project-specific basis, consistent with the USOA's requirements. The costs for overhead activities are collected into pools and allocated to the capital projects. For example, Facilities overhead costs (related to preventative maintenance, repairs, and improvements to facilities) are allocated to capital projects based on direct labor. Depending on the nature of the capital project, it could have more or less of the specific driver(s), for example, labor, leading to different amounts of overhead allocations (Exhibit A-43, Schedule HH6 provides a list of possible "other" overheads and a description of how they are allocated). Since other overheads can vary depending on the type of project and the direct costs charged to the project, Staff's proposed fixed rate has no sound basis and is unreasonable. Moreover, the Company provided actual incurred Other Costs information in discovery (Exhibit A-41, Schedule FF9), but Staff indicated that it did not review this discovery response (Exhibit A-41, Schedule FF10). Staff simply made an assumption and did not review other available information to verify (or in this case, disprove) that assumption. Therefore, Staff's proposal to reduce "Other" capital costs by a flat rate of 5.17% should be rejected as unfounded and disproven (Pfeuffer, 4T 461-63; Uzenski, 7T 2785-2786).

Staff, in its Initial Brief, responds:

> The Company's rebuttal position fails to incorporate Staff's actual recommendation. It is not that the Company should only have 5.17% of Other Costs for all projects. "Staff's recommendation is that, in the absence of information regarding how Other Costs are determined and differ for projects, only 5.17% of total project costs should be included in rates at this time for Other Costs." (Wang, 8 TR 5221-22.) Given the information provided by the Company, including in rebuttal, it is unclear how Other Costs are determined for specific projects. [Staff Initial Brief, pp 82-83.]

To the contrary, the Company squarely addressed Staff's recommendation, and demonstrated with evidence that it should be rejected, as discussed above and further explained on the record. It is similarly inaccurate for Staff to suggest that information is lacking where Staff did not review the readily available information (Pfeuffer, 4T 463, further discussed above), and to maintain that "it is unclear how other costs are determined," even after Ms. Uzenski further explained that the Company allocates costs consistent with the USOA, provided examples, and sponsored an exhibit with further detail, as reflected in part above (7T 2785-2786; Exhibit A-43, Schedule HH6).

Staff's Initial Brief, pp 56-57, proposes disallowances ($9,726,000 in the bridge period; $16,060,000 in the projected test year), the total capital costs of five Technology and Automation projects (Asset Management Upgrades, Hosting Capacity Enablement, Load Forecasting & Analytics, Other Modernize Grid Management, and Work Management & Scheduling Upgrades projects) based solely on an indicated concern that the costs were developed using a "high level" methodology.

The Company previously explained that it is not reasonable or prudent to propose disallowing an entire group of projects based solely on a concern about a cost-estimating model. This is especially true where the Staff does not question the reasonableness or prudence of the projects themselves. The Company also explained in response to Staff discovery (Exhibit A-41, Schedule FF11) that the high-level estimates (referenced in Exhibit A-23, Schedule M6) were developed based on defined scope and timelines and have been vetted thoroughly by the Company's Technology Investment Committee. Staff's further suggestion that there seems to be "[l]ittle

consideration for the project scope, goals, and desired outcomes" (Wang, 8T 5188) is similarly inaccurate, and neglects how the Company plans these investments following the Company's robust multi-year Annual Planning Cycle (APC) process. Therefore, Staff's proposed disallowances should be rejected (Pfeuffer, 4T 464-465; Sharma, 7T 1928, 2129).

Staff maintains its initial position, as stated in witness Wang's direct testimony, but neither addresses the Company's position nor provides additional support for its own. The bottom line remains that: "Staff recommends all projected bridge and test year costs for the five projects with high-level IT costs be disallowed" (Staff Initial Brief, p 57). The Company maintains that its cost-estimation methodology is appropriately detailed and employs the Company's extensive experience in conducting similar projects. Even assuming for argument's sake that there is some merit in Staff's "concern[] about the accuracy of the high-level IT cost estimates" (Staff Initial Brief, p 56), the cost of all five projects is not $0. There is no sound basis for Staff's proposed 100% disallowance, particularly where nobody (including Staff) raises any issue about the projects being reasonable and prudent.

Staff proposed additional disallowances in Technology Programs & NWA. Staff's Initial Brief, pp 53-54, asserts: "The Technology Programs & NWA subprojects are all either completed with no ongoing costs or are now separate projects with capital costs included elsewhere in the U-20836 case, Staff recommends full disallowance of the projected bridge period capital costs for this project totaling $2,000." The Company previously explained that it disagrees because these in fact are past investments that were made in 2021. Staff incorrectly attributes these past (2021) investments to the future (2022 bridge period), so Staff's proposed disallowance should be rejected (Pfeuffer, 4T 466).

Staff's Initial Brief, pp 53-54, responds that (1) the bridge period includes 2021, and (2) the programs and subprojects are either completed or located elsewhere. Staff's response misses the Company's point and neglects the temporal context: (1) 2021 is the past, and (2) Staff's reasoning concerns the present and future. There is a disconnect in Staff's reasoning that the Company fully explained, so Staff's proposed disallowance should be rejected.

1. Grid Edge Insights & New Technology

Staff's Initial Brief, pp 54-56, proposes a complete disallowance ($1.989 million in the bridge period; $1.783 million in the projected test year) for the Grid Edge Insights & New Technology project, reasoning that there were conflicting scopes provided in Company exhibits and a discovery response. The Company previously explained that Staff's proposal lacks a sound foundation because it relies on Exhibit S-7.12, page 3, which was a discovery response referencing the scope for New Technology Pilots. The Company noted that if there are any new technology pilots (*future* potential expenditures), then the costs would be shown on this line item but did not imply that this changed the *current* scope of work proposed in the Grid Edge Insights & New Technology project. The Company also confirmed the current scope of work for this project by identifying some of the specific scope of work, but Staff overlooked this confirmation. Thus, the Company did not provide conflicting scopes for the project, and the Company also provided evidence of the current scope of the project with specific detail, so Staff's proposed disallowance should be rejected (Pfeuffer, 4T 467-468).

Staff's Initial Brief, pp 55-56, responds: "Staff is unmoved by the Company's rebuttal . . . Staff can only assume that the projects will be as the Company described them in discovery, which is much more general and not necessarily focused on cybersecure control and communications schemes for DERs and microgrids."

The Company maintains that there was no sound basis for Staff's assumption in the first place, as discussed above. There is also no sound basis for Staff to continue to "assume" something that the Company further clarified and disproved on rebuttal. Most importantly, the Commission's decision must be based on the record, not Staff's assumptions.[78] Therefore, Staff's proposed disallowance should be rejected.

2. Grid Automation Telecommunications.

Robust and secure communications channels are foundational for a modern grid. Many devices on DTE Electric's system, however, are either not yet connected for remote monitoring and control or are connected through a communication network that is not fully integrated. The Grid Automation Telecommunications program will address communication gaps, deploy a consistent channel with sufficient and reliable bandwidth to meet the current and growing requirements of a modern electrical system, and allow deployment of the appropriate cybersecurity protocols. In addition, the Company will strategically extend its existing fiber ring to locations that provide the most benefit, providing improved reliability and increased cybersecurity (Pfeuffer, 4T 348-351).

[78] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

3. Distribution Automation.

There appears to be no dispute on DTE Electric's efforts on Distribution Automation,[79] which have unfolded over the past several years.[80]

4. Conservation Voltage Reduction (CVR)/Volt Var Optimization (VVO).

DTE Electric's Initial Brief, pp 78-79, explained that the Company initially began evaluating CVR/VVO as a generation alternative to reduce peak demand and energy consumption as part of the Company's Integrated Resource Plan (IRP) that the Commission approved in Case No. U-20471.[81] The Company continues to implement and evaluate CVR/VVO through pilots both as an offset to peak generation, and additionally because of the potential benefits to the distribution grid. In addition to completing the pilot that the Commission authorized in the IRP (see February 20, 2020 Order in Case No. U-20471, pp. 74-76), the Company installed or plans to install CVR/VVO on 8 substation transformers and 28 circuits in 2021, 18 substation transformers and 56 circuits in 2022, and 44 substation transformers and 136 circuits in 2023. Based on discussions with industry experts and utilities that have implemented advanced CVR/VVO, savings in energy

[79] The Department of Energy (DOE) report "Distribution Automation: Results from the Smart Grid Investment Program," published in September of 2016, states: "Distribution automation (DA) uses digital sensors and switches with advanced control and communication technologies to automate feeder switching, voltage and equipment health monitoring; and outage, voltage and reactive power management. Automation can improve the speed, cost, accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers" (Pfeuffer, 4T 351).

[80] Today, roughly 32% of general-purpose substations and 25% of the distribution circuits in DTE Electric's territory have SCADA monitoring and control. Approximately 5% of the distribution circuits have automatic loop schemes, which can automatically transfer sections of the circuits onto adjacent circuits when an outage is detected. The Company is strategically implementing Distribution Automation to maximize customer benefits. The scope of work for 2021 includes the design of full SCADA control and monitoring of one substation and development of standards and processes that can be utilized to accelerate the installation of distribution automation equipment across the electrical system, as well as the design of 5 substations and 25 circuits for automation in 2022 (Pfeuffer, 4T 351-355).

[81] VVO manages system-wide voltage levels and reactive power flow to achieve one or more specific operating objectives, which can include reducing losses, managing voltage volatility due to intermittent renewable generation, optimizing operating parameters, and/or optimizing power factors. CVR, as one of the VVO options, is designed to maintain customer voltage levels in the lower portion of the allowable voltage ranges, thus reducing system losses, peak demand, or energy consumption (Pfeuffer, 4T 355).

consumption and peak demand for substations with advanced CVR/VVO in the range of 1.5% to 3.5% may be achievable,[82] but the Company will confirm the actual savings through the projects described in this case (Pfeuffer, 4T 355-359).

Staff's Initial Brief, pp 45-47, proposes a $14,500,000 disallowance in the projected test year for CVR/VVO, reasoning that the projects were in the "preliminary stage" because the Company did not initially plan to select substations for 2023 in the third quarter of 2022. The Company disagrees because it began the project in 2019, and through 2021 had successfully invested $4.6 million (Exhibit A-41, Schedule FF9, page 9, line 11) against a forecast of $4.5 million (Exhibit A-12, Schedule B5.4, page 11, line 11). The Company also maintains a prioritized list of substations for CVR/VVO based on expected energy savings, which currently has 17 substations and 126 circuits identified for 2023 (Pfeuffer, 4T 488). Thus, the project is not in the preliminary stage.

Staff responds that "[w]hile the CVR/VVO project as a whole is not in the preliminary stage, future individual projects that are part of the larger CVR/VVO effort are. Even though the year the projects will be undertaken is known – 2023 – the fact that selection of the circuits and substations that will be upgraded has not yet occurred yet makes the projects preliminary."

The Company disagrees because this is an established program as Staff acknowledged, the program has an undisputed track record, and there is no basis to think that the program will simply stop in 2023 as Staff effectively suggests, given the mature stage of the program. Staff's proposed 100% disallowance (0% for 2023) is contrary to the record and unreasonable.

[82] Details of the results of the initial pilots did fall within this range, as reported in DTE Electric's April 13, 2002, Integrated Resource Plan Annual Report in MPSC Case No. U-20417 (Docket No. 0789).

Staff also did not indicate any concerns about reasonableness or customer benefits. The sole basis for the Staff's proposed disallowance concerns the timing of identifying specific circuits for 2023. The Company maintains that it is reasonable to identify circuits in the third quarter of the year before execution because identifying circuits from a list of prioritized circuits too far ahead of time would lock the Company into work on circuits that might not be the optimal choice. Therefore, Staff's proposed disallowance should be rejected (Pfeuffer, 4T 487-489).

5. Automation Configuration and Test Record Database.

Staff's Initial Brief, pp 58-60, recommends a full disallowance ($2,043,000 in the bridge period; $1,827,000 in the projected test year) for the Automation Configuration and Test Record Database (Test Record) project. Staff indicated a concern that the project includes preliminary-stage activities and data conversion costs, and that such items should be expensed (Wang, 8T 5191). DTE Electric's Initial Brief, p 80, explained that Staff's concerns are unwarranted because the project does not include preliminary-stage activities, and data conversion costs will be expensed (Pfeuffer, 4T 452). Therefore, Staff's proposed disallowance should be rejected as unfounded and disproven.

Staff's Initial Brief, p 59, responds that "there is no data supporting the Company's rebuttal claims . . . Staff cannot assume the Company's rebuttal assertions are correct given the lack of opportunity to confirm these claims and identify how much, if any, of the project costs for data conversion and cleanup costs will actually be expensed."

The Company maintains it appropriately explained that Staff's concern was unfounded, and the Company's testimony alone is sufficient evidence. There was no need to provide additional "data" on a non-issue (plus proving a negative presents logical and practical problems). Staff also did not have to "assume" anything about the Company's rebuttal. If Staff had some lingering doubt (*e.g.*, as now indicated, the project *has* preliminary activities because it *had* preliminary activities),

then it could have pursued the matter. For example, the AG's Initial Brief references extensive discovery responses that she received regarding the Company's rebuttal testimony (and which further support the Company's positions). It is also inappropriate for Staff to raise new criticisms of the Company's evidentiary presentation in briefing.[83]

The context also bears emphasis. Staff does not contend that the project should not be done, or that the money should not be invested. Instead, Staff's indicated concern was (and is) only that a portion of the expense should be expensed rather than capitalized (affecting, at most, a portion of the return "on" the investment, but not any of the return "of" the investment). Thus, Staff's proposed 100% disallowance has also always been unreasonable as well as unfounded. For all of these reasons, Staff's unfounded, unreasonable, and disproven proposal should be rejected.

6. Operational Technology and Error Free Communication (EFC)

Staff's Initial Brief, pp 61-63, proposes a full disallowance ($12,608,000 in the bridge period; $333,000 in the projected test year) for the Operational Technology and Error Free Communication (EFC) project, based on the apparent misperception that the project is a minor system upgrade or enhancement that should be expensed instead of capitalized (Wang, 8T 5194: "The project appears to be focused on manipulation of the Company's current data from various areas into one single source of data to generate a new type of data report").

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[83] The Commission previously explained:

> The Commission finds that a delicate balance must be maintained concerning the burden of proof. The company has the burden of going forward and demonstrating that it has proposed just and reasonable rates. In this instance, Detroit Edison made that showing. The Staff in response may challenge that evidence and present evidence of unreasonableness. At that point, however, the Staff has the burden to demonstrate its position is correct. The company may then rebut the Staff's criticisms of its case. The problem here is that the specific criticism that the company had not adequately explained itself came too late in the process for a fair determination on that issue, particularly given the evidence the company presented in support of its position. [January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, pp 37-38.]

DTE Electric's Initial Brief, pp 80-81, explained that to the contrary, the EFC project is a significant project that fundamentally changes the Company's underlying process to communicate with customers, and the project scope goes well beyond simply generating a new type of report and facilitating data retrieval. Unlike IT maintenance work, this project is a major undertaking that requires reworking the interfaces between Company systems (order management, customer information, outbound notification, and outage management) to work in ways that the systems were not originally designed to operate. The project also, and among other things, includes building a new system (Premise Power Status, or PPS) to house the data and business logic driving the flow of information. Therefore, this is a significant project (not simply data manipulation or writing new reports for current systems as Staff suggested) that is appropriately classified as capital, and Staff's proposed disallowances should be rejected as unfounded and disproven (Pfeuffer, 4T 452-454).

Staff's Initial Brief, p 62, responds that costs can be capitalized if they meet three criteria, and: "The Operational Technology and Error Free Communication project meets criteria (2) and (3). However, does it meet criteria (1)? Staff asserts the Company being able to tell customers whether the Company definitely knows whether customers have power or not does not constitute significant additional functionality."

Staff's new assertion is unfounded and contrary to the record, as summarized above. Therefore, Staff's proposed disallowance should be rejected.

7. Non-Wires Alternatives (NWA).

DTE Electric's Initial Brief, pp 81-88, explained that the Company met the Commission's expectation that it provide a "robust suite of NWA pilots", which focus on using alternative technologies to address circuit or substation overload concerns to help delay or offset traditional

grid upgrades (Pfeuffer, 4T 359-360, 468).[84] NWAs may play a vital role in grid modernization, and these pilots will help determine when and how the Company may use these new technologies. The Company also explained why Staff's "ample evidence" criticisms were contrary to the record and otherwise inappropriate.[85]

MI-MAUI and Ann Arbor's Initial Brief, p 28, states: "MI-MAUI and Ann Arbor Support the Battery Trailer, Omega, Fisher, and Port Austin NWA Pilot Costs as Proposed . . . Ann Arbor and MI-MAUI believe each of these pilots is likely to result in helpful information on ways to reduce the cost of energy while also reducing the environmental impact of DTE's energy provision."

Staff's Initial Brief, pp 71-74, recommends that 1/3 of the NWA: Omega Load Relief project be disallowed ($2,366,000 in the bridge period; $223,333 in the projected test year) to remove costs that it suspects are associated with solar implementation. The Company disagrees because it made clear in discovery responses that the project cost does not include any investment in solar capability.

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[84] NWAs are defined in section 4.3 of the DGP (using the Staff's definition that the Commission adopted in the August 20, 2020 Order in Case No. U-20147, pp 11, 41) as:

> An electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades.

The Commission further advised that it "expects to be presented with 'a robust suite of NWAs that may be evaluated for prudency as possible programs'" (August 20, 2020 Order in Case No. U-20147, pp 43-44, quoting the May 8, 2020 Order in Case No. U-20561, p 112).

[85] Staff proposed numerous disallowances for NWA expenditures, referring numerous times in discovery responses to a need for "ample evidence" (Exhibit A-41, Schedule FF13). To the contrary, and in addition to the Company's audit and discovery responses, the Company provided: (1) direct testimony (10 pages); (2) Exhibit A-23, Schedule M1 (33 pages); (3) Exhibit A-23, Schedule M6 (36 pages); and (4) Exhibit A-12, Schedule B5.4 (30 pages). Staff also did not indicate any concerns about the Company meeting the pilot documentation requirements described in Case No. U-20645, and the Company provided Exhibit A-12, Schedule B5.4 for that purpose (Pfeuffer, 4T 470). In addition to being unfounded, Staff's "ample evidence" criticism is also inappropriate because Staff was unable to identify what type of evidence it would want the Company to provide, above and beyond what it already provided. Instead, Staff took no position on whether the Company presented a "robust suite of NWAs," and did not define how a "robust suite of NWAs" will be evaluated (Exhibit A-41, Schedule FF2).

See, for example, Exhibit S-7.30 ("The Company will not be pursuing utility scale solar or rooftop solar for NWA Omega load relief project. The project scope and *associated costs does not include solar*") (Emphasis added). The proposed 1/3 disallowance is also arbitrary and cannot reflect solar costs because no solar costs exist in the first place (Pfeuffer, 4T 471).

Staff's Initial Brief, p 72, acknowledges that the Company's discovery response "indicates the project does not include solar costs," but maintains that a prior document indicated that it did include solar costs, and: "Including costs in rates for activities which the Company declares will not occur is unreasonable and imprudent. Given the contradictory exhibit and discovery information from the Company, Staff asserts the record fails to support the Company's request."

Staff misses the relevant point – the Company does not "request" solar costs in the first place. The Company made that clear in its discovery responses as indicated above. Staff indicates that Exhibit A-23, Schedule M6 Revised, p 52, suggests otherwise. But page 54 shows that the Company requests $7.8 million for 2021-2023. Ms. Pfeuffer further explained:

> Initial conceptual engineering scope for the Omega project considered adding solar. However, as stated in Staff Witness Wang's Exhibit – S-7.30 response to STDE-15.35 "The Company will not be pursuing utility scale solar or rooftop solar for NWA Omega load relief project. The project scope and associated costs does not include solar." The Company made clear that the project cost does not include any investment in solar capability through discovery responses such as the one quoted above. Additionally, the amount of one third proposed for the disallowance is an arbitrary value that does not, and in fact *cannot*, reflect the cost of solar related to this project since no such costs exist. [4T 471. Emphasis in original.]

Staff's Initial Brief, pp 72-73, further suggestion that its proposed 1/3 disallowance is somehow supported because there are three items on an initial project scope document similarly lacks merit and relevance, and further reflects Staff's arbitrariness as indicated above. The Company properly addressed Staff's indicated concerns through discovery, and Staff could have

pursued more discovery if it had some lingering doubt.[86] It is inappropriate for Staff to continue to assert a disproven misperception.

Staff also proposed an additional disallowance ($1,692,396 in the bridge period; $159,750 in the projected test year) by "adjusting the total labor costs so that it is 11% of total material costs, more like the NWA: Battery trailer project" (Wang, 8T 5213). The Company previously explained that it disagrees because the projects are not comparable in this regard. The labor cost for the Omega project includes site preparation, which entails cable and conduit installation, and below-grade work. The labor for the mobile battery trailer project does not include site preparation costs. Thus, there are different labor costs for different types of labor. Staff's proposed disallowance should be rejected as unfounded and disproven (Pfeuffer, 4T 472).

Staff responds that it is "unmoved by the Company's rebuttal" because: "Though the Omega Load Relief project includes installation of the batteries, the NWA: Battery Trailer project also must include the design and build of the mobile battery storage unit, which requires more labor than just purchasing a battery outright" (Staff's Initial Brief, p 73).

Staff's response defies the record and fails to acknowledge indisputable differences between the projects. Saying that both projects include labor misses the relevant point – the Omega project includes site preparation at a real property location (and thus higher labor costs), and the battery trailer project does not include site preparation (and therefore does not include those higher costs). There is no sound basis for Staff to be "unmoved" by the Company's clear and definitive evidence, and in any event, the record firmly supports the Company's recovery.

[86] Not to suggest that there should be more discovery. The volume of requests has already reached an excessive level for the Company, and receiving parties do not acknowledge, or sometimes even read, the Company's responses. (see, for example, Pfeuffer, 4T 463).

Staff's Initial Brief, pp 74-76, proposes a $2,083,000 disallowance in the projected test year for the NWA: Port Austin Load Relief project, by (1) reasoning that the costs associated with the re-use of the Omega battery for the NWA: Port Austin Load Relief project might not materialize, (2) estimating the solar scope to cost $2 million, and (3) proposing that all costs beyond the $2 million (which Staff attributed to the mobile battery trailer) be disallowed (Wang, 8T 5214). The Company previously explained that it disagrees, first noting that the cost that Staff associated with mobile battery transportation and connection is a small fraction of the costs that Staff attributed to its proposed disallowance. The Port Austin project entails the installation of solar, site preparation including below-grade work, overhead construction, and mobile battery transportation and installation. This scope is necessary regardless of the timing of the mobile battery installation, which is one of the last phases of the project, and only includes battery transportation from Omega and connection to the system (Pfeuffer, 4T 473).

Also, even assuming that there are delays with Omega project completion, this would not eliminate the need for the battery, since the Port Austin project requires both solar and storage to address the loading situation. In the interest of cost efficiency, the Company plans to reuse the battery first used at Omega, rather than purchase a new battery for this pilot, which is still an option should any problem arise with the existing battery. Thus, there is no sound reason to think that these costs might not materialize as Staff suggested (Pfeuffer, 4T 474-475; Exhibit A-23, Schedule M1, page 409).

Staff's Initial Brief, p 75, first mischaracterizes the Company's rebuttal as not addressing Staff's proposed disallowance, further asserting "Staff's disallowance centers on the reasonableness and prudency of including costs in rates that may not materialize." To the contrary, the Company squarely addressed Staff's indicated concern, as discussed previously and above.

Staff's Initial Brief, p 75, then pivots from its "materialize" concern to a suggestion that there could be a timing issue, asserting: "In its rebuttal, the Company did not detail the unexpected completion date of the subtransmission line that will alleviate Omega issues so the battery can be moved to Port Austin. There is a possibility that the battery will not be available for use at Port Austin until after October 2023, when the test year ends in this case."

Staff's response lacks merit because: (1) it is inappropriate for Staff to raise new criticisms of the Company's evidentiary presentation in briefing,[87] (2) Staff's newly-asserted and unsupported "possibility" cannot support a decision, [88] and (3) Staff's suggestion of a "used and useful" requirement is contrary to controlling law. [89]

Moreover, instead of supporting the Company's efforts to reduce NWA costs by reusing a mobile battery system, Staff has taken the position that it cannot say whether batteries are needed for the Port Austin project (Exhibit A-41, Schedule FF13), in apparent disregard of the evidence. In addition to the discussion above, see Exhibit A-23, Schedule M1, pages 408-10; Exhibit A-23,

[87] The Commission previously explained:

> The Commission finds that a delicate balance must be maintained concerning the burden of proof. The company has the burden of going forward and demonstrating that it has proposed just and reasonable rates. In this instance, Detroit Edison made that showing. The Staff in response may challenge that evidence and present evidence of unreasonableness. At that point, however, the Staff has the burden to demonstrate its position is correct. The company may then rebut the Staff's criticisms of its case. The problem here is that the specific criticism that the company had not adequately explained itself came too late in the process for a fair determination on that issue, particularly given the evidence the company presented in support of its position. [January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, pp 37-38.]

[88] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

[89] *ABATE v Public Service Comm*, 208 Mich App 248, 258-59; 527 NW2d 533 (1994).

Schedule M6, pages 59-62; and Exhibit A-12, Schedule B5.4.7, pages 1-4 (Pfeuffer, 4T 475). Therefore, Staff's proposed disallowance for the Port Austin project should be rejected.

Staff's Initial Brief, pp 47-49, proposes a full disallowance ($1,534,000 in the bridge period; $4,952,000 in the projected test year) for the NWA: Veridian project, reasoning that it lacked internal Company approval (Wang, 8T 5176). The Company previously explained that this disallowance is inappropriate because since the time of the filing of the instant case, the Company has internally approved the project, and it is proceeding (Pfeuffer, 4T 476; Exhibit A-51, p 2).[90]

Staff's Initial Brief, p 48, responds: "Providing additional information in rebuttal, such as the updated project approval assertions, does not afford Staff and other intervenors time to review the updates and confirm the information."

To the contrary, "providing additional information" in rebuttal is entirely appropriate. That is the entire point of rebuttal. Staff raised a concern, and the Company responded to that concern with evidence. The context also bears emphasis – this was internal approval. It is a technical Company internal requirement but does not suggest a substantive issue concerning the project or its cost. It is analogous to adding a signature to a document that Staff and Intervenors have had ample time to review, and do not otherwise contest.

Staff's assertion that there was not enough time to confirm the information similarly lacks merit. Staff does not suggest any reason to suspect that confirmation did not occur, but instead acknowledges that "the Company internally approved the project to move forward eight days before Staff and intervenor testimony was due" (Staff Initial Brief, p 48). Even assuming for argument's sake that any confirmation was needed, then Staff could have pursued simple discovery.

[90] In further response to Ann Arbor witness Stults' suggestion that the Veridian project would not lead to a true microgrid, Ms. Pfeuffer further explained that the project as proposed by the Company meets the conceptual definition of a microgrid (4T 485). Ms. Pfeuffer also provided a further discussion regarding Ann arbor grid planning, addressing among other things witness Stults' apparent misperceptions (4T 523-281).

Staff further suggests that "ALJ's and the Commission have previously rejected cost recovery requests based on updated information provided in rebuttal." Staff's Initial Brief, pp 48-49, citing the December 29, 2021 Order in Case No. U-20940 for the proposition that "[c]ost recovery requests in a rate case need to be fully justified in a utility's direct case." But immediately before Staff's quote, the Order reflects that the Commission was discussing "full business cases and updated figures." See also, Order, p 138, reflecting that the discussion concerned business cases that were provided in rebuttal. Staff's reliance on the September 26, 2019 Order in Case No. U-20322 is similarly misplaced. The Commission explained:

> As with other issues in rate base and cost of service, it is not adequate to present the primary evidence in support of the direct case on rebuttal when the parties can no longer test the evidence (other than through cross-examination). Proper rebuttal is 'that given by one party to contradict, repel, explain or disprove evidence produced by the other party and tending directly to weaken or impeach the same." *Kirk v Ford Motor Co*, 147 Mich App 337, 345; 383 NW2d 193 (1985) (citation omitted); June 3, 2010 order in Case No. U-15985, pp. 23-24. Rebuttal is not intended for presentation of the entire direct case in support of a capital expense category. [September 26, 2019 Order, in Case No. U-20322, p 29.]

As discussed above, the Company properly supplied notice of internal approval as rebuttal under the Commission's standard, and it is nothing like the "primary evidence in support of the direct case" or "presentation of the entire direct case," which has been found inappropriate. Moreover, the Company had a right to rely on the Commission's standards for rebuttal.[91] Therefore, Staff's proposed disallowance should be rejected.

[91] See for example, *In re Complaint of Consumers Energy Co*, 255 Mich App 496, 501; 660 NW2d 785 (2002) (reversing the MPSC because it misinterpreted and misapplied its own rule in order to reach its desired result); *DeBeaussaert v Shelby Twp*, 122 Mich App 128, 130; 333 NW2d 22 (1982) ("Once an agency has issued rules and regulations to govern its activity, it may not violate them"); *Bohannen v Sheridan-Cadillac Hotel, Inc*, 3 Mich App 81, 82; 141 NW2d 722 (1966) ("When an administrative agency promulgates a rule for the benefit of litigants and then deprives a litigant of this right, it is a violation of both the 1908 and 1963 Michigan Constitutions").

Staff's Initial Brief, pp 49-53, proposes a full disallowance ($678,000 in the bridge period; $292,000 in the projected test year) for the NWA: Small Solar and Storage Testbeds project, based on underlying reasoning that: "Only studying these technologies in customer installations will yield information on the real-life behavior, issues, and opportunities from actual installations within the Company's service territory . . . The necessity of conducting a pilot in a testbed and laboratory setting, instead of initiating field deployment, is not clear and the benefits of it over field deployment are not justified by the Company" (Wang, 8T 5178-5179).

The Company previously explained that Staff's reasoning is incorrect for several reasons including: (1) Some of the interactions and tests will recreate scenarios that would not be safe at a customer location but can be tested in a controlled and safe environment in the lab; (2) In the lab, tests could be undertaken without having to gain access to customer locations and/or modifying customers' premises and without impacting customers' power quality; (3) In the lab, the Company can reuse the infrastructure for different testing scenarios, instead of having to find or create scenarios in the field; (4) The lab gives the Company the ability to collect high data resolution and detailed information, and to reuse monitoring hardware; (5) In the lab, the Company can repeatedly test scenarios (*e.g.*, abnormal electrical system events that might occur infrequently in the field) and generate new scenarios; and (6) testing will include capabilities that are emerging or not currently available on the market, so the Company will be better prepared when the capabilities are mature (Pfeuffer, 4T 776-778).[92]

Staff further suggested that testing is not necessary prior to field deployment because of "the findings and outcomes from research organizations like EPRI, the learnings from other U.S.

[92] Staff also seemed to have the impression that the Company would develop NWAs in an office environment. The Small Solar and Storage Testbed provides technical facilities to develop NWAs, akin to a lab environment (Pfeuffer, 4T 483).

utilities, and the Company's prior experimentation with smart inverters" (Wang, 8T 5179). The Company generally agrees that there is value in participating with organizations such as EPRI and benchmarking with other utilities and does not intend to duplicate efforts; however, technology is evolving rapidly, and the Company seeks information regarding how it could be utilized on the Company's system. Using EPRI or similar organizations as a substitute for the testbed would require building testing that is specific to DTE Electric's system and use cases. The Company would be charged for this service, and be subject to EPRI's or others' schedules, which might not align with when the Company needs the information (Pfeuffer, 4T 478, 481). Staff also acknowledged in discovery that the Company is in a better position to determine the availability of test reports on situations that are unique to the Company's distribution system (Pfeuffer, 4T 480-481; Exhibit A-41, Schedule FF14).

Staff further suggested that "the Company has previously conducted field experiments of smart inverters directly without the creation of a testbed" (Wang, 8T 5180). Staff oversimplified the Small Solar and Storage Testbeds project. The Company has demonstrated technology in the past without creating a testbed only where it first conducted a risk assessment, and the installed physical and engineered controls allowed minimal to no potential adverse effects (Pfeuffer, 4T 779).

Staff also neglected that, unlike utility grade smart inverters, retail consumer electronics are frequently designed with fewer or no safety features to meet lower price points. The Company discovered (while designing the test bed) that these lower-priced inverters can pose safety and reliability risks due to the lack of security features. If the Company does not have the Small Solar and Storage testbed, then this type of grid-impacting flaw might go undiscovered and could potentially lead to safety or reliability concerns that the Company would have to resolve in the field.

This situation can be avoided if issues are identified in the testbed and resolved prior to installation (Pfeuffer, 4T 480-483).

Staff's Initial Brief, pp 50-53, generally misses the Company's points, and otherwise responds with speculation and flawed logic. For example, regarding the discussion immediately above concerning the Company's discovery of a grid-impacting flaw, Staff's Initial Brief, pp 52-53, asserts: "Given that these learnings were identified in the designing of the testbed, this further supports Staff's concerns regarding the necessity of the testbed itself." It is unclear how Staff reached such a conclusion. The record reflects that the Company would not have discovered the flaw if it had not started down the road towards a testbed. That is no reason to stop going down that road as Staff suggests.

The Company invested significant resources, in both time and capital, to develop a robust suite of NWAs in response to the Commission's request. To validate the proposed suite of NWA projects and associated learnings, the Company also engaged EPRI to evaluate the Company's NWAs. EPRI completed its report in June 2022, and states:

> DTEE's approach of incrementally developing NWA capabilities by implementing a series of demonstration projects is appropriate. The existing suite of planned pilot projects will cover several NWA use-cases and leverage multiple DER technologies. The demonstrations will identify key control, protection, cyber security, and other considerations that will shape future standard processes to address NWA effectively and efficiently within planning, operations, and other areas. [Pfeuffer, 4T 484.]

In summary, the Company developed a "robust suite of NWAs" in response to the Commission's stated expectation. The Company also provided voluminous evidence supporting its pilots and the expenditures that it made on them. Staff's proposed disallowances are unfounded, and at times contrary to Staff's own evidence. Therefore, Staff's proposed NWA disallowances should be rejected (Pfeuffer, 4T 484).

Staff also proposes a 90% disallowance of the labor portion of the costs associated with the NWA: EV Charging Demonstration at ACM for the sole reason that it is a "high-level estimate" (Staff Initial Brief, pp 76-77). The Company disagrees, and Staff's proposed disallowance should be rejected, for the same reasons the Company disagreed with other Staff disallowances based solely on the "high-level estimate" issues in this brief, at section V. B. 4. iii. c.

8. Advanced Distribution Management System (ADMS)

DTE Electric's Initial Brief, pp 88-94, explained and supported the Company's investments in the Advanced Distribution Management System (ADMS).[93]

The AG's Initial Brief, p 51, reflects that her witness Coppola asserted that "it is not clear what the additional data requirements are and what incremental value will be generated by the additional functionality" (8T 4765), and proposed disallowances of $2,334,000 for the ten months ending October 31, 2022, and $2,883,000 for the projected test year (8T 4766-4767).

The Company previously explained that it disagrees because Ms. Elliott Andahazy's direct testimony provided detailed information regarding the successful implementation of the initial ADMS: NMS project investment, how the Company determined the need for additional investments in the network model, and the actual work it will complete with the requested $6.3 million. The Company also provided further details by responding to 16 discovery questions (as

[93] ADMS is the technology platform that will substantially improve DTE Electric's ability to manage the flow of electricity from the point of generation to the point of delivery, to monitor the condition of the grid, to safely operate it, and to respond to emergency conditions and outages more quickly. DTE Electric is replacing several systems that are at end of life with the following components that comprise ADMS: Generation Management System (GMS); Energy Management System (EMS); Outage Management System (OMS); Distribution Management System (DMS). The Company is also adding the Network Management System (NMS) as part of ADMS. Customer benefits include reduced outage durations and better communications on the status of their electric service and expected restoration times (Elliott Andahazy, 7T 1490-1495. See section 12.1 of the DGP for details regarding benefits of the ADMS in different scenarios). The Commission previously found "this capital expense amount to be reasonable in light of the significant improvements in reliability, integration with distribution resources, and substation outage risk that are offered by ADMS, and the fact that it is becoming commonplace in the industry" (May 2, 2019 Order in Case No. U-20162, p 29).

seen in Exhibit A-46, Schedule KK1, particularly response AGDE-7.205a). Ms. Elliott Andahazy further explained on rebuttal why it is reasonable that the ADMS data requirements would evolve after completing the initial ADMS and NMS project scope. In summary, the additional investment includes technology to better align field conditions and maps to the digital representation of the grid, integration between asset systems, new data models to support planning and operations topography and characteristics, and advanced analytics to leverage sensor data to continuously improve the Network Model. Therefore, the AG's proposed disallowance should be rejected. (Elliott Andahazy, 7T 1498-1502, 1536-1537).

Ms. Elliott Andahazy further discussed the progress and strategy for deploying the OMS and DMS components of the ADMS project, due to delays in the delivery of the Compass mobile tool, driven largely by the complexity of the technology and restrictions imposed during the COVID pandemic. The Company modified the project management process to ensure that the delivery dates of the OMS and DMS components will not be further delayed and will leverage another field work force (field force) management solution called ClickSoft, which is already included in the Company's strategic plan for overhead and underground field resources. Customers will benefit from shorter restoration times and improved response to trouble in the field. Despite the delays, it is still important for DTE Electric to pursue the OMS and DMS components of ADMS for SAIDI improvements, replacement of end-of-life technology, seamless integration of components, automating manual processes, and improved situational awareness. The Global Prioritization Model (GPM) also continues to rank ADMS as the top project due to its importance to the Company's plan to improve reliability for customers and modernize the grid to respond to increasing weather volatility, new technologies, and electrification (Elliott Andahazy, 7T 1502-1513).

The AG's Initial Brief, p 51, suggests that the Company's evidence is not "compelling and convincing," but that is not the standard,[94] and the Company's evidence (here and elsewhere) would also meet the higher standard that the AG suggests.[95] Plus, the AG does not articulate any reason, let alone offer proof, to support her position (see footnote 2).

The AG's Initial Brief, p 52, reflects that her witness Coppola proposed a complete ($40,879,000) disallowance for the DMS/OMS project ($28,449,000 for the ten months ending October 31, 2022, and $12,430,000 for the test year), asserting:

> [T]he cost overruns have not been adequately justified and at least a major portion of those incremental cost may have been imprudently incurred. It would neither be fair nor reasonable for the Company to recover 100% of those from customers. The Company needs to be held accountable for its premature decision to proceed with a suite of products that were not fully developed and proven [Coppola, 8T 4769].[96]

The Company disagrees because the DMS/OMS provides benefits to customers including SAIDI improvements (outlined above), and the AG did not provide any evidence showing any lack of customer value. The AG also ignored that ADMS (of which DMS/OMS is an essential component) is the essential technology to support the modernized grid, and that the ADMS investment was required to replace existing systems that were reaching end-of-life (Elliott Andahazy, 7T 1494-1495, 1540-1542).

The AG's Initial Brief, pp 151-53, responds by incorrectly characterizing discovery responses, which actually further support the Company's position (Exhibit AG-1.59, pp 1-3).

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[94] The correct standard is a preponderance of the evidence, as explained herein in Section III.

[95] *Aquilina v General Motors Corp*, 403 Mich 206, 210-211; 267 NW2d 923 (1978) ("The proof required in an administrative proceeding…is the same as that required in a civil judicial proceeding: a preponderance of the evidence.").

[96] AG witness Coppola also recounted his testimony from Case No. U-20162 criticizing new technology (8T 4768), but the ALJ in that case noted that the ADMS projects will help address systems "that have reached end-of-life" (PFD, p 83), and the Commission adopted the ALJ's findings, further noting: "Simply because technology is new does not mean that it should be ignored, or that it will not provide a benefit to ratepayers" (May 2, 2019 Order in Case No. U-20162, p 28).

Moreover, the AG's $40.9 million proposed disallowance is substantially greater than the total increase that the Company requests (the Company's original $29.2 million request has been corrected to $27.0 million as described in discovery responses; see Exhibit A-46, Schedule KK2). Ms. Elliott Andahazy further explained that the total project cost increased by (1) $3.7 million of planned investment that was disclosed but not included in Case No. U-20561 due to the years involved in that case; (2) $6.6 million for an expanded ADMS Reporting project (as corrected in STDE-4.28, Exhibit A-46, Schedule KK2; the original ADMS project assumed a nominal investment in reports associated with ADMS data, but the Company then learned about the rapidly-evolving benefits of Cloud computing and made the strategic decision to move its IT investments in that direction for all future development where the Cloud approach is consistent with safety or regulatory standards); (3) $6.9 million included for the emergent trouble portion of the ClickSoft project already planned in the Company's strategic investment, but which is merely being pulled forward to correspond to the OMS cutover date; and (4) $9.8 million for project delays due to COVID and the delayed delivery of the Compass mobile tool (as corrected in STDE-4.25, Exhibit A-46, Schedule KK2). The AG did not even claim that items 1-3 are unreasonable or imprudent, and item 4 is a combination of the impacts of the delayed Compass mobile tool and the COVID pandemic. It appears that the AG seeks to retroactively disallow capital that the Commission approved previously because witness Coppola maintains his overall disagreement with the investment because it encompasses new technologies, not because of project delays and project investment increases (Elliott Andahazy, 7T 1503-1505, 1513-1517, 1541; Exhibit A-12, Schedule B5.4, page 11, line 2).

In summary, when the Company selected OSI Inc., that company offered a fully integrated platform of ADMS components, with multiple components seen as industry leading. When OSI had

challenges meeting the timely delivery of the new Compass mobile tool with the required functionality, the Company was able to pull ahead the emergent trouble portion of the ClickSoft project that was slated to come later as an alternative to ensure no further delays would affect field personnel's use of this system. The Commission has already reviewed and approved project investments, and there is no new evidence claiming that the project is not providing the value that the Company identified. Therefore, the AG's proposed disallowance should be rejected (Elliott Andahazy, 7T 1497-1498, 1542-1543).

In Staff's Initial Brief, witness Wang increased her proposed disallowance for ADMS: DMS/OMS from the blanket 20%, to the percent underspent on this project in 2020. However, as explained more fully above, this is inappropriate where in 2021 the Company overspent on ADMS: DMS/OMS, which is shown in Exhibit A-41 Schedule FF9:

Projects ($000s)	U-20561 2021 Forecast Exhibit A-12 Sch B5.4, p 9, ln 4.	2021 Actuals Exhibit A-41 Schedule FF9	% Projected Cost Actually Spent
ADMS: DMS/OMS	9,900	22,390	226%

Staff witness Wang proposed two disallowances associated with the ADMS: NMS project - one for "other cost" adjustment, and one for "high-level" estimate. The Company incorporates its discussions above regarding Staff's "Other Cost" adjustment and "high-level" estimate disallowance proposals. Regarding the "high-level" estimate, witness Elliott Andahazy further explained that Staff's basis for the 20% disallowance included a review of historic underinvestment in technology projects. The ADMS: NMS project, and the associated costs included in this rate case, are not based on a "high-level" cost estimate, so the project should not be subject to the proposed across-the-board 20% disallowance. For all these reasons, Staff's proposed disallowances are unfounded and unreasonable, so they should be rejected (Elliott Andahazy, 7T 1537-1538).

Staff witness Wang proposed two disallowances associated with the ADMS: DMS/OMS project - one for "other cost" adjustment, and one for "historic spend adjustment." The Company incorporates its discussion of Company witness Pfeuffer's Rebuttal Issue 12 regarding the "other cost" adjustment" (4T 461-463; 7T 2785-2786) and witness Pfeuffer's Rebuttal Issue 11 regarding the "historic spend adjustment" estimate (4T 454-461). Witness Elliott Andahazy further explained that regarding the "historic spend adjustment," Staff based its disallowance on an underestimate from 2020 (Exhibit S-7.42) but neglected to address the cause of the delays in 2020 (discussed at Elliott Andahazy, 7T 1503-1505) and assumed that these delays would continue into 2022 and 2023, without providing any supporting evidence. Ms. Elliott Andahazy's direct testimony also discussed mitigation steps that the Company put in place to prevent further delays (examples include modifying the implementation sequence of remaining components, pulling up the implementation of the emergent trouble portion of the ClickSoft project for the OMS rollout, and modifying the project management processes), but Staff did not address these measures (Elliott Andahazy, 7T 1506-1507, 1512, 1543).

As discussed above in response to the AG, the Commission previously found the investment in ADMS: DMS/OMS to be beneficial to customers. The remaining investment is needed to complete the project and ensure its full functionality for the benefit of customers. Staff offered no argument against the importance of the investment and did not mention either customer benefits or the replacement of an end-of-life system. Staff's proposed disallowances ($8.756 million in the bridge period, and $2.161 million in the projected test year) are based on the arbitrary use of one year of historical capital investment, and the arbitrary selection of "other costs" percent of total project capital. Therefore, Staff's proposed disallowance should be rejected (Pfeuffer, 4T 454-463; Elliott Andahazy, 7T 1544-1545; Uzenski, 7T 2785-2786).

iv. System Operating Center (SOC) Modernization: The Electric System Operations Center (ESOC) and Alternate System Operations Center (ASOC)

DTE Electric's Initial Brief, pp 94-100, explained and supported the System Operating Center (SOC) Modernization project, which is aimed at replacing the Company's outdated primary SOC and outdated backup SOC by constructing two facilities (the Electric System Operations Center (ESOC) and Alternate System Operations Center (ASOC)) designed using current industry security, resiliency, and operability standards.

The AG's Initial Brief, p 53, proposes a $20.5 million disallowance for the ESOC, asserting that the "Company has not adequately justified the expanded scope of the project or made a compelling and convincing case that the additional capital expenditures for the ESOC were justified." The Company incorporates its prior discussion explaining why the AG's proposal should be rejected (DTE Initial Brief, p 96-97). The AG's suggestions that the Company must satisfy a "compelling and convincing" burden of proof or some nebulous "adequately justified" standard are also contrary to applicable law including the "preponderance of the evidence" standard, as above discussed in section III.

The AG's Initial Brief, p 54, responds only by asserting that in a discovery response, Company witness Elliott Andahazy "confirms the point of Mr. Coppola's testimony, that not all employees previously planned to occupy the ESOC have done so, effectively undercutting her rebuttal." The AG's characterization is misleading at best because the referenced discovery response only concerned past years. The AG asked witness Elliott Andahazy to "provide the dates during 2020 and 2021 when all the employees occupied the office space in the new ESOC." She responded:

> In 2020 thru July 2021, no employees occupied the new ESOC as it was still under construction. As described in my response to discovery question STDE-4.37, employees started to transition into the new ESOC in August 2021 thru February

> 2022. Therefore, there was not a date in 2021 where all employees occupied the new ESOC. [Exhibit AG-1.59, p 4.]

Therefore, and as the Company explained previously, the AG's proposed disallowance should be rejected as unfounded and unreasonable, especially as Witness Elliot-Andahazy explained that all employees will be on site simultaneously in several scenarios, including peak load days in the summer and major storm, and may be called back to work at the ESOC at any time (Elliot-Andahazy 7T 1549).

Staff's Initial Brief, pp 63-67, recommends a capital disallowance of $14,369,000 in the projected bridge period and $62,000 in the projected test year for the ESOC project. The Company disagrees as it explained previously (DTE Electric Initial Brief, pp 97-99).

Staff's further discussion adds only an additional layer of unfounded speculation. For example, in response to the Staff's third reason for its proposed disallowance (Staff asserted that it "cannot exclude the possibility that the addition of the mezzanine level to the ESOC was motivated by non-functional considerations, such as aesthetics" (Wang, 8T 5202)), the Company explained that Staff's "possibility" assertion is unsupported speculation that cannot support a decision.[97] In contrast, the Company provided record evidence showing that the redesign was driven by operational efficiencies as discussed previously. Staff maintains that "the possibility that the redesign was motivated by reasons beyond supporting 60 additional employees cannot be excluded" (Staff Initial Brief, p 65).

[97] *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency's decision was not supported by in evidence that a reasonable person would consider adequate).

Staff neglects that "possibility" is not a relevant standard. Indeed, just about anything might be considered "possible," regardless of how remote it is as a matter of probability. The Company maintains that it satisfied the applicable "preponderance of the evidence" standard, and that Staff's contrary speculation cannot support a decision.

Staff's Initial Brief, pp 67-68, also recommends that 2/3 of the ASOC project capital costs be disallowed, which results in a capital disallowance of $5,930,000 in the projected bridge period and $14,424,000 in the projected test year. The Company disagrees as it explained previously, and again notes the inconsistency of Staff proposing a disallowance due to alleged uncertainty regarding whether costs will materialize, but at the same time stating that it "believes the Company will turn its attention to construction and occupancy of the ASOC soon" (Staff initial Brief, p 67). There also is no reason to think that construction of the ASOC will not occur (as Staff speculates) because the Company is obligated to meet NERC and business continuity requirements to have an alternate control center in case of a locational emergency at ESOC.[98] Staff also does not suggest that the Company doesn't need the ASOC or that the investment is not reasonable or prudent.

For all of these reasons, the AG and Staff's proposed disallowances should be rejected as unfounded and unreasonable, and the Company's SOC: ESOC and ASOC requests should be fully approved.

[98] The Company also addressed the need for the ASOC in Case Nos. U-20162 and U-20561 and provided additional testimony in this case addressing the need for the ASOC, the new plans, and the costs. Groundbreaking is planned by early 2023. The reason that construction did not occur previously was due to discovery of inflated costs associated with the original project, and the Company made changes to the project, including relocation to a dual-purpose site, that will keep the investment in line with the original estimates (Elliott Andahazy, 7T 1527-1530, 1551-1552).

v. Contribution in Aid of Construction (CIAC)

DTE Electric's Initial Brief, pp 100-104, discussed the Company's response to the Commission's directive to provide additional CIAC information (May 8, 2020 Order in Case No. U-20561, p 98), and why the Company's current CIAC policy should continue.

MNSC's Initial Brief, pp 110-24, largely re-asserts the MEC Coalition's proposal from Case No. U-20561, which they acknowledge would result in cost shifting (*Id*, p 122). The Company maintains its position for the reasons that it explained previously.[99]

MNSC further notes the Staff's January 15, 2022 CIAC Workgroup Report in Case No. U-20697, and that the Commission has not ruled on its recommendation to continue the CIAC discussions (MNSC Initial Brief, p 111, n 476; and p 123). MNSC further asserts that "the Commission should direct the Staff to reconvene and elicit from DTE the necessary information to . . . develop a modern and equitable CIAC policy" (*Id*, pp 123-24). The Company disagrees with MNSC's goal and underlying premise that there is something wrong with the current CIAC policy, as discussed previously and above. If the Commission chooses to continue the CIAC discussions, then the Company presumably would again participate. It bears emphasis, however, that appropriate CIAC policy is not to simply follow MNSC policy. Any continuation of the CIAC Workgroup should not be driven by MNSC's apparent preferences or otherwise be used to support an inappropriate position that the Commission declined to adopt in Case No. U-20561. In any event

[99] MNSC witness Ozar further proposed that the revenue requirements associated with the Company's credits toward CIAC should be split in two, with one group continuing to be assigned to distribution revenue requirements and recovered in distribution charges, and the second group assigned to power supply revenue requirements and recovered in power supply charges (Ozar, 8T 4036-4037).

The Company disagrees because credits for line extensions support investment in distribution plant for equipment such as transformers, conductors, poles, etc. System work for line extensions is not an investment in production plant, so credits should not be recovered in the production (power supply) revenue requirement. The current approach, in which distribution plant investment is recovered through distribution rates, continues to be the most appropriate method for recovering CIAC credits (Willis, 6T 996).

for purposes of this case, the Company properly responded to the Commission's directive for additional information, producing the current record confirming that the Company's current CIAC policy should be maintained.

vi. Advanced Metering Infrastructure (AMI)

DTE Electric's Initial Brief, pp 104-11, discussed Advanced Metering Infrastructure (AMI), and responded to Staff's initially recommended disallowance of $0.6 million for meters seasonally affected by vegetation. Staff no longer recommends a disallowance ("Upon the receipt of the additional information, Staff retracts this recommendation . . . The ALJ and Commission should approve the Company's $0.6 million request . . .") (Staff Initial Brief, pp 88-89). There is no further dispute on this issue.

The Company also previously discussed its request for approximately 950 advanced power quality (PQ) meters for the largest C&I customers,[100] and further explained that the Commission should at least approve $698,000 to cover the costs of replacing 3G meters with non-PQ 4G meters. "Staff agrees with the Company on the allowance of $0.698 million in costs to cover the replacement of existing 3G meters with non-PQ 4G meters" (Staff Initial Brief, p 90, further explaining that Staff was unclear in which period this expenditure is included, so Staff reduced its proposed disallowance in the bridge period).

The Company appreciates Staff's movement on these issues, but respectfully maintains that the full cost of the PQ meters should be allowed. Staff suggests that "[u]ntil the benefits of the

[100] The investment in PQ meters for the Company's highest-load customers is designed to reduce impact and/or damage to grid assets or customer equipment if disturbances occur. These customers have loads of 1 megawatt or greater and would have the largest potential for equipment damage in these scenarios. The PQ meters must be in service before the electrical disturbances occur so that the disturbances are detected immediately, and relevant data is available to inform personnel and/or customers if immediate, mitigating action is needed (Smith, 7T 1917).

advanced power quality meter can be qualified or proven with actual evidence, the Company's request should be denied." By analogy, that is like not building a bridge because there is no actual count of people driving over the bridge. The Company again notes that it is in an evidentiary dilemma – it cannot provide "actual evidence" of customer benefits from the investment until it makes the investment that will provide the "actual evidence" of those benefits by capturing occurrences and responses to power disturbances. There is, however, reasonable evidence of numerous benefits based on industry use of PQ meters by other utilities, as reflected by generally available publications (Smith, 7T 1909-1911). The investment is also otherwise justified, as the Company explained previously.

In addition, Staff has misunderstood the Company's request for recovery of historical expense, incorrectly recommending disallowance in the bridge period and test year (Staff Initial Brief, p. 90). The Company is requesting recovery of $3.9 million of investments made to deploy power quality metering within its service territory above the $9.2 million approved in U-20561 (Smith, 7T 1911-1912). For the reasons previously stated, the PQ meters were an appropriate investment made at an appropriate time for the Company's highest-load customers, and the $3.9 million investment should be approved.

vii. Community Lighting

DTE Electric's Initial Brief, pp 111-13, explained and supported the Company's Community Lighting capital expenditures for 2020 through the projected period ending October 31, 2023.

Staff's Initial Brief, pp 91-92, proposes capital disallowances of $1,848,079 in the bridge period, and $1,154,236 in the projected test year. MI-MAUI and Ann Arbor's Initial Brief, p 60, agrees.

The Company previously explained that it disagrees because Staff's disallowances are based solely on historical spend, rather than the Company's more detailed forecasting for the bridge and test year periods (Exhibit A-34, Schedule Y6). Staff did not account for (1) the slowdown in new business installations due to volatility attributable to COVID (disruptions in crew availability in 2021), (2) a high-impact storm season that resulted in crews that would otherwise have been assigned to new business installs, instead being re-assigned to storm restoration work, and (3) the impact of the Company's night patrol program (further discussed elsewhere regarding Community Lighting O&M), which is proactively identifying outages resulting in a corresponding higher outage restoration spend. Staff also apparently did not consider forecasted capital expenditures ($1 million per year) for the Company's proposed cable replacement program (which is new and not reflected in historical spend) to replace failing in-service cable (Bellini, 7T 1774-1775). Therefore, the Company's capital expenditures should be fully approved.

Staff's Initial Brief, p 92, responds that "[t]he Company's assertions that Staff's recommendation is based solely on historical spend is incorrect. Staff's recommendation is based on ratio of the Company's 2021 actual spend to forecasted spend for the same period."

Staff's reasoning is inaccurate because 2021 *is* historical. Staff similarly misses the mark in suggesting dismissal of the Company's evidence as somehow "not pertinent to Staff's recommended disallowance." (*Id*, p 92). Instead, the Company's evidence directly refutes Staff's recommended disallowance, so it is highly "pertinent." Finally, Staff suggests that "one cannot assume that [the Company's] forecasts in this case will be any more accurate" (*Id*, p 92). Staff's

speculative suggestion ignores the record, [101] as reflected for example by points (1) and (2) above, summarizing that 2021 was impacted by COVID and storms, which is also beyond credible dispute.

MAUI and Ann Arbor's proposal that credits should be applied from the point a street light outage is reported is unreasonable and is based upon an analysis that is significantly flawed. Ex-12, Schedule O-1 demonstrates during one of the worst storm seasons in history, standard outage events were restored on average 5.6 days from when they were reported and closer to 3.5 days historically. The analysis provided by Witness Bunch to support an immediate outage credit completely fails to account for follow up outage events involving solutions beyond the Company's control. As explained in detail in Witness Bellini's testimony, delays in restoration often result from lack of special-order material on hand by the municipality, unique municipality permitting requirements for underground facility repairs, pole knockdowns, third-party damage to infrastructure and false positive reports of outages (T7 1763-1766).

To the extent that MI-MAUI and Ann Arbor further suggest that any of the Company's capital costs should be disallowed (or increased by purchasing networked lighting controls), the Company incorporates its prior responses to their witnesses.

5. Demand Response (DR) Programs and DTE Insight

DTE Electric's Initial Brief, pp 113-17, discussed the Company's capital expenditures for its Demand Response (DR) portfolio and DTE Insight.

[101] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

i. Residential Generator Pilot

DTE Electric's Initial Brief, p 117, discussed the Company's plans to invest $0.46 million in the bridge and test periods to conduct a residential customer-owned natural gas generator pilot.[102]

Staff's Initial Brief, pp 94-95, recommends capital expenditure disallowances of $183,631 in the bridge period and $235,069 in the test year. The Company previously responded that much progress has been made in the development of the pilot since the first of the year, including an RFI process and the selection of Generac Grid Services for the implementation of the pilot. The Commission should approve the pilot because it is moving forward as planned and the Company is committed and prepared to launch a successful pilot (Farrell, 7T 1701-1702).

Staff responds that "[w]hile the Company's rebuttal does provide useful information on the proposed residential generator pilot and shows commitment from the Company to move forward, it does not address all of Staff's concerns" (Staff Initial Brief, p 94). The Company thought that it addressed Staff's concerns, but Staff states "[t]he Company does indicate plans to speak with Consumers Energy about the pilot (7 TR 1702.) but Staff is not aware of any results of that conversation or if it has taken place" (*Id*, p 95). The Company maintains that it properly supported its proposal, and it is inappropriate for Staff to now raise new criticisms after the record is closed.[103]

[102] The pilot will leverage a third-party service provider's platform using telemetry to shift customers' load to the electric generator in real-time peak events. Pilot participants will benefit by receiving an incentive from the Company and reduced electric bills during peak events (Farrell, 7T 1689-1991; Exhibit A-12, Schedule B5.6, page 1, line 3, columns (c) through (f)).

[103] January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, pp 37-38.

ii. Battery Storage Demand Response Pilot

DTE Electric's Initial Brief, pp 17-18, discussed the Company's plans to invest in a battery energy storage pilot using a behind-the meter (BTM) lithium-ion battery storage system (BESS) at C&I customers' sites.[104]

Staff "support[ed] the idea of the pilot," but recommended that the Commission deny the pilot based on the belief that the Company's proposal lacked specific details about how the pilot will be operated or implemented (Mathews, 8T 5282-5283). The Company responded that the pilot is sufficiently developed, explaining that since this case was filed, the Company completed both the RFI and RFP processes. The Company selected Hitachi as the pilot integrator and executed the contract in Q1 2022. The size of the batteries will be 500kW/2MWh total at two customer sites to reduce peak customer and system demand over an event of up to 4 hours. Therefore, the Commission should approve the bridge period expenditures of $1,356,847 and test year expenditures of $1,514,933 (Farrell, 7T 1702-1703).

Staff's Initial Brief, pp 95-96, maintains Staff's original position for a full (rounded to $2,872,000) disallowance, stating that "[a]lthough the Company has made progress on the implementation of the program, it has not addressed Staff's concerns about programmatic specific details." (*Id*, p 96). It is unclear what Staff has in mind, or why Staff may consider it sufficient to disallow the pilot, particularly after supporting the idea and acknowledging the Company's

[104] The pilot is designed to test the ability to achieve peak demand shaving or shifting during demand response events, targeting C&I customers enrolled on Rates D4, D6.2 or D11 (excluding sites or load under Rider 10) since these customers are more suited to pilot participation due to their peak load profiles, outdoor space availability and operational capabilities. The pilot is appropriate because the Company needs to gain experience with the application of storage technology by end-use customers and interactions with the wholesale market in order to develop well-designed tariffs and related pilot programs for customer-owned battery storage, as indicated by the August 11, 2021 Order in Case No. U-21032. The Company forecasts $2.8 million in capital expenditures (Farrell, 7T 1684-1689; Exhibit A-12, Schedule B5.6, page 1, line 3, columns (c) through (f)).

progress. The Company maintains that it adequately supported the pilot, so it should be approved under the applicable standards discussed above.

Walmart's suggestion that the Company be ordered to "work with interested parties" on DR programs that, for example, permit a customer to fail to comply with DR load reduction requirements and shift the consequences to others should similarly be dismissed in favor of the Company's reasonable proposals. (Walmart Initial Brief pp 9-10)[105]

6. Information Technology

DTE Electric's Initial Brief, pp 118-41, explained and supported the Company's Information Technology (IT) investment spending, and responded to various proposed disallowances by the Staff and AG.

i. IT Projects with a Level 1 Cost Estimate

Staff's Initial Brief, pp 96-100, proposes a complete ($50,726,000) disallowance of the projected costs associated with the 26 business cases identified by the Company as having a Level 1 cost estimate, characterizing them as insufficiently supported. As discussed in DTE Electric's Initial Brief, pp 124-26, the Company disagrees, emphasizing that it has made significant efforts to address feedback from Staff and the Commission in Case No. U-20561 by providing exhibits with additional project details. These exhibits include all of the requested data and the associated workpapers, which contain project details, investment scope, cost breakdown estimates, benefits, and alternative and cloud strategy for investments in the test period. (Sharma, 7T 2129; Pizzuti 7T

[105] See also *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm,* 269 Mich App 473; 713NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.)

2251). The Company also provided business case cost estimation worksheets with detailed breakdown of cost-by-cost type and the new additional project details exhibit with cost breakdown as requested by Staff in previous cases (Sharma, 7T 2132-2133).

Staff's assertion that "[a] project with a level 1 cost estimate is immature and solely a concept being screened for feasibility within the Company's annual expense plan" (Staff Initial Brief, p 97) misconstrues the Company's Annual Planning Cycle (APC) Process. Investments are marked as "Level 1" only because of the timing of the estimate in the multi-year APC process rather than indicating the accuracy of the estimated costs, so this designation should not lead to an assumption that known cost details are insufficient or will result in significant variance (Sharma, 7T 1927-1928, 2129). The Company also submitted cost breakdown information with Exhibit A-24, Schedule N3 Revised (Sharma, 7T 2129), and Mr. Sharma explained why historical spend is a valid benchmark for estimating future spend for each of the Level 1 projects, as the projects are either considered repeatable, like IT projects executed in prior years, or similar in scope or complexity to other IT projects (Sharma, 7T 2130-2133), as further discussed in DTE Electric's Initial Brief.

Staff's Initial Brief, pp 98-100, responds that the Company's rebuttal "only solidifies Staff's position regarding the accuracy of Level 1 cost estimates . . . Staff doubts the accuracy of the estimation as the Company suggests." Staff insists that things like confidence levels or historic accuracy levels should be used as a basis for determining the level of precision of the Company's Level 1 costs estimates. The Company does not evaluate confidence levels related to its cost estimates. Even so, as explained by Mr. Sharma, it is possible to develop concise cost estimates without the aid of confidence intervals or historical estimates because in many instances IT projects

are so substantially similar in many ways to past projects that it is possible to provide concise estimates at the Level 1 estimation stage. (Sharma 7T 2129-2132)

The Company maintains that it properly supported the projects under the "preponderance of the evidence" standard,[106] and that Staff's doubts about cost accuracy do not justify a disallowance. [107] Staff's proposed remedy (100% disallowance) is also inconsistent with Staff's reasoning, particularly since Staff acknowledges that the Company provided information "necessary to understand the scope of the project" (Staff Initial Brief, p 99), and Staff does not dispute the projects based on reasonableness or prudence. Assuming for argument's sake that there is some merit in Staff's concern about a "lack of precision and uncertainty of Level 1 cost estimates," then there might be a basis to consider a range of outcomes, as discussed below regarding projects with Level 2 costs estimates. But there is no sound basis to assign $0 to the projects for a perceived lack of precision. Lack of precision does not equate to lack of existence. Staff's proposal for no recovery based on an alleged uncertainty about whether the Company is 100% accurate is broad sweeping and does not consider the significant support that DTE Electric has provided for these projects.[108] Therefore, the project costs should be approved.

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[106] *Aquilina v General Motors Corp*, 403 Mich 206, 210-211; 267 NW2d 923 (1978) ("The proof required in an administrative proceeding…is the same as that required in a civil judicial proceeding: a preponderance of the evidence.").

[107] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

[108] See, for example, *Entergy Gulf States, Inc v Louisiana Public Service Comm*, 730 So2d 890, 901 (1999) (reversing agency's decision as "untenable" and finding all its reasons to be "arbitrary or capricious or unsupported by the record"); *Bureau of Health Care Services v Pol*, unpublished opinion per curiam of the Court of Appeals, issued June 23, 2016 (Docket No. 327346; 2016 WL 3452174 at * 7) (reversing agency decision).

ii. IT Projects with a Level 2 Cost Estimate

Staff's Initial Brief, pp 100-103, proposes a 20% ($35,949,000) capital investment disallowance ($19.596 million in the ten months ending October 31, 2022; $16.353 million in the projected test year) for 108 projects, reasoning that "[w]hile Level 2 costs estimates are more mature than Level 1 cost estimates and include a more detailed breakdown of costs . . . These cost projections are incomplete" (*Id*, pp 100-101).

DTE Electric's Initial Brief, pp 126-27, explained that the Company disagrees because, as outlined in Mr. Sharma's testimony and further supported by exhibits and workpapers, the Level 2 projects are based on defined and detailed scopes and timelines, and are vetted by all IT departments/teams during the cost estimation process. Also, 92 of the 108 Level 2 projects ($31.5 million) are in progress so the cost estimates are closer to a Level 3 cost estimate (Sharma, 7T 2134).

Staff's Initial Brief, p 102, responds that this new information does not change Staff's position because there is no indication that the costs changed, and they are still Level 2 cost estimates. Staff neglects the Company's point about the additional assurance of accuracy for the vast majority of the projects at issue.

Staff's proposed 20% disallowance also neglects that the Company has consistently spent close to its Level 2 estimate or higher. For example, there was just a small 2% overspend variance ($103.3 million compared to $105.4 million total actual spend) for the 68 projects greater than $0.25 million completed as requested in Case No. U-20561 for the year 2020 (Sharma, 7T 2134-2135; Exhibit A-42, Schedule GG3, 2020 IT Project Historical Spend Variance Comparison).

Staff's Initial Brief, pp 102-103, responds that "38 of the 68 projects listed were over-projected and under-spent. The percent difference between the projected spend and the actual spend

varied significantly, with extremes ranging from 100% over projection to 316% under projection. This causes Staff to greatly question the Company's estimation practice."

Staff again neglects the Company's point, which is that even assuming inaccuracy in individual project estimates (as Staff suggests), the over-projections and under-projections offset each other, trending back towards the overall projection (a collective variance close to 0). Just as there was a 2% variance for the 68 projects in Case No. U-20561, a similar overall projection accuracy can be expected for the 108 projects at issue here.

The Company also disagrees with Staff's 20% disallowance as it is arbitrary and unsupported. Staff chose 20% by equating the Level 2 cost estimates with the American Association of Cost Engineering (AACE) Class 3 estimates, and used the lower bound of -20% as the basis for its proposed disallowance (Rogers, 8T 5346). The AACE is just one method of cost estimation, and even if it were applicable, Staff's 20% proposal neglects that the AACE class 3 cost estimate also provides an upper bound of +30% (Sharma, 7T 2134). Also, while the Company does not agree that the Commission should apply any percentage disallowance, it would be more accurate to compare Level 2 estimates to AACE class 2 estimates with a -15% to +20% range (Sharma, 7T 2135-2136).

Staff maintains its 20% proposal, stating that "[o]f the 38 IT projects in Rebuttal Exhibit A-42 Schedule GG3 that were over projected and under spent, the average variance for underspending was -40%" (Staff Initial Brief, p 103). Looking at only a portion of the data to support Staff's previously-determined outcome, does not provide an accurate representation of the Company's spending. Again, looking at all of the data, the Company's overall projections are accurate and nowhere near 40% variability.

Therefore, Staff's proposed 20% disallowance should be rejected as unsupported and contrary to both the Company's supporting project level detail and to history demonstrating that the Company's overall IT investment does not come in 20% under budget (Sharma, 7T 2136-2137; Pizzuti, 7T 2251).

iii. IT Projects without Business Cases

DTE Electric's Initial Brief, p 127, reflects that Staff initially recommended a $1.87 million disallowance ($0.36 million for the bridge period; $1.51 million for the test year) for five projects without supporting business cases. The Company agreed with Staff's $1.51 million test year reduction, but in rebuttal submitted a business case for consideration of a $0.36 million recovery (Sharma, 7T 2137; Exhibit A-42, Schedule GG1 MIGP – Integrate DTE Insight Program business case). Staff's Initial Brief, pp 117-19, maintains Staff's position, but revises Staff's proposed disallowance to $1,539,000 ($0.325 million in the bridge period; $1.214 million in the test year) for accuracy. The Company appreciates Staff's revision for accuracy, but respectfully maintains that it should recover an additional $0.36 million based on the business case as indicated above.

iv. IT Project Spend Capitalization Policy, and Proposed Disallowances

For convenience and continuity of discussion, IT O&M is addressed here with other IT issues (although the overall discussion concerns capital expenditures), due to the nature of Staff's proposals to (1) shift some IT capital expenditures to O&M expense, and (2) disallow O&M expense. The Company disagrees with both of Staff's proposals, as discussed below.

a. Staff's shifting proposal.

Staff's Initial Brief, pp 127-30, recommends a $7.71 million disallowance, reasoning that costs for four IT projects (ClickSoft Application Health; Distribution Application Health; Fuel Supply Application Health; and Fermi Enhancements) were improperly categorized as capital

expenditures when they should be O&M expenses. DTE Electric's Initial Brief, pp 127-29, explained that the Company disagrees and maintains that the disallowance should be rejected based on the Company's capitalization policy. Staff does not substantively respond to the Company's discussion of evidence. For illustrative example, compare the detailed examples of added functionality for the DO application health project (Uzenski, 7T 2794-95) with Staff's assertion that "these examples still do not qualify for capitalization" (Staff Initial Brief, p 129). The Company maintains that it satisfied the "preponderance of the evidence" standard[109] and that Staff's contrary speculation carries no weight, [110] incorporating its prior discussion, the additional detail in the record, and section III above.

The Company previously explained that Staff also proposed a double $2.54 million disallowance for the DERMS project with regard to Distribution Operations. The Company agrees that there should be a reduction from the IT forecast, but the Commission should reject the proposed duplicative disallowance from the Distribution Operations forecast (Pfeuffer, 4T 486-487).

Staff's Initial Brief, pp 77-78, and 132-33, instead asserts that Staff recommends two separate DERMs disallowances – one for duplicative costs, and the second because the DERMS project allegedly is in a preliminary stage, and allegedly not eligible for capitalization. Staff alleges that because the Company has not selected a vendor this is indicative that the project is in its preliminary stages and, therefore, costs should not be capitalized. Staff has assumed, without

[109] *Aquilina v General Motors Corp*, 403 Mich 206, 210-211; 267 NW2d 923 (1978) ("The proof required in an administrative proceeding…is the same as that required in a civil judicial proceeding: a preponderance of the evidence.").

[110] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

evidence, that the Company's capital projections for software development include the project costs that must be expensed to O&M under GAAP. They do not. Even if the DERMs project is currently in a preliminary stage, the Company's capital request reflects only those costs properly capitalizable (i.e., starting with the development stage) (Uzenski, 7T 2793).

Staff's Initial Brief, pp 279-80, further suggests that there should be at least one meeting among the Staff, the Company, and other interested stakeholders regarding the Company's IT cost capitalization procedures. As Ms. Uzenski stated in her testimony, a meeting on accounting practices with all potential stakeholders is not necessary nor a good use of limited resources, however, but the Company would agree to meet with Staff on the issue.

b. Staff's disallowance proposal.

Staff's Initial Brief, pp 171-72, reflects that Staff proposed a $11.2 million O&M reduction and suggested that this disallowance is related to the IT capital expenditures that it proposed to disallow (see generally, Rogers, 8T 5342; Exhibit S-12.8). In addition to the discussions above that capital expenditures should be approved, DTE Electric's Initial Brief, pp 129-30, explained that the Company disagrees with Staff's $11.2 million disallowance for two additional reasons.

First, Staff's proposed IT O&M reductions were not included in the Company's requested revenue deficiency. Instead, the Company's projected O&M uses 2020 historical investment and adjusts for inflation and other specific projection adjustments (Exhibit A-13, Schedules C5). Since the Company's projection adjustments did not include the amounts at issue, they should not be disallowed (Uzenski, 7T 2777). Staff's Initial Brief, p 172, notes this argument, but does not offer a response.

Second, if the Commission were to decide to disallow any O&M expenses, then that disallowance should be reduced to the portion that applies to DTE Electric only. The O&M cited by Staff is the amount supporting all DTE Energy users of the assets. The IT O&M costs recorded

at DTE Electric are based on the bill down of costs from the LLC, or about 73% of the total, as reflected by Exhibit A-43, Schedule HH1, column (f). Therefore, if the Commission disallows any O&M related to these IT projects, the amount should be calculated in accordance with column (f). (Uzenski, 7T 2777-2778).

"Staff agrees with this argument. If the ALJ and the Commission adopt Staff's IT project disallowances and Enterprise Automation disallowances, the shared asset revenue for these disallowances should also be adjusted as shown on Exhibit A-43, Schedule HH1. These revenue adjustment impacts are not reflected in Staff's Initial Brief" (Staff Initial Brief, p 135. See also, p 172: "Staff agrees with the Company that the O&M adjustment should be attributable to DTE Electric only, therefore reducing the recommended disallowance for projects with Level 1 and Level 2 cost estimates by 27%").

Staff's Initial Brief, pp 169-71, also proposes an additional 0.5% ($2,876,229) IT O&M disallowance based on the general assumptions that "[g]iven that IT O&M is typically assumed to be 10%, but varies from 6-13% in actuality . . . Staff recommends a midpoint of 9.5%" The Company previously explained that it disagrees with Staff's analysis and resulting proposal. Staff incorrectly assumed that all IT O&M is related to capital projects. Instead, as the Company explained in response to Staff's discovery questions (included as Exhibit A-43, Schedule HH2), not all IT investments are associated with a capital project, and the O&M noted in individual business cases is not used to calculate projected O&M. IT O&M expense includes cloud computing fees, hardware and software defect remediation, business support service, and IT administration. Thus, Staff's proposed disallowance should be rejected (Uzenski, 7T 2778-2779).

Staff's Initial Brief, p 170, responds: "The values used in Staff's IT O&M disallowance were not assumptions but provided by the Company in discovery responses. (See Exhibit S-7.49.)"

It is true that the Company provided the *values*, but those values were in the context of responding to Staff's request concerning one specific project (Exhibit S-7.49, p 4). Then, Staff incorrectly *assumed* it was appropriate to apply those project values to an across-the-board IT disallowance, including other matters such as cloud computing fees, as discussed above.

Staff's Initial Brief, p 171, inaccurately indicates that the Company suggests that "Staff cannot propose disallowances to IT O&M based on knowledge learned from discovery." The Company makes no such suggestion. Instead, Staff apparently made an unjustified assumption based on that discovery, as discussed above.

Staff's Initial Brief, p 170, asserts: "Staff finds it counterintuitive that the Company's methodology to project IT O&M costs is estranged from actual proposed work." But the Commission's decision must be based on evidence (summarized above), not Staff's assumptions, or what Staff may find counterintuitive in the face of evidence disproving its incorrect assumptions.[111]

v. IT Projects Historical Spend Analysis

DTE Electric's Initial Brief, p 131 explains why the Company disagrees with Staff's proposal for a $1.85 million disallowance based on calculations shown at Wang, 8T 5231-5232. [112]

[111] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

[112] The Company disagrees because Staff extrapolated data from a very small sample size to arrive at the conclusion that a portion of IT project cost estimates should be disallowed. The entire exercise is unnecessary and leads to an incorrect conclusion because (1) the projects are prudent and in progress, (2) the cost estimates are very detailed and commensurate with the scope of work being completed, and (3) the actual expenditures for the 2020 historical period on the sample of projects chosen by Staff was higher than the projected spend in Case No. U-20561. (Sharma, 7T 2139-2140; Exhibit A-42, Schedule GG4, showing projected spend of $8.2 million and actual spend of $12.3 million).

Staff's Initial Brief, pp 131-32, maintains the Staff's position, but does not respond to the Company or suggest any other basis for Staff's proposal.

vi. Other Individual IT Project Disallowances

DTE Electric's Initial Brief, pp 131-32, discussed the Company's considerations when evaluating IT projects for investment, and goal of providing Distinctive Service Excellence (reflected for example in the DTE IT 5-Year plan).

Staff recommended a disallowance for three IT projects (further discussed in DTE Electric's Initial Brief and below) that support a multi-year strategy to improve the customer's transactional journey. Evaluating these projects as individual, stand-alone projects, without considering how they fit into the context of delivering Distinctive Service Excellence, overlooks this additional value that they provide (Pizzuti, 7T 2253). Staff also proposed a total of $13.4 million capital disallowances for six IT projects (Reservation Application; Network Advanced Metering Infrastructure Support; Controllers Financial Planning Tool; Virtual Desktop Infrastructure; Command Center Stand Up; and GRC Tool Expansion for Regulatory Assets). The Company disagrees because the projects are prudent, necessary and well supported, as outlined in DTE Electric's Initial Brief and below, and further detailed in Mr. Sharma's rebuttal testimony (7T 2140-2145).

a. Platform integration-SAP integration.

Staff's Initial Brief, pp 108-109, proposes a complete disallowance ($1.836 million in the bridge period; $0.514 million in the projected test year), indicating concerns about customer benefits. DTE Electric's Initial Brief, pp 132-33, explained that the Company maintains that the project's benefits and value are reflected in its name - integration. The project provides integration between the SAP systems (in the back end) and many of the Company's Customer Service IT

projects that provide an enhanced or new customer experience in its digital channels (the front end, and customer-facing system or technology). All front-end customer experiences where data is collected require integration and connection to the back-end SAP customer systems where data is processed and stored in order to process transactions more smoothly. Migration of functionality and capability from disparate legacy systems to a single SAP platform allows information from the Company's operations to flow to front-end systems that directly serve the customer, thus benefiting customers by providing more comprehensive information to the customer during their experience. (Pizzuti, 7T 2253-2254).

Staff maintains its position, stating that the Company "still did not explicitly explain how this investment will benefit customers [who will] still receive their billing data and account balances without this investment" (Staff Initial Brief, p 109).

b. Automation application monitoring enhancement.

Staff's Initial Brief, pp 109-11, proposes a complete disallowance ($2.363 million in the bridge period; $0.357 million in the projected test year), reasoning that the Company did not demonstrate that it "will improve safety or reliability of electric service to customers . . . [so it] is an imprudent expense at this time" (*Id*, p 110). DTE Electric's Initial Brief, pp 133-34, explained that the project's capability and benefits include enabling interface monitoring, job monitoring, user experience monitoring, business process modeling, and providing an alert when computing power/performance is low for supporting these processes. The project is expected to improve the SAP Customer Relationship and Billing (CR&B) system's uptime by 1% and reduce unplanned outages by 1%, which equates to an approximately $50,000 per year reduction in IT support time to resolve unplanned events (Pizzuti, 7T 2255).

Staff maintains its position, asserting that the IT savings are insufficient as compared to the investment (Staff Initial Brief, pp 110-11). The Company also maintains its position, noting that

the above-described savings are consequential (avoided IT support time) and that there is further value in avoiding system downtime, which prevents customers from transacting business with DTE Electric in their channels of choice.

c. Supporting capabilities – test data and test data management.

Staff's Initial Brief, pp 111-12, proposes a complete disallowance ($0.914 million in the bridge period; $0.256 million in the projected test year), reasoning that the Company did not demonstrate "that this project improves the safety or reliability of electric service to customers" (*Id*, p 111). DTE Electric's Initial Brief, p 134, explained that Staff neglects that IT projects must be thoroughly tested before they are put into production to avoid adverse effects. The Company maintains that the project provides benefits by increasing the efficiency, and improving the effectiveness, of the Company's IT project testing processes and ability to meet IT project delivery deadlines, and prevent potential defects or issues from occurring downstream of the project (Pizzuti, 7T 2255-2256).

Staff maintains its position, acknowledging the Company's rebuttal, but not responding to its substance. The Company maintains its position, noting that it agrees with Staff that safety and reliability are important customer benefits, but disagreeing with Staff's suggestion that they are the *only* possible benefits. Therefore, and as further discussed in the introductory comments of DTE Electric's Initial Brief regarding strategic context and additional customer benefits, all of the costs for these projects should be approved.[113]

[113] There is a discrepancy in Staff's revenue requirement relating to the Advanced Customer Pricing Pilot (ACPP) and Time-of-Use (TOU) project. The Company understands that Staff fully supports the Company's "Alternative" TOU proposal costs as outlined in Exhibit S-23.01, less contingency, and requests that the Commission approve these costs (Pizzuti, 7T 2256-2257). Staff properly reflected it in their Initial Brief position.

d. Digital Experience Group (DEG).

Staff recommended a 60% ($3,109,000) disallowance of historical 2020 capital costs, reasoning that "[w]hile Staff supports the goal of eliminating silos and creating a cross-functional team to improve Customer IT, the Company has not provided adequate detail of the customer benefit for this expenditure in relation to the cost . . . [and] customers are more concerned with reliable, affordable electricity, correct meter reading, and accurate billing" (Armstrong, 8T 5493). DTE Electric's Initial Brief, pp 134-35, explained that the Company disagrees and has provided evidence of benchmarking with utility peers demonstrating that customers care about being able to use digital channels to interact and transact business with the Company. Successful results, such as order tracking and enhanced notifications that reduced the need for a customer to call, led to call reduction savings from the Move In/Move Out (MIMO) DEG; and an improved outage web experience and more accurate outage reporting from the Outage DEG investments confirmed the need of these projects and their customer benefits, justifying their full cost recovery (Pizzuti, 7T 2190, 2262-2263).

e. Digital transactional experience.

Staff proposed a 60% disallowance ($3.87 million) in the bridge period, stating that Staff supported the concept of improving customer service, but "it is unclear how this expenditure line accomplishes this goal with reasonable costs" (Armstrong, 8T 5496). DTE Electric's Initial Brief, p135, explained that the Company disagrees because this project continues and builds on the

success of the 2020 DEG project as described above.[114] These investments also generated favorable results and customer benefits.[115]

Staff "continues to question" the additional benefits provided by investments in this area, and that it views the cost as "excessive" (Staff Initial Brief, pp 121-22). The Company maintains that the investment is justified as it explained previously.

f. Prepay billing program.

Staff's Initial Brief, pp 119-20, proposes a total disallowance of the Company's proposed voluntary PrePay Billing Program's capital costs of $7,975,000 in the bridge period and $4,647,000 in the projected test year. DTE Electric's Initial Brief, p 136, explained that the Company disagrees because PrePay represents an attractive voluntary alternative for customers who wish to gain more insight and control over their energy usage or who struggle with paying their bill with today's post-pay billing model. The Company further maintains that the capital expenditures related to PrePay are reasonable and prudent, but appreciates Staff's position that recovery for these costs would be pending formal approval of the filed PrePay Case U-21087 (Armstrong 8T 5491; Pizzuti, 7T 2267). The Company understands and agrees that the necessary billing rule waivers are required to proceed with the program. However, the Company disagrees to the extent Staff suggests that the Company should seek costs in a subsequent and separate case even if the Commission were to approve the

[114] The Company continued funding for the MIMO and Outage Digital Product Teams to add improvements that support higher engagement and completion rates in these transactions in 2021 by improving digital process flows, providing more and clearer information to the customer, and simplifying navigation of the web and mobile web experiences. The Digital Product Teams also expanded its scope of work to include Billing and Collection transactions, adding more digital and voice self-service solutions for our customers (Pizzuti, 7T 2264).

[115] Investment in the MIMO Digital Transactional Experience, in conjunction with the Closed Loop Framework, led to higher customer satisfaction scores (as measured by Net Promoter Score) and First Contact Resolution. Continued focus on the Outage Digital Transactional Experience led to higher completion rates despite the record number of storms in summer 2021. Investment in the Collections Digital Transactional Experience by adding a Collections order tracker and the ability for customers to request a Promise-to-Pay Hold or to Restore Service in the IVR saw early, yet promising results with customers choosing to conduct these transactions in a self-service channel versus interact with a CSR, in line with peer benchmarking (Pizzuti, 7T 2264-2266; Exhibit A-44 Schedule II3).

necessary waivers prior to the conclusion of this case as the Company has demonstrated that the costs are reasonable and prudent (Pizzuti, 7T 2267).

Staff maintains its position, referencing Case No. U-21087, and further asserting that "[t]he expenditures of the prepay program have not been scrutinized for reasonableness" (Staff Initial brief, p 120). The Company disagrees because Case No. U-21087 was properly addressed above, the expenditures were presented for review in this Case No. U-20836, [116] and they are reasonable as indicated above.

g. Reservation application.

Staff's Initial Brief, pp 103-105, recommends a total ($0.5 million) disallowance in the 22-month bridge period ending October 31, 2022, reasoning that the cost is unnecessary, there are less expensive options, and the COVID-19 pandemic is now in an endemic state. DTE Electric's Initial Brief, pp 136-37, explained why the Company disagrees.

Staff maintains its position, emphasizing its view that there are other less expensive options available, and suggesting that compliance with pandemic guidelines should be less burdensome in the future (Staff Initial Brief, p 104). The Company disagrees because the project started during the pandemic, and although COVID-19 may be transitioning to an endemic state (which was the claim made by Staff's witness), there are continuing requirements to maintain employee health and safety through social distancing and contact tracing. The program also positions the Company for any future outbreaks. Finally, Staff's suggestion that the Company could contact trace and sanitize used

[116] "The state, as well as an individual, may be estopped by its acts, conduct, silence and acquiescence." *Wiersma v Michigan Bell Telephone Co*, 156 Mich App 176, 185; 401 NW2d 265 (1987). *See also, Michigan Gas Utilities v Public Service Comm*, 200 Mich App 576, 584-85; 505 NW2d 27 (1993) (rejecting agency's attempt to disavow its prior decision, explaining that if an estoppel existed, it was against the agency); *Entergy Gulf States, Inc v Louisiana Public Service Comm*, 730 So2d 890, 901 (1999) (reversing agency's decision as "untenable" and finding all its reasons to be "arbitrary or capricious or unsupported by the record").

facilities in an effective way without this application neglects the complexity of the manual effort needed to complete contact tracing and sanitizing requirements (Sharma, 7T 2141). Staff responds by suggesting that the Company would have to contract trace and sanitize anyway, neglecting the Company's point about the difference in effort involved with and without this application.

h. Network advanced metering infrastructure support.

DTE Electric's Initial Brief, p 137, discussed Staff's initially-proposed full disallowance ($2.0 million in the historic period, $4.6 million in the bridge period, and $2.2 million in the projected test year). Staff's Initial Brief, pp 105-106, no longer supports this proposal, explaining in part that "Staff finds the additional information convincing and the investment reasonable and prudent" (*Id*, p 106).

i. Controllers financial planning tool.

Staff's Initial Brief, pp 106-108, recommends a complete disallowance ($2.187 million in the bridge period and $0.613 million in the projected test year). DTE Electric's Initial Brief, pp 137-38, explained that the Company disagrees because it had a Level 2 estimate that reflected the costs of the products that were considered, and provided scope details. The project is currently in progress following the Company's selection of one of the alternatives that it considered (Oracle EPM product) as a viable solution to replace the current SAP BPC Planning tool. Thus, Staff's indicated concern has been addressed. Staff also indicated that it is not opposed to this type of investment (Rogers, 8T 5352), and Mr. Sharma's testimony further demonstrates that the investment is prudent and necessary (7T 1958-1959, 2143).

Staff responds by questioning the accuracy of the Level 2 cost estimate, and asserting that "this project is an example of the uncertainty Staff has with the Company's APC process and its designation of Level 1, 2, and 3 cost estimates" (Staff Initial Brief). The Company respectfully disagrees. Even assuming for argument's sake that Staff's indicated concern about cost-estimate

accuracy has merit, then the result should be in accordance with other projects having a Level 2 cost estimate, where Staff proposes a 20% disallowance (see section V. B. 7. ii above – IT projects with Level 2 Cost Estimate). Staff's Draconian (100%) disallowance for cost-estimate accuracy concerns is inappropriate and contrary to Staff's own reasoning. Plainly the cost is not $0, and there is no other basis for a disallowance, so Staff's proposed disallowance should be rejected.

j. Virtual desktop infrastructure.

Staff's Initial Brief, pp 113-14, recommended a total disallowance ($0.203 million in the bridge period and $0.252 million in the projected test year) stating that "[t]his project is no longer essential. Its purpose of matching virtual desktop infrastructure to an increased demand for remote work is irrelevant since COVID-19 has entered the endemic phase." DTE Electric's Initial Brief, p 138, explained that to the contrary, while the COVID-19 pandemic initiated the demand to enhance the Virtual Desktop Infrastructure, the Company will continue to operate with employees working from home or in a hybrid work model, and the investment is required (Sharma, 7T 2096-2097, 2143-2144).

k. Command Center stand up.

DTE Electric's Initial Brief, pp 138-39, discussed the Company's disagreement with Staff's proposal for a total disallowance ($0.406 million in the bridge period and $0.044 million in the projected test year). Mr. Sharma explained that this investment is required, and that it will establish a physical command center where the Company will be able to monitor critical IT assets with enhanced dashboards allowing improved response times to IT applications trouble events. This relates directly to customers because the critical applications support key business operational processes that allow the Company to fulfill its business processes, operations, and customer service requirements. Mr. Sharma also provided numerous examples of critical assets and applications that

are monitored by the Command Center and that directly support customers (Sharma, 7T 2099, 2144).

Staff's Initial Brief, pp 114-16, maintains Staff's position, asserting that despite Mr. Sharma's rebuttal testimony, Staff still has concerns because it is "unsure if this investment is for the building of a completely new standalone facility." It is not and the Company maintains that the project is supported and should be approved.

l. GRC tool expansion for regulatory assets.

Staff proposed a complete disallowance ($0.103 million in the historical year; $0.45 million in the bridge period) reasoning that the benefit of reducing manual labor does not outweigh the project's cost (Rogers, 8T 5360 26). DTE Electric's Initial Brief, pp 139-40, explained that the Company disagrees because there are benefits beyond annual time savings, and cost-benefit was not the only consideration in selecting this as a prudent investment. The investment will ensure that IT assets have the necessary compliance and risk elements associated to comply with regulations and standards. The investment will also manage regulation, business, and technology changes more effectively, and allow the Company to proactively respond to risks (Sharma, 7T 2044, 2145).

Staff maintains its position (Staff Initial Brief, pp 116-17), as does the Company.

Finally, DTE Electric's Initial Brief, p 139, reflects that Staff indicated that it does not recommend a disallowance of the gas portion of shared IT assets (Rogers, 8T 5370), which presumably means that Staff is not reducing the shared asset revenue to account for Staff's proposed disallowances to IT shared assets. The Company forecasted $57.2 million of revenue from shared assets, assuming the capital projects in this case are approved (Exhibit A-13, Schedule C3, line 14). If the Commission disallows a capital project that is for a shared asset, then for consistency it must also remove the revenue related to that asset from projected net operating income (Crozier, 7T

2394; Uzenski, 7T 2786-2787). Exhibit A-43, Schedule HH1, column (e) shows the reduction to shared asset revenue for each project proposed for disallowance by Staff.

Staff's Initial Brief, p 135, states: "Staff agrees with this argument. If the ALJ and the Commission adopt Staff's IT project disallowances and Enterprise Automation disallowances, the shared asset revenue for those disallowances should also be adjusted as shown on Exhibit A-43, Schedule HH1. These revenue adjustment impacts are not reflected in Staff's initial brief."

vii. AG's proposed disallowances

a. Time of use.

The AG's Initial Brief, pp 66-69, proposes a complete disallowance ($18.9 million for the bridge period; $11.2 million for the test year), reasoning that the "project appears to be much more than the pilot program approved by the Commission," and recommending "that the Commission suspend any further work and spending on the pilot program until a lower cost path is agreed to by the parties and approved by the Commission" (8T 4803-4804).

DTE Electric's Initial Brief, p 140, responded that it appears the AG's proposals are based on the incorrect premise that the projected costs are for the pilot, however, the costs are for the full implementation of TOU rates that the Commission directed the Company to achieve for the summer of 2023. The Company also proposed an alternative TOU implementation plan, with a capital cost reduction of approximately 35% as reflected in Exhibit S-23.01, which Staff supports.[117]

The AG's Initial Brief reiterates her position but does not add to the discussion. The Company maintains that the AG's position is based on an incorrect premise, and notes that no other

[117] Staff's Exhibit S-23.01 shows the TOU Alternative capital costs to be $19.5 million ($10.1 million for twelve months ending October 31, 2022 and $9.4 million for twelve months ending October 31, 2023). The Company understands that Staff fully supports the Company's "Alternative" TOU proposal costs as outlined in Exhibit S-23.01, less contingency, and requests that the Commission approve these costs (Pizzuti, 7T 2256-2257). Staff agrees (Staff Initial Brief, p 146).

party appears to have a similar misperception. The project is also critical for the successful implementation of TOU rates, so full cost recovery of TOU IT costs should be approved (Foley, 6T 1146-1147; Pizzuti, 7T 2268-2269).

b. Voluntary prepay billing program.

The AG's Initial Brief, pp 69-72, proposes a complete ($12.6 million) disallowance ($6.7 million for the twelve months ended 12/31/2021; $1.3 million for the ten months ending 10/31/22; and $4.6 million for the projected test year), suggesting that there is no evidence that customers are seeking this type of service, and questioning whether customers would benefit from it (8T 4805-4806). DTE Electric's Initial Brief, p 140-41, explained why the Company disagrees.[118]

The AG does not respond directly, but instead references Case No. U-21087. DAAO's Initial Brief, p 61-67, takes a similar approach. The Company disagrees with the AG and DAAO's characterizations of PrePay. As discussed above in section V. B. 7.vi. f (Prepay Billing Program), if the necessary billing rule waivers are approved in Case No. U-21087, then the Company's costs should be approved in this Case No. U-20836. The Company further maintains that it is inappropriate for the AG and DAAO to attempt to re-argue Case No. U-21087 here and reserves all rights in both cases.

c. Digital transactional experience and journey work product transformation teams.

The AG's Initial Brief, pp 72-75, proposes a complete ($6.5 million) disallowance in the bridge period of 2021 costs for the Digital Transaction Experience project, and a $4.2 million

[118] The Company disagrees because it provided extensive evidence that PrePay is an attractive voluntary alternative for customers who wish to gain more insight and control over their energy usage, or who struggle with paying their bills with today's post-pay billing model. The Company further maintains that the capital expenditures are reasonable and prudent and has provided significant details about the design of the program, customer segments that might benefit most from participating in it (see Exhibit A-44, Schedule II4), enrollments, eligibility requirements, and how Phase 1 of the program will help the Company understand the customers who are interested in PrePay and what they find most compelling about the program (Pizzuti, 7T 2270-2271).

disallowance in the projected test year for the Journey Work Product Transformation Teams because the Company did not complete a traditional cost benefit analysis (8T 4808-4809). DTE Electric's Initial Brief, p 141, explained why the Company disagrees.[119]

The AG responds that the Company's discovery responses (Exhibit AG-1.71, pp 2-6) "confirm that the Company did not perform a full cost benefit analysis . . . Therefore, the requested cost recovery remains unsupported" (AG Initial Brief, p 74). To the contrary, cost recovery is supported by the evidence discussed previously and above, as well as the AG's referenced discovery responses, which further reflect that the projects have significant benefits, including financial benefits. The AG suggests no reason or support for her suggestion that a narrower analysis would be appropriate, let alone required (See footnote 2). The AG's further suggestion that "DTE has not made a compelling and convincing case" neglects that there is a "preponderance of the evidence" standard, as well as that the AG has the burden to prove her own positions (see DTE Electric's Initial Brief, section IV. A).

7. Corporate Staff Group

DTE Electric's Initial Brief, pp 142-45, explained and supported Corporate Staff Group (CSG) capital spending for physical infrastructure, fleet, and other projects, which was $123.0 million in 2020 and is projected to be $227.4 million for the 22 months ending October 31, 2022

[119] The Company disagrees because the Project Prioritization Score (PPS) is used in place of a traditional cost benefit analysis and is a critical component of the Company's IT APC process. The Company uses the PPS score to evaluate IT capital investments across multiple business benefit categories in addition to costs. Through discovery responses, the Company also provided a projection of cumulative call volume reduction and associated O&M cost benefits expected from investments in the Digital Product Teams and the IT digital transformational projects they support (see Exhibit AG-1.23, page 9), and referenced a supplemental attachment that was provided in response to Staff audit question CR-1.2 (Exhibit A-44, Schedule II5) that had the Company's most-recent forecasted cumulative call reduction of approximately 1.2 million calls from six transactions that provide the largest opportunity for migration of calls to the IVR and web from 2022-2025, and the associated cumulative O&M savings of approximately $7 million (Pizzuti, 7T 2210-2211, 2272-2273).

and $139.9 million for 12 months ending October 31, 2023 (Uzenski, 7T 2727; Exhibit A-12, Schedule B5.8, page 1, line 10).

i. HQ Energy Center

Staff's Initial Brief, pp 135-38, proposes a $7,700,00 disallowance in bridge period capital expenditures for HQ Energy Center,[120] which would bring the total approved capital expenditures for this project to $40.1 million, or the breakeven point identified in the NPVRR analysis (DeCooman, 8T 5297). Staff alternatively considers a partial disallowance of $3,850,000 as reasonable, which would split the incremental costs above the breakeven point identified in the NPVRR analysis between ratepayers and shareholders (Staff Initial Brief, p 136; DeCooman, 8T 5298). The Company previously explained that it agrees with Staff's alternative recommendation, but the underlying analysis should be updated to reflect a $1.4 million difference between the breakeven point and the updated project costs (Uzenski, 7T 2781-2784).

More specifically, the breakeven point referenced by Staff was based on the updated $47.8 million spend and the assumption that Detroit Thermal's rates would increase at a compound annual growth rate (CAGR) of 4.5%, consistent with actual rates from 2018-2020, which were the rates assumed in the Company's original analysis (Exhibit A-43, Schedule HH4, column (b)). Detroit

[120] The HQ Energy Center is a new facility that went in service in November 2021. It includes a steam plant fueled by natural gas, and a chilled water plant for the downtown campus. The Company needed a steam production facility because it depended on purchasing steam from Detroit Thermal, at prices that increased annually, and the Company experienced negative impacts from Detroit Thermal's planned and unplanned outages. The Company also needed a new chilled water system because the current chilled water system was at the end of its useful life (Uzenski, 7T 2732-2733).

The Commission previously approved capital expenditures for the (May 2, 2019 Order in Case No. U-20162, pp 46-47). The Commission also approved additional capital expenditures in Case No. U-20561, where the total capital investment was forecasted at $39.4 million, resulting in a lower net present value of the revenue requirement (NPVRR) compared to an NPVRR under the status quo. The project subsequently incurred construction cost increases, resulting in an updated forecasted total cost of $47.8 million. The project still made sense, however, due to Detroit Thermal's rates and other service considerations (Uzenski, 7T 2735).

Thermal's rates actually increased at a 6.2% CAGR from 2020-2022 (Exhibit A-43, Schedule HH4, line 2). Using that actual 6.2% CAGR, the NPVRR for the status quo increases to $68.1 million, as compared to $59.7 million in the original analysis (Exhibit A-43, Schedule HH4, line 4, columns (b) and (c)). The updated breakeven point is $46.4 million (Exhibit A-43, Schedule HH4, line 5, column (c)). Using Staff's method of comparing the updated project cost of $47.8 million to the updated breakeven point of $46.4 million, Staff's proposed $7.7 million disallowance becomes $1.4 million (Uzenski, 7T 2782-2783; Exhibit A-43, Schedule HH4, line 6, column (c)).

Staff responds by suggesting that the Company's updated CAGR is inflated because it relies in part on 5 months of 2022 data, and that a CAGR calculation using the three most recent full years of data (2019-2021) would produce a lower CAGR. That is mathematically accurate, but Staff reaching back another year in history (to 2019) skews the CAGR downward and neglects the whole point of doing an *updated* analysis. For example, Detroit Thermal's base rate increased pursuant to the August 11, 2021 Order in Case No. U-20824, as Ms. Uzenski observed (7T 2782). The Company maintains that it properly performed the analysis based on the most recent data available.

The Company previously explained that it generally agrees with Staff's recommendation that the Company break out the HQ Energy Center O&M so it can be evaluated in the Company's next rate case and will establish new accounts to capture most of the O&M expense related to operating the HQ Energy Center; however, some expenses are part of broader work streams related to the entire downtown campus, and it is not practical to track the amount attributable to the HQ Energy Center (Uzenski, 7T 2780). "Staff would find this acceptable" (Staff Initial Brief, p 271), so this issue is resolved for purposes of this case.

The AG's Initial Brief, pp 77-78, vaguely incorporates witness Coppola's proposal for a $5.2 million disallowance ($3.9 million for a revised cost of new gas service, and $1.3 million of

DTE project management), but offers no response to the Company's explanation of why that proposal should be rejected.[121] The AG responds to Ms. Uzenski's rebuttal explaining that the economic case for the HQ Energy Center has improved due to Detroit Thermal increasing its rates for steam sales (discussed above), by asserting that "Ms. Uzenski fails to mention that the cost of natural gas to fuel the energy center has also increased" (AG Initial Brief, p 78). The AG's point is unclear. See footnote 2. The AG's referenced discovery response further reflects that natural gas prices are not comparable to Detroit Thermal's full cost of steam service (Exhibit AG-1.63, p 2).

Therefore, as discussed previously and above, the ALJ should recommend and the Commission should adopt Staff's alternative recommendation using the updated $1.4 million difference (updated project costs of $47.8 million compared to updated breakeven point of $46.4 million), resulting in a disallowance of $0.7 million, and the additional capital expenditures should be approved.

ii. Enterprise Automation

DTE Electric's Initial Brief, pp 144-45, explained that Enterprise Automation engages in automation, digitalization, and process improvement initiatives across the Enterprise. Robotic Process Automation (RPA) software is used to program automations that perform repeatable, rules-based, and digitized tasks. The Company projected capital costs of $10.5 million for 2021 and $11.0 million per year in 2022 and 2023 (Uzenski, 7T 2737-2738).

[121] Mr. Coppola reasoned that the Company did not justify why the cost of installing gas service would increase by $3.9 million, or why its own project management costs exceeded previous estimates (8T 4815-4816). To the contrary, the Company explained in response to discovery request STDE-23.11c that the increased cost of installing gas service was caused by the City of Detroit's requirement to open cut along Fort Street, Third Street, and Plum Street instead of direct boring as the Company originally planned. Further, in response to discovery request STDE-23.11b, the Company explained that the increase in project management cost was due primarily to an increase in Allowance for Funds Used During Construction (AFUDC). Therefore, these costs are justified and should be approved (Uzenski, 7T 2781).

Staff proposed disallowances of $0.596 million for 2021 (as not spent), $9.161 million for the ten months ending October 31, 2022, and $11.0 million for the projected test year. The Company agreed with the $0.596 million reduction for 2021 but disagreed with the remaining $9.2 million and $11.0 million disallowances (Uzenski, 7T 2784).

"Staff appreciates the updated information and withdraws its recommendation to disallow $9.161M in the 10 months ending 10/31/2022" (Staff Initial Brief, p 141). The only remaining dispute concerns Staff's proposed $11.0 million disallowance for 2023. The Company disagrees with this disallowance because it anticipates spending a (now undisputed) $11.0 million in 2022 and plans on using the same methodology to identify, evaluate, prioritize, and execute Enterprise Automation projects to spend the same amount in 2023.

Staff responds that it "does not agree with this methodology . . . With the 2023 opportunities not yet identified, some or all of the $11.002M may not be spent, similar to the projected expense in 2021." (Staff Initial Brief, p 142). Staff's proposed 100% disallowance is unreasonable and inconsistent. Staff never disputed the $9.9 million of actual spending in 2021, and now does not dispute any of the $11.0 million for 2022, as discussed above. Staff also does not dispute the nature of Enterprise Automation spending and noted that Enterprise Automation has grown 63% since its inception (Rogers, 8T 5364 30). Staff's suggestion that spending should be $0 for 2023 is contrary to the record and unreasonable. Therefore, the Commission should fully approve Enterprise Automation capital expenditures, except for $0.6 million for 2021 (Uzenski, 7T 2784-2785).

8. Marketing Pilots

i. Charging Forward

DTE Electric's Initial Brief, pp 146-47, provided background on the Company's Charging Forward program and costs.

ii. eFleets

DTE Electric's Initial Brief, p 147, provided background on Phase Two of the Company's Charging Forward pilot program (Phase Two or eFleets) and costs.

iii. Charging Forward Expansion

DTE Electric's Initial Brief, pp 147-53, discussed the Company's proposal for Charging Forward Expansion (which appears to have overwhelming support) and responded to various witnesses suggested modification. The various topics are also discussed in Staff's Initial Brief, pp 204-22; CEO's Initial Brief, pp 77-81; ChargePoint's Initial Brief; EVgo's Initial Brief; ITC's Initial Brief; MEIBC/IEI's Initial Brief, pp 1-22; MNSC's Initial Brief, pp 144-53; and Zeco's Initial Brief.

The Company maintains its positions (and because the benefits of clarity outweigh any burden of duplication), reprints its prior discussion, noting where parties have changed their positions or otherwise added to the discussion.

The Company agrees in part with suggestions that it propose a permanent charging Forward program but will not be able to file a "final plan" as Staff suggests (Freeman, 8T 5545) because various elements of Charging Forward are at different levels of maturity and the EV market continues to evolve quickly. Therefore, the Company proposes to begin introducing permanent offerings, as applicable, starting with its next rate case. The Company also does not agree with Staff's indicated expectation to see a "rigorous cost-benefit analysis" (Freeman, 8T 5545) because there is not yet alignment on the approach and requiring it would unnecessarily end the Company's ability to transition relevant Charging Forward elements to permanent offerings. The Company also disagrees with proposals by MNSC (Jester, 8T 3765) and MEIBC/IEI (Sherman, 8T 4380-4381) to determine the net effects of EV adoption and charging. These proposals are infeasible because they assume that the Company has access to information that instead is not available (Burns, 7T 2506-2510).

Staff responds that: "Considering the outstanding questions regarding permanent programming, Staff recommends the Commission direct the Company to provide additional information regarding the future of the EV pilot programs in its next rate case" (Staff Initial Brief, p 217). The Company generally agrees that it will inevitably provide "additional information" in the Company's next rate case, further noting that it understands Staff's stated position to supersede its later comments reflecting Staff's earlier position about filing an analysis/report (Staff Initial Brief, pp 221-22).[122] For purposes of clarity it bears emphasis, however, that the Company is either unable to provide the additional information recommended in Staff's three (3) suggestions found at Staff Initial Brief, p. 222 or the premise of the suggestion (i.e., that there is a demand component in Company Rate D3) is factually incorrect. Therefore, the Company cannot agree.[123]

Regarding Residential CaaS recommendations, the Company intends to use its existing supply chain request for proposal (RFP) approach with targeted follow ups to appropriately balance commercial considerations and customer satisfaction, which would seem to fully address Staff's interest in specifying how contractors will be vetted and selected (Freeman, 8T 5541).

"Staff now supports approval of the program based on the Company's clarifications . . . Company witness Burns' rebuttal testimony more fully explained the CaaS program and alleviated Staff's Initial Concerns" (Staff Initial Brief, p 208).

The Company disagrees with MNSC's proposal that participants be required to choose between a time of use tariff and participation in the BYOC program (Jester, 8T 3827) because that

[122] On a somewhat related matter, Zeco's Initial Brief, pp 10-11, suggests that the Commission should consider the expected filing of Michigan's NEVI plan. This is beyond the record, and the Commission must base its decision on the record (see DTE Electric's Initial Brief, section IV. A). Future matters can be addressed in a future case.

[123] See also *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm,* 269 Mich App 473; 713NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.)

proposal is based on the incorrect premise that the Company is phasing out its $500 Residential Rebate program.

Staff appears to agree with the Company (Staff Initial Brief, p 209).

The Company partially agrees with CP (Deal, 8T 4573-4576) and recognizes that having a minimum technical standard is important for customers. Therefore, the Company will require that chargers be ENERGY STAR certified (or automaker manufactured) in order to qualify for the residential elements. ENERGY STAR certified chargers are all UL-certified, and the list of chargers is accessible to customers through the ENERGY STAR website. The Company disagrees that chargers should be required to be networked because: (1) the cost of networked chargers is typically more, with ongoing networking fees; (2) the load management and data capabilities of networked chargers can also be obtained through vehicle telematics; and (3) customers participating in Residential CaaS and residential rebates could opt for a NEMA 14-50 outlet (or similar, since some cars come equipped with Level 2 plugs), which the Company considers the same as a non-networked charger (Burns, 7T 2510-2513).

At bottom, "Staff supports the Company's proposal and recommends the Commission approve the Company's Residential Level 2 Charging proposal" (Staff Initial Brief, p 208).

Regarding Equitable Access to EVs, the Company is exploring options to reduce the cost of Income-Eligible Rebates and agrees to reach out and report on Equitable Access to EVs, which would seem to address Staff's indicated concerns (Burns, 7T 2513-2514).

The Company does not agree with various suggestions that the Commission require the Company to either update distribution hosting capacity maps or publish EV charging maps (Burns, 7T 2515).[124] Ms. Pfeuffer further explained that the Company's hosting capacity map was created to guide development of DERs in an efficient manner and inform planning decisions, in accordance

[124] A Hosting Capacity Analysis (HCA) is the amount of Distributed Energy Resources (DER) that can be accommodated without adversely impacting operational criteria such as power quality, reliability, and safety under existing grid control and operations, and without requiring infrastructure upgrades (Robinson, 7T 1577).

with the August 20, 2020 Order in Case No. U-20147.[125] Proposals to update the map to include loading information raise concerns because load is dynamic and load maps are quickly outdated and involve significantly different analysis than DER hosting capacity. Any attempt to create an up-to-date and accurate EV hosting capacity map would require substantial investment in real-time IT infrastructure and significant business process change to serve an undefined need and a small stakeholder group of developers with speculative projects. Plus, the information could potentially be misleading, and the associated costs to implement these changes would effectively subsidize third-party EVSPs at customer expense. Therefore, the suggestions should be rejected (Pfeuffer, 4T 530-35).

The Company disagrees with proposals that it only support Charging Hubs through a make-ready model and not full ownership for four reasons. First, the Company is seeking key learnings that it can best achieve through a full ownership model. Second, Make-Ready Rebates have been available for years, yet no third party has approached the Company to deploy centrally located infrastructure designed for medium and heavy-duty vehicles using the rebates. Third, the scope and scale of the Charging Hub proposed in this case is not comparable to the example that EVgo provided (Dumit, 8T 4695). Fourth, if the Commission does not approve DTE-owned Charging Hubs, then the Company would lose the ability to leverage potential opportunities in (1) applying for federal funds and achieving the key learnings at a lower cost to customers, and (2) complementing eFleets Advisory Services to site a Charging Hub near interested customers to allow them to pilot fleet electrification at a much lower cost. The Company is also confident that it will be able to identify sites that meet its buildout criteria and has strategically designed the Charging Hub rate to not undercut DCFC deployments for passenger vehicles (Willis, 6T 942-944; Burns, 7T 2515-2519).

Staff's Initial Brief, pp 211-12, recommends approval of the Company's Charging Hubs

[125] Company witness Robinson further discussed the Company's HCA efforts (7T 1577-1582).

pilot, noting in response to ChargePoint and EVgo's opposition that "this is a limited pilot program that will fill an information gap for Medium and Heavy-Duty EV charging . . . the structure proposed by the Company is appropriate at this stage" (*Id*, p 212).

"ITC supports the Charging Hubs program as proposed . . . The program is small in scale but provides an opportunity to collect key data that can inform future EV charging infrastructure within the state" (ITC Initial Brief, pp 3, 7).

The Company disagrees with MNSC's proposal that Make Ready Rebates be modified to ensure that make ready infrastructure is capable of supporting 350 kW DCFCs (Jester, 8T 3822) because "futureproofing" sites by assuming every charger is 350kW would unnecessarily create excess capacity for sites that might not use it for years (or ever). The Company similarly disagrees with MNSC's proposal that DCFC rebates should require that the DCFC should support at least 150 kW charging rates (Jester, 8T 3822) because there are instances where that amount of output is either cost-prohibitive or not the best-matched solution for a specific use case (due to average dwell time). The Company believes that the existing DCFC tiered rebate structure allows for the right amount of charging output for the right use cases in the right places, as further reflected by historical results (Burns, 7T 2519-2520). EVgo also opposes establishment of minimum size requirements for DCFC and favors flexibility. (EVgo Initial Brief p. 10)

DTE Electric disagrees with MEIBC/IEI's proposal that the Company pursue a reliability standard of a minimum of 97% uptime per individual charger for a minimum of five years, reported across a 12-month period (Sherman, 8T 4387). The Company agrees with the importance of charger reliability but doesn't believe that it is DTE Electric's role to manage it. Furthermore, it is unclear how the Company would enforce such a requirement or who will (or should) be responsible for maintaining it because many parties have some responsibility for keeping chargers functioning. Therefore, the Company recommends allowing Network Providers to build their reporting capabilities in this regard rather than prematurely requiring it and burdening Charging Forward

(Burns, 7T 2520-2521).

MEIBC/IBI's Initial Brief, pp 16-17, indicates that a Notice of Proposed Rulemaking (NOPR) was released recently, which recommends a 97% uptime requirement, and: "It is highly unlikely that this proposed uptime standard will be changed in the final rule." The Company maintains its position because this matter is beyond the scope of the record upon which the Commission must base its decision (see DTE Electric Initial Brief, section IV. A) and what MEIBC/IEI might consider "likely" is speculation that cannot support a decision. [126]

DTE Electric similarly disagrees with MEIBC/IEI's proposal that the Company should require that chargers receiving incentives make information about charging port status available through the various online EV charging web sites and/or apps that carry that information (Sherman, 8T 4388). This requirement would add unnecessary administrative burden, and the Company does not know how it would be enforced (Burns, 7T 2521).

MEIBC/IBI's Initial Brief, p. 21, seems to concede the point, but maintains its position based on the NOPR. The Company disagrees with reliance on the NOPR as discussed above.

In response to EVgo's assertion that the Company should develop a publicly-available scoring rubric to provide transparency in its prioritization process (Dumit, 8T 4684), the Company agrees that if Make-Ready rebates are approved, then it will publish a scoring rubric for potential site hosts to use within 30 days (Burns, 7T 2521-2522).

"EVgo welcomes the Company's adoption of its recommendation and its willingness to develop a publicly available scoring rubric" (EVgo Initial Brief, p 7).

In response to statements about Commercial CaaS, the Company maintains that the targeted customer segments have little access to nearby EV chargers and low participation in Charging

[126] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

Forward so far, so the Company has proposed Commercial CaaS to see how it can effectively increase equitable access to charging. The Company believes this is an important part of the Charging Forward pilot phase. The Company will allow participants to select any charger from DTE Electric's qualified Make-Ready rebate list, and continue to refresh the list annually (Burns, 7T 2522-2523).

"Staff agrees and recommends this program be approved" (Staff Initial Brief, p 211).

In response to CEO's recommendations to expand Transit Batteries (Cobaleda, 8T 3555), because this element is participant-funded and aligns well with increased Federal Transit Authority Low-No grant opportunities, the Company agrees and is willing to enroll more buses if the approved funding is sufficient to purchase additional transit bus batteries. The Company would also not oppose expanding Transit Batteries to include school buses (Burns, 7T 2523-2524).

Staff's Initial Brief, pp 212-13, recommends approval of the Transit Batteries program.

iv. Residential Battery Pilot

DTE Electric's Initial Brief, pp 153-55, discussed the Company's proposal for a customer-sited behind-the-meter residential battery pilot for up to 500 residential customers.[127] The Company requests to recover capital costs of $1.1 million for the 22-month bridge period and $3.1 million for the projected test year, as well as $0.2 million of O&M costs for the projected test year (Burns, 7T 2492; Exhibit A-12, Schedule B5.10, line 11, columns (e), and (f)).

Staff's Initial Brief, pp 142-44, proposes a full ($4,244,000) disallowance of capital costs due to the lack of third-party-owned batteries, despite recognizing that the "pilot has the potential

[127] At full enrollment, the batteries would provide 5 megawatts (MW) of stored energy (10 kW per customer). 250 income-eligible participants would be offered a free battery system and 250 participants would pay a monthly subscription fee to have access to use the stored battery energy in the event of an outage. Outside of outage events, DTE Electric would have access to use the battery to derive key learnings to determine the best path forward for residential battery storage (Burns, 7T 2484). See also Exhibit A-12, Schedule B5.10.1 for a high-level summary of how Residential Batteries meets the requirements for a pilot as provided in the February 4, 2021 Order in Case No. U-20645).

to be very helpful and provide important information to the Company." [128] MEIBC/IEI agrees with Staff (MEIBC/IEI's Initial Brief, pp 26-33) and makes proposals regarding how the Company should develop battery pilots (*Id*, pp 33-38). CEO's Initial Brief, pp 69-76, and DAAO's Initial Brief, pp 68-76, similarly opposes the pilot based largely on utility ownership of batteries. MI-MAUI and Ann Arbor's Initial Brief, pp 29-32, oppose the pilot as proposed and suggest alternatives.

DTE Electric maintains that this is a small, properly-focused pilot, and the purpose of a pilot is to provide utility learnings, not advance third-party interests. Company ownership of the battery systems is the optimal structure for a residential storage pilot due to (1) the ability to achieve critical circuit level concentration, (2) current market dynamics, and (3) safety considerations (Burns, 7T 2524-2526). More specifically:

Company-owned battery systems will support achieving critical circuit level concentration to function as a grid asset and capture associated learnings. Company ownership of multiple battery systems is the most efficient and effective way to achieve the level of concentration that would allow the Company's Systems Operations Center (SOC) the ability to impact circuit performance by using the battery systems. Company ownership will also enable key learnings, which include the ability to test concentrated storage's impact on the firm rating of a circuit during a peak event, and how the outflow of energy from sited storage onto the grid might impact items such as volt/volt-amps reactive (VAR) and frequency (Burns, 7T 2525-2526).[129]

[128] Staff's Initial Brief, p 144, also discusses an unrelated matter concerning Rider 17. See section X. K. 2 below.

[129] See also *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public*

The current market is nascent and adoption to date is skewed towards higher-income segments. A utility-owned battery pilot will help with equity, especially the portion offered for free to income-eligible customers on targeted circuits (Burns, 7T 2526).

From a safety perspective, alternative ownership models, specifically BYOD, have the potential to exacerbate system issues during high-demand events by allowing customers to control charging/discharging onto the grid. Company ownership of the battery systems mitigates this risk by creating a layer of monitoring and controls to prevent battery assets from becoming harmful to the grid (Burns, 7T 2526).

For all of these reasons, the Company maintains that Company ownership of the battery systems will best support the objectives of a residential battery pilot, and requests that the Commission approve the pilot as proposed.

v. Miscellaneous MNSC Proposals

MNSC makes a variety of suggestions that it wishes the Company to implement. For example, MNSC proposes a pilot for electrifying propane, fuel oil and kerosene heated homes (MNSC Initial Brief, pp 154-57), a pilot for a continuous distribution system monitoring (MNSC Initial Brief, pp 157-61), distribution system planning modifications (MNSC Initial Brief, pp 162-67), and evaluation of the value of reliability (MNSC Initial Brief, pp 168-69). The Company declines the invitation to implement these suggestions. See *Union Carbide v Public Service Comm,* 431 Mich 135, 146; 428 NW2d 322 (1988); *Sparta Foundry Co v Public Utilities Comm*, 275 Mich 562, 564; 267 NW 736 (1936). Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App

Service Comm, 269 Mich App 473; 713NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.)

370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm,* 269 Mich App 473; 713NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.)

VI. RATE OF RETURN

DTE Electric's Initial Brief, p 155, outlined the Company's request for a weighted, after-tax 5.56% overall rate of return (Vangilder, 7T 2809; Exhibit A-14, Schedule D1, line 10, column (g)), which the Commission should adopt for the reasons discussed previously and below.

A. Capital Structure

1. Debt and Equity Balances

DTE Electric's Initial Brief, pp 156-57, explained and supported why the Company's capital structure should be maintained at 50% debt and 50% equity. Staff's Initial Brief, p 148, and the AG's Initial Brief, p 79, agree. The only prior dispute was by MEC/CUB's witness, but now "MNSC accepts for this case maintaining the Company's proposed 50% permanent debt ratio for now" (MNSC Initial Brief, p 83). There is no disagreement. Therefore, DTE Electric's 50/50 capital structure should be maintained.

B. Debt Cost Rates

1. Long-Term Debt

DTE Electric's Initial Brief, p 157, summarized the Company's recommendation for a 3.69% weighted cost of long-term debt. Staff's Initial Brief, p 148, and the AG's Initial Brief, p 80, agree.

2. Short-Term Debt

DTE Electric's Initial Brief, p 158, summarized the Company's recommendation a 1.74% cost of short-term debt. Staff's Initial Brief, p 148, and the AG's Initial Brief, p 80, agree.

C. Return on Common Equity

DTE Electric's Initial Brief, pp 158-70, explained and supported Dr. Villadsen's recommendation that a just and reasonable Return on Equity (ROE) for DTE Electric's common equity capital is 10.25%. This is the midpoint of Dr. Villadsen's range of 9.9% to 10.6% and is conservative because DTE Electric has greater-than-average risk (Villadsen, 7T 1309-1310, 1355-1356, 1398).

Staff's Initial Brief, pp 147-53, recommends 9.6%. The AG's Initial Brief, pp 80-92, recommends 9.5%. ABATE's Initial Brief, pp 57-70, recommends 9.4%. MNSC's Initial Brief, pp 59-82, recommends 8.8%. DAAO's Initial Brief, pp 77-85, and Walmart's Initial Brief, pp 2-6, oppose the Company's request to increase its ROE to 10.25%, but do not make a specific ROE recommendation. MI-MAUI and Ann Arbor's Initial Brief, pp 2-24, suggests a "below-average return on equity" based on various unfounded, illegal and/or irrelevant propositions, some of which are discussed infra.

DTE Electric's prior discussion largely anticipated the Staff and Intervenor arguments, and otherwise thoroughly addressed this topic. The Company further emphasizes that proposals to lower its ROE are not reasonable in the current environment of high inflation and rising interest rates. For example, ABATE asserts:

> The utility industry's relatively strong financial position is further buttressed by the federal reserve's efforts to support the economy to achieve maximum employment and manage long-term inflation to around a 2% level. (Walters 8 Tr 3055-61). Specifically, the federal reserve has implemented procedures to support the economy's efforts to achieve these policy objectives including lowering the Federal Overnight Rate for securities and again engaging in a Quantitative Easing program

> to moderate the demand in the marketplaces and support the economy. (*Id*). All of these actions are known by market participants due to federal reserve transparency. [ABATE Initial Brief, pp 59-60.]

The Company agrees only that the federal reserve's actions are well known. Contrary to ABATE's suggestions, however, it is indisputable that inflation is well above 2%, and the federal reserve has made consecutive rate hikes. Dr. Villadsen emphasized recent events including rising interest rates and inflation:

> In light of the evidence provided by Intervenors, it is evident that interest rates have increased in recent months. This is supported by, for example, when the Federal Open Markets Committee in March raised interest rates by 25 basis points, and then again by 50 basis points in May 2022. This was the first "tightening" since December 19, 2018. This year, more tightening is anticipated, with the funds rate projected to reach 3.0 percent by late 2023. Further, as acknowledged by Mr. Walters, the Russian army invaded Ukraine on February 24, 2022. The ongoing war resulted in increased uncertainty regarding oil and agricultural prices. Consistent with these events, Blue Chip Economic Indicators (BCEI) now project inflation at 6 percent this year, up from 4.2 percent just a month ago. Further, forecasts for U.S. GDP growth have declined, where first quarter of 2022 reported *negative* GDP growth of 1.4 percent, raising questions of a "recession" for many consumers. [Villadsen, 7T 1428-1429. Emphasis in original; footnotes omitted.]

The Commission might further take notice of more recent events including a 75-basis point interest rate increase in June 2022, and most recently another 75-basis point interest rate increase in July 2022. Thus, there have been four consecutive interest rate hikes (so far) this year. The AG's Initial Brief, p 88, also acknowledges that "more recently inflation has become a concern and to combat that, the Federal Reserve has pledged to increase short term interest rates and has taken actions expected to increase long term interest rates."

The Commission has considered such matters previously and should continue to do so. In DTE Electric's last general rate case, the Commission set DTE Electric's currently authorized ROE at 9.9%, explaining in part:

> At this time, the Commission finds that an ROE of 9.90%, which is at the lower end of DTE Electric's proffered range of 9.75% to 10.75%, most appropriately

> compensates DTE Electric for the regional economic and company-specific aspects of risk, while maintaining its ability to attract capital, and ensuring the continued vitality of the company. . . .
>
> The Commission will continue to monitor a variety of market factors in future applications, including market reactions to recent events and measures of volatility and uncertainty, as well as measures of investor confidence, and the utility's risk profile. [May 8, 2020 Order in Case No. U-20561, pp 176-177.] [130]

The Commission has also emphasized that proposals to radically reduce a utility's ROE (particularly as ABATE and MNSC have made) are neither realistic nor helpful to the Commission (September 13, 2018 Order in Case No. U-18999, p 52). The Commission has repeated its recent request for parties "to consider the degree of financial adjustment they are requesting the Commission to undertake in one proceeding, because it is not realistic to make a significant change in ROE absent a radical change in underlying economic conditions." *Id*, quoting March 29, 2018 Order in Case No. U-18322, p 44. Here, the underlying economic conditions support an increase in DTE Electric's ROE, as Dr. Villadsen recommended, rather than any decrease.

Dr. Villadsen explained that the determination of DTE Electric's ROE takes place during the ongoing impacts from the COVID-19 pandemic, which has led to unprecedented low Treasury bond yields and shifts in the relative risks of industries. Since Case No. U-20561 (where the Commission set DTE Electric's ROE at 9.9%), the systemic risk of utilities (measured by beta) has increased, as has the MRP, while the risk-free rate as measured by government bonds has decreased. The dramatic increase in beta (0.91% as of June 30, 2021, as compared to approximately 0.6% in Case No. U-20561) combined with an increase in the MRP has resulted in a substantially higher utility-specific risk premium (Villadsen, 7T 1308-1311, 1329-1330, 1335).

[130] The Commission also recently approved a settlement agreement including a 9.9% ROE and 50.75% common equity ratio for Consumers Energy (July 7, 2022 Order Approving Settlement Agreement in Case No. U-21148, p 2).

Dr. Villadsen further explained, as indicated in part above, that interest rates are expected to continue increasing, and it is the expected risk-free rate over the period when rates will be in effect that is needed to estimate DTE Electric's ROE (7T 1320-1322). The VIX and SKEW index indicate that investors expect volatility to continue for at least a year (Villadsen, 7T 1322-1324). It is reasonable to expect that the current MRP will remain elevated compared to historical levels, especially given the uncertainty related to the extent of economic and financial impacts from COVID-19 (Villadsen, 7T 1328). Rising inflation has also introduced new uncertainties to the capital markets, and points to an increase in the return that investors require to hold risky assets (Villadsen, 7T 1331-1335).

This is also a particularly inopportune time to weaken the Company's credit metrics due to the Company's need for capital spending, as discussed in DTE Electric's Initial Brief and above. The Commission has declined to follow such arguments in past cases. (January 31, 2017 Order in Case No. U-18014, pp 65-66; December 11, 2015 Order in Case No. U-17767, pp 54-55).

DAAO's and MI-MAUI and Ann Arbor's arguments lack merit and relevance to a ROE analysis, and also constitute proposals for subsidies and to deprive the Company of a return "of" and "on" its investment in providing service, which are contrary to law as discussed above, particularly in section III.

DTE Electric further notes that its Initial Brief addressed some of MI-MAUI and Ann Arbor's underlying propositions in the context of other topics. Other propositions do not merit serious consideration, such as the invitation for the Commission to radically depart from controlling law by reducing the value of the Company's property by analogy to inapplicable property-tax cases (MI-MAUI and Ann Arbor Initial Brief, pp 10-11). There is similarly no merit or relevance in MI-MAUI and Ann Arbor's considerable effort trying to discredit the Company for allegedly choosing

to fall behind on tree trimming in 2013-2014 and failing to catch up to a five-year cycle (MI-MAUI and Ann Arbor Initial Brief, pp 11-18). The whole discussion is based on a flawed premise neglecting that following Michigan's 2013 ice storm, DTE Electric began investing in a new Enhanced Vegetation Management Program (EVMP, now re-named the Enhanced Tree Trimming Program or ETTP), which essentially removes vegetation in a clearance corridor rather than the historic clearance circle around DTE Electric's lines and equipment. The Company has vigorously pursued tree trimming, with the Commission's oversight and approval, in every subsequent rate case, as recounted briefly at DTE Electric's Initial Brief, p 183. The ALJ is undoubtedly well-aware of applicable law and history, so the Company will not belabor the topics, but of course reserves all rights in this regard. [131]

DTE Electric's Initial Brief otherwise thoroughly explained and supported the analyses and other considerations supporting the Company's position and responded to other parties' positions as relevant to a ROE discussion. Therefore, the Company incorporates its prior discussion from its Initial Brief demonstrating that alternative analyses by Staff, the AG, ABATE, and MNSC have numerous flaws, resulting in understated recommendations that should be corrected or simply rejected in favor of Dr. Villadsen's complete and correct expert analysis.

D. Other Cost Rates

DTE Electric's Initial Brief, p 170, reflects that tax law requires, and prior Commission orders have allowed a return on Job Development Investment Tax Credits (JDITC) at the rate of return for permanent capital, so the associated returns for JDITC-Debt and JDITC-Equity reflect the corresponding permanent capital rates of 3.69% and 10.25%, respectively. Deferred income

[131] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28.

taxes are at zero cost (Villadsen, 7T 2811-2813; Exhibit A-14, Schedule D1, lines 6, 7, and 9). Staff agrees with the Company except regarding the ROE percentage (Staff Initial Brief, Appendix D).

E. Overall Rate of Return

Staff's Initial Brief, p 147, recommends an overall cost of capital of 5.3%. The AG's Initial Brief, p 80, recommends 5.26%. The Company maintains that the sum of the weighted cost of the above-described capital components results in a weighted, after-tax 5.56% overall rate of return (Villadsen, 7T 2809, 2811; Exhibit A-14, Schedule D1, line 10, column (g)). A 1.3496 revenue conversion factor is appropriate for the projected period (Villadsen, 7T 2810; Exhibit A-13, Schedule C2). The corresponding weighted pre-tax overall rate of return is 6.98% (Exhibit A-14, Schedule D1, line 10, column (i)). DTE Electric supports the use of the 5.56% overall rate of return in the derivation of its revenue requirements and the use of the 6.98% pre-tax overall rate for the return on rate base.

VII. ADJUSTED NET OPERATING INCOME AND REVENUE DEFICIENCY

DTE Electric's Initial Brief, p 171, explained that the Company revised its projected Total Electric Adjusted Net Operating Income (NOI) to be approximately $912.8 million (Initial Brief, Attachment A, page 3. See also Section I of the Initial Brief and above). The Company continues to support an NOI of $912.8 million as shown on the Reply Brief Attachments A and B.

A. Sales Forecast

DTE Electric's Initial Brief, pp 171-75, explained and supported the Company's projected future sales, and the rigorous and accurate forecasting methodology that the Company uses to determine those sales. Staff initially proposed a 17 GWH increase to residential sales, and a 140 GWH increase to the small C&I forecast. The Company previously explained two modifications that should be made to the underlying analysis to be more methodologically appropriate. "Staff

finds the Company's critique of the sales adjustment valid and now finds usage of the Company's originally filed sales forecast reasonable for projecting sales revenue, thus removing the $19,786,000 sales volume adjustment that Staff initially supported" (Staff Initial Brief, p 155).

The only remaining dispute is by the AG, who finds the C&I forecast to be reasonable but proposes to increase the residential sales forecast by 796.4 GWh (from 15,114.0 GWh to 15,910 GWH), with a corresponding sales revenue increase of $52,652,407 (AG Initial Brief, pp 19-20). Company forecasting expert Leuker explained that witness Coppola's underlying analysis comparing 2020 and 2021 residential sales was flawed because it compared a full year of residential sales in 2021 to 2020, but COVID-19 related variances were present for less than ten months in 2020. To get an apples-to-apples comparison, it is appropriate to look at only the months in which COVID-19 related policies were present. A comparison of March through December in both 2020 and 2021 shows that residential use-per-customer is on a downward trajectory of -0.3%, which is consistent with the Company's expectation that as more people return to the office, residential use-per-customer will decrease (Leuker, 7T 2643-2644).

The AG points to a discovery response (Exhibit AG-1.60, p 1) as confirming that in four of the months, customers used more electricity than in the prior year, and claims that "[i]f Mr. Leuker's premise was correct . . . a more consistent pattern of sales reduction in nearly every month should be seen" (AG Initial Brief, p 21). The AG's briefing suggestion of what she might consider intuitive carries no weight. The data is shown at a granular level in Mr. Leuker's Table 1 (at 7T 2644), Mr. Leuker is the expert with qualifications to opine on that data, and Staff now completely agrees with him. The same response essentially applies to the AG's further reliance on Exhibit AG-1.60, p 2.

Mr. Coppola also took issue with the Company's use of Google Mobility data, asserting that it has no prior track record as an accurate predictor of sales, and that the Company did not provide

any back testing to show its accuracy (8T 4851). Mr. Leuker responded by explaining that the COVID-19 pandemic rapidly changed the way people used electricity. The Company, as well as load forecasting groups across the country, expected that as more people stayed home, residential electricity consumption would increase, and C&I consumption would decrease. The Company used Google Mobility data to quantify this expectation by measuring the magnitude of changed behaviors from COVID-19 related mitigation strategies. The mobility data was tested in the Company's sales models and proved to be statistically significant. Other industry experts such as Itron's Load Forecasting Group (an industry-leading load forecasting consulting group) have also examined and recommended the use of mobility data as a reasonable methodology to address COVID-19 related variances in load forecast (Leuker, 7T 2645-2646). Mr. Coppola was also incorrect in asserting that the Company provided no back testing. Instead, the Company provided test results showing that the Company's residential model had 99.5% accuracy with the use of Google Mobility data but would have significantly under-forecasted residential sales volumes for 2021 without that data (Leuker, 7T 2646-2647; Exhibit AG-1.37, page 5).

The AG responds that Mr. Leuker "never used such mobility data in prior cases, undercutting its reliability" (AG Initial Brief, p 21). To the contrary, the evidence summarized above reflects that the data is reliable. Exhibit AG-1.60, p 3, further reflects that the COVID-19 pandemic triggered the need to include mobility data in forecast models.

Mr. Leuker also observed that Mr. Coppola has again changed his proposed forecasting method.[132] Changing forecasting methodologies from case to case is unjustified, arbitrary, and lends itself to outcome-based data mining. In contrast, the Company has consistently used an end-use

[132] Mr. Coppola's alternative residential sales forecast was based on just using 2021's use-per-customer value and adjusting it only for Energy Waste Reduction (EWR), distributed generation, and electric vehicles (8T 4852).

approach to forecast residential sales, with demonstrated accuracy (Leuker, 7T 2648; Exhibit A-15, Schedule E5). Mr. Coppola's proposed methodology is also extraordinarily uncommon for utility load forecasting. There are two predominant methods to forecast residential electricity sales. The Company uses the most widely used one. Mr. Coppola's simplistic methodology also improperly ignored trends in the underlying data. The Company's residential sales forecast is also validated by the Staff's analysis, which used more recent data than the Company used (which is an appropriate consideration) to arrive at an initially recommended 17 GWh (0.11%) increase, to 15,131 GWh (Leuker, 7T 2649-2650). Now the Staff agrees completely with the Company, as discussed above.

The AG's Initial Brief, p 21, suggests that Mr. Leuker's rebuttal is undercut because he did not investigate how Mr. Coppola's various forecasts turned out, but the AG apparently never did so despite having the burden to support her own propositions, and she offers no reason why Mr. Leuker should have further pursued Mr. Coppola's flawed and rejected forecasts. Also, since Mr. Leuker's forecasting has proven accurate,[133] it is fair to assume Mr. Coppola's contrary forecasts turned out to be inaccurate. In any event, Mr. Coppola's methodological errors remain as discussed above.

Thus, there is no sound basis to adopt Mr. Coppola's sales forecast methodology or resulting residential sales forecast. Staff now also agrees completely with Mr. Leuker's sales forecasts. Therefore, the ALJ should recommend, and the Commission should adopt Mr. Leuker's sales forecasts.

[133] For example, the 2019 total sales forecast compared to total weather-normalized service area sales reflects 98.2% accuracy. On average, for historical years 2016 through 2019, the absolute percent variance for the total sales forecast is 0.77% (Leuker, 7T 2617, 2637; Exhibit A-15, Schedule E5, page 1). DTE Electric also achieves better accuracy than peer utilities across the nation in forecasting various customer classes, total sales, and peak demand (Leuker, 7T 2638; Exhibit A-15, Schedule E5, page 2).

B. Fuel and Purchased Power Revenue and Expense

DTE Electric's Initial Brief, p 176, outlined the Company's proposals to maintain the current Power Supply Cost Recovery (PSCR) base of 31.26 mills per kilowatt-hour at the generation level, and to update the loss factor to 1.0731, which will result in a PSCR base of 33.55 mills per kilowatt-hour at the sales level as reflected on Exhibit A-13, Schedule C-4.

Staff's Initial Brief, p 160, reflects that "Staff has determined that the Company's original sales forecast is reasonable for use in this case. Therefore, the PSCR expense increase described by Ms. Kindschy of $5,246,289 is no longer necessary and is being removed from Staff's case."

C. Operating and Maintenance (O&M) Expenses

DTE Electric's Initial Brief, p 176, reflects that (as discussed in Section I), the Company's projected O&M has been adjusted by a $8.6 million reduction to Pension Expense, a $4.2 million reduction to Tree Trim Surge O&M Savings, a $3.0 million reduction to Merchant Fees, and a $1.0 million reduction to Customer Service Representative costs, resulting in projected total O&M of $1,264.0 million in the test period (See Attachment A, page 3).

Staff's Initial Brief, p 160, reflects that Staff updated its originally filed $1,218,255,000 projection to $1,226,280,000.

1. Inflation

DTE Electric's Initial Brief, pp 177-78, explained and supported Ms. Uzenski's inflation rates of 3.1% for 2021, 2.9% for 2022, and 2.42% for January 1 through October 31, 2023, as shown on Exhibit A-13, Schedule C5.15, line 15. These are composite rates using a 3.0% inflation rate for

labor, and the consumer price index (CPI)-Urban for non-labor costs (Uzenski, 7T 2710).[134] The AG's Initial Brief, pp 22-23, accepts the rates, noting her disagreement with the methodology, but recognizing that any re-calculation would result in only a small expense adjustment. DTE Electric incorporates its prior discussion about the methodology and maintains that the record reflects that the Company's labor costs are largely driven by collective bargaining agreements with unionized employees.

ABATE's Initial Brief, pp 54-55, suggests that it is reasonable to expect the Company to continue to control or minimize O&M in a manner such that the total expense will change at a rate slower than the rate of inflation. The Company agrees that it has managed its O&M expenses well over the last decade, but the Company cannot continually offset wage growth (3.0% as discussed previously and above) by managing non-labor O&M at levels much lower than the rate of inflation. Moreover, ABATE witness York acknowledged current CPI forecasts indicating that inflation "is expected to average 5.7% in 2022, and 3.0% in 2023" (York, 8T 3013). Thus, the Company will have even more difficulty managing inflationary pressures in the bridge period and test year than the Company predicted when it filed this case (Cooper, 7T 2389-2390).

ABATE's Initial Brief, p 55, further asserts that the labor escalation should be based on "the same published independent economists' projections of future CPI growth that DTE used for non-labor cost escalation." (8T 3014). The Company disagrees, incorporating its prior discussion,[135] and again notes the high CPI forecasts acknowledged by ABATE's own witness.

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[134] Mr. Cooper further explained that he conservatively estimated annual wage increases of 3.0% for 2021, 2022, and 2023, based largely on mandatory base pay increases and progression increases set forth in the Company's collective bargaining agreements with labor unions representing DTE Electric employees (7T 1813-1814).

[135] Mr. Cooper explained in part that over the last three years, the Company's average increase in employee wages has increased by 3.1%, during which the annual pay adjustment for each year was 3.0%. This actual experience demonstrates that the Company's projection of 3.0% is reasonable, and superior to ABATE's alternative proposal (Cooper, 7T 1885).

Therefore, the Company's proposed composite inflation rates are fully justified and should be adopted.

2. Energy Supply (Exhibit A-13, Schedule C5, lines 1, 3 and 4; Schedules C5.1, C5.4 and C5.5)

DTE Electric's Initial Brief, p 179, summarized the Company's actual and forecast Energy Supply O&M expenses, and explained that they are reasonable and prudent, so they should be recovered.

3. Fuel Supply and Midwest Energy Resources Company (MERC) (Exhibit A-13, Schedule C5, line 2; Schedule C5.2)

DTE Electric's Initial Brief, p 179, explained and supported the Company's Fuel Supply and Midwest Energy Resources Company (MERC) O&M expenses.

4. Nuclear Power (Exhibit A-13, Schedule C5, line 3; Schedule C5.3)

DTE Electric's Initial Brief, pp 180-81, explained and supported Fermi 2's O&M expenses, and Program Evaluation Review Committee (PERC) Regulatory Asset amortization.

The AG's Initial Brief, pp 23-24, incorporates Witness Coppola's proposal that DTE Electric not start the Extended Power Uprate (EPU) Study in 2023, and to remove the associated 2023 PERC O&M EPU expenditures of approximately $4.9 million. The Company incorporates its prior discussion explaining that the AG's position should be rejected as unreasonable and imprudent.

The AG responds by quoting a limited portion of a discovery response and asserting that "[i]t is incredible to the AG that Mr. Davis wants to undertake a research project at a cost of nearly $5.0 million, which clearly cannot be economically justified, in order to simply gain some knowledge" (AG Initial Brief, p 23). Mr. Davis instead more fully explained:

> Knowledge has value. Time has value. As I explained in my direct testimony and in my rebuttal testimony the Extended Power Uprate (EPU) Study will take several

> years to complete as it requires a refueling outage window to execute certain investigations and measurements. The Fermi 2 Power Plant has the potential for an additional 172 Mwe of carbon-free, baseload generation capacity that the Company could consider as a potential generation resource that could be evaluated in a future integrated resource plan – it is certainly reasonable and prudent to understand the opportunities and risks associated with such an uprate. [Exhibit AG-1.68.]

The AG's Initial Brief, p 24, further asserts that "DTE has not made a compelling and convincing case that the study would lead to an outcome that would provide a competitive cost of adding capacity, even after considering that the added capacity would be carbon free." But there is a "preponderance of the evidence" standard, not some further burden to make a "compelling and convincing case" (see, for example, DTE Electric's Initial Brief, p 9). There is similarly no merit in the AG's suggestion that a guaranteed "outcome" is required. Indeed, the general point of doing a study is to determine an unknown outcome. Thus, the EPU Study is not being conducted to arrive at an "outcome" (as Witness Coppola inaccurately indicated). Instead, the EPU Study is to provide a comprehensive and fully transparent analysis of the potential to safely operate Fermi 2 at EPU conditions, which would potentially increase the baseload, carbon-free generation capacity of Fermi 2 by approximately 172 Mwe. The EPU Study would also provide the Company with an improved understanding of the operational considerations required to operate Fermi 2 at EPU conditions, and narrow the uncertainty of scope, schedule, and expenditures associated with the work that would be required to complete an EPU, which is a reasonable and prudent approach (Davis, 7T 2571-2572, 2585-2586).

Thus, the record including the AG's own exhibit fully supports the EPU study as reasonable and prudent, so its cost should be approved

5. Distribution (Exhibit A-13, Schedule C5, line 6; Schedule C5.6)

DTE Electric's Initial Brief, p 181, explained and supported $318.0 million of Distribution Operations' O&M expenses for the projected test period.

i. O&M Restoration Costs

Staff's Initial Brief, pp164-65, proposes that O&M restoration costs remain based on a five-year average rather than the Company's proposed three-year average, which would increase the Company's O&M projection by $14.777 million. As discussed previously and above regarding emergent capital expenditures, the Company believes that a three-year average better reflects current conditions. If the Commission adopts a five-year average for emergent capital, however, then the same method should apply to O&M restoration costs, resulting in a $14.777 million increase as Staff proposed (Pfeuffer, 4T 505). "Staff agrees with the Company that the emergent replacements capital and storm restoration O&M programs need to be treated the same" (Staff Initial Brief, p 165).

ii. Tree Trimming

DTE Electric's Initial Brief, pp 182-89, explained and supported the Company's proposals for $103.9 million of 2023 base O&M funding, surge funding of $67.0 million in 2023, and $52.7 million in 2024. The Company is *targeting* to complete the surge program by the end of 2024, which is one year earlier than previously proposed in Case Nos. U-20162 and U-20561, due to the Company's additional funding as discussed in the Company's application in Case No. U- 21128.

The AG's Initial Brief, pp 25-26, proposes to remove $5.7 million in cost savings from the Company's forecasted O&M expense due to savings from the surge program. The Company previously explained that it agrees, in part, but the correct amount is $4.2 million,[136] and the Company has adjusted its revenue deficiency accordingly (DTE Initial Brief, p 1).

[136] Ms. Hartwick explained that the $5.7 million includes three items. Savings from two items (Tree Trim Storm ($2.4 million) and Dist. Ops Storm & Trouble ($1.8 million)) should be considered as reductions to the Company's O&M expense but were inadvertently omitted from the O&M calculation in Exhibit A-13, Schedule C5.6. In contrast, savings from the third item (Tree Trim Reactive) were included in Exhibit A-22, line 4, so those savings have already been accounted for in the proposed O&M expenses (Hartwick, 7T 2334).

Staff's Initial Brief, pp 181-83, and 287-88, supports the Company's projected tree trimming expense, but proposes a $4,833,000 decrease by applying the currently-approved 2.73% short-term debt rate on the tree trim regulatory asset, instead of the Company's proposed rate of return on permanent long-term debt and equity capital.[137] The AG's Initial Brief, pp 93-95, proposes a $5,626,000 reduction by using a short-term debt rate of 1.74%. Both Staff and the AG essentially reason that circumstances had not changed significantly since the Commission approved the surge in Case No. U-20162. The Company maintains its position, incorporating its prior discussion regarding changed circumstances as reflected by securitization Case No. U-21015.

MNSC recommended that the Commission require the Company to initiate a pilot to test variable cycle tree trimming, however, this is not necessary as the Company continues to explore opportunities to improve efficiencies in the Tree Trimming program, including considering the benefits that may come from a variable cycle.

Therefore, the Commission should adopt the Company's tree-trimming requests and reject all contrary and additional proposals.

iii. Community Lighting (Exhibit A-13, Schedule C5.6, lines 8 and 22)

DTE Electric's Initial Brief, pp 189-93, explained and supported Community Lighting O&M expenses for 2020 through the projected period ending October 31, 2023.

[137] The Company proposes to defer Surge costs up to $248.8 million above base rates from 2021 through 2024 (Exhibit A-22 Revised, Schedule L1, page 1, line 12, columns c-f). The Commission previously approved regulatory asset treatment for the incremental costs of tree trimming above base rates through 2022 totaling $246.1 million, $156.9 million of which was deferred in 2019 through June 2021, and has been securitized pursuant to the June 23, 2021 Order in Case No. U-21015. Securitization remains appropriate to recognize the long-term nature of the program. Recovery over a longer period provides a better matching of costs with anticipated savings, minimizing the cost impact to customers (Hartwick, 7T 2322-2323). Exhibit A-11, Schedule A1.1 identifies the $7.0 million return on the tree trim Surge regulatory asset for the projected test period (Vangilder, 7T 2813).

Staff's Initial Brief, pp 165-67, proposes a $241,596 disallowance because the Company did not spend the full amount in 2021. The Company previously explained that it disagrees for two reasons.[138] Staff responds by suggesting that the Company's logic is somehow flawed in using O&M spending to project O&M spending. Staff further asserts that its O&M projection is not based on O&M spending, but instead is based on capital spending, and: "It is reasonable and prudent to expect that accompanying O&M costs will be reduced if the Company underspends capital by the same percentage in future projected periods. One can reasonably assume that O&M costs will be reduced by the same percentage as the reduction in capital work" (Staff Initial Brief, pp 166-67).

The Company maintains its prior position, and further observes that there is no basis for Staff's indicated assumptions that capital expenditures and O&M costs have such a relationship. They are two different things, and the Company does not understand how the Staff could reach such assumptions, other than to note some general similarity in subject matter to a discussion in section V. B. 7. iv. B (Staff's disallowance proposal). Staff's assumptions are also entirely speculative and unsupported, and therefore cannot support a decision. [139]

MI-MAUI and Ann Arbor's Initial Brief, pp 53-75, makes various criticisms and recommendations about streetlighting. The Company incorporates its prior discussions responding to MI-MAUI and Ann Arbor witnesses (DTE Initial Brief, pp 112-13, 190-93, 229, n 95). See also

[138] First, Staff referenced the Company's projected O&M spend, in which the Company used its historical 2020 YE spend. The Company projected no additional O&M spend and only seeks adjustments as a result of inflation though the bridge period and projected test year. Second, Staff referenced O&M spend in 2021 to establish a ratio of actual spend compared to approved spend. The Company's 2021 O&M actuals were far in excess of the amount the Company seeks to recover in this case. Therefore, the Company's O&M request should be fully approved (Bellini, 7T 1775-1776).

[139] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

Staff's Initial Brief, pp 261-62, opposing MI-MAUI witness Bunch's proposal to shift costs onto other customers.

The Company further notes that unsupported speculation does not merit a response, [140] and MI-MAUI and Ann Arbor at times mischaracterize Mr. Bellini's testimony. For example, regarding restoration time, their Initial Brief, p 74, suggests that excluding events that take the Company a long time to fix is "equivalent to a student asking to exclude from calculations of their grades all the times they failed a test, and then arguing their grade isn't so bad." To the contrary, the discussion concerned municipalities (particularly Ann Arbor) essentially complaining about self-caused delays.[141] Courts also do not tolerate litigants complaining about their own actions.[142]

MI-MAUI witness Bunch suggested that the Company is needlessly washing lamps on an accelerated basis and out of step with IES recommended practices (8T 3472). Mr. Bellini disagreed because the IES study did not include the luminaire type predominately used by the Company and

[140] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

[141] There are (1) events where DTE crews are impeded from performing a repair due to a need to wait for a permit, Miss Dig, etc., as well as (2) events that require special order material (SOM) for which the city, not DTE, is responsible for purchasing and maintaining the SOM in order to complete restoration work. When unimpeded, the Company has been able to address outage events in under five days, except in 2014 and 2021, which had significantly higher and more severe storm seasons that required streetlight crews to be redirected to perform storm restoration work. The type of repair must also be considered. For example, to repair underground damage, Ann Arbor requires a significant amount of detail denoted on Company engineered permit drawings. This level of detail is not required by other municipalities before a permit is granted to allow restoration work to begin. The level of detail to ensure compliance with Ann Arbor's permitting requirements often takes several weeks to compile (Bellini, 7T 1752-1753). Mr. Bellini provided additional details regarding third parties striking underground cable in response to MI-MAUI witness Hess' criticism about outages (7T 1771-1772), and Ann Arbor's time-consuming permitting requirements in response to witness Hess' criticisms about restoration times (7T 1772-1773; Exhibit A-34, Schedule Y5).

[142] See, for example, *People v Witherspoon*, 257 Mich App 329, 333; 670 NW2d 434 (2003) ("[I]n general, an appellant may not benefit from an alleged error that the appellant contributed to by plan or negligence"); *Dresselhouse v Chrysler Corp*, 177 Mich App 470, 477; 442 NW2d 705 (1989) ("A party is not allowed to assign as error on appeal something which his or her own counsel deemed proper at trial since to do so would permit the party to harbor error as an appellate parachute").

was not specific to the environment where the LED luminaires operate. MI-MAUI and Ann Arbor's Initial Brief, p 66, misconstrues this as simply suggesting that the Company uses a model of LED luminaire that needs more frequent cleaning, ignoring Mr. Bellini's explanation that heavy truck traffic and salt spray are unique to a Midwest state such as Michigan, and particularly to the Company's service territory. Plainly, an LED in Phoenix, Arizona will be impacted differently from dirt depreciation than the same LED in the metro-Detroit area. The Company studied the impacts of dirt depreciation unique to the roadway conditions where the Company's luminaires operate, the results of which indicate that washing on a five-year cycle maintains a safe driving environment (Bellini, 7T 1762-1763).

6. Customer Service (Exhibit A-13, Schedule C5, line 7; Schedule C5.7)

DTE Electric's Initial Brief, pp 193-97, explained and supported the actual and projected O&M expenses for the Customer Service organization as reasonable and necessary.

i. Customer Service Representatives (CSRs)

Mr. Sparks explained that the $7.9 million of Customer Records and Collections Expenses is driven in part by the need for 120 additional CSRs and associated expenses to address more complex call types such as customers with high bills and low-income and the associated ongoing training and development needed to improve operational performance and customer satisfaction. Additional CSRs are also required to reduce the Company's average speed to answer service level in the call center. (Sparks, 7T 1637-1638). This category also includes $2.3 million for TOU Full Implementation ongoing costs that include billing exceptions ($1.3 million), digital experience ($0.5 million), and AMI support ($0.5 million) (Sparks, 7T 1638).

The AG's Initial Brief, pp 26-28, proposes a $9.7 million reduction in O&M expense, without indicating its basis. Witness Coppola indicated that it relates to the additional 120 CSRs

(8T 4860-4861), but Mr. Sparks clarified that only $5.6 million relates to the incremental 120 CSRs. The $9.7 million also includes an unrelated (1) $1.8 million driven by lag hire in 2020 due to the pandemic and (2) $2.3 million associated with ongoing O&M for TOU implementation (7T 1642-1643).[143]

The AG asserts that "[w]ith regard to the TOU program, the Company plans to bring in more outside vendor resources instead of hiring new employees. Therefore, this program should not increase Company CSR counts" (AG Initial Brief, p 26, citing Exhibit AG-1.61, p 1). The AG misconstrues her own discovery request, which asked the Company to "[c]onfirm that the TOU program and lag hiring also require the addition of CSRs."

Mr. Sparks further explained that Call Center staffing is driven primarily by average handle time (AHT) and call volume. Changes to call handling requirements and the need for continuous training and development, are driving the need to increase staffing levels. Since the start of the COVID pandemic, the Call Center has had a heightened focus on exercising special care for the Company's most vulnerable customers. DTE has experienced approximately a 174 second AHT increase in calls that involve low-income customers because, for example, it takes extra time for

[143] Mr. Coppola also suggested that because overall headcount increased from 2019 to 2020, "it does not appear that there was much if any delayed hiring" (8T 4860). Mr. Sparks explained that the change in headcount was driven by incremental CSRs hired for a new call center in Cass City during 2020, with the associated cost offset by a $3 million decrease in external call vendor spend (7T 1643).

Mr. Coppola further suggested that additional CSRs are unjustified in light of the Company's proposed digital enhancements (8T 4860). Mr. Sparks explained that the AG's proposal conflates different things. Digital enhancements reduce the volume for the type of calls that customers can perform without the assistance of a CSR. What remains are more complex calls that may require additional handling time and knowledgeable CSRs to respond and resolve customer needs, and the Company is seeing an increase in average handle time (AHT) as CSRs are responding to more complex customer discussions. Thus, the new technologies being adopted by the Company will allow CSRs to spend the time with customers as they need and deserve, while other customers can navigate tasks via a digital channel if they prefer. The Company agrees, however, to a $0.95 million reduction to the overall O&M requested in this case to capture call volume reduction savings (250,000 reduction in calls multiplied by the existing vendor cost per call of $5.85, allocated 65% to DTE Electric) (Sparks, 7T 1642-1644, 1647; 7T 2266-2267).

CSRs to explain specialized COVID payment plans and properly pre-screen and advise customers regarding requirements for agency resources (Sparks, 7T 1645-1646).

The AG disregards the evidence, and instead simply asserts that "there is no compelling evidence to justify the additional headcount increase that DTE seeks" (AG Initial Brief, p 27). Again, the standard is "preponderance of the evidence," not some higher standard like "compelling evidence" (See, for example, DTE Electric's Initial Brief. p 9). The Company carried its burden, as discussed previously and above. In contrast, the AG appears to have abandoned her own witness's testimony as unsupportable, leaving her to address the record evidence of DTE Electric's reasonableness with inaccurate characterization and supposition. The AG's criticisms carry no weight and should be rejected, even assuming they are considered at all (See footnote 2 above).

Therefore, the AG's proposed headcount cost disallowance should be rejected, but the Company agrees to a $0.95 million reduction to its overall O&M request to capture call volume savings as discussed previously and above (Sparks, 7T 1644, 1646-1647).

ii. Merchant Fees

Staff and the Company agree with Staff's proposed merchant fee expense amount of $17.5 million (Staff's Initial Brief, pp 172-73), which is a slightly more conservative and accurate projection that should be adopted.

The AG's Initial Brief, p 29, vaguely incorporates Mr. Coppola's proposal for an $8.2 million reduction to residential merchant fee expense to $10.9 million. The Company incorporates its prior discussion explaining that the AG's proposal should be rejected because it only accounts

for annual growth from 2020 to 2021,[144] and Mr. Coppola's reasoning is also flawed.[145] The AG suggests nothing to rehabilitate her witness or otherwise add to the discussion. Therefore, the AG's flawed proposal should be rejected, and merchant fee expense should be set in accordance with the Staff and Company's agreement.

7. Uncollectible Accounts Expense (Exhibit A-13, Schedule C5, line 8; Schedule C5.8)

DTE Electric's Initial Brief, pp 197-98, reflects that the Company included $59.6 million of uncollectible expense based on a three-year average of actual uncollectible expense for 2017-2020, excluding 2018 because uncollectible expense was abnormally high. Staff initially proposed a $9,560,000 downward adjustment, which it has now revised to $4,174,000. AG witness Coppola proposed a $9.4 million reduction to $50.3 million (8T 4862-4864). Both proposals are based on using the cash-basis method for estimating uncollectible expense. The Company incorporates its prior discussion explaining why the cost-basis method should not be used.[146]

The Company further explained that if the cash-basis method is to be used (which it should not be), then Staff's forecast using an updated 2019-2021 three-year average of net write offs as a

[144] DTE Electric used a three-year historical growth rate to forecast the projected test years to avoid anomalies from any specific year (such as 2020, which was impacted by the pandemic). (Burns, 7T 2528).

[145] He stated: "As more and more customers pay their bill with a credit card, there are fewer customers left who will make use of credit cards to pay their gas bills. This is basic logic. The 2021 actual data supports this conclusion" (8T 4864-4865). Mr. Coppola inaccurately assumed that merchant fees are directly related to the number of customers paying their bill with a credit or debit card. Instead, merchant fees are driven primarily by the volume of payment transactions and the rate of fees (per transaction) charged by the various credit and debit card companies and banking institutions. Therefore, the merchant fee forecast is based on the growth in actual transaction fees assessed to DTE Electric annually (Burns, 7T 2527-2528).

[146] The cash basis method of estimating uncollectible expense is inconsistent with how expense is recorded and with how other costs and revenues are calculated for both MPSC reporting and for ratemaking. The estimation of future expenses should be consistent with the practice used to record the actual expenses to ensure recovery of the Company's reasonable and prudent costs. An average of the amounts charged to FERC account 904 provides such consistency. The cash-basis method also does not factor in special circumstances that are accounted for under the accrual method (for example, delaying write-offs that are being disputed or negotiated, and the temporary suspension of disconnects during 2020 due to the pandemic). (Johnson, 5T 823-824, 828-829).

percentage (%) of revenue to forecast projected uncollectible expense is reasonable, rather than the AG's selective use of 2017, 2020 and 2021 (Johnson, 5T 830-831). Two corrections[147] should also be made, which would result in an uncollectible expense of $55,398,915 million (Johnson, 5T 829-830; Exhibit A-37, Schedule BB1).

Staff responds that it "audited the Company's exhibit submitted in rebuttal and agreed with the corrections. Staff projects that the Company's electric uncollectible expenses will be $55,398,915, a reduction of $4,174,085 from the Company's projection of $59,573,000" (Staff Initial Brief, p 175).

The AG's Initial Brief, pp 28-29 vaguely incorporates and maintains Mr. Coppola's proposal, but does not add to the discussion. The Company also again objects to the AG forcing others (including now the ALJ) to chase down discovery responses that are inconsistent with the AG's characterization of them and/or have no apparent relevance. See footnote 2.

Therefore, the AG's proposal should be rejected, and if the Commission agrees with Staff's methodology, then the proper amount is $55,398,915, in accordance with the Staff and Company's agreement.

8. Regulated Marketing (Exhibit A-13, Schedule C5, line 9; Schedule C5.9)

DTE Electric's Initial Brief, pp 198-99, generally explained and supported the Company's Regulated Marketing O&M expenses.

Staff's Initial Brief, p 175, recommends a $183,000 reduction based on Staff's proposed disallowance of the residential battery pilot.

[147] They are: (1) include revenues associated with surcharges (Energy Waste Reduction, Nuclear Surcharge Revenue, LIEAF Surcharge Revenue) and incremental revenue from rate relief to avoid understating the revenue associated with uncollectible expense, and (2) do not double count the savings from the Business Rules Framework (BRF+) project.

9. Corporate Support (Exhibit A-13, Schedule C5, line 10; Schedule C5.10)

DTE Electric's Initial Brief, p 199, reflects that the Corporate Staff Group's (CSG) O&M expenses (excluding employee benefit costs, and after rate case adjustments and normalizations) as allocated to DTE Electric were $168.6 million for the 2020 adjusted historical test period, and are expected to increase to $176.1 million for the projected period ending October 31, 2023.

i. Membership Dues

DTE Electric's Initial Brief, pp 199-200, reflects that the Company acquires and maintains corporate memberships that help in its mission to provide safe, affordable, and reliable energy.

DAAO's Initial Brief, pp 99-102, asserts that the Commission should disallow all corporate memberships that are not required by law for energy operations, because certain organizations allegedly spend some of their income lobbying against ratepayer interests. DAAO's position should be rejected as unsupported by law, and contrary to well-established regulatory practice and the record. [148] Exhibit A-27, Schedule Q1 lists corporate memberships included in DTE Electric's O&M expense. The benefits that the Company receives from the memberships listed in Exhibit A-27, Schedule Q1, pages 3-5 generally fit into one or more of the following categories: Benchmarking; Best practices; Research; and Networking. Some of the memberships are also a non-discretionary cost of doing business. *None of the membership costs associated with the organizations listed on Exhibit A-27, Schedule Q1 involve lobbying activities* (Crozier, 7T 2358-2359). Ms. Uzenski further explained how certain memberships and membership costs were excluded from customer rates (7T 2698; Exhibit A-3, Schedule C14).

[148] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

The Company also requests $0.5 million for membership in the Low Carbon Resource Initiative (LCRI), which is a five-year joint effort between the Electric Power Research Institute (EPRI) and the Gas Technology Institute (GTI) aimed at accelerating the development and demonstration of low and zero-carbon energy technologies for large-scale deployment.[149] There appears to be no disagreement.

10. Pension and Benefits (Exhibit A-13, Schedule C5, line 11; Schedule C5.11)

DTE Electric's Initial Brief, pp 200-201, explained that the Company projects $127.4 million of employee pension and benefits costs, which after adjustments for the portion of these costs capitalized, transferred, and eliminated as being related to separate surcharge programs, results in a net employee pension and benefits O&M expense of $106.7 million for the projected test year (Cooper, 7T 1811; Exhibit A-13, Schedule C5.11 Revised).

i. Pension

DTE Electric's Initial Brief, pp 201-205, explained how the Company developed its projected original and updated pension expense, [150] and the Company's proposal for a pension deferral mechanism.

The AG's Initial Brief, pp 32-37, incorporates and maintains AG witness Coppola's proposal that the Company's projected pension expense be reduced $17,442,000, from $9.145

[149] The Company is joining the LCRI because it recognizes the need for research and development to support viable, affordable, and sustainable solutions as it moves toward reaching a zero-carbon power generation fleet by 2050. By joining the LCRI, the Company will leverage resources with over 45 other companies worldwide, including Consumers Energy and other utility peers, to evaluate a wide range of pathways to economy-wide decarbonization. Customers will benefit because participation in the LCRI will give the Company immediate and direct access to LCRI projects, which will allow the Company to best leverage the successes and learnings of the overall effort for the benefit of customers (Morren, 5T 721-722).

[150] Mr. Cooper presented an updated pension cost projection prepared by Aon, the Company's independent actuary that reflected pension expense for the projected test year of $0.6 million, which reflects actual asset returns in 2021 and a 2.91% discount rate and represents the most up to date and reliable pension cost estimate (7T 1882, Exhibit A-35, Schedule Z6).

million to -$8.297 million (8T 4873). The Company disagrees because there are significant flaws in the AG's proposal. For example, it is based on sensitivities prepared by the Company in response to the AG's discovery requests, which do not reflect the same analytical rigor that would be used in a formal projection of pension costs by the Company's independent actuaries. The AG's reliance on pension cost projections not prepared by the Company's actuaries is inconsistent with the Commission's requirement that pension cost projections used in determining revenue requirements be based on independent actuaries, which "ensures that the expense has been reviewed and vetted by the actuary and is the most accurate projection available" (Case No. U-17990, Order dated February 28, 2017, p 97). While the AG's Initial Brief asserts that the Company was unable to identify any "major shortcomings" in the sensitivity analyses prepared by the Company the AG's claim is unverifiable because, due to timing constraints, the Company was unable to have its actuaries prepare the sensitivities requested by the AG (Exhibit AG-1.54, page 4 of 4). The sensitivities also included, at the AG's request, an assumption that the Expected Return on Assets (ERoA) would remain at 7.0% for the entire projected period, which is an unreasonable assumption (Cooper, 7T 1876-1883).

The AG's Initial Brief, pp 32-33, attempts to cast doubt on this testimony by referencing discovery responses (Exhibits AG-1.54 and AG-1.55), which instead confirm and further support the Company's position. For example, the AG's Initial Brief cites the minutes of the Pension Investment Committee to support the claim that there has not been any change in investment direction, but the AG fails to acknowledge that those minutes expressly reflect the investment Glide Path that provides for alternative investment mixes based on the funded status of the Pension plan (Exhibit AG-1.55, page 22 of 28).

The AG's support for the 7.0% ERoA is premised on the actual return on pension assets over the last 12 years, the opinion that there exists significant discretion in determining the ERoA and the claim that the Company has not shifted its pension assets into more conservative asset classes. On rebuttal, Mr. Cooper demonstrated the unreasonableness of the 7.0% ERoA assumption by disputing the reliability of only 12 years of actual pension asset returns. Moreover, the use of only 12 years of actual pension asset returns fails to recognize the substantial shift in pension assets during that period. Specifically, the proportion of assets invested in fixed income assets has increased from only 25% in 2010 to 48% in 2021 with a further increase in the target fixed income allocation to 57% in 2022 (Cooper, Rebuttal Table 5, 7T 1879). This shift in the mix of pension assets reflects the Company's investment policy of reducing the risk of pension funded status as the total funding of the pension liabilities increases, which has increased from 78% in 2010 to 97% in 2021 (Cooper Rebuttal Table 6, 7T 1880). Finally, the AG's proposal to include the 7.0% ERoA assumption is inconsistent with the ERoA assumptions used by the 100 largest pension plans, which has declined from 8.21% in 2010 to 6.33% in 2021 (Cooper Rebuttal Table 7, 7T 1883). Accordingly, the AG's advocacy of the 7.0% ERoA is unreasonable because it fails to recognize the risk reduction investment strategy of the Company and is dramatically higher than the ERoA used by other pension plan sponsors. While Witness Coppola avers that the Company has significant discretion in setting the ERoA, it is obvious that the Company's ERoA reflected in its updated pension cost projections of 6.8% in 2022 and 6.6% in 2023 are already at the high end of the range of reasonableness (7 T 1883). The AG's Initial Brief also attempts to buttress the claim that a higher ERoA is justified by comparing the average annual assets for each of the asset classes (Equities, Fixed Income and Alternatives) for each of the 12 years ending in 2021 (AG Initial Brief, pp 34-35). However, the AG's conclusions are flawed because they suffer from the same problem

as Mr. Coppola's analysis: 12 years is too short of a period to establish long-term expected returns. In measuring risk premia for use in estimating the cost of equity, expert witnesses in this case have relied upon historical returns over 30 years and as far back as 1926 (8 T 5093). Moreover, while the AG advocates the use of only actual asset returns over the last 12 years, the AG ignores that the return on the Company's pension assets for the three months ended March 31, 2022, was a negative 7.1% (Exhibit AG-1.48, page 2 of 4).

The AG's responds by inviting the ALJ to wade through discovery responses, and then, without further explanation or support, concludes for example that "the claim made by Mr. Cooper of a shift in investment strategy is baseless" (AG Initial brief, p 33). To the contrary, Mr. Cooper's expert testimony is sufficient to support a decision. [151] There is also no requirement to unravel and search for authority on the AG's contrary assertions (see footnote 2 above). The Company also again objects to the AG mischaracterizing and/or ignoring what the discovery responses actually say. The AG's Initial Brief also argues that the Company is not following a coherent investment strategy because the asset allocation changes each year (AG Initial Brief, p. 33). However, the AG provides no record support for its claim that a more coherent investment policy would establish an asset mix goal and then change the actual asset mix to meet that goal. AG Witness Coppola never made such claim in his testimony. In contrast, Mr. Cooper explained that the Company's investment policies are based on reducing the risks of pension asset investments as the pension plans become more fully funded (7 T 1879). There is no basis for the assertion that the Company's investment policy is "unsound".

Company accounting expert Uzenski further explained that the AG's proposal to include a negative pension expense of $8.297 million is also inappropriate because if pension expense is

[151] *Great Lakes Steel v Public Service Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983).

included in the revenue requirement as a negative amount, then this would result in a reduction in cash revenue without a corresponding reduction in cash expenditures. The required funding of the pension plan is made independently of the amounts recognized in expense, and cash cannot be refunded from the pension plan assets when book expense is negative (Uzenski, 7T 2779).

The AG's Initial Brief, pp 35-36, responds by suggesting that this should not present a cash flow hardship to the Company. In support of this claim the AG counters her own argument by stating that pension expense included in rates and pension funding are not the same. The AG observes that the Company is planning to contribute $50 million to the pension plan in 2023. The inclusion of $8.297 million negative pension expense in rates combined with the $50 million in pension funding under the AG's proposal would result in a cash drain on the Company of almost $60 million.

The AG's Initial Brief also claims that in Case No. U-20697 Consumers Energy proposed to include $53.6 million of negative OPEB expense by reference to an exhibit in Case No. U-20697 (AG Initial Brief, p. 35). In this instance the AG is relying on information that is not on the record in this proceeding and therefore not subject to any scrutiny or assessment of relevance to the facts presented in this case. For example, we don't know how Consumers Energy cash flow metrics compare to the Company's or even whether since this negative expense relates to OPEB expense rather than pension expense Consumers Energy is able to offset the cash flow through withdrawals from its OPEB funds. Therefore, AG's reference to the OPEB expense of Consumers Energy must be disregarded.[152]

[152]Michigan's Constitution requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. The APA similarly precludes the Commission from making decisions based on non-record materials. MCL 24.276.

While the AG opines that the increase in interest rates in 2022 will cause the pension liability decline, as discussed by Mr. Coppola, the AG concludes that as a result of this potential reduction in pension liabilities the Company may not have to make any pension contributions in 2023 or 2024, which is a conclusion not discussed by Mr. Coppola. Nor does this conclusion reflect the impact of actual losses on pension assets in 2022, which through March 31, 2022, are already a negative return of 7.1%. (Exhibit AG-1.48, page 2 of 4) While the Company's future pension expense may be reduced as a result of an increase in the discount rate, future pension costs will increase to the extent the actual return on pension assets is less than expected. For example, the impact of the reduction in the 2021 estimated actual return on pension assets from 12.0% as reflected on Exhibit A-13 C5.12.1 to the actual 2021 return on pension assets of 8.4%, as reflected on Exhibit AG-1.48 resulted in pension expense for the projected test period to increase from a negative $7.923 million to a positive pension expense of $6.463 million, or an increase in pension expense of $14.386 million. This demonstrates the potential for extreme volatility in the Company's future pension costs due to either changes in actual results, as in the case of return on assets, or changes in point in time measurements, as in the case of discount rates (7 T 1790).

To address the potential volatility and the possibility that future pension costs could be negative, the Company proposes a deferral mechanism for pension expense similar to the mechanism in place for the Company's OPEB expense, and consistent with the Commission approved deferral of pension expense for DTE Gas (Case No. U-20940, Order dated December 9, 2021, p.154). Under the Company's proposal actual pension expense would be deferred to a regulatory asset if positive, or a regulatory liability if negative, with the net deferred amount carried on the balance sheet for review in a future rate case. If the Commission adopts the Company's proposal, then the $0.6 million pension expense for the projected test year would be eliminated

($0). Staff also expressed its agreement with the Company's proposal in a discovery response, Exhibit A-43, Schedule HH3 (Cooper, 7T 1790; Uzenski, 7T 2712, 2779).

Therefore, the Commission should either adopt the Company's updated projected pension expense of $0.6 million (Exhibit A-35, Schedule Z6), or adopt the Company's proposed pension deferral mechanism.

ii. Other Post-Employment Benefit (OPEB) Expenses

DTE Electric's Initial Brief, pp 205-206, explained that the Company's OPEB costs are projected to decrease from a negative $27.0 million in the historical test period to a negative $35.0 million in the projected period, or negative $21.5 million inclusive of the effects of costs capitalized and transferred (Cooper, 7T 1792-1794; Exhibit A-13, Schedule C5.12.3). The Company also proposes the continued deferral of the negative net OPEB expense consistent with prior treatment.

iii. Active Healthcare Benefits

DTE Electric's Initial Brief, pp 206-11, explained that the Company's costs to provide benefits to its active employees largely concern health care and are projected to increase from $41.4 million in the historic test year, to $55.5 million in the projected test year.

The AG's Initial Brief, pp 30-32, vaguely incorporates AG witness Coppola's proposal to reduce health care costs to $48.5 million.[153] The Company incorporates its lengthy prior discussion explaining why Mr. Coppola's methodology is flawed and his corresponding conclusion should be rejected. The AG vaguely suggests that discovery responses "confirm Mr. Coppola's testimony and render Mr. Cooper's rebuttal arguments on this topic not credible" (AG Initial Brief, p 30, citing

[153] Mr. Coppola proposed to reject the Company's normalization adjustments related to COVID-19 and constant dollar, and to instead take the average of 2020 Active Healthcare costs (which he incorrectly he adjusted) and 2021 costs to get an average cost per employee of $10,834, which he then escalated by the average annual increase in costs per employee from 2017 through 2020 (2.5%) to arrive $48.5 million after allocating a portion to capital expenditures (8T 4867-4869).

Exhibit AG-1.53, pp 1-3). Instead, to the extent this matter is even considered (see footnote 2), the discovery responses further support the Company's position. There is similarly no merit in the AG's further inaccurate and/or speculative attempts to rely on discovery responses or claim that they are "not credible" if they do not align with her position (AG Initial Brief, pp 30-31).

Finally, the AG's Initial Brief, contends that "Mr. Cooper shows a table [at 7T 1874] and claims that healthcare costs per employee have been volatile. This is not true. The graph in the table shows a steady increase in costs until 2020 and 2021." To the contrary, the table plainly shows that healthcare costs decreased in 2014, 2016, 2018, and 2020. Healthcare costs also went up in 2021, contrary to the AG's suggestion. Indeed, perhaps the most obvious flaw in Mr. Coppola's $48.5 million projection is that it is $2.8 million lower than the Company's $51.3 actual Active Healthcare expense incurred in 2021 (Cooper, 7T 1867; Exhibit A-35, Schedule Z2, column h, line 15).

Therefore, the Commission should approve the Company's requested $55.5 million Active Healthcare expense.

iv. Other Employee Benefit Costs

DTE Electric's Initial Brief, p 211, reflects the Company's projected $9.872 million of Other Employee Benefits.

11. Employee Compensation

DTE Electric's Initial Brief, pp 211-21, explained and supported the Company's incentive compensation programs for both its executive and non-executive employees.[154] DTE Electric seeks to recover the $63.8 million net projected test period incentive compensation expense, which

[154] The programs consist of short-term incentive plans provided through the Annual Incentive Plan (AIP), applicable to executive level employees, and Rewarding Employees Plan (REP), available to all other non-represented employees. In addition, the Company provides a multiple year incentive plan delivered through the Long-Term Incentive Plan (LTIP), which is generally available to managers and above, and up to 10% of other non-represented employees. Mr. Cooper provided a detailed description of the design and mechanics of these plans (7T 1814-1844, 1851-1852; Exhibit A-21, Schedules K1 through K7).

excludes the expense allocated to the Company for DTE Energy's top five executives (Cooper, 7T 1821-1822). The performance measures included within the plans include both operating and financial metrics.

Staff's Initial Brief, pp 175-78, proposes to exclude $42,537,000, representing incentive compensation expense related to financial measures, because past Commission decisions have done so. Staff further explains that: "Staff does not dispute the overall reasonableness of employee compensation, but instead argues that there should be a distinction on who pays based on the metrics included" and "Staff's position is based on long-standing Commission precedent" (*Id*, pp 176-77). The Company maintains that the Commission has based its decisions on the evidence (*e.g.*, April 17, 2018 Order in Case No. U-18255, p 49) and has expressly recognized that "each case must be evaluated on the record in that case" (January 31, 2017 Order in Case No. U-18014, p 85). [155] Thus, financial measures have not been, and cannot lawfully be, categorically disallowed simply because the Commission has disallowed them in the past as Staff suggests.[156] This proposed disallowance, along with similar proposals including ABATE's proposed $41.473 million disallowance related to financial measures (ABATE Initial Brief, pp 56-57), also ignores the benefits resulting from a financially healthy company and the importance of offering total compensation that is sufficient to attract and retain employees, as further discussed below (Cooper, 7T 1865).

Staff's proposed $42,537,000 disallowance includes $1.064 million of Long-Term Incentive plan (LTIP) expense dependent on Nuclear Generation business unit operating measures. This

[155] The Commission also approved Consumers Energy Company's (Consumers) cost recovery for its employee incentive compensation program (EICP), which was structured with 50% of an employee's incentive based on achievement of operational and performance measures, and the other 50% based on the achievement of financial measures (November 19, 2015 Order in Case No. U-17735, pp 73-74, 78).

[156] Michigan's Constitution requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. The APA similarly precludes the Commission from making decisions based on non-record materials. MCL 24.276.

proposed disallowance is improper even under Staff's reasoning because the payouts are driven by operating measures that are unrelated to financial results, and therefore meet the Commission's traditional practice of requiring quantified customer benefits through improved reliability and lower costs (Cooper, 7T 1848-1850). Staff instead reasons that although this is based 80% on operating measures, Staff disallowed the entire payout because it is made in performance shares, which Staff views (inaccurately as discussed below) as dependent of the Company's financial operation (Staff Initial Brief, pp 177-78).

Staff's Initial Brief, pp 178-79, further proposes the disallowance of $5,587,000 of Restricted Stock expense that the Company pays to employees, reasoning that it relates to the achievement of financial performance measures (McMillan-Sepkoski, 8T 5264). Mr. Cooper explained that Restricted Stock, which represents $5.857 million of projected LTIP expense, is granted annually to encourage continued employment of certain key executives, and the value is not dependent on the Company's achievement of any financial measures. Therefore, Staff's proposed disallowance is unfounded and should be rejected (Cooper, 7T 1849, 1853).

Staff asserted that both Performance Shares and Restricted Stock are "based on DTE Energy Company stock prices, which is a financial measure used by the Company to determine the amount of the award" (McMillan-Sepkoski, 8T 5264). Staff's assertion is incorrect. The stock price is not used to measure the awards; instead, the stock is used as a medium to deliver the awards (like dollars, bitcoin, or other methods of payment). The number of shares used to pay the LTIP grant is simply adjusted depending on the stock price when the grant is paid (Cooper, 7T 1850).

Similarly, with regard to the Nuclear Generation operating measures, the cost is no different than the AIP and REP costs relating to operating measures. The principal distinction is that these

LTIP awards are made in stock rather than cash. This distinction in the *method* of payment (and not the underlying *measure* of payment) does not support different treatment (Cooper, 7T 1851).[157]

Staff disagrees but offers no logical reason. Staff also acknowledges that the restricted stock expense is recognized based on the value of DTE Energy's stock at the date of the grant, but ownership does not vest until typically three years from the grant (Staff Initial Brief, p 178). Thus, the grant is disconnected from DTE Energy's financial performance. For simple example, a $1,000 grant could be 10 shares of $100 stock, or 20 shares of $50 stock. Either way, the expense is $1,000, regardless of DTE Energy's stock price. Plus, the whole point of this discussion concerns DTE Electric's recovery of expenses (here, measured at the time of the grant). Whether employees ultimately make or lose money based on DTE Energy's stock price years later is irrelevant.

The AG's Initial Brief, pp 37-40, vaguely incorporates and maintains witness Mr. Coppola's proposal for the complete elimination of incentive compensation expense related to financial measures ($41.473 million), plus 40% of incentive compensation expense related to operating measures ($8.490 million), which totals $49.963 million; however, he proposed a $51.028 million disallowance (8T 4880-4881). The difference is $1.065 million, which equals the LTIP expense related to Nuclear Generation operating measures. Mr. Coppola offered no basis to disallow this expense, so the Company assumed it was just inadvertently included in his total proposed disallowance (Cooper, 7T 1854-1855). The AG's Initial Brief, p 39, suggests that this item should be included simply because it is in Mr. Coppola's total proposed disallowance. To the contrary, neither Mr. Coppola nor the AG explained or supported any disallowance for this item, so any

[157] Staff's proposal was also apparently based on an incorrect inference. Staff cited a phrase from the Company's LTIP employee plan description booklet (Exhibit S-3.6), indicating that the LTIP is "a reward to employees for assisting the Company in reaching its financial performance goals" (McMillan-Sepkoski, 8T 5264). Staff's inference is incorrect because the LTIP employee plan descriptive booklet describes the potential benefits to employees of future increases in DTE Energy's stock price, but that benefit has no impact on the Company's costs (Cooper, 7T 1853-1854).

suggested disallowance is unfounded and abandoned. The same can be said for the AG's Initial Brief, p 39, confusing discussion about a 1.7% increase in employee headcount as somehow supporting Mr. Coppola's suggestion that productivity is not increasing, which in any event makes no relevant or meritorious point.

AG witness Coppola proposed to exclude 40% of incentive compensation expense relating to operating measures based on his analysis of the operating performance levels achieved for the years 2017 through 2021 (8T 4880-4881; Exhibit AG-1.49). Mr. Cooper explained that Mr. Coppola's analysis is flawed because it failed to recognize that while certain measures may produce results less than Target, other measures can produce results greater than Target. There are also various gradients of performance between Threshold and Maximum. Exhibit A-35, Schedule Z1 shows that for the last five years, the actual weighted performance was 96.5% for the AIP, and 83.4% for the REP (Cooper, 7T 1859-1860).[158] This average annual performance method is more accurate than Mr. Coppola's simplistic binary approach (either the target was met, or not), and it recognizes that actual payouts can fall within a wide spectrum of performance levels. Moreover, variations in year-to-year performance further reflect the ambitious goals set each year to motivate ever-improving operating performance. It is not reasonable to assume that only 60% of operating performance measures will be achieved as the AG suggests. The Company's goal is to establish costs at levels that are likely to be achieved, so it is reasonable to assume that the Company will, on an overall basis, achieve Target performance levels (Cooper, 7T 1860-1861).

[158] The Company's initial filing also included Exhibit A-21, Schedule K7, which reflected the Company's actual operating measures performance for 2016 through 2020 for the AIP and REP for all employee groups. It showed that the average of the annual operating performance results for 2016 through 2020 was 100.9% for the AIP, and 87.5% for the REP. The combined five-year average for both the AIP and REP was 94.2% (Cooper, 7T 1842).

The AG's Initial Brief, p 40, suggests that a discovery response (Exhibit AG-1.53, p 3) shows why using the average overall score is inappropriate. The AG misconstrues the discovery response and neglects the Company's evidence. The AG also offers no response to the Commission previously relying on similar evidence to reject essentially the same argument that the AG repeated in this case. The Commission instead authorized DTE Electric's recovery of incentive compensation relating to operating measures, explaining in part: "The Commission notes that DTE Electric provided evidence showing that the company has achieved performance targets for AIP at an average of 96.3% and for REP at an average of 82.8%, from 2012 to 2016. (7T 837). When looking at historical performance over a longer period, the Attorney General's recommendation that 50% should be disallowed is simply not supported" (April 18, 2018 Order in Case No. U-18255, p 49). See also, May 2, 2019 Order in Case No. U-20162, p 93.

Energy Michigan's Initial Brief, pp 12-14, echoes its witness Zakem's proposal for the disallowance of incentive compensation expense for all measures in which the costs are greater than the benefits (8T 4497-4500). The Company disagrees, and previously explained that in addition to the extensive prior discussion supporting its proposal and responding to other parties, Energy Michigan's proposal is flawed for two additional reasons.[159]

Energy Michigan's Initial Brief, p 13, suggests that "DTE's rebuttal to this recommendation is mystifying," and proceeds with a discussion that appears to misunderstand and/or incorrectly

[159] First, the cost/benefit analysis reflected in Exhibit A-21, Schedule K6 represents only the reasonably-quantified financial benefits of the Company achieving target performance for each of the metrics included in the incentive compensation plans. It is also important to recognize that certain measures provide benefits to customers but evade specific quantification. For example, the quantifiable benefits of the MPSC Customer Complaints measure are only $228,000 based on time savings but does not include additional unquantifiable benefits to customers (such as avoidance of frustration) or savings by the Commission resulting from a reduction in complaints (Cooper, 7T 1863-1864).

Second, Energy Michigan's proposal is a new, unreasonable, and unsupported interpretation of the Commission's standard for recovering incentive compensation expense, which has consistently assessed the net customer benefits on an aggregated basis, and not the net benefits for each measure (Cooper, 7T 1863-1865).

characterize the Company's positions. Since Energy Michigan does not offer anything new to explain or support its position, there is nothing further to discuss.

Therefore, and as further discussed in DTE Electric's Initial Brief, the Commission should approve DTE Electric's request to include all of the Company's incentive compensation expense (except for the top five DTE Energy executives) in the revenue requirement adopted in this case.

D. Depreciation and Amortization

DTE Electric's Initial Brief, p 221, explained and supported the Company's projected $1,086.1 million of depreciation and amortization (D&A) expense for the projected test period, consisting of the originally filed $1,087.9 million, revised by $1.8 million as indicated in section I of DTE Electric's Initial Brief.

Staff's Initial Brief, p 179, proposes $1,047.1 million due to the impact of Staff's proposed capital expenditure disallowances. The AG's Initial Brief, p 92, similarly adjusts depreciation expense based on the AG's proposed reductions in capital expenditures. Staff's and the AG's proposals should be rejected as discussed in DTE Electric's Initial Brief and this Reply Brief, with corresponding D&A effects. The Company's projected D&A expense of $1,086.1 million is reasonable and should be approved by the Commission.

E. Property and Other Taxes

DTE Electric's Initial Brief, pp 221-22, explained and supported $307.7 million of Property Tax expense and $48.6 million of Other Tax Expense for the projected test year. Staff's Initial Brief, p 180, agrees. There is no disagreement, so the ALJ should recommend, and the Commission should approve the Company's Property and Other Taxes expenses.

F. Income Tax Expenses

DTE Electric's Initial Brief, p 222, explained and supported a total income tax recovery of $137.6 million, consisting of $83.2 million federal income tax (FIT) expense, $51.8 million of Michigan Corporate Income Tax (MCIT) expense, and $2.6 million municipal income tax expense.

Staff's Initial Brief, p 84, recommends $104.3 million of FIT, and $61.0 million of state and local taxes due to Staff's adjustments to the Company's revenues and expenses. Staff's proposed revenue and expense adjustments should be rejected as discussed in DTE Electric's Initial Brief and this Reply Brief, with corresponding tax effects.

VIII. OTHER REVENUE RELATED ISSUES

A. Accounting Requests

DTE Electric's Initial Brief, pp 223-25, outlined the Company's accounting requests, which were largely discussed elsewhere. The only dispute concerns outage credits. Kroger's Initial Brief, pp 1-2, echoes its witness Bieber's opposition to the Company's proposal to defer the costs of customer outage credits. The Company incorporates its prior discussion at DTE Initial Brief, p 225. The same response essentially applies to DAAO's Initial Brief, pp 52-54, suggestions that outage credits should be larger and not recoverable (See also section III above).

Staff's Initial Brief, p 272, states: "Staff agrees with the Company's cost recovery proposal to a degree. The Staff agrees with the idea of deferring the costs into a regulatory asset and evaluating them in the next case for reasonableness and prudency. Staff does not entirely agree with the Company, however, that DTE Electric should recover outage credits paid out due to outages that were 'shown not to be the company's responsibility.'" Staff further indicates that the quoted language could be interpreted in an overbroad manner and offers a proposal to refine its meaning.

B. Line Loss Study

The Company agrees that Staff's proposal is generally consistent with the Company's intent but disagrees with Staff's suggestion that only certain types of outages caused by third parties (ie. including transmission system failures, customer failure to maintain clearances on service lines, but excluding automobile collisions) should be compensated) (Staff Initial Brief pp. 272-273). The list of the type of outages that would be specifically recoverable was presented as an example, not an exhaustive list. (7T 2360). The Company's proposal in this case is to defer the costs and specific cause types for later review in the first case when the costs are requested for recovery.

DTE Electric's Initial Brief, pp 225-27, explained and supported the Company's line loss study.[160] Exhibit A-28, Schedule R1 provides the results (page 1 in MW; page 2 in MWh). The Company also conducted a marginal line loss study that augments the line loss study. The results are included in Exhibit A-28, Schedule R1, page 3.

The Company also previously explained that ABATE witness Andrews proposed that "DTE should be required to update the 2019 Line Loss study to explicitly calculate the 4CP and 12CP loss factors based on the monthly peak demands" (8T 2996). Exhibit A-28, Schedule R1 uses monthly average values for line loss factors. The Company will consider exploring a revised methodology for calculating line loss factors in the future but does not support including the loss factors calculated by witness Andrews because they have not been reviewed and are based on incomplete system values (Asghar, 7T 1465).

[160] A line loss study determines the losses in the electrical system that occur between the point of generation and end-customer usage (Robinson, 7T 1558).

ABATE's Initial Brief, pp 31-35, essentially recounts its witness Andrews' alternative loss factors, and then suggests that the Company should not have "simply discarded" ABATE's proposal (*Id*, p 36). See Also Kroger's Initial Brief, pp 4-5. ABATE misconstrues the Company's position. The Company said that it will consider exploring alternatives, but it does not support ABATE's proposal under present circumstances, as indicated above. The Company maintains that its position is appropriate. See also Staff's Initial Brief, p 269 (reflecting Staff's reason for rejecting ABATE's estimate of demand losses).

IX. SUMMARY OF REVENUE DEFICIENCY AND REQUESTED RATE RELIEF

Based on the adjustments described above in Section I, DTE Electric supports and requests approximately $367.9 million in rate relief. See Reply Brief Attachments A and B**.**

X. COST ALLOCATION AND RATE DESIGN

A. DTE Electric's Cost of Service Study Supports the Company's Rate Design Proposals.

DTE Electric's Initial Brief, pp 228-34, explained and supported the Company's proposal to allocate costs among its customers.

CEO's Initial Brief, pp 23-28, echoes its witness Lucas' suggestion that the Company's approach to allocating its sales forecast among residential rate schedules is not methodologically appropriate. He asserted that the Customer Usage change portion of the residential sales forecast "should be prorated over all the classes like the other adjustments rather than consolidated into D1" when considering residential billing requirements, and further recommended that rates should then be recalculated with the new billing determinants (Lucas, 8T 3597; recounted at CEO Initial Brief, pp 27-28).

The Company disagrees because (as it previously explained but recounts for context) its method to allocate residential sales is consistent with the method used in past cases, including Case

No. U-20561. While CEO witness Lucas apparently agrees that there is no inherent flaw in the Company's method, stating that "[i]n a normal case . . .this approach may be fine" (8T 3596), he suggested that 2020 was abnormal because of COVID. Nonetheless the Company's forecasting is accurate as discussed in DTE Electric's Initial Brief and above, and Mr. Lucas does not articulate why his proration approach might be more appropriate than the Company's method. Finally, Mr. Lucas suggested a forecasted per capita change to D1 usage of 8.2%, when considering customer increases and excluding impacts of weather (8T 3594). This is substantially similar to the 7.03% per capita change across the full residential forecast, since D1 sales comprise approximately 89.6% of forecasted residential sales. Thus, Mr. Lucas' suggested distinction between D1 adjustments is overstated and does not suggest any error in the Company's methodology or calculation (Willis, 6T 979-980).

CEO's Initial Brief, p 24, suggestion that Mr. Willis' "rebuttal testimony did not address Witness Lucas concerns related to the unique challenges of the COVID-19 pandemic" is without merit because it neglects that much of CEO's discussion is premised on an indirect challenge to DTE Electric's sales forecast, which was sponsored by Mr. Leuker (*e.g.*, *Id* at p 24: "In creating its sales forecast for the upcoming test year, the Company likely over-emphasized the nature of its rate bases 'return to work' plans related to COVID-19," and p 27, indicating that Mr. Lucas disagrees with Mr. Leuker about residential usage patterns). CEO offers no support for what it may consider "likely," [161] and Mr. Lucas has no qualifications to dispute the forecast made by the Company's

[161] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

forecasting expert (See section III above). The Company's sales forecast is accurate, as Staff now fully agrees (See section VII. A above)

The Commission adopted the 4CP 75-0-25 method for allocating certain production costs in Case No. U-17689 (in accordance with 2014 PA 169) and has continuously applied it in subsequent DTE Electric rate cases, Case Nos. U-17767, U-18014, U-18255, U-20162 and U-20561. The Commission also reminded future parties of the standard "that any party proposing to revise the production cost allocation method in a future case include in its evidentiary presentation an analysis using the equivalent peaker method or an approximation for comparison purposes" (May 2, 2019 Order in Case No. U-20162, p 129, quoting the January 31, 2017 Order in Case No. U-18014, p 100).

The AG's Initial Brief, pp 96-125, echoes her witness Dismukes' recommendation that "the Commission modify the weighting of the existing 4 CP 75-0-25 cost allocation method to one that equally weights demand and energy concerns, or a 4 CP 55-0-45 cost allocation methodology" (8T 4938; recounted at AG Initial Brief, pp 96, 110, and 124). The Company disagrees because Mr. Dismukes made a nearly identical recommendation in Case No. U-20561 (at 9T 2857), which the Commission properly rejected, finding that "the record evidence is insufficient to overcome [MCL 460.11(1)'s] statutory allocation, as no party adequately demonstrated that a different methodology more adequately reflected the actual cost of service" (May 8, 2020 Order in Case No. U-20561, p 220).

Mr. Dismukes' present 4CP 55-0-45 recommendation similarly lacks a sound foundation because it is based primarily on system load factors, which is not an equivalent peaker method as described by the NARUC Electric Cost Allocation Manual (Maroun, 6T 1059; Exhibit A-39, Schedule BB2). The analysis presented in Exhibit AG-2.5 is also not an approximation of the

equivalent peaker method. The NARUC manual describes two methods for allocating costs using equivalent peaker methods, which are based on (1) the original cost to install generating units, and (2) a comparison of the rate bases of base load and peaker units. In contrast, Exhibit AG-2.5 determines the demand/energy split by (1) using capacity factors, and (2) comparing a levelized total cost to the MISO CONE price. Mr. Dismukes did not present an equivalent peaker analysis and he failed to demonstrate that the current production cost allocator is not cost based. As such, the 4CP 75-0-25 production cost allocator should remain unchanged (Maroun, 6T 1060). See also, Staff's Initial Brief, pp 265-68,[162] ABATE's Initial Brief, pp 9-31, and Kroger's Initial Brief, p 4.

The AG's Initial Brief, pp 110-14, 121-25, also echoes her witness Dismukes' further recommendation that "the Commission allocate costs associated with demand-related secondary-voltage distribution systems based on class NCP [non-coincident peak] demands" (8T 4942; recounted at AG Initial Brief, pp 113-14, 124-25). The Company disagrees because Mr. Dismukes made the same recommendation in Case No. U-20561 (at 9T 2865). In that case, the Commission agreed with the ALJ's recommendation to reject the AG's proposal as insufficiently supported by a small sample of 18 cases, and that the AG could raise the issue again with additional evidence (May 8, 2020 Order in Case No. U-20561, pp 224-225). Here, the AG presented the same evidence, so there is no basis to reconsider the issue.

The AG's Initial Brief, p 122, acknowledges the "additional evidence" requirement, but asserts that the "Company is incorrect [because the] AG did provide evidence." The AG neglects the difference between the same evidence and "additional evidence." For example, concerning the 18 cases referenced above, compare the AG's Initial Brief, p 123, recounting Mr. Dismukes'

[162] Some of Staff's discussion concerns Walmart witness Perry. Walmart's Initial Brief, pp 6-9, does not oppose the 4CP 75/0/25 production cost allocation methodology, but suggests in the alternative that an A&E methodology might be appropriate.

assertion regarding 72.2 percent of 18 rate cases filed between 2010 and 2018, with the U-20561 PFD, pp 398-99, quoting Mr. Dismukes. Further review of the record reveals that Mr. Dismukes' underlying testimony in this case (at 8T 4942) is exactly the same as the ALJ quoted in Case No. U-20561.

The Company also disagrees that a change is either necessary or appropriate. First, the basis for Mr. Dismukes' recommendation is not robust (18 general rate cases over an eight-year period, out of hundreds of rate cases during that period). As indicated above, the Company raised the same point in Case No. U-20561, and the ALJ and Commission agreed. Further, simply because a method is used by another utility or in another state does not, in itself, justify its use for DTE Electric. In sum, Mr. Dismukes did not present meaningful evidence that could support deviating from the current, well-established practice (Asghar, 7T 1462-1464).

Staff's Initial Brief, pp 264-65, recounts Staff's recommendation to allocate uncollectibles based on total revenue. DTE Electric's Initial Brief, pp 232-33, explained why the Company disagrees. Staff's Initial Brief, p 265, further asserts that in the alternative, the allocation should be "by a three-year average of net write-offs," and indicates that the "Company supports Staff's alternative proposal to allocate collectibles expense based on a 3three-year [sic] average of net write-offs. (3 TR 194)." (*Id*, p 264). Staff apparently conflates the forecast of uncollectibles with the allocation of uncollectibles. See section VII. C. 7 above. Thus, the Company maintains its position.

Staff's Initial Brief, pp 186-87, reflects its recommendation "that the Company be required, in its next rate case, to propose a method for allocating the cost of the AMI communication system between the billing function and any other functions it is utilized for (for example, to deliver load control signals as discussed by Company witness Phillip L. Smith), including all said functions. In

Staff's opinion, insofar as the AMI communication network is used for something other than billing, an appropriately allocated portion of that cost should be removed from the calculation of the customer charge, the non-transmitting meter charge offset, and allocated on a basis consistent with that use rather than how it is currently allocated" (Revere, 8T 5141-5142).

The Company disagrees because although AMI meters provide ancillary benefits to customers, the fact remains that (1) the addition of a customer requires investment in an AMI meter, and (2) costs are predominately driven by the supply of service to customers. The Commission also denied a similar proposal in a prior proceeding (December 17, 2020 Order in Case No. U-20697, p 285). Therefore, the most appropriate approach is to continue classifying 100% of meter costs as customer related, and recover these costs through customer charges, as proposed by the Company and utilized in tariffs approved by the Commission in prior rate cases (Maroun, 6T 1069-1070).

DTE Electric's Initial Brief, p 234, reflected the Company's disagreement with MNSC witness Jester's proposal that the Commission direct the Company and Staff to "build up a database for further analysis" based on information about other utilities in other states (8T 3739). See also, Staff Initial Brief, pp 258-59. In light of this, "MNSC is not pursuing this recommendation further in this case" (MNSC Initial Brief, p 168).

B. Revenue Requirements by Unit/Grouping Study (Plant Study)

DTE Electric's Initial Brief, pp 234-36, discussed the Company's revenue requirements by unit/grouping study (Plant Study; Exhibit A-32 Revised), and the Company's disagreement with MNSC witness Jester's proposal that the Commission require DTE Electric to perform the plant study in future rate cases. MNSC did not address the plant study in their Initial Brief, making the Company's point that there is no continuing need for or interest in such a study. Therefore, the Commission should not require one.

C. State Reliability Mechanism (SRM) Capacity Charge

DTE Electric's Initial Brief, pp 236-40, discussed the Company's capacity charge revenue requirement ($1,627.0 million, reflected on Exhibit A-16, Schedule F1.5 Revised, line 8).

MNSC's Initial Brief, pp 95-102, echoes their witness Jester's various allegations and alternative calculations. The Company maintains its disagreement, as it explained previously (DTE Electric Initial Brief, pp 237-39), and further notes that MNSC attempts to undermine the Company's credibility on various individual points that make no difference to the overall outcome. MNSC's Initial Brief, pp 95-99 recommends that certain costs in the Company's cost of service study and SRM capacity charge calculation should be allocated differently, allegedly to better reflect cost causation. One of these items is the fixed costs of the Midwest Energy Resources Company facility, or MERC. MNSC never disputes that the MPSC has approved rates that include the MERC allocation in every case since U-15244. MNSC implies that the MPSC's consistent allocation treatment regarding MERC is of no import because: first, as to the treatment of MERC costs since DTE Electric's U-15244 rate case, the January 13, 2009 Commission Order in that case never discusses the assignment or allocation of MERC costs, nor does the allocation of MERC costs appear anywhere in the cost-of-service exhibit DTE filed in U-15244. This simple observation by MNSC, that MERC costs are not specifically addressed in the order or appear explicitly on an exhibit does not mean the Commission was unaware of their inclusion or how they were allocated, which both appear in the supporting workpapers submitted with the Company's underlying rate case filings. Commission intention and awareness is also demonstrated in MNSC's Initial Brief p.

98, citing the Case No. U-18248 November 21, 2017 Order which reflects a discussion of MERC costs[163] and their allocation in the capacity charge calculation.

Even assuming any merit in any other points (which there is not, but the Company declines to recount history or otherwise burden the discussion), [164] MNSC's proposals would still be wrong and should be rejected under any realistic view of the overall picture. See also ABATE's Initial Brief, pp 19-31.

Energy Michigan's Initial Brief, pp 1-4, echoes its witness Zakem's proposal that "any expenses other than fuel should be removed from the "net of projected fuel" calculation (8T 4505). The Company disagrees because the Commission allowed the Company to include "Fuel-Related Costs" in Case No. U-20561, as these costs are all incurred as a result of producing energy from the Company's generation resources. Energy Michigan's Initial Brief, pp 2-3, responds that "[t]his statement is true as far as it goes," but suggests that it is unclear why the Commission did so, and that Case No. U-20561 should be considered as an "inadvertent outlier."

The Company disagrees that Case No. U-20561 should not be followed. The treatment was, and remains, appropriate to ensure all customers are treated fairly. If any of these costs were to be excluded from the Fuel-Related Costs category, then the Company's PSCR customers would subsidize customers paying the SRM Capacity Charge. The energy sales revenue would also not be possible without incurring the Fuel-Related Costs, so anyone receiving the revenue benefit should bear the associated cost (Burgdorf, 4T 149).

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[163] In the Order, MERC is referred to obliquely as "a Wisconsin fuel handling facility." (Case No. U-18248 Order dated November 21, 2017, p. 33)

[164] See, for example, the April 18, 2018 Order in Case No. U-18255, p 54 (rejecting the RCG's challenge to full normalization ratemaking for the change in the City of Detroit tax rate, which the Commission decided in Case No. U-17767, where DTE Electric's witnesses did not re-present the status quo nor specifically recall the details on cross examination).

Energy Michigan's Initial Brief, p 3, further suggests that the Company's PSCR reference is irrelevant because a different statute governs the SRM. It is true that there are different statutes, but there are related concepts, and this issue is just the latest in a series of attempts by alternative energy suppliers to advance their economic interests by shifting costs onto the Company's full-service customers.

Energy Michigan's Initial Brief, pp 4-6, echoes its witness Zakem's further proposal that the Commission eliminate the true-up calculation when calculating capacity charges as long as the previous charge has not been applied to any party, presumably meaning an Electric Choice customer (8T 4510). See also, Kroger's Initial Brief, pp 2-3. The Company disagrees because the enabling statute[165] does not say that its requirement to include a capacity charge true-up is contingent on whether an Electric Choice customer paid a capacity charge during the period being reconciled. Therefore, the energy sales net of fuel true-up must be included in the calculation of the capacity charge (Crozier, 7T 2393-2394).

Energy Michigan responds by asserting that this "makes no practical sense and interprets the statute to reach an absurd result" (Energy Michigan Initial Brief, pp 4-5, citing a case for the proposition that statutes should be construed to prevent absurd results). Energy Michigan neglects that the "absurd results" consideration is well down the line in statutory-interpretation principles, as even reflected in its own cited case. The primary principle is that statutory language must be

[165] MCL 460.6w(4) states:

> The commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in section (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year.

applied as written. [166] Statutory language is not unclear (and subject to subjective views of what may be "absurd") just because parties disagree. Every litigated case (such as this) concerns parties advocating different interpretations, so the existence of differing viewpoints cannot be the standard for finding ambiguity.[167] A statute or rule is also not ambiguous just because it is unclear. "Instead, a great many unambiguous provisions of the law are far from clear. The interpretive process is often quite difficult, struggling to remove a great deal of textual underbrush. A provision of law that is unambiguous may well be one that merely has a better meaning, as opposed to a clear meaning."[168]

Here, the statute (quoted above) is clear. For example, it repeatedly uses the term "shall," which denotes a mandatory duty imposed by the Legislature and excludes the idea of administrative discretion.[169]

Energy Michigan's Initial Brief, pp 6-7, echoes its witness Zakem's further proposal that when calculating the SRM capacity charge, the data for the projection should be for the same year as the data for the actuals (8T 4512). The Company disagrees because, for example, the projection for the 2019 PSCR year was embedded in rates that were approved in Case No. U-20561 (a general rate case where capacity expense is established), and which the Company charged throughout 2021.

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[166] *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("We presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"). *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003).

[167] See, for example, *Mayor of City of Lansing v Public Service Comm'n*, 470 Mich 154, 165-66; 680 NW2d 840 (2004) (rejecting the "reasonable minds can differ" standard of ambiguity). Instead, "a finding of ambiguity is to be reached only after 'all other conventional means of interpretation have been applied and found wanting." *Id* at 165, quoting *Klapp v United Ins Group Agency, Inc*, 468 Mich 459, 474; 663 NW2d 447 (2003).

[168] *Mayor of City of Lansing, supra,* 470 Mich at 166, n 7.

[169] *Macomb Co Rd Comm'n v Fisher*, 170 Mich App 697, 700; 428 NW2d 744 (1988); *Southfield Twp v Drainage Bd*, 357 Mich 59, 76-77; 97 NW2d 281 (1959) ("the word 'shall' is mandatory and imperative and, when used in a command to a public official, it excludes the idea of discretion").

The Company's capacity charge true up compares the actual energy sales net of fuel for the year to the projection of that data that was embedded in its rates that it charged to its customers during that year. (Crozier, 7T 2392-2393). See also Staff's Initial Brief, pp 269-70.

Energy Michigan's Initial Brief, pp 7-11, further suggests that the SRM capacity charge should be clearly set forth in the record and based on record evidence. But Energy Michigan acknowledges that "[i]n previous DTE rate cases, U-20162 and U-20561, the final orders included an Attachment C which showed the Calculation of the SRM capacity charge." (*Id*, p 7). No customer would ever pay the capacity charge number as Energy Michigan suggests it be calculated. Each rate schedule has a unique capacity charge as shown on Exhibit A-16 Schedule F3. Thus, Energy Michigan's suggestion seems to be a solution in search of a problem.

Staff's Initial Brief, p 263, asserts that the Company inappropriately included MISO Schedule 17 Market Administrative Costs as a fuel cost that offsets projected energy sales revenue (Gottschalk, 8T 5119). The Company disagrees, because, as discussed above, the method of subtracting the Fuel-Related Costs category remains the same as from Case No. U-20561, where the costs were discussed by the Company and properly included in the approved method of subtracting out Fuel-Related Costs. These costs remain appropriate for inclusion in Fuel-Related Costs to ensure all customers are treated fairly. These costs occur only with the production of energy from the Company's generation assets. To give the benefit of energy sales to customers being charged the SRM without including all of the attributable costs to produce the energy would be unfair to the Company's PSCR customers who would end up paying those extra costs, thereby subsidizing customers on the SRM Capacity Charge (Burgdorf, 4T 123, 150-151).

D. Residential Rate Design Proposals

DTE Electric's Initial Brief, p 241, reflects that Exhibit A-16, Schedule F3 shows the present and proposed rate designs and corresponding revenue by rate schedule. Staff's Initial Brief, pp 231-32, accepts the Company's residential rate design.

1. Time of Use (TOU) Full Implementation

DTE Electric's Initial Brief, pp 241-46, discusses the Company's initial proposal (which the Company still maintains) for full implementation of TOU rates using proposed Rate Schedule D1.11 (Residential Service Rate – Standard TOU), which mimics the structure of Rate D1-A. Staff and some Intervenors proposed to extend TOU pricing beyond power supply non-capacity costs. In response, the Company provided its "Alternative TOU Full Implementation proposal," which, among other things, incorporated a rate design that applies TOU pricing to both the capacity and non-capacity portions of power supply (supplemental response to Audit DWI-1.1; Exhibit A-45, Schedule JJ1 Revised).

"MNSC supports the Company's alternative TOU proposal" (MNSC Initial Brief, p 103). GLREA's Initial Brief, p 6, prefers the Company's alterative proposal over its original proposal, but suggests a greater on-peak/off-peak differential. Staff's Initial Brief, pp 244-47, criticizes the Company's initial proposal, and asserts that the Company's alternative proposal should be approved with Staff's modifications. The Company incorporates its prior response to Staff and CEO witness Lucas (DTE Electric Initial Brief, pp 243-44),[170] further noting that it is unclear if Staff still supports some of its witnesses' earlier suggestions. See also, Staff's Initial Brief, p 187, agreeing with CEO

[170] Both Staff's Initial Brief, p 246, and CEO Initial Brief, pp 18-23, suggest that the Company should not have assumed a 3% shift from on-peak to off-peak. The Company discussed this matter previously and maintains that it properly addressed the issue.

witness Lucas that the differential should be higher, but disagreeing with his goal of incentivizing peak shifting,[171]

Therefore, the Company's proposed Rate Schedule D1.11 (Residential Service Rate – Standard TOU), either as originally proposed or as defined in the "Alternative TOU Full Implementation" proposal in DWI-1.1, should be approved, along with related cost recovery. In the event that the Commission approves the "Alternative TOU Full Implementation", the corresponding contract term language in Exhibit A-16, Schedule F8, sheet D-14.06 should reflect the default nature of the rate schedule and therefore the "Contract Term" provision in Exhibit A-16, Schedule F8, sheet D-14.06 should be stricken and replaced with the contract term language set forth on Exhibit A-16, Schedule F8, sheet D-2.00.

2. Rate D1.12, the residential "Stable Bill Service Level" demand-based tariff

DTE Electric's Initial Brief, pp 246-50, explained and supported the Company's proposal to establish Rate Schedule D1.12 (Residential Service Rate – Stable Bill Service Level).

Staff's Initial Brief, pp 247-52; CEO's Initial Brief, pp 5-18; GLREA's Initial Brief, pp 7-10; MEIBC/IEI's Initial Brief, pp 38-51; MI-MAUI and Ann Arbor's Initial Brief, pp 38-43; and MNSC's Initial Brief, pp 104-10, criticize the Company's proposed D1.12 rate and assert that it should be rejected. The Company incorporates its prior discussion responding to arguments, and again acknowledges that there are multiple ways to achieve higher levels of cost-alignment, and it would potentially be supportive of alternative demand-based structures if the Commission deemed them appropriate to implement. Therefore, while the Company maintains that its proposed D1.12

[171] If the Commission orders a different rate design, then customer behavior that is different than what underlies proposed Rate Schedule D1.11 could potentially be expected. Therefore, the Commission should also allow the Company to adjust the projected billing determinants associated with the ordered rate design to ensure cost recovery (Foley, 6T 1145-1146).

rate is appropriate, it would also generally support TOU demand charges as a way to better achieve cost-alignment, although any specific application would need to be closely assessed.

Therefore, the Company's proposed Rate Schedule D1.12 (Residential Service Rate – Stable Bill Service Level) should be approved.

3. Energy Assistance

DTE Electric's Initial Brief, pp 54, discussed the Company's energy assistance programs, and responded to various indicated concerns and arguments.

Staff's Initial Brief, pp 222-25, disagrees with the Company about prioritizing 5,000 senior citizen customers to receive the Low-Income Assistance (LIA) credit. The Company maintains that it appropriately addressed bill affordability for some of the Company's most vulnerable customers. Staff's proposal to instead randomly apply LIA credits to low-income customers would also reverse the current successful policy of pairing the LIA with the Low-Income Self Sufficiency Plan (LSP) (Johnson, 5T 832).

In further response to Staff's indicated concern about tariff language allowing the Company's discretion in the distribution of the LIA enrollment, Ms. Johnson explained that the tariff allows the Company to act appropriately to ensure that all funds are distributed, but it does not allow the Company to move away from what has been ordered. The Company agrees that it is important to engage Staff when considering how it distributes the credit; however, a requirement to consult with Staff and file a case with the Commission every time the Company determines it should adjust the distribution of the credit could significantly hinder the ability to adjust as needed for vulnerable customers who need assistance (Johnson, 5T 832-833).

Staff and the Company apparently now agree that the difference in projected and actual low-income-credit customer counts should be recorded as a regulatory asset/liability (Staff Initial Brief,

pp 125-26, explaining in part at p 126: "Staff does not disagree with the Company's directive to avoid reconciliations every two years and it does not take issue with future regulatory asset/liability balances being addressed in future rate cases."[172]

The Company is also forecasting RIA enrollment of 61,745 customers in the projected test year. Current RIA enrollment is at 64,000 electric low-income customers. All eligible customers seeking the RIA credit are granted enrollment. The numbers continue to trend upward, so it is reasonable to expect that enrollments will remain at or above the 60,000 level (Johnson, 5T 817).

Staff's Initial Brief, pp 155-58, instead proposed to limit the RIA enrollment forecast to 33,000 and move any RIA overflow onto LIA until the 32,000 LIA cap is reached. Ms. Johnson explained that Staff's proposal falls far short of the demonstrated need for energy assistance. Reducing that assistance as Staff proposed would be a step backwards from the progress that has been made and that continues to be needed in identifying and helping struggling households. The Commission should adopt the Company's forecast of 61,745 RIA enrollments and retain the current practice of pairing LIA enrollments with LSP, along with the Company's discretion to enroll non-LSP households when space is available (Johnson, 5T 833-834).

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[172] The Commission previously reduced the Residential Income Assistance (RIA) enrollment level from 60,000 to 43,000 customers and retained the LIA program enrollment at 32,000 customers. The Commission also authorized the Company to track enrollments up to the projected enrollment of 60,000 for RIA and 50,000 for LIA, to be booked as a regulatory asset (May 8, 2020 Order in Case No. U-20561, p 239).

Instead of simply deferring any amounts over the amount in base rates, the Company initially proposed a mechanism that would allow the Company to carry over any unspent RIA and LIA credits from one year to the next. If the credits issued in one year are lower than the base amount, then those unused credits could be used to fund assistance in the following year (Johnson, 5T 816). Staff disagreed, and instead suggested simply recording the unused credits as a regulatory liability (Braunschweig, 8T 5277). The Company agreed that it is appropriate to record a regulatory liability for underspending but proposed that any underspent amounts be netted against any regulatory assets recorded for overspent amounts such that a cumulative net balance is carried forward for disposition in a future rate case. This would eliminate the need for the Company to file, and the Staff to review, a reconciliation for each two-year period as the Company had initially proposed (Uzenski, 7T 2787-2788).

Staff also proposed a $2,587,050 increase to present sales revenue based on the suggestion that there was a discrepancy regarding RIA enrollments among Company witness Johnson's direct testimony, an audit response, and the Company's proposed rate design (Braunschweig, 8T 5274-5277). The Company disagrees because witness Johnson characterized current enrollment as of June 2021. The audit response and Part III filing reflect historic multi-year average figures. The Company's rate design forecasts what the Company estimates enrollments will be during the projected test year based on historic actuals and known and measurable changes, consistent with how billing determinants are generally designed. Thus, there is no inconsistency or conflict in the three numbers reflecting three different time periods and approaches.

Staff's Initial Brief, pp 156-158, characterizes the Company's rebuttal testimony on this matter incorrectly, stating "Willis' rebuttal confirms that the Company is misinterpreting the data and using the combined RIA/LIA enrollment figure as a basis for solely their RIA project…they cannot interpret their data correctly nor align their data with testimony." To the contrary, the Company's explanation of historic RIA enrollments (Willis, 6T 975-976), both in chart form and the numbers discussed in the text, reflect only actual RIA bill credits issued in each month. They do not include any portion of LIA enrollments. The Company has not misinterpreted its data nor is it misaligned with testimony.

Staff's suggestion that RIA enrollments are trending downward is contrary to the actual trend of rising RIA enrollments over the last 51 months, and particularly the last two years, with the Company issuing over 73,000 RIA bill credits in March 2022. The Company's proposal of 61,745 monthly average RIA enrollments is a reasonable forecast given historical test year information and is corroborated with 2021 and partial 2022 data. Therefore, the Commission should

reject Staff's proposal, and instead adopt the Company's proposed forecast of 61,745 RIA credits and resulting revenues (Willis, 6T 975-976).

MI-MAUI and Ann Arbor's Initial Brief, pp 43-53, echoes witness Bunch's various assertions about the Company's practice of deposits and collections. The Company incorporates its prior discussion.[173] The Company further notes that much of MI-MAUI and Ann Arbor's discussion is entirely speculative (*e.g., Id* at p 49 ("This data suggests….")).[174]

DAAO's Initial Brief, pp 34-60, criticizes the Company's low-income programs, contending, for representative example, that they "do not go far enough to provide low-income ratepayers with the support that they need" (*Id*, p 35), and "DTE should raise the [income] threshold to 250% of the federal poverty line to provide equitable energy assistance" (*Id*, p 43). The Company sympathizes with some of DAAO's indicated concerns, but disagrees with DAAO's proposals, incorporating its discussion in section III above. See also, Staff's Initial Brief, pp 228-31, opposing Soulardarity's proposed changes to energy assistance programs, and encouraging Soulardarity to participate in the Energy Affordability and Accessibility Collaborative.

4. Payment Stability Plan (PSP) Pilot

DTE Electric's Initial Brief, p 254, discussed the Company's Payment Stability Plan (PSP) pilot. DAAO's Initial Brief, p 46, vaguely suggests that the PSP pilot should be changed based on

[173] Ms. Johnson explained numerous incorrect assumptions that Mr. Bunch made about the meaning of data, so his calculations were grossly inaccurate. He also failed to consider other matters, including that the intention of the deposit program is to reduce uncollectible expense, which produces benefits, and that the Company provides multiple means of notifying customers regarding why they are assessed a deposit. Therefore, Mr. Bunch's unfounded and otherwise flawed recommendations should be rejected (Johnson, 5T 835-838).

[174] All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28. an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material, and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003).

DAAO's concerns about energy assistance. The Company disagrees, incorporating its prior discussion responding to DAAO's energy-assistance concerns. Prematurely changing the pilot would also defeat the purpose of having a pilot, as Staff observed (Braunschweig, 8T 5282-83).

E. Commercial Secondary Rate Design Proposals

DTE Electric's Initial Brief, pp 254-55, explained that the Company's commercial secondary rate design is consistent with the methodology that the Commission approved in past cases. The Company does not propose any changes to secondary service charges, except for secondary standby service provided under Rider 3.[175] Staff's Initial Brief, p 232, accepts the Company's commercial secondary rate design.

F. Commercial and Industrial Primary Rate Design Proposals

DTE Electric's Initial Brief, pp 255-56, explained that the Company's proposed primary delivery rates are cost-based by voltage level (as reflected on Exhibit A-16, Schedule F1.2), and that the Company's proposed changes to Rate Schedule D8 only clarify the existing terms and conditions of service, and do not change them. Staff's Initial Brief, p 233, accepts the Company's industrial primary rate design.

G. Streetlighting Rate Design

DTE Electric's Initial Brief, pp 256-58, explained and supported the Company's proposed Community Lighting rates. MI-MAUI and Ann Arbor's Initial Brief, pp 53-75, makes various criticisms and recommendations that relate to streetlighting rates. Mr. Bellini responded to MI-

[175] The Rider 3 secondary service charge was erroneously reduced from $90 to $11.25 in Case No. U-20561. This change was not proposed by any party in that case and was an oversight in the rate design. Secondary service provided under Rider 3 requires interval metering, so it is appropriate to have a service charge in line with other services requiring interval metering. Therefore, the Company proposes to increase the secondary service charge under Rider 3 to $70, in line with primary voltage service (Willis, 6T 941-942).

MAUI witness Bunch's apparent misperceptions about expense allocation and explained that witness Bunch's proposal to change the existing methodology of developing rates would have a significant financial impact on certain communities (7T 1747-1748). The Company also incorporates its prior discussions responding to MI-MAUI and Ann Arbor witnesses (DTE Initial Brief, pp 190-93, 229, n 95). See also Staff's Initial Brief, pp 261-62, opposing MI-MAUI witness Bunch's proposal to shift costs onto other customers.

H. Nuclear Surcharge

DTE Electric's Initial Brief, p 258, explained and supported the Company's proposal to increase the nuclear surcharge only with respect to inflation for the Site Security and Radiation Protection portion of the surcharge. There is no dispute, so the proposal should be approved.

I. Distributed Generation (DG) Tariff (Rider 18)

DTE Electric's Initial Brief, pp 259-61, discussed Distributed Generation (DG) service and summarized the Company's proposed changes to Rider 18.[176]

1. Inflow Rate Design

As indicated above in section X. D 2, Staff's Initial Brief, pp 247-52; CEO's Initial Brief, pp 5-18; GLREA's Initial Brief, pp 7-10; MEIBC/IEI's Initial Brief, pp 38-51; MI-MAUI and Ann Arbor's Initial Brief, pp 38-43; and MNSC's Initial Brief, pp 104-10, criticize the Company's

[176] First, the Company proposes to set the outflow credit, on a per kWh basis, to be the total of (1) the average monthly MISO hourly LMP for the DTE Electric appropriate load node, calculated and applied separately for each pricing window for customers taking service on TOU rates, and (2) a credit for avoided line losses as calculated through the Company's most recent line loss study.

Second, the Company proposes that future customers taking service under Rider 18 will also take service under the Company's proposed D1.12 (Residential Service Rate – Stable Bill Service Level) rate.

Third, if the Commission approves the Company's above-described changes to Rider 18 as proposed, then the Company is prepared to voluntarily increase the size of its DG program to 3.0% of the Company's average in-state peak load for full-service customers during the previous five (5) calendar years.

proposed D1.12 rate and assert that it should be rejected. The Company incorporates its prior discussion.

In further response to CEO's Initial Brief, pp 28-39; DAAO's Initial Brief, pp 87-97; and GLREA's Initial Brief, pp 22-24, the Company also incorporates its prior discussion in this section (at DTE Electric Initial Brief, pp 261-63) responding to various arguments regarding the Company's proposal to require future Rider 18 customers to take base inflow service on the Company's proposed D1.12 rate.

MNSC's Initial Brief, pp 125-28, and MI-MAUI and Ann Arbor's Initial Brief, pp 39-41, further assert that the Company's Rider 18 proposal would allegedly violate the Public Utilities Regulatory Policies Act of 1978 ("PURPA") or other law based on the testimony of witnesses Jester, Wu and Stults. None of these witnesses is qualified to offer a legal opinion (see section III above). Moreover, PURPA in particular may be simple in concept, but it is complicated and difficult in application, as the Commission presumably has come to appreciate. A full discussion is beyond the scope of this brief, but the Company generally incorporates its filings in Case No. U-18091, which recently settled after years of proceedings (July 7, 2022 Order in Case No. U-18091).[177] MI-MAUI and Ann Arbor's further argument about an alleged "exit fee" is an extraordinarily strained reading of law based on factually and electrically incorrect assumptions and inexplicable reference to the Mobile Home Act.

2. Outflow Compensation

In response to Staff's Initial Brief, pp 183-86 253-54; CEO's Initial Brief, pp 39-50; DAAO's Initial Brief, pp 87-94; GLREA's Initial Brief, pp 12-22; MEIBC/IEI's Initial Brief, pp

[177] However, see also MCL 460.1177(4) with respect to the two permissible choices for outflow compensation (the Company's Rider 18 proposal utilizes one of the two permissible choices) and note that DG customers undoubtably receive a different and additional service than the Company's 2 million other full-service customers that only receive power inflows.

51-56; and MNSC's Initial Brief, pp 129-34, the Company incorporates its prior discussion (at DTE Electric Initial Brief, pp 263-66) responding to various arguments regarding the Company's proposal to modify Rider 18 outflow to be based on average monthly LMPs, adjusted for line losses. See also, Staff's Initial Brief, p 187-97, disagreeing with various intervenor outflow proposals.

3. Program Design and Additional Issues

In response to CEO's Initial Brief, pp 50-54; DAAO's Initial Brief, pp 94-98; and MEIBC/IEI's Initial Brief, pp 56-61, the Company incorporates its prior discussion (at DTE Electric Initial Brief, pp 266-69) responding to various arguments regarding the design of the Company's DG program and related costs.

Also, MEIBC/IEI's Initial Brief, p 56, suggests that the Commission establish "legacy rights" for Rider 18 customers that, among other things, would include the rate structure that existed when they enrolled on the rate, and "run with the land" in the sense of following the Rider 18 system "for the lifetime of that system in a manner that is fully transferable to any customer that operates or own [*sic* owns] the system." The Company disagrees because, even assuming for argument's sake that such a thing would be legal, it would be improvident and contrary to well-established principles of government for the Commission to surrender its powers and purport to bind future Commissions.[178] See also Section III supra.[179]

[178] See generally, *Studier v Michigan Public School Employees' Retirement Bd*, 472 Mich 642, 659-69; 698 NW2d 350 (2005).

[179] By way of example and not limitation, as a matter of fundamental ratemaking law, DTE Electric is entitled to a commensurate return of and on its investment in providing utility service. *See, Bluefield Waterworks Improvement Co v Public Service Commission of West Virginia*, 262 US 679, 690-694; 43 S Ct 675; 67 L Ed 1176 (1923); *Federal Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944). *See also, Permian Basin Area Rate Cases*, 390 US 747, 769-70; 88 S Ct 1344; 20 L Ed 2d 312 (1968); *FPC v Memphis Light, Gas and Water Division*, 411 US 458; 43 S Ct 1723; 36 L Ed 2d 426 (1973); *General Telephone Co v Public Service Comm*, 341 Mich 620; 67 NW2d 882 (1954); *Michigan Consolidated Gas Co v Public Service Comm*, 389 Mich 624; 209 NW2d 210 (1973).

The Company incorporates its prior discussion disagreeing with Intervenor suggestions that the Commission can or should establish a successor tariff to the current Rider 18 that would become effective once the category-specific reservations of the Company's DG program are met.[180]

The Company further observes that MCL 460.1173(3) plainly states: "An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years." It is also axiomatic that statutes must also be applied as written.[181]

Regardless, MEIBC/IEI's Initial Brief, pp 59-61 (see also CEO's Initial brief, pp 53-54), asserts that the Commission follow the suggestions of witness Barnes to establish a "Customer-Sited Generation Tariff" and thereby advance "the continued expansion of distributed generation absent legislative action." (See also MNSC's Initial Brief, p 135, and GLREA's Initial Brief, pp 24-30, similarly proposing that the Commission follow witness Barnes', Jester's and Richter's unfounded propositions).

To the contrary, the Commission possesses only the limited authority that the Legislature conferred upon it,[182] and "agencies cannot exercise legislative power by creating law or changing

[180] As indicated previously and above, there already are tariffs (specifically Rider 14 and Rider 5), that will allow DG customers to interconnect their systems once MCL 460.1173(3)'s category-specific reservations are met. The Company is not offering, and does not support, the creation of any additional tariffs involving customer generation (Foley, 6T 1229-1231). (See also *Union Carbide* supra; Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) "The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best." *Attorney General v. Public Service Comm,* 269 Mich App 473; 713 NW2d 290 (2005) MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.)

[181] *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("We presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"). *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003).

[182] *Consumers Power Co v Public Service Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999).

the laws enacted by the Legislature."[183] The suggestion that the Commission could avoid the controlling law through creative labeling (*e.g.,* calling "distributed generation" something other than "distributed generation") does not merit serious consideration. [184] The Court of Appeals also recently invalidated a rule because it conflicted with a statute in *Emagine Entertainment, Inc v Dep't of Treasury*, 334 Mich App 658, 664; 965 NW2d 720 (2020), explaining in part that it was unlawful for an agency to "writ[e] a rule to alleviate what it considers to be a statutory gap . . . In a nutshell, the [agency] did not have the authority to circumvent the legislative process and administratively amend [a statute.]"

DAAO acknowledges that "the law constrains the Commission's ability to order DTE to raise the DG cap." Then, however, after disparaging commentary regarding the Company, DAAO asserts that the Commission should order the Company to do various other things "to increase the accessibility of DG solar" (*Id*, p 98).[185] But the law constrains the Commission from doing that too. The Company's control over its own property is a crucial element of the Company's property rights.[186] The Commission's relationship to the Company is as a utility regulator, and not a utility

[183] *In re Complaint of Rovas Against SBC Michigan*, 482 Mich 90, 98; 754 NW2d 259 (2008)

[184] "Courts are not bound by the labels that parties attach to their claims." *Buhalis v Trinity Continuing Care Services*, 296 Mich App 685, 691; 822 NW2d 254 (2012). Instead, it is "well settled that the gravamen of an action is determined by reading the complaint as a whole, and by looking beyond mere procedural labels to determine the exact nature of the claim." *Buhalis*, 296 Mich App at 691-91, quoting *Adams v Adams (On Reconsideration)*, 276 Mich App 704, 710-11; 742 NW2d 399 (2007). See also, *Local 1064, RWDSU AFL-CIO v Ernst & Young*, 449 Mich 322; 535 NW2d 187 (1995) (affirming the trial court's rejection of the plaintiff's contention, explaining in part that it is well-established that a court may "look behind the technical label that plaintiff attaches to a cause of action to the substance of the claim asserted"); *Aetna Cas & Sur Co v Sprague*, 163 Mich App 650, 654; 415 NW2d 230 (1987) (rejecting mischaracterizations as a "transparent attempt to trigger insurance coverage")..

[185] DAAO's suggestions are based in part on an incorrect premise regarding lobbying, which is addressed in section VII. C. 9. (Membership Dues).

[186] See generally, *Loretto v Teleprompter Manhattan CATV Corp*, 458 US 419, 435-36; 102 S Ct 3164; 73 L Ed 2d (1982) (holding that a New York law requiring a landlord to permit a cable television company to install cable facilities on the landlord's property constituted a taking of the landlord's property); *Kaiser Aetna v United States*, 444 US 164, 176; 100 S Ct 383; 62 L Ed 332 (1979) (a requirement that subjected a formerly private pond to public access took away the landlord's right to exclude, one of the most essential sticks in the bundle of rights that are commonly characterized as property").

manager. Our Supreme Court aptly described the bounds of regulation in *Union Carbide v. Public Service Comm*., 431 Mich 135; 428 NW2d 322 (1988) as follows:

> The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions. "It must never be forgotten that while the State may regulate with a view to enforcing reasonable rates, it is not the owner of the property of public utility companies and is not clothed with the general power of management incident to ownership." [citations omitted].[187]

Moreover, the suggestions by DAAO and others that the Commission require DTE Electric (and effectively the Company's non-DG customers) to subsidize DG customers and/or private businesses (*e.g*., third-party solar suppliers and/or installers to sustain or advance the solar industry) presents an additional, constitutional problem because the Company's private property would essentially be taken by another private entity. Mich Const 1963, art 10, §2 provides that: "Private property shall not be taken for ***public use*** without just compensation therefor being first made or secured in a manner prescribed by law" (emphasis added). The Fifth Amendment of the United States Constitution similarly provides that "the government may not take private property unless it is done for a public use and with just compensation."[188] Taking DTE Electric's private property and giving it to other private entities (*e.g*., by asserting control over property and forcing its use to supply subsidized service) violates the "public use" requirement.[189] The Commission's authority

[187] See also *Ford Motor Co. v. Public Service Comm*, 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) ("The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best."); *Consumers Power Co, Public Service Comm*, 189 Mich App 151, 180; 472 NW2d 77 (1991) ("To the extent that the PSC actually ordered Consumers to enter, or not enter, into any particular contract, it exceeded its authority").

[188] *Silver Creek Drain Dist v Extrusions Div, Inc*., 468 Mich 367, 374; 663 NW2d 436 (2003).

[189] *Wayne Co v Hathcock,* 471 Mich 445, 478; 684 NW2d 765 (2004). See also *Shizas v City of Detroit*, 333 Mich 44, 50, 59-60; 52 NW2d 589 (1952); *Bd of Health v Van Hoesen*, 87 Mich 533, 537; 49 NW 894 (1891) ("The state has no right to take the property of one citizen, and give it to another, whether with or without compensation").

does not include the ability to take property for the private use of another.[190] DTE Electric's status as a publicly-regulated company does not deprive it of constitutional protections against takings.[191]

The Company appropriately raises these constitutional issues, recognizing that the Commission lacks authority to decide them since "an agency exercising quasi-judicial power does not undertake the determination of constitutional questions or possess the power to hold statutes unconstitutional."[192]

Simply as a matter of basic utility law, however, the suggestions by DAAO and others merely recommend the prior regulatory practice of subsidized rates that has since been eliminated by legislation. The law requires that the Commission set cost-based rates. MCL 460.11 states in part:

> Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of service to each customer class."

The statute's plain language must be applied as written - cost causers shall pay their costs.[193] There is similarly no legal basis for suggestions that the Commission should otherwise function as an agency to advance what certain intervenors may consider to be appropriate policy changes

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[190] *Bohn Lumber, Prod v Public Service Comm*, 317 Mich 174, 182; 826 NW2d 875 (1947).

[191] *Missouri Pacific Ry Co v Nebraska*, 164 US 403, 417; 17 S Ct 130; 41 L Ed 489 (1896) (reversing order of the Nebraska State Board of Transportation requiring a railroad to surrender parts of its land to private persons for the purpose of building and maintaining their elevator on it, explaining: "The taking by the state of the private property of one person or corporation, without the owner's consent, for the private use of another, is not due process of law, and is a violation of the 14th Article of Amendment of the Constitution of the United States").

[192] *Wikman v Novi*, 413 Mich 617, 646-47; 322 NW2d 103 (1982); *Taylor v Detroit Edison Co*, 475 Mich 109, 122; 715 NW2d 28 (2006)

[193] *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("we presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"); *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); and *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003) ("where the language of a statute is clear, it is not the role of the judiciary to second-guess a legislative policy choice; a court's constitutional obligation is to interpret, not rewrite, the law").

beyond the scope of this case (and the Commission's jurisdiction generally), as discussed in section III above.

Thus, the lengthy commentary by DAAO and others about the asserted benefits of DG, and disparaging comments regarding the Company, are distractions that lack relevance and merit. Regardless of how one may feel about the conceptual benefits of DG, third-party economics are the responsibility of third parties, not the Commission or the Company. The Company is simply trying to apply cost-causation principles so that non-DG customers do not subsidize DG customers. Similarly, the Commission's job is to set cost-based rates in this context and does not extend to shifting ratepayer funds to subsidize third-party businesses.

Staff's Initial Brief, p 186, vaguely proposes to allow customers with DG to take service on rate schedule D1.8 Dynamic Peak Pricing. GLREA's Initial Brief, p 7, vaguely agrees. The Company disagrees as it explained previously. In part, the Company noted "[u]nder Staff's proposal, the outflow credit during a D1.8 critical peak event would be approximately 10 times today's D1 outflow credit. This has no plausible avoided cost basis." (DTE Electric Initial Brief, pp 268-69)

Finally, MI-MAUI and Ann Arbor's Initial Brief, pp 32-38, argues that the Commission should reduce the Company's revenue requirement by the cost of its DG surveys, and commence an investigation, because the surveys allegedly were not done for the benefit of ratepayers. They essentially contend that the survey questions "led [Ann Arbor witness] Roth to conclude that the purpose of these interviews was ***not*** to improve the customer experience regarding the DG program. Instead, Roth stated the purpose of the survey was market research for DTE to see if they could successfully compete with other installers" (*Id*, p 36. Emphasis in original).

This argument merits no serious consideration because Roth did not testify as an expert at all (8T 3388). Therefore, she is not qualified to testify about survey issues (or anything else requiring technical expertise), and her speculative assertions (as indicated above, and elsewhere) cannot support a decision (see section III above). Company witness Burns further explained that there is no viable issue here, and no basis for MI-MAUI and Ann Arbor's requested relief:

> DTE routinely conducts customer research to gain greater insight on various topics to improve customer satisfaction and engagement. As stated in the Company's response to discovery (AAMDE-1.1ai), the purpose of the survey was to explore customer experiences, perceptions, and the expectations as it relates to the entire distributed generation program. Surveying customers will frequently generate both positive and constructive insights, which help the Company understand what is working well, and what needs improvement. [7T 2528.]

Therefore, the Company's proposed changes to Rider 18 should be approved, and any alternative recommendations should be rejected or modified as discussed previously and above.

J. Retail Access Service Rider (RASR)

DTE Electric's Initial Brief, pp 269-70, discussed the Company's proposed three changes to the current RASR. Energy Michigan witness Zakem proposed changes in response to the Company's proposed insertions regarding the timing of "enrollment" and "enrollment date" (8T 4492). The Company recommended building on witness Zakem's proposed language by capitalizing the defined terms and referencing Case No. U-15801 (as set forth at Willis, 6T 1002-1003). "Energy Michigan accepts DTE's enhancements as shown in Mr. Willis's rebuttal testimony. Therefore, DTE and Energy Michigan agree on how the RASR should be revised" (Energy Michigan Initial Brief, p 16).

K. Other Proposals

1. Rider 3

Bloom's Initial Brief recounts the testimony of its witnesses Morse (incorrectly characterizing Rider 3 standby charges) and Jester (recommending that the Commission do four things). The Company incorporates its prior response explaining why Bloom's propositions should be rejected (DTE Initial Brief, pp 270-74). Staff's Initial Brief, pp 254-57, also discusses why Bloom's claims and proposals should be rejected.

2. Rider 17

GLREA's Initial Brief, pp 30-31, concerns its witness Richter's proposal that the Commission order a new Rider, under which DTE Electric would purchase Renewable Energy Credits (RECs) from customers with renewable energy systems. Staff apparently agrees (Staff Initial Brief, p 144). The Company disagrees because it reached a settlement agreement in Case No. U-20713, which included amendments to the eligibility and structure of Rider 17. Therefore, any discussion of legacy Rider 17 is ill-timed and inappropriate in this case. The discussion of updated Rider 17 would be appropriate in the Company's Section 61 proceedings (Crozier, 7T 2395-2396). See also *Union Carbide* supra; Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) ("The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best"); *Attorney General v. Public Service Comm,* 269 Mich App 473; 713 NW2d 290 (2005) (MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.

3. Power Factor Clause

ABATE's Initial Brief, pp 73-75, echoes its witness Andrews' proposal to provide a credit to primary voltage customers with a monthly power factor greater than .9 in the amount of 0.5% of the energy charges on the bill, and no changes to the currently approved power factor penalties for customers with a power factor less than .85 (8T 2999-3000). As previously indicated (DTE Electric Initial Brief, p 275), the Company agrees that a power factor less than the currently approved threshold of .85 imposes a material enough cost to warrant a penalty, but the Company disagrees that being slightly above the penalty threshold (.9 vs .85 in ABATE's proposal) is a reason to offer a credit. The Commission should reject ABATE's proposal because, as witness Andrews acknowledged, customers with a power factor of less than 1 induce losses.

ABATE's Initial Brief, p 73, n 53, responds by suggesting that less of a loss is a benefit. To the contrary, a loss is a loss. The Company should not provide credits to customers who continue to induce losses simply because their losses are relatively less than another customer's losses. Credits should only be issued for absolute savings to the system, because otherwise (as with ABATE's proposal) other customers would effectively have to fund the credit. ABATE's proposed credit threshold is also arbitrary and unjustified (Willis, 6T 997-998).

4. Community Solar

Staff's Initial Brief, pp 197-204, and DAAO's Initial Brief, pp 103-17, discuss proposals indicating similar goals, but very different ideas about how a community solar project might be designed (*e.g.*, even on the fundamental issue of size). DTE Electric's Initial Brief, pp 275-76, responded. The Company maintains that the Commission should not adopt a community solar project in this case because there is not enough time to evaluate any proposal here. For example, the incremental capital and O&M costs to upgrade the Company's billing system and administer such a program have not been considered. The Company also currently has two community solar

pilots that were part of the Company's last VGP filing, Case No. U-20713. The Company believes that adding another community solar pilot with similar goals would not be beneficial but does agree to discussions to inform the potential for future programs, with the potential for a proposal in the Company's next rate case (Crozier, 7T 2384-2387). [194]

Staff agrees that the overarching goals of the existing pilots are similar to Staff's proposal, and apparently with Ms. Crozier's recommendation for more discussion (Staff Initial Brief, p 204).

5. Earnings Sharing Mechanism (ESM)

In connection with its arguments about projected test years (see section V of DTE Electric's Initial Brief, and section IV above), ABATE's Initial Brief, pp 7-9, further suggests that an asymmetrical earnings sharing mechanism (ESM) should be imposed on the Company in this case. DTE Electric's Initial Brief, p 276, explained that ABATE's suggestion should be rejected as premature (at best) and because there is not enough time to properly consider such a mechanism following ABATE's filing of intervenor testimony. See also, January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, pp 37-38 (rejecting assertion that "came too late in the process for a fair determination on that issue"); *Jordan v Dep't of Health and Human Services*, ___ Mich ___; ___ NW2d ___ (July 28, 2022) (2022 WL 3007975) (vacating decision and remanding to agency because the record was too incomplete to facilitate meaningful appellate review).

This same response applies to ABATE's further suggestion that an "alternative acceptable approach was also proposed by Staff" (ABATE Initial Brief, p 8, going on to quote a portion of a discovery response in Exhibit AB-35). But Staff's Initial Brief, p 259-61, expressly takes no

[194] See also *Union Carbide* supra; Accord *Ford Motor Co. v. Public Service Comm,* 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) ("The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best"); *Attorney General v. Public Service Comm,* 269 Mich App 473; 713 NW2d 290 (2005) (MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs.

position on whether there should be an ESM, instead opposes ABATE's proposed refund method, and suggests that after some consideration, "a more appropriate method would be as described" in Exhibit AB-35. Thus, there is no consensus on whether there even should be and ESM, and it seems that even those who find some conceptual merit in a hypothetical ESM are still contemplating how such a mechanism might work. There is not even a solid proposal on the table to discuss, let alone an opportunity develop a record.[195]

Therefore, the Company maintains its position that if an ESM is to be considered, then it should be evaluated as part of a broader performance-based ratemaking (PBR) conversation. A larger discussion of PBR might include topics such as ABATE's ESM proposal and other metrics, incentives, and capital trackers as described by the Company in its Distribution Plan, Exhibit A-23, Schedule M1 (Crozier, 7T 2387-2388).

XI. REQUEST FOR RELIEF

DTE Electric respectfully requests that the Commission issue its final order:

A. Granting DTE Electric's request for final rate relief, as further supported and explained in its Application, testimony, exhibits, and Initial Brief (including Attachments A and B), and this Reply Brief (including Reply Brief Attachments A and B) approving rates that will recover the Company's revenue deficiency of approximately **$367.9 million**, based on a November 1, 2022 through October 31, 2023 projected test year;

B. Approving an annual revenue increase effective as soon as possible in the projected test year;

[195] Moreover, ABATE's whole ESM exercise appears to be driven by ABATE's disagreement with our Legislature's choice to reduce regulatory lag (discussed in section IV above), and further based on the flawed premise of villainizing the Company for receiving unexpected revenues due to customer usage under COVID directives, as discussed in section III above.

C Approving new rates effective as early as November 21, 2022 in the manner described in the Company's Application, testimony, exhibits, Initial Brief (including Attachments A and B), and this Reply Brief (including Reply Brief Attachments A and B);

D Approving DTE Electric's proposed capital structure and return on equity;

E. Granting DTE Electric's request for tree trimming expenditures, and the associated request for regulatory asset treatment through 2024;

F. Approving recovery of DTE Electric's generation investments;

G. Approving recovery of DTE Electric's investments related to the strengthening of the Company's distribution system and reliability improvements;

H. Granting DTE Electric's request to approve the PSCR base;

I. Approving DTE Electric's proposals to implement certain customer rate schedules and tariffs;

J. Approving all proposed pilot programs as requested by the Company;

K. Approving all proposed regulatory accounting treatments as requested by the Company;

L. Approving a capacity charge based on the methodology established in Case No. U-20561 and the capacity-related costs approved in this proceeding;

M. Approving the remainder of DTE Electric's proposals and requested relief as set forth in the Company's Application, testimony, exhibits and Initial Brief (including Attachments A and B), and this Reply Brief (including Reply Brief Attachments A and B); and

N. Granting such other lawful relief that the Commission deems reasonable and appropriate.

Respectfully submitted,

DTE ELECTRIC COMPANY

Legal Department

Dated: August 16, 2022

By: Jon Christinidis Digitally signed by Jon Christinidis Date: 2022.08.16 15:07:17 -04'00'

Attorneys for Applicant
Andrea Hayden (P71976)
Jon P. Christinidis (P47352)
David S. Maquera (P66228)
Paula Johnson-Bacon (P55862)
Lauren D. Donofrio (P66026)
Carlton D. Watson (P77857)
Breanne K. Reitzel (P81107)
One Energy Plaza, 1635 WCB
Detroit, Michigan 48226
(313) 235-7706

DTE Electric Company
Computation of Revenue Deficiency
Projected 12 Month Period Ending October 31, 2023
($000)

MPSC Case No. U-20836
Reply Brief
Attachment A

Line No.	(a) Description	(a) Source	(b) U-20836 Staff Brief Position	(c) Adjustments	(d) U-20836 Reply Brief Position
1	Rate Base	Attach A, Page 2	$ 20,631,922	$ 610,860	$ 21,242,782
2	Adjusted Net Operating Income	Attach A, Page 3	969,073	(56,249)	912,824
3	Rate of Return	Attach A, Page 4	5.30%	0.26%	5.56%
4	Income Requirements		1,093,038	87,211	1,180,249
5	Income Deficiency (Sufficiency)		123,965	143,460	267,425
6	Revenue Conversion Factor	Exh, A-13, Sch. C2	1.3496	-	1.3496
7	**Revenue Deficiency (Sufficiency)**		**$ 167,308**	**$ 193,618**	**$ 360,926**
6	Tree Trim Surge	Exh, A-11, Sch. A1	2,188	4,833	7,021
7	**Revenue Deficiency (Sufficiency)**		**$ 169,496**	**$ 198,451**	**$ 367,947**

DTE Electric Company
Rate Base - Average Net Plant
For the 12 Month Average Period Ending 10/31/2023
($000)

MPSC Case No. U-20836
Reply Brief
Attachment A

Line No.	(a) Description	(b) U-20836 Staff Brief Position	(c) Adjustments		(d) U-20836 Reply Brief Position
1	Plant in Service	$ 24,482,349	$ 599,745	(1)	$ 25,082,094
2	Plant Held for Future Use	66,804			66,804
3	Construction Work in Progress	1,620,679			1,620,679
4	Total Utility Plant	26,169,832	599,745		26,769,577
5					
6	Less: Depreciation Reserve	6,940,096	(11,115)	(2)	6,928,981
7					
8	Net Utility Plant	19,229,736	610,860		19,840,596
9					
10	Net Capital Lease Property	16,402			16,402
11	Net Nuclear Fuel Property	155,492			155,492
12					
13	Total Utility Property and Plant	19,401,630	610,860		20,012,490
14					
15	Less: Capital Lease Obligations	19,036			19,036
16					
17	Net Plant	19,382,594	610,860		19,993,454
18					
19	Allowance for Working Capital	1,249,327			1,249,327
20					
21					
22	Rate Base	$ 20,631,922	$ 610,860		$ 21,242,782

(1) (2) Capital adjustments to Plant and Depreciation Reserve:

	Net Cap Ex	Plant Adj. (1)	Accum. Depr. (2)	
Production: Steam Generation - Non-Routi	$ (12,454)	$ (10,696)	$ (376)	Staff Brief Appendix E
Production: Hydro Generation - Non-Routi	(3,305)	(3,078)	(137)	Staff Brief Appendix E
Production: Steam Generation - Non-Routi	(76,494)	-	47,089	Staff Brief Appendix E
Production: Other Generation - Non-Routir	(65,821)	(38,229)	(533)	Staff Brief Appendix E
Distribution: Base Capital Programs	(96,038)	(69,604)	(2,159)	Staff Brief Appendix E
Distribution: Strategic Capital Programs	(489,486)	(355,129)	(12,941)	Staff Brief Appendix E
Distribution: Community Lighting	(3,002)	(2,425)	(116)	Staff Brief Appendix E
Demand Side Management	(3,992)	(2,873)	(450)	Staff Brief Appendix E
Information Technology	(138,210)	(98,522)	(18,158)	Staff Brief Appendix E
Corporate Staff	(39,723)	(24,010)	(2,226)	Staff Brief Appendix E
Residential Battery Pilot	(4,244)	(2,672)	(36)	Staff Brief Appendix E
Production: Other Generation - Non-Routir	(8,100)	(8,100)	(294)	Staff Brief Appendix E
Information Technology	(4,170)	(3,136)	(171)	Staff Brief Appendix E
Initial Brief Concessions				
Engineering Transformer Database	370	185	19	Company Brief Att A pg 2
Decommission DOBW-move	370	185	19	Company Brief Att A pg 2
Documentum (EDM) Modernization	370	185	19	Company Brief Att A pg 2
IT - Inbound Email Threat Analytics	400	200	20	Company Brief Att A pg 2
Headquarters Energy Center	700	700	97	Company Brief Att A pg 2
Enterprise Automation	596	596	219	Company Brief Att A pg 2
Wixom Pole Yard	4,500	3,084	170	Company Brief Att A pg 2
ACPP/Time of Use	13,194	11,369	676	Company Brief Att A pg 2
DERMS - Duplicate Project	2,500	2,227	385	Company Brief Att A pg 2
	$ (922,039)	$ (599,745)	$ 11,115	

DTE Electric Company
Adjusted Net Operating Income
Projected 12 Month Period Ending October 31, 2023
($000)

Line No.	(a) Description	(b) U-20836 Staff Brief Position	(c) Adjustments	(d) U-20836 Reply Brief Position
	Net Operating Income			
	Operating Revenues			
1	Sales Revenues	$ 5,083,110	$ (2,587) (1)	$ 5,080,523
2	Other Operating Revenue	-		-
3	Fuel and Purchased Power	1,360,015	(275) (2)	1,359,740
4	Net Margin	3,723,095	(2,312)	3,720,783
5				
6	**Operating Expenses**			
7	Operations and Maintenance Expenses	1,226,280	37,715 (3)	1,263,995
8	Depreciation and Amortization	1,047,063	39,053 (4)	1,086,116
9	Property and Other Taxes	356,311		356,311
10	Total Operating Expenses	2,629,655	76,768	2,706,423
11				
12	**Operating Income**	1,093,440	(79,080)	1,014,360
13				
14	**Other Operating Income Adjustments**			
15	Allow. For Funds Used During Constr	44,400		44,400
16	Amortization of Loss on Reacquired Debt	(3,565)		(3,565)
17	Other (Income)/Deductions	158		158
18	Total Operating Income Adjustments	40,993	0	40,993
19				
20	**PreTax Net Operating Income**	$ 1,134,433	$ (79,080)	$ 1,055,353
21				
22	**Federal Income Tax**	104,329	(17,335)	86,994
23	**State and Local Income Taxes**	61,032	(5,496)	55,536
24				
25	**Net Operating Income**	$ 969,073	$ (56,249)	$ 912,824

(1)(2) Operating Revenues

- Sales Revenues	$ (2,312)		Staff Brief Appendix C
- Fuel and Purchased Power	(275)	(2)	Staff Brief Appendix C
	$ (2,587)	(1)	

(3) O&M

Steam Power Generation O&M (Kindschy)	$ 4,581	Staff Brief Appendix C
Retoration O&M (Becker)	(14,777)	Staff Brief Appendix C
Community Lighting (Wang)	242	Staff Brief Appendix C
Distribution Ops App Health (capital to O&M with downward adjustment) (Wang	(685)	Staff Brief Appendix C
Distribution Ops App Health (O&M adjustment, decrease by 48%) (Wang)	14	Staff Brief Appendix C
Fuel Supply Application Health (Wang)	(404)	Staff Brief Appendix C
IT O&M (Wang)	2,876	Staff Brief Appendix C
Level 1 IT Projects (100%) (Rogers)	4,293	Staff Brief Appendix C
Level 2 IT Projects (20%) (Rogers)	2,572	Staff Brief Appendix C
Merchant Fees (McMillan-Sepkoski)	2,973	Staff Brief Appendix C
Uncollectible Expense	4,174	Staff Brief Appendix C
Residential Battery Pilot O&M (Matthews)	183	Staff Brief Appendix C
Incentive Compensation (McMillan-Sepkoski)	42,537	Staff Brief Appendix C
Restricted Stock (McMillan-Sepkoski)	5,857	Staff Brief Appendix C
	$ 54,435	

Initial Brief Concessions

Tree Trim O&M - Surge Savings	(4,200)	Company Brief Att A pg 3
Customer Service Representatives	(950)	Company Brief Att A pg 3
Merchant Fees	(2,970)	Company Brief Att A pg 3
Pension Expense	(8,600)	Company Brief Att A pg 3
	$ (16,720)	
	$ 37,715	(3)

(4) Depreciation and Amortization

Production: Steam Generation - Non-Routine Additions	$ 323	Staff Brief Appendix E
Production: Hydro Generation - Non-Routine	82	Staff Brief Appendix E
Production: Steam Generation - Non-Routine Removals	-	Staff Brief Appendix E
Production: Other Generation - Non-Routine	757	Staff Brief Appendix E
Distribution: Base Capital Programs	2,847	Staff Brief Appendix E
Distribution: Strategic Capital Programs	14,525	Staff Brief Appendix E
Distribution: Community Lighting	99	Staff Brief Appendix E
Demand Side Management	575	Staff Brief Appendix E
Information Technology	18,634	Staff Brief Appendix E
Corporate Staff	2,577	Staff Brief Appendix E
Residential Battery Pilot	53	Staff Brief Appendix E
Production: Other Generation - Non-Routine	160	Staff Brief Appendix E
Information Technology	220	Staff Brief Appendix E

Initial Brief Concessions

Engineering Transformer Database	(37)	Company Brief Att A pg 3
Decommission DOBW-move	(37)	Company Brief Att A pg 3
Documentum (EDM) Modernization	(37)	Company Brief Att A pg 3
IT - Inbound Email Threat Analytics	(40)	Company Brief Att A pg 3
Headquarters Energy Center	(53)	Company Brief Att A pg 3
Enterprise Automation	(119)	Company Brief Att A pg 3
Wixom Pole Yard	(234)	Company Brief Att A pg 3
ACPP/Time of Use	(796)	Company Brief Att A pg 3
DERMS - Duplicate Project	(445)	Company Brief Att A pg 3
	$ 39,053	(4)

DTE Electric Company
Rate of Return Summary
Projected 12 Month Period Ending October 31, 2023
Based on Average Rate Base
($000)

Line No.	Description	Amount ($000)		Percent	Cost %	Weighted Cost % (1)	Weighted Cost %		
	U-20836 Staff Brief (Test Period Average Basis)								
1	Long-Term Debt	$ 8,410,859	49.95%	39.55%	3.686%	1.841%	1.46%	1.0000	1.46%
2	Preferred Stock	0	0.00%	0.00%	0.000%	0.000%	0.00%		0.00%
3	Common Shareholders' Equity	8,426,264	50.05%	39.62%	9.600%	4.805%	3.80%	1.3496	5.13%
4	Total	16,837,123	100.00%			6.646%			
5									
6	Short-Term Debt	265,492		1.25%	1.739%		0.02%	1.0000	0.02%
7									
8	Other Interest Bearing Accounts	0		0.00%	1.739%		0.00%	1.0000	0.00%
9									
10	Job Development - ITC - Debt	23,688		0.11%	3.686%		0.00%	1.0000	0.00%
11	Job Development - ITC Equity	23,688		0.11%	9.600%		0.01%	1.3496	0.01%
12	Total Job Development - ITC	47,376							
13									
14	Deferred Income Taxes (Net)	4,117,952		19.36%	0.000%		0.00%		0.00%
15									
16	Total	21,267,944		100.00%			5.30%		6.63%
	U-20836 Reply Brief (Test Period Average Basis)								
17	Long-Term Debt	$ 8,410,859	49.95%	39.55%	3.686%	1.841%	1.46%	1.0000	1.46%
18	Preferred Stock	0	0.00%	0.00%	0.000%	0.000%	0.00%		0.00%
19	Common Shareholders' Equity	8,426,264	50.05%	39.62%	10.250%	5.130%	4.06%	1.3496	5.48%
20	Total	16,837,123	100.00%			6.971%			
21									
22	Short-Term Debt	265,492		1.25%	1.739%		0.02%	1.0000	0.02%
23									
24	Other Interest Bearing Accounts	0		0.00%	1.739%		0.00%	1.0000	0.00%
25									
26	Job Development - ITC - Debt	23,688		0.11%	3.686%		0.00%	1.0000	0.00%
27	Job Development - ITC Equity	23,688		0.11%	10.250%		0.01%	1.3496	0.02%
28	Total Job Development - ITC	47,376							
29									
30	Deferred Income Taxes (Net)	4,117,952		19.36%	0.000%		0.0000%		0.00%
31									
32	Total	21,267,944		100.00%			5.56%		6.98%

DTE Electric Company
Revenue Requirement Adjustments to Company's Filing
Projected 12 Month Period Ending October 31, 2023
($000)

Line No.	(a) Description	(b) Source	Rate Base Changes	(c) Revenue Deficiency
				(Pre Tax Amts)
1	**Staff's Brief Position**	Staff Brief Appendix A		**$ 169,509**
2				
3	**Adjustments to Revenue Deficiency:**			
4				
5	**Capital Structure**			
6	ROE - 10.25% versus 9.60%	(1)		74,017
7				
8				
9	**Rate Base (2)**			
10	Net Rate Base, Increase/(Decrease)	Attachment A page 2	610,860	40,508
11				
12			610,860	
13				
12	**Net Margin**	Attachment A page 3		2,312
13				
13	**Operations and Maintenance Expenses**			
14	Net disallowances recommeded by Staff	Attachment A page 3		54,435
15	Net concessions from the Company	Attachment A page 3		(16,720)
16				
17				
18	**Depreciation and Amortization**			
19	Depreciation Expense, Increase/(Decrease)	Attachment A page 3		39,053
20				
21	**Tree Trim Surge**	Attachment A page 1		4,833
22				
23	**Total Adjustments to Company's Initial Revenue Deficiency**	Line 6 through Line 22		$ 198,438
24				
25	**Company's Reply Brief Position**	Line 1 + Line 23		**$ 367,947**

(1) Rate Base of $21,242 million x change in rate of return (0.258%) x revenue multiplier of 1.3496
(2) Rate Base Change multiplied by pre-tax return 6.63% (Attachment A page 4)

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-20836

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

CAITLIN D. MYERS states that on August 16, 2022, she served a copy of DTE Electric Company's Reply Brief in the above captioned matter, via electronic mail, upon the persons listed on the attached service list.

Caitlin D. Myers

Digitally signed by Caitlin D. Myers
Date: 2022.08.16 15:06:35 -04'00'

CAITLIN D. MYERS

ADMINISTRATIVE LAW JUDGE
Hon. Sharon L. Feldman
Hon. Katherine E. Talbot
Michigan Office of Administrative Hearings and Rules
7109 West Saginaw Hwy
Lansing, MI 48917
feldmans@michigan.gov
talbotk@michigan.gov

ABATE
Michael J. Pattwell
Clark Hill PLC
212 E. Cesar E. Chavez Avenue
Lansing, MI 48906
mpattwell@clarkhill.com

Stephen A. Campbell
Clark Hill PLC
500 Woodward Avenue, Suite 3500
Detroit, MI 48226
scampbell@clarkhill.com

Consultants:
Jim Dauphinais
Brian C. Andrews
Chris Walters
Jessica York
jdauphinais@consultbai.com
bandrews@consultbai.com
cwalters@consultbai.com
jyork@consultbai.com

BLOOM ENERGY; CHARGEPOINT, INC.; ENERGY MICHIGAN, INC.; MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL; INSTITUTE FOR ENERGY INNOVATION
Laura A. Chappelle
Timothy J. Lundgren
Justin K. Ooms
Potomac Law Group PLLC
120 N. Washington Square, Suite 300
Lansing, MI 48933
lchappelle@potomaclaw.com
tlundgren@potomaclaw.com
jooms@potomaclaw.com

Consultants:
Laura Sherman
Justin Barnes
Matthew Deal
laura@mieibc.org
jbarnes@eq-research.com
matthew.deal@chargepoint.com

CITIZENS UTILITY BOARD OF MICHIGAN; MICHIGAN ENVIRONMENTAL COUNCIL; NATURAL RESOURCES DEFENSE COUNCIL; SIERRA CLUB
Christopher M. Bzdok
Tracy Andrews
Olson, Bzdok & Howard, P.C.
420 East Front Street
Traverse City, MI 49686
chris@envlaw.com
tjandrews@envlaw.com
jill@enlaw.com
kimberly@envlaw.com
karla@envlaw.com
breanna@envlaw.com

SIERRA CLUB
Shannon Fisk
sfisk@earthjustice.org
Hema Lochan
hlochan@earthjustice.org

Consultants:
Tyler Comings
Joshua Castigliego
Tanya Stasio
Daniel Garrett
Robert Ozar
tyler.comings@aeclinic.org
Joshua.castigliego@aeclinic.org
tanya.stasio@aeclinic.org
dgarrett@resolveuc.com
rozar@5lakesenergy.com

CITY OF ANN ARBOR; MICHIGAN MUNICIPAL ASSOCIATION FOR UTILITY ISSUES
Valerie J.M. Brader
Valerie Jackson
Rick Bunch
Rivenoak Law Group P.C.
3331 W. Big Beaver Rd., Suite 109
Troy, MI 48084
valerie@rivenoaklaw.com
valeriejackson@rivenoaklaw.com
ecf@rivenoaklaw.com
rick@mi-maui.org

ENVIRONMENTAL LAW AND POLICY CENTER/ECOLOGY CENTER/SOLAR ENERGY INDUSTRIES ASSOCIATION/VOTE SOLAR
Margrethe Kearney
Heather Vogel
Alondra Estrada
Daniel Abrams
Bradley Klein
Kevin Lucas
William Kenworthy
Charles Griffith
1514 Wealthy Street SE, Suite 256
Grand Rapids, MI 49506
mkearney@elpc.org
hvogel@elpc.org
aestrada@elpc.org
MPSCDocket@elpc.org
dabrams@elpc.org
bklein@elpc.org
klucas@seia.org
will@votesolar.org
charlesg@ecocenter.org

EVGO SERVICES, LLC
Brian R. Gallagher
Moblo Fleming PC
93555 Orchard Hill Pl., Ste 310
Novi, MI 48375
bgallagher@moblofleming.com

Nikhil Vijaykar
Keyes & Fox LLP
580 California Street, 12th Floor
San Francisco, CA 94104
nvijaykar@keyesfox.com

GERDAU MACSTEEL, INC.
Jennifer Utter Heston
Fraser Trebilcock Davis & Dunlap, P.C
124 W. Allegan, Ste 1000
Lansing, MI 48933
jheston@fraserlawfirm.com

Consultants:
Jeffry Pollock
Joseph Selsor
Kitty Turner
JCP@jpollockinc.com
JMS@jpollockinc.com
KAT@jpollockinc.com

GREAT LAKES RENEWABLE ENERGY ASSOCIATION INC.; RESIDENTIAL CUSTOMER GROUP
Don L. Keskey
Brian W. Coyer
University Office Place
333 Albert Avenue, Suite 425
East Lansing, MI 48823
donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com
adminasst@publiclawresourcecenter.com

INTERNATIONAL TRANSMISSION COMPANY
Richard J. Aaron
Olivia R.C.A. Flower
201 Townsend Street, Suite 900
Lansing, MI 48933
RAaron@dykema.com
OFlower@dykema.com
mpscfilings@dykema.com

MICHIGAN ATTORNEY GENERAL
Joel King
Assistant Attorney General
ENRA Division
525 W. Ottawa Street, 6th Floor
P.O. Box 30755
Lansing, MI 48909
KingJ38@michigan.gov
ag-enra-spec-lit@michigan.gov

Consultants:
Sebastian Coppola
David Dismukes
Michael Deupree
David Kantrow
Stephen Butler
Andrea Attipoe
Taylor Deshotels
Tyler French
Emily Mouch
Cameron Cates
sebcoppola@corplytics.com
daviddismukes@acadianconsulting.com
michaeldeupree@acadianconsulting.com
davidkantrow@acadianconsulting.com
stephenbutler@acadianconsulting.com
andreaattipoe@acadianconsulting.com
taylordeshotels@acadianconsulting.com

tylerfrench@acadianconsulting.com
emilymouch@acadianconsulting.com
cameroncates@acadianconsulting.com

MICHIGAN CABLE TELECOMMUNICATIONS ASSOC.
Michael S. Ashton
Fraser Trebilcock Davis & Dunlap
124 West Allegan Street, Suite 1000
Lansing, MI 48933
mashton@fraserlawfirm.com
ljohnson@fraserlawfirm.com

MPSC STAFF
Benjamin J. Holwerda
Spencer A. Sattler
Daniel E. Sonneveldt
Nicholas Q. Taylor
Lori Mayabb
7109 West Saginaw Hwy, 3rd Fl
Lansing, MI 48917
holwerdab@michigan.gov
sattlers@michigan.gov
sonneveldtd@michigan.gov
taylorn10@michigan.gov
mayabbl@michigan.gov

SOULARDARITY; WE WANT GREEN, TOO
Andrew Bashi
Great Lakes Environmental Law Center
4444 Second Avenue
Detroit, MI 48201
andrew.bashi@glelc.org

Jackson Koeppel
jkoeppel.consulting@gmail.com

Mark Templeton
Robert Weinstock
Simone Gewirth
University of Chicago Law School
Abrams Environmental Law Clinic
6020 South University Avenue
Chicago, IL 60637
templeton@uchicago.edu
rweinstock@uchicago.edu
sgewirth@uchicago.edu
aelc_mpsc@lawclinic.uchicago.edu

THE KROGER CO.
Kurt J. Boehm
Jody Kyler Cohn
Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202
kboehm@BKLlawfirm.com
jkylercohn@BKLlawfirm.com
mkurtz@BKLlawfirm.com

Consultant:
Justin Bieber
jbieber@energystrat.com

UTILITY WORKERS LOCAL 223
John A. Canzano
Ben King
Mcknight, Canzano, Smith Radtke & Brault, P.C.
423 N. Main Street, Suite 200
Royal Oak, MI 48067
jcanzano@michworkerlaw.com
bking@michworkerlaw.com

WALMART, INC.
Melissa M. Horne
Higgins, Cavanagh & Cooney, LLP
10 Dorrance Street, Suite 400
Providence, RI 02903
mhorne@hcc-law.com

ZECO SYSTEMS, INC. D/B/A GREENLOTS
Sean P. Gallagher
Gallagher Law
321 West Lake Lansing Road
East Lansing, MI 48823
Sean@legalspg.com

Thomas Ashley
tom@greenlots.com