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September 25, 2024

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

RE: In the matter of the application of **DTE GAS COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority
MPSC Case No. U-21291

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter is DTE Gas Company's Exceptions to the Proposal for Decision with Attachment A. Also attached is the Proof of Service.

Very truly yours,

Carlton. Watson

CDW/cdm
Attachments

cc: Service List

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
DTE GAS COMPANY for authority to)
increase its rates for the distribution)
of natural gas and for other relief)
_____)

Case No. U-21291

DTE GAS COMPANY'S EXCEPTIONS
TO THE PROPOSAL FOR DECISION

Dated: September 25, 2024

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INTRODUCTION

On September 4, 2024, the Administrative Law Judge (ALJ) issued a Proposal for Decision (PFD) regarding DTE Gas Company's (DTE Gas, DTE, or the Company) Application for authority to increase its rates for the distribution of natural gas and for other relief. While DTE Gas agrees with the ALJ's recommended disposition of some issues, the overall revenue recommendation of the PFD is concerningly low and consists of recommendations that are based on incorrect calculations, inapplicable analyses, foundations that do not exist in the evidentiary record as required by the Michigan Administrative Procedures Act (APA) and, conversely, conclusions that evidence does not exist in the record when in fact it does.¹

DTE Gas's exceptions are discussed in detail in the following sections; however, two significant proposals in the PFD are worth highlighting. First, the PFD's calculation of a return on equity (ROE) goes beyond the record evidence and any recommendation by the parties in this case. A decision that is not based on record evidence runs afoul of the APA, which requires that a decision be made "upon consideration of the record as a whole or a portion of the record . . . and as supported by and in accordance with the competent, material, and substantial evidence."² Second, the proposed \$62 million disallowance of actual capital costs for assets that are in service and being used by customers forces the Company to write off those costs. This is an untenable result, particularly considering that the costs were incurred as part of the Company's Infrastructure Recovery Mechanism (IRM) – a program that the Commission has routinely approved and viewed as vital to the safety and reliability of the gas system.

¹ MCL § 24.285 relevantly states that "[a] decision or order shall not be made except upon consideration of the record as a whole or a portion of the record as may be cited by any party to the proceeding and as supported by and in accordance with the competent, material, and substantial evidence."

² MCL 24.285.

In addition to these, there are other untenable disallowances such as the disallowance of costs for the Company's Mesick-Buckley new customer attachment project—a project that received state support and grant funding—and the adoption of an \$8 million disallowance for forecasted sales (suggesting an underestimation) while simultaneously agreeing with an intervenor position that forecasted sales are overestimated.

In addition to the above examples, each of DTE Gas's specific exceptions are explained in more detail below. DTE Gas attempts to be succinct in light of the Michigan Public Service Commission's (Commission) knowledge, expertise, and prior decisions. Further support for DTE Gas's positions and the reasons for those positions can be found in DTE Gas's Application (including Attachments), testimony, exhibits, Initial Brief (including Attachments A and B), and Reply Brief, all of which are incorporated by reference here. The first portion of DTE Gas's discussion focuses on inconsistencies between the text of the PFD and the supporting calculations. Thereafter, for consistency and ease of reference, the second portion of DTE Gas's discussion presents the issues largely in the order that they arise in the PFD. Parties are referenced as designated in the PFD, and related matters are addressed collectively in the most relevant or logically sequential context.

It is important to note that lack of discussion by DTE Gas on any one issue suggested by or consequence resulting from the PFD should not be deemed to constitute agreement by DTE Gas. Finally, DTE Gas maintains and reserves all of its appellate rights, as well as all other rights, to address issues in other proceedings.

DISCUSSION

I. THE PFD CONTAINS MULTIPLE CALCULATION INCONSISTENCIES.

The PFD recommends a \$97,950,000 revenue deficiency (PFD, p 419; PFD, Appendix A). However, the Company's review of the specific disallowances that appear to be adopted on each issue revealed numerous inconsistencies between the amounts in the PFD Appendices and the recommendations made in the narrative of the PFD.

For example, the PFD Appendices contain no reference to various revenue categories—Residential and Commercial; End User Transportation (EUT); Exchange Gas Services; and Home Protection Plus (HPP) Margin—despite the PFD narrative's specific findings on these topics. Additionally, the PFD Appendices indicate a removal of \$22,431,000 compared to the text of the PFD, which indicates a removal of only \$17,379,000. Finally, the narrative of the PFD indicated that \$7,400,000 in capital expenses related to cathodic protection should be moved out of the IRM and into rate base, but the PFD's Appendices fail to reflect this change.

Based on the Company's review and calculations, the apparent revenue deficiency proposed by the PFD is approximately \$87 million. The following table indicates the as-filed revenue deficiency position of the PFD Appendices, the positions taken on these issues in the PFD's narrative, and the corresponding revenue deficiency impact.

Description	PFD Discussion	Revenue Deficiency Impact
PFD Revenue Deficiency as Filed		\$ 97,950,000
<i>Revenue Adjustments</i>		
Residential & Commercial	PFD...finds that AG has adequately supported that the incremental forecasted revenue for the projected test year is \$8,290,000 (PFD p 240).	\$ (8,290,000)
End User Transportation	PFD agrees with AG...that using the current volumetric rate for Rate schedule XXLTL yields additional revenue of \$503,000 (PFD pp 248–250).	(503,000)
Exchange Gas Services	PFD agrees with AG...opting to use the most recent information which excludes an anomalous year (2020) adversely affected by COVID, thus adjusting revenues by \$2,832,000 (PFD pp 254–255).	(2,832,000)
HPP Margin	PFD recommends the adoption of AG's proposal to increase DTE's projected operating income by \$4,617,000 (PFD p 257).	(4,617,000)
<i>Operations and Maintenance Adjustments</i>		
Operation & Maintenance	PFD agrees that proposed O&M disallowance for 2023 should reflect the two instances where disallowances overlap with adjustments that DTE made. PFD adopts AG's proposed disallowance (\$22,431,000 per PFD Appendix) in an adjusted amount of \$17,379,000 (net \$5,052,000) (PFD pp 267–269).	5,052,000
<i>Capital Adjustments</i>		
Cathodic Protection	PFD agrees with AG to reject DTE's proposal and instead move \$7,400,000 of capital from the IRM to base rates in the projected test year. (\$372,000 impact to Revenue Deficiency) (PFD p 87).	372,000
Total Amount of Corrections		\$ (10,818,000)
Corrected Revenue Deficiency		\$ 87,132,000

These inconsistencies are significant, resulting in nearly \$11 million, or more than a 10% difference between the PFD's positions. Accordingly, the Commission should exercise caution when assessing the positions adopted by the PFD.

Nevertheless, even before the Company's reconciliation of the numbers, the PFD's recommended revenue deficiency was woefully insufficient. Indeed, when considering that \$106 million of the Company's request consisted of the IRM roll-in—i.e., costs that have been spent on critical infrastructure vital to the safety and reliability of the gas system—that would have been fully recovered through the existing IRM surcharge, the PFD has actually suggested a revenue *sufficiency* exists. This recommendation should be increased based on the record evidence discussed below. Pages 1 through 4 of Attachment A to these Exceptions support the Company's current position.

II. DTE GAS TAKES SPECIFIC EXCEPTION TO MULTIPLE PFD FINDINGS.

A. DTE GAS HAS A \$262.4 MILLION REVENUE DEFICIENCY.

DTE Gas initially requested a rate increase of approximately \$266 million, but the Company agreed with intervenor proposed changes or identified errors that reduced its revenue deficiency to \$262.4 million. DTE Gas's Reply Brief accordingly supported a revised revenue deficiency of approximately \$262.4 million for the projected test year.

The PFD recommends a \$97.950 million revenue deficiency (PFD, p 419; *see also* PFD Appendix A, Line No. 8, column (e)). The PFD's recommended revenue deficiency is insufficient and should be increased based on the controlling law and the record evidence discussed below. Attachment A to these Exceptions reflects the Company's position.

B. TEST YEAR

The PFD recommends that the Commission adopt the twelve-month period ending September 30, 2025, as proposed by DTE Gas, as the projected test year (PFD, p 12). Accordingly, the Company raises no exception to this PFD recommendation.

C. DTE GAS'S RATE BASE IS \$6,939,800,000.

1. Capital Expenditures

The PFD begins by reciting the Attorney General's (AG's) overall perspective of DTE Gas's capital expenditures (PFD, pp 14–17). It is unclear whether the PFD's proposed capital disallowances are based on the AG's perception, but it bears emphasis that the excerpt cited by the PFD is not rooted in the evidence presented in this case and contains speculation regarding the reasoning for capital investments. Additionally, the selective data recited by the PFD regarding the Company's requested rate increase lacks context. For example, the PFD emphasizes the AG's point that DTE Gas is seeking a 9% rate increase (PFD, p 16). While that is correct, it is equally important to note that the Company has not had a rate increase in three years – during some of the highest inflationary periods in recent decades. And more importantly, decisions regarding rate case increases must be based on record evidence, not speculation.³

a. LDAR Notice of Proposed Rulemaking

On May 4, 2023, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Notice of Proposed Rulemaking (NPR) titled "Pipeline Safety: Gas Pipeline Leak

³ Agency decisions, including decisions by the Commission, cannot be based on speculation, and speculative agency decisions are unconstitutional. Mich. Const. of 1963, Art. 6, § 28; *see also In re Complaint of Rovas Against SBC Mich.*, 482 Mich. 90, 101, 754 N.W.2d 259 (2008) ("The [Michigan] constitution requires that [agency findings in contested cases] be supported by competent, material, and substantial evidence on the whole record." (Punctuation omitted)).

Detection and Repair” to implement congressional mandates regarding methane emissions reductions from new and existing natural gas transmission, distribution, and gathering pipelines. The NOPR responds to Section 113 of the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act), which required PHMSA to establish a rule related to minimum requirements for Leak Detection and Repair (LDAR) and the use of advanced leak detection technologies and practices (3T 363). The NOPR also codifies the mandate in the PIPES Act that requires operators to update their inspection and maintenance plans to include protection of the environment and replacement or remediation of pipe known to leak (3T 363). The NOPR is expected to become final in September 2024 and effective six months after publication (3T 364). If the final rule is published on September 1, 2024, the effective date would be March 1, 2025 (3T 364). Once the NOPR becomes a final rule, it will be codified in Part 192 of the Code of Federal Regulations (CFR), which provides the minimum federal safety standards for the transportation of natural gas (3T 365).

DTE Gas is required by PHMSA and the Commission to adhere to Part 192 of the CFR (3T 365). As such, DTE Gas is implementing an expanded LDAR program to comply with the NOPR and Part 192 of the CFR (3T 365). The LDAR program has both safety and environmental benefits (3T 365). Specifically, the LDAR program enhances leak survey, patrolling requirements, and establishes defined criteria and timelines for repair of leaks (3T 365). The LDAR program also lowers methane emissions by requiring advanced leak technologies to find and repair more leaks in a shorter timeframe (3T 365–366).

DTE Gas included \$14.97 million of LDAR capital expenditures for the period of January 1, 2023, through September 30, 2025, consisting of: (1) \$2.5 million in leak grading and repair costs; (2) \$11.6 million in advance leak detection program costs; (3) \$0.3 million in transmission

blowdown costs; and (4) \$0.6 million in pressure relief device costs (3T 364–365; Exhibit A-12, Schedule B5.1, page 2, line 16, columns (f) and (g)).

The AG and Staff each took issue with the Company’s request for LDAR capital expenditures. AG Witness Coppola argued that the Company’s requested LDAR capital expenditures were premature given that the NOPR is unlikely to become final until September 2024 and will not become effective until March 2025 at the earliest (4T 1447–1448). Witness Coppola contended that, until the Company can present a comprehensive plan of how and when its current LDAR program will be compliant with the NOPR final rule, it is inappropriate to approve additional capital expenditures (4T 1448). Therefore, Witness Coppola recommended that the Commission reject the Company’s requested \$14.97 million in LDAR capital expenditures (4T 1448).

Similarly, Staff did not support including LDAR capital expenditure expenses until the NOPR final rule is published and the actual effective date is known (4T 1792–1793). However, Staff did recommend that the Commission approve \$6 million in LDAR capital expenditures relating to the purchase of Picarro units (4T 1792–1793). As such, Staff recommended a disallowance of LDAR capital expenditures of only \$8.97 million (4T 1793).

The PFD agrees with the AG and Staff, stating that “DTE’s proposed capital expenditures are premature and should not be recovered until such a time that the final LDAR rule is published and the actual effective date is known” (PFD, p 24). However, the PFD disagrees with the Company and Staff that the \$6 million in capital expenditures for the procurement of Picarro units should be permitted, stating that:

Neither DTE nor Staff offer any reason why this expenditure should be treated differently from the other LDAR capital expenditures; that is, why the Picaaro [sic] expenditures to be made in anticipation of future LDAR mandates should be allowed while other LDAR expenditures similarly to made in anticipation of the

same LDAR mandates are not. Thus, this PFD recommends that the Attorney General's proposed disallowance of \$14,970,000 of capital expenditures and the \$10,276,000 of O&M expense forecasted by DTE for the projected test year be accepted.

(PFD, p 25).

The Company disagrees. First, while the NOPR is not yet final, it is expected to go into effect during the projected test period—currently estimated for March 1, 2025 (DTE Gas Initial Brief, p 100). Second, the PFD is incorrect that neither the Company nor Staff “offer any reason” for why recovery of \$6 million in LDAR capital expenditures relating to the purchase of Picarro units should be treated differently from other LDAR capital expenditures. As Witness Abona explained, recovery of LDAR capital expenditures relating to the purchase of Picarro units is fully justified because the procurement was proactive (3T 390). While the Company currently uses Picarro units for advanced leak detection in Southeast Michigan, there are currently no Picarro units in Greater Michigan (3T 390). The purchase of Picarro units was in process prior to the issuance of the NOPR and is not dependent on the NOPR becoming final; rather, the purchase of Picarro units is crucial in supporting the Company's strategy to expand its leak detection capabilities in Greater Michigan to match those in Southeast Michigan (3T 390–391). Staff agrees with the Company that the purchase of the Picarro units is a “prudent investment” and supports the Company's initiative to implement and expand the Picarro technology ahead of the NOPR becoming effective (Staff Initial Brief, p 13). In sum, the Company needed to purchase the Picarro units before the NOPR became final; otherwise, it would not be able to adhere to the LDAR mandates (3T 390–91). As such, the Company maintains that its position is supported by the preponderance of the evidence on the record.

Accordingly, the PFD's recommendation that all LDAR capital expenditures be disallowed, including the \$6 million in capital expenditures for the procurement of Picarro units, should be rejected.

b. System Reliability

From January 1, 2023, through September 30, 2025, DTE Gas will have incurred \$101.8 million of system reliability capital expenditures (3T 346; Exhibit A-12, Schedule B5.1, page 2, line 8, columns (f) and (g)).

The AG recommended a \$7,019,000 disallowance for the nine months ending September 2024 and a \$6,573,000 disallowance for the twelve months ending September 2025 (AG Initial Brief, pp 19–20). The AG claimed that several of the listed projects are in the planning or early design phase, indicating that the projects have not yet been sufficiently developed through the engineering phase to be certain for completion within the 2025 projected test year (AG Initial Brief, p 19). As such, the AG instead calculated projected unit counts for 2024 and 2025 based on an average of actual unit figures from 2021 and 2023 (AG Initial Brief, pp 19–20).

The PFD agrees with the AG's proposed disallowance, reasoning:

While DTE offers some reasons in support of its projections, DTE fails to rebut the Attorney General's assertion that several of the listed projects are in the planning or early design phase and thus have not yet been sufficiently developed through the engineering phase to be certain for completion within the 2025 projected test year.

(PFD, pp 31–32).

To the contrary, DTE Gas demonstrated that the projects that the AG proposes for disallowance are sufficiently developed. Specifically, as shown in the Company's response to the discovery request that Witness Coppola relies on to support his incorrect claim that several of the projects are insufficiently developed (AGDG-5.149a and b), none of these projects are in an "early" design phase (4T 1441–42). Therefore, the PFD is incorrect that DTE Gas did not rebut

this assertion. Nonetheless, the AG's proposed disallowance sets an arbitrary and subjective standard for rate recovery of capital projects. By insisting that projects be at a certain stage of development or receive specific approvals, the AG ignores the relevant and applicable standard for inclusion in rate recovery: reasonableness and prudence. Consistent with this standard, the Company has detailed ample evidence to show that these projects are critical to the continued safety and reliability of DTE Gas's system, rendering these investments reasonable, prudent, and worthy of recovery (*see* 3T 350–51, 353–54). Therefore, the PFD's proposed disallowance should be rejected.

c. Gas Storage Plant

From January 1, 2023, through September 30, 2025, DTE Gas will have incurred \$56.6 million of routine storage plant capital expenditures (3T 370; Exhibit A-12, Schedule B5.1, page 1, line 4, columns (f) and (g)). Specifically, the Company forecasted routine storage plant capital expenditures of \$22.3 million for 2023; \$19.3 million for the nine months ending September 2024; and \$14.9 million for the twelve months ending September 2025 (Exhibit A-12, Schedule B5.1, page 1, line 4, columns (d), (e) and (g)).

The AG disputed the Company's forecasted gas storage and compression capital expenditures for the nine months ending September 2024 and the twelve months ending September 2025 (AG Initial Brief, pp 41–43). The AG argued that the Company's estimated gas storage and compression capital expenditures were unreasonable and that the Company did not adequately justify the higher forecasted costs in comparison to recent historical unit cost plus forecasted inflation (AG Initial Brief, p 41). Accordingly, the AG recommended that the Commission disallow \$9,506,000 for the nine months ending September 2024 and \$3,819,000 for the twelve months ending September 2025 (AG Initial Brief, pp 42–43).

The PFD agrees with the AG, stating:

This PFD finds that DTE’s explanation in support of these projected expenditures is lacking any specificity backing up its general statements that the associated construction activities are complex. Moreover, while referencing a specific cost for a turbine engine replacement, which it asserts are projected to occur based on the equipment surpassing the recommended cumulative hour threshold, DTE does not provide any estimate of the number of such replacements to occur even though such an estimate should be easy to compile from objective criteria (the number of turbines projected to exceed the run hour threshold). Thus, this PFD agrees that DTE’s projections are not adequately supported and thus recommends that the Commission adopt the Attorney General’s recommended disallowance of \$9,506,000 for the 9 months ending September 2024 and the \$3,819,000 for the 12 months ending September 2025.

(PFD, pp 38–39).

The Company disagrees and takes exception. The Company provided ample evidence explaining the complexity of the construction activities for gas storage and compression capital expenditures (3T 392–93). The Company also provided data for each of these projects, including a description of each project and a breakdown of the costs for each project (Exhibit A-12, Schedule B5.9). Using the Belle River Mills Valves & Actuators initiative as an example, the Company also provided a detailed explanation of the project scope and the complexity of the associated construction activities (3T 392–93). As such, the Company’s recitation of the construction activities mandated by the Belle River Mills Valves & Actuators project can hardly be classified as “lacking [] specificity” (PFD, p 38). Additionally, the Company also provided evidence of specific cost information for a typical turbine engine replacement and explained that several compressor units would require an engine replacement to ensure safe and reliable operation (3T 393). The PFD claims that the Company should have also provided an estimate of the number of such replacements to occur (PFD, p 39) and assumes that such evidence should have been easy to present. Notably, no party in the case requested this information. It is improper for the PFD to speculate on the type of information that should have been provided and to classify the Company’s

projections as unsupported due to the omission of that information.⁴ Accordingly, the PFD's recommended disallowance should be rejected.

2. Gas IT Spending

Witness Fedele states that from December 31, 2022, the end of the historical test year, through September 30, 2025, the end of the projected test year, DTE Gas will have incurred \$33.1 million of Gas Information Technology (IT) capital expenditures. DTE asserts that its IT investment spending is part of the DTE IT Five-year Plan for 2021–2025, which was filed on March 22, 2021, in Case No. U-20561.

Staff recommended a 20% disallowance for IT projects with Level 2 cost estimates, resulting in a total capital disallowance of \$1,755,600, along with a corresponding operations and maintenance (O&M) disallowance of \$120,780 (4T 1601). The PFD agrees with Staff, asserting that this is consistent with the Commission's previous approach, and that DTE "has not effectively rebutted Staff's assertions in support of the disallowance" (PFD, p 45).

The Company disagrees and takes exception. As a preliminary matter, Staff's approach of cutting O&M expenses to match its recommended capital expenditure reductions is inappropriate—this approach applies a general rule to O&M reductions rather than considering the specific nature of O&M expenses. Further, the PFD is silent on the robust and rigorous process that the Company uses to develop these IT cost estimates (*See* DTE Initial Brief at 30). Additionally, the PFD fails to acknowledge the factual misstatement offered by Staff in support of its recommended disallowance, namely, that Level 2 cost estimates are obtained prior to a

⁴ As discussed in footnote 3, *supra*, agency decisions, including decisions by the Commission, cannot be based on speculation, and speculative agency decisions are unconstitutional. Mich. Const. of 1963, Art. 6, § 28; *see also* *Rovas*, 482 Mich. at 101.

comprehensive review (PFD, p 45). DTE Gas demonstrated on the record that Level 2 cost estimates are a part of the rigorous Annual Planning Cycle (APC) process and developed through input and comprehensive reviews by experienced subject matter experts and cross-functional teams based on various data points such as scope, technology, historical data, and vendor quotes (DTE Gas Initial Brief, p 30). Simply stating that “DTE has not effectively rebutted Staff’s assertions,” with nothing more, ignores the record evidence that DTE Gas put forward on this subject, which demonstrates that these projects have in fact completed significant reviews. The PFD’s recommendation, both with regards to Staff’s reductions to capital expenditures and O&M expenses, should accordingly be rejected.

3. Large Capital Projects

DTE Gas included several Large Capital Projects in its Application and takes exception to two project disallowances: the Fort Street Main Replacement and the Traverse City/Alpena Reinforcement Project (TCARP).

a. Fort Street Main Replacement

The Fort Street Main Replacement is an eight-phase project in the City of Detroit requiring the design and installation of 12.9 miles of new steel and plastic main, abandonment of 14.2 miles of steel main, installation of forty-three valves, and installation of eleven district regulators (4T 1911). This project also includes the abandonment of eleven district regulators and replacement of ninety-two services (4T 1911–12). While the eight phases are not sequential, phases one and two were completed in 2019, while phases three and five were completed in 2022 (4T 1912). Phases five through seven will be completed from 2023 through 2025, with the remainder of phase three, as well as phases four and eight, to be completed in 2026 and 2027 (4T 1912).

The AG argued that the \$32,753,000 forecasted by DTE for the projected test year for this project are not likely to be spent and recommended that the Commission remove that amount from DTE's forecasted capital expenditures in this rate case (4T 1450). The PFD agrees with the AG, reasoning that DTE Gas stated in direct testimony that phases five, six, and seven will be completed from 2023 through 2025 in coordination with other major projects in the area, including the I-375 Reconstruction Project (PFD, pp 49–50). The PFD concludes that “it would be imprudent for DTE Gas to proceed with construction activities without a firm timeline and an approved project plan from [the Michigan Department of Transportation (MDOT)] and the City of Detroit” (PFD, p 50).

The Company takes exception to the PFD's disallowance of this capital project. As a preliminary matter, the AG's testimony on this point, as summarized and adopted by the PFD, is contradictory. The PFD notes that the AG admitted “capital spending [for this project] forecasted for 2024 appears likely to occur” but simultaneously argues that those amounts are “not likely to be spent” (PFD, pp 48–49). Further, the PFD's finding on this point wholly ignores critical components of DTE Gas Witness Fedele's rebuttal testimony. First, the Company reiterates that the Fort Street Main Replacement project is a standalone project “and not part of a larger municipal coordination or public improvement project” (4T 1981). Notably, Witness Fedele testified that “[w]hile the Company is flexible in scheduling this work to align with municipal projects, the overall project execution and completion is not dependent on the work performed by the governmental agencies” (4T 1981). Witness Fedele also testified that DTE “works in advance to ensure project designs are per the governmental requirements and coordinated to accommodate any future work required by these agencies” (4T 1981).

Nowhere in this testimony does DTE Gas indicate that the Fort Street Main Replacement project is dependent on the coordination with other government agencies (4T 1981). In fact, all

design work has been completed for this project and permit requirements have been incorporated, indicating that this work will commence whether other government agencies like MDOT proceed with their separate projects or not (4T 1981). The PFD’s characterization of this project is therefore flawed and inconsistent with the record; as such, the PFD’s disallowance should be rejected.

b. Traverse City/Alpena Reinforcement Project

Regarding the Traverse City/Alpena Reinforcement Project (TCARP), the PFD agrees with the AG and finds that DTE Gas has failed to offer any explanation for why delays associated with the project would cause internal labor to increase by \$1.8 million, overhead costs to increase by \$1.1 million, and contractor and material costs to increase by \$50,000, each when no work took place and no new employees were hired during the delay (PFD, pp 71–72). Accordingly, the PFD recommends adoption of the AG’s proposed \$3 million disallowance of historical capital from rate base in this case and calls for DTE Gas to remove this amount permanently from future rate cases (PFD, p 72).

The PFD’s contention that DTE Gas “fail[ed] to offer any explanation” for cost increases due to delay is incorrect. Again, the PFD simply misses, or entirely disregards, record evidence in forming a recommendation. In rebuttal testimony, Company Witness Fedele clearly stated that “by extending Phase 3 [of the project] out an additional year, the cost of corporate overheads also increased” (4T 1987). Witness Fedele noted that this affected labor costs and construction costs (4T 1987), all of which were relevant to engineering, project management, material coordination and verification, construction oversight, operation staff, and internal construction team costs (4T 1986). Moreover, the additional \$1.8 million in labor cost was accounted for, as Witness Fedele noted that this amount was “[c]ontained within the \$2.7 million internal labor component in 2022” (4T 1987). Thus, DTE Gas not only offered explanations for these cost increases, but DTE Gas

also testified that these explanations were both reasonable and prudent (*See* 4T 1986–87). In claiming that DTE Gas failed to offer any explanation for these cost increases, the PFD is therefore patently incorrect.

4. Infrastructure Recovery Mechanism

a. Cathodic Protection Costs

The PFD recommends that the Commission reject DTE’s proposal to include cathodic protection capital expenditures in the IRM and instead include those costs in the projected test year (PFD, pp 87, 92). The Company notes for the Commission’s benefit that this is not a disallowance of cathodic protection costs but rather a determination regarding how such costs will be recovered. The Company also reiterates that the PFD’s underlying calculations did not correctly account for this change. Accordingly, the Commission should adopt the corrected amounts related to this item as proposed by the Company in Section I above.

b. Main Replacement

The PFD recommends that the Commission reduce Main Replacement Program capital expenditures by approximately \$62 million (PFD, p 95). Additionally, the PFD agrees with the Association of Businesses Advocating Tariff Equity’s (ABATE) proposal to limit DTE Gas’s average retirement of 190 miles of main each year to meet the eighteen-year pace approved in Case No. U-18999, which matches DTE’s yearly minimum goal mileage of 190 miles for the Company’s Gas Renewal Program, but is less than the 206 miles being proposed by DTE (PFD, pp 94–95).

The Company takes exception with the PFD’s proposal to disallow approximately \$62 million in capital expenditures for the period of 2022 through December 31, 2024. These dollars have been or will have been spent on main replacement and the assets are or will be in service by the time the order in this case is issued. Importantly, no party—including ABATE—argues that these *historical* expenditures are imprudent or unreasonable. In fact, ABATE noted in testimony

that “the replacement of legacy gas mains has significantly reduced the average number of gas leaks per mile” (4T 1317).

The PFD appears to base its \$62 million disallowance of historical costs on ABATE’s discussion in testimony, wherein ABATE Witness Fitzhenry recommends that the Company “adjust the rate of main replacements in order to reduce the impact of capital expenditures on customers’ rates” (4T 1318). Purely by way of example, ABATE illustrates how its sixteen-mile adjustment in the rate of replacement could result in an 8% reduction in capital spend—or approximately \$62 million—in 2022, 2023, and 2024 (4T 1318). But this is not an outright number to be used as a disallowance. Rather, ABATE’s proposal is merely a change in the number of miles replaced, which ABATE maintains could result in approximately \$62 million reduction in capital expenditures (4T 1318). In other words, as framed by ABATE, this was an adjustment that may affect capital spend, but has no impact on the dollars already spent on main replacement. Clearly, DTE Gas cannot reduce the 235 miles of main that have already been replaced (*See* 4T 599). Put simply, the PFD misconstrues ABATE’s argument and its proposed disallowance should be rejected on this ground alone.

Notwithstanding the PFD’s misunderstanding of ABATE’s proposal, the proposed disallowance is legally unsound. Of the \$62 million proposed for disallowance, \$20.5 million was incurred in 2022 and \$20.9 million was incurred in 2023. Capital expenditures of \$255 million were used to calculate the main renewal portion of the IRM surcharge for 2022 and 2023. In 2022, the actual main renewal expenditures were \$263 million. In 2023, the actual main renewal expenditures were \$258 million (at the time of filing) (Exhibit A-12, Schedule B5.3 (col. l-m)). As such, \$7 million (from 2022 actual spend) and \$18 million (from 2023 actual spend) of the ALJ’s proposed disallowed costs were *already being recovered by way of the IRM surcharge*. A lawfully

established rate remains in force until altered by a subsequently established lawful rate and the Commission cannot penalize DTE Gas for collecting these amounts during the interim period. *Michigan Bell Tel. Co. v. Pub. Serv. Comm'n*, 315 Mich. 533, 347, 24 N.W.2d 200 (1946). Any rate that does so is confiscatory and would be unconstitutional. *Id.* If the Commission were to agree with the PFD on this issue, such a finding would amount to both retroactive ratemaking and confiscatory rates. Such a disallowance would result in a write-off of investments already made by the Company and which are currently in-service and benefitting customers.

Further, the PFD's proposal to adjust the Company's target to 190 miles of main each year keeps DTE Gas consistent with minimum mileage goals, but the reduction in capital expenditures prevents DTE Gas from being able to maintain a steady level of expenditures. This limits DTE Gas to replacing only 190 miles per year, even if it may be prudent to exceed this amount based on the circumstances of a given year. Put another way, the removal of these capital expenditures removes any flexibility and would ensure that DTE Gas meets *only* the 190-mile target, nothing more. By maintaining capital expenditure amounts, DTE Gas will have a reasonable amount of flexibility to address complex, time-consuming main renewals, which will still be encountered regardless of the approved mileage target, as well as the flexibility to exceed the 190-mile target when doing so is prudent and in the best interest of customers.

Accordingly, the Commission should reject the PFD's proposed approximately \$62 million capital expenditure disallowance.

5. Customer Attachments - Mesick Buckley and Peach Ridge AEPs

The Customer Attachment Program (CAP) was authorized by the Commission (for multiple utilities) in 1995 and is designed to enable the expansion of cleaner, safer, more reliable, and more affordable gas to new customers (*See Order Approving Settlement Agreement*, Case No.

U-10745 (June 5, 1995) (finding, under the then-proposed Rules, that “it is expected that a new customer attachment will, over the long run, have a beneficial impact on the rates charged to existing customers”). Under the CAP, the costs of installing the necessary facilities for expansions are charged to new customers (DTE Gas Initial Brief, p 165). The Company’s CAP also includes community expansion projects (CEPs) (3T 403). CEPs extend the Company’s natural gas infrastructure to underserved areas (3T 403).

MNSC testified that the Commission should disallow the inclusion into rate base of \$838,000 in new market attachment capital expenditures for the Mesick-Buckley CEP and \$912,000 for the Peach Ridge CEP, arguing that DTE Gas’s assumptions about subscription rates for these programs were overstated (4T 876). The PFD adopts MNSC’s proposed disallowances (PFD, p 101). The PFD simply agrees with MNSC in finding that DTE Gas’s projections for these projects were “unrealistic and thus unreasonable” (PFD, p 101).

However, the PFD ignores the fact that the Mesick-Buckley project will be constructed as a result of the Commission’s Low Carbon Infrastructure Enhancement and Development grant that was awarded to DTE Gas (3T 362). Under this grant agreement from the State of Michigan, an additional \$5.5 million in New Market Attachments funding will be spent to bring gas to underserved areas (3T 632). The Company’s assumptions that MNSC criticized were part of the Company’s grant application to receive these funds. Further, these projects expand natural gas access into areas that do not currently have natural gas available due to increased demand from homeowners who want to convert from the higher cost of propane to natural gas; thus, these assets will in fact be used and useful for the communities that they will serve (3T 361–62). In short, the funding for these projects has already been allocated, the projects have already been approved, and the assets will be used and useful.

Additionally, the PFD fails to address DTE Gas's argument that MNSC incorrectly calculates customer connections (DTE Gas Initial Brief, p 168). The customer connection data Witness Hopkins relies on in calculating the alleged shortfall in customer connections does not provide an accurate depiction of the total customer count spanning a period of five years (3T 399). Only four of the fifteen projects Witness Hopkins takes issue with have been evaluated over a five-year period, which is the time frame the Company uses for its attachment rate model (3T 399). The remaining eleven projects commenced between 2019 and 2022 (3T 399). Therefore, given the lack of an accurate representation over a five-year period, it is not possible to precisely determine customer connection shortfall, subscription level, or typical attachment rate (3T 399). The PFD fails to consider the Company's evidence on this issue, much less reconcile how the MNSC's disallowance is reasonable given this incorrect calculation.

Thus, the PFD's finding that DTE's projections for these projects are unrealistic or unreasonable is misplaced, and the Commission should therefore reject the PFD's finding on this point.

D. CAPITAL STRUCTURE AND RATE OF RETURN

1. Test Year Capital Structure

DTE Gas requested a capital structure consisting of 51.5% equity and 48.5% long-term debt (4T 2188). The PFD finds that DTE Gas has not established that its requested capital structure is reasonable and consistent with prior Commission orders or that deviating from a capital structure evenly balanced between debt and equity is appropriate (PFD, p 124). The Company disagrees and takes exception.

The PFD incorrectly assumes that a "balanced capital structure" must be an exact and even 50/50 split between debt and equity and mischaracterizes the Commission's prior directives

involving Consumers Energy Company (Consumers Energy) and the Company's request in this case (*See* PFD, pp 124–25). First, this is DTE Gas's rate case, not Consumers Energy's rate case. It is inappropriate for the PFD to treat a string of cases for a different utility as mandatory and binding precedent on the outcome in this case as each utility is different, and the merits of its own financial health should guide the recommendations for the appropriate capital structure.⁵ In fact, the PFD agrees with this when it states that “the balance the Commission desires in determining an appropriate capital structure is that between the risks and costs of investor and debt funding *for the utility at issue* (PFD, p 127) (emphasis added).

Regardless, the Commission's prior recognition that a “financially healthy public utility should have a relatively balanced capital structure” does not direct or require an even 50/50 split in capital structure to achieve a *relatively* balanced capital structure (*See Order*, Case No. U-16794 (June 7, 2012), p 44). The Commission's prior orders encourage movement toward a balanced capital structure but reserve the Company's right to advocate for a different ratio (*See id.*). The fact that Staff recommended a capital structure of 51/49 in each of DTE Gas's last two rate cases, including the current case, further supports DTE Gas's argument that a *relative* balance does not require a 50/50 split.

Moreover, movement toward a “more balanced” capital structure should appropriately be taken in steps rather than all at once. In its Order in Case No. U-18999, the Commission approved a capital structure of 52/48 and directed DTE Gas to present a strategy for returning to a balanced capital structure, but did not direct the Company to file a 50/50 capital structure (*Order*, Case No.

⁵ *See Order*, Case No. U-20816 (October 27, 2022) at 14 (“Further, the Commission does not find it useful to compare DTE Gas's actions and choices to Consumers' actions and choices, [...]. To do so would require the record to contain highly detailed presentations from both companies and an analysis to be performed that would include an exhaustive comparison of the differences and similarities between the two companies and their business practices and choices. Such a presentation and analysis is neither required by statute nor practicable.”).

U-18999 (September 13, 2018), at 41). In its Order in Case No. U-20940, the Commission approved the ALJ's recommendation, finding that a capital structure of 51% equity and 49% debt is a reasonable transition to a more balanced capital structure (*Order*, Case No. 20940 (Dec. 9, 2021), at 77).

As emphasized throughout this proceeding, DTE Gas supports the Commission's desires for a relatively balanced capital structure. However, given the high interest rates in the market and the Company's short-term debt, it would be unwise and unreasonable to lower the Company's capital structure to less than 51% equity, as recommended by the AG and ABATE. DTE Gas has a proportionally larger short-term debt balance to meet its seasonal gas purchases, which adds a greater burden to its credit metrics than its peer utilities (4T 2197–98). In addition, DTE Gas will be financing and funding approximately \$1.8 billion of capital expenditures for the period of January 2023 through September 2025 (*See* 4T 1898, 2200). It is imperative for DTE Gas (separate and apart from DTE Electric) to be viewed as financially sound with an investment grade rating to ensure access to competitive capital costs on reasonable terms during a period of significant capital investment (4T 2200). The Company's requested equity ratio for the test year will enable the Company to maintain its credit ratings and help withstand any unforeseen shocks in the financial markets, thereby facilitating a smooth implementation of its critical, safety-driven capital expenditure program (4T 2200). The PFD fails to consider the impact of any of these factors on the Company's financial risk. The Commission must holistically and specifically consider the Company's financial risk in determining the approved capital structure. Once appropriately adjusted for the Company's financial risk, the capital structure recommendations of Staff, AG, and ABATE would be consistent with and supportive of DTE Gas's 10.25% ROE at 51.5% equity (4T 2562).

Finally, the PFD fails to acknowledge that a decrease in the requested 51.5% equity capital structure will require a corresponding increase in ROE to ensure a fair, risk adjusted return and maintain the Company's financial health. Reducing the capital structure without increasing the ROE will subject the Company to increased credit risk and jeopardize its financial health. In sum, DTE Gas takes exception to the PFD's 50% equity and 50% debt recommendation for its failure to appropriately discuss, consider, or incorporate the Company's financial risks into its capital structure determination.

2. Return on Common Equity

The PFD's 9.4% return on equity (ROE) recommendation is unsupported and is significantly lower than the recommendations of four of the five parties that provided expert witness testimony on this issue. As such, the PFD's recommended ROE does not comport with the evidence in the case, and no party has provided sufficient evidence or justification that DTE Gas should be penalized with such an ROE.

The PFD reviews each of the models used by party experts in estimating the appropriate ROE for the Company in this case (PFD 135–97). The ALJ then opines on whether the results of each model should be considered (*Id.* at 197–227). However, the ALJ's reasoning for ignoring certain models (e.g., the Risk Premium Model) and approaches is flawed. First, although it may be persuasive whether FERC endorses a particular model, it is not a requirement for this Commission or the parties advocating before it to restrict their recommendations to only those from FERC. Second, as acknowledged by the PFD, FERC determined in Opinion 569-A that it is appropriate to use the Risk Premium model to estimate a reasonable ROE (PFD at 209). If reliance on FERC's approved models is a signal for its appropriateness in Michigan, it is inappropriate for the ALJ to dismiss the use of the Risk Premium model as one of many used in support of the

recommendations in this case simply by preference. Further, the PFD makes a conclusory and unsupported statement that the regression-derived Risk Premium estimate used by DTE Gas is inflated and should not be considered (PFD at 209). However, the regression-derived Risk Premium approach used by the Company is the same Risk Premium method approved by FERC in Order No. 569-A. If weight is to be given to the FERC-approved models, the approved methods for conducting those models should also remain within the Commission's consideration, rather than being summarily dismissed (*See* 4T 2582).

The PFD lists the average ROEs determined by the parties based on the limited models accepted by the ALJ to determine a range of ROEs from 9.0–10.5% with an average of 9.5% (PFD 210–211). Notably, the PFD's 9.4% recommendation is not only below the average of this range but also lower than the midpoint of the ALJ's range (9.75%) and lower than the recommendations of every other party in the case. The Company requested an ROE of 10.25%, whereas Staff, the AG, and ABATE all recommended 9.8%, 9.85%, and 9.45%, respectively. Even the Citizens' Utility Board's (CUB) witness recommended an ROE of 9.46%, which is higher than the PFD's recommendation.

The PFD's initial proposed ROE of 8.0–8.5% ignores the entire record in this case and is so low as to be confiscatory. To allegedly gradually introduce such a drastic change, the PFD suggests that an ROE of 9.4% is an appropriate step in this case. However, the PFD's recommendation is untethered from the evidence in this case and is wholly unsupported by DTE, Staff, the AG, ABATE, and CUB's recommendations. There is no support in this case, or in ratemaking generally, for a 50-basis point reduction to a gas utility's ROE to purely "move towards the range of general market returns" (PFD at 226). Notably, general market returns is not the appropriate standard or benchmark for establishing a utility ROE. Rather, the *Hope* and *Bluefield*

standards, which have governed utility rate setting for decades, provide that the ROE should “be commensurate with returns on investments in other enterprises having corresponding risks.”⁶ The PFD’s discussion on this issue is unreasonable and inconsistent with not only *Hope* and *Bluefield*, but also this Commission’s longstanding ratemaking precedent.

Further, while reasonable experts may disagree, it is a mischaracterization to classify the Company’s requested 10.25% ROE as excessive when it reasonably falls within the ALJ’s narrowed ROE range. Moreover, the high end of the ALJ’s range is based on the AG’s ROE analysis, not the Company’s, which eliminates any allegation of a Company-calculated outlier upwardly biasing the result (4T 2579 (discussing rebuttal of ABATE Witness Walters’ accusation of removing low-end results and not high-end outliers)). DTE Gas agrees with the PFD’s reiteration that the Commission has stated that “the determination of a fair and reasonable ROE is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved” (PFD at 135 (punctuation omitted)). However, this rationale seems to be lacking from the PFD’s ROE and is instead replaced with one never seen before in Michigan.

The PFD appears to validate the appropriateness of considering the comparable average ROEs awarded to gas utilities by state commissions and affords deference to those averages cited by Staff, AG, and ABATE through 2023 (PFD at 211–12). Dr. Villadsen cited the increase of the average allowed ROE to 9.9% in 2024; however, the PFD dismisses the 2024 average ROEs cited

⁶ *Federal Power Comm. v. Hope Nat. Gas Co.*, 320 U.S. 591, 603, 64 S. Ct. 281, 88 L.Ed. 333 (1944); see also *Bluefield Water Works Co. v. Pub. Serv. Comm. of W. Va.*, 262 U.S. 679, 692, 43 S. Ct. 675, 67 L.Ed. 1176 (1923) (“A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties . . .”).

by Dr. Villadsen and indicates that the Company “does not provide information regarding the dates of the rate orders, the name and location (state) of the utility, and the specific rates which make up the asserted average, with which the other parties [and] this ALJ [...] can assess whether there are any outliers which might by unduly be influencing the average” (PFD at 212).

The Company disagrees. As mentioned, Dr. Villadsen cites to a general increase in allowed ROE across the country, illustrated by a graphic with data from the S&P Global Capital IQ (4T 2590).⁷ Similarly, ABATE Witness Walters relies upon the S&P Global Market Intelligence in creating his Figure CCW-1 (4T 1338). Yet Walters neglects to include what only DTE is penalized for here—lack of “dates of the rate orders, the name and location (state) of the utility, and the specific rates” Yet the PFD points to ABATE’s summary of ROEs in the PFD’s analysis as “consistent evidence of recently authorized ROEs for gas utilities rendered by other state commissions across the country” (PFD at 211). Given that ABATE and DTE Gas both supplied summaries of recent authorized ROEs from S&P data in similar form, one cannot be found to be lacking when the other is “consistent evidence” to be relied upon.

Additionally, there are flaws in the averages themselves that the PFD relies upon. ABATE Witness Walters’ analysis misses the mark by failing to recognize in his testimony the easing and tightening by the Federal Reserve, which has shown an uptick in allowed ROEs for utilities since about 2020 (4T 2588).

Therefore, the most recent average allowed ROEs for 2024 provided by Dr. Villadsen should not be ignored, and DTE strongly disagrees with the claim that this data is unsupported.

⁷ Of note, the raw data supporting Dr. Villadsen’s illustrated graphic was available to the ALJ and interested parties, none of whom requested any additional information via discovery.

The PFD erroneously and unilaterally disregards the average ROEs awarded to gas utilities in the present year, as presented in the record only by DTE Gas.

In an odd discourse, the PFD overly emphasizes CUB Witness Bandyk's references "evidence" from market observers indicating that state commission-authorized ROEs are on average too high and higher than the market-based rates for utilities (electric and gas) in the United States (PFD at 182–83). The ALJ seemingly agrees with the articles' argument that, because investment in regulated utilities is less risky than other businesses, regulated utilities are only entitled to returns that are lower than those earned by other businesses in the general market (PFD at 215). However, this argument is misguided given both the capital-intensive nature of public utilities and the obligation to serve that is embedded in the regulatory compact. Reliance on such a premise infers that commissions, including the Michigan Public Service Commission, have consistently made the wrong determination. Further, these "market observations" are not credible or applicable to the case at hand. For example, the article provided in CUB-Exhibit 5 is akin to a blog post written by an attorney in 2016 who has not been qualified as an expert, contrary to the claim by CUB Witness Bandyk. It would be inappropriate for the Commission to rely on stale, inexpert opinion as if it were credible "evidence." Such market observations rely on limited academic research that does not take into consideration a utility's unique business risks and outright ignores the record evidence presented by DTE, Staff, the AG, and ABATE.

For all of these reasons, the Commission should reject the PFD's recommended ROE.

3. Long-Term Debt Balance

The PFD found that the long-term debt balance "should coincide with the allocation of the total permanent capital of \$5.5 billion to 50% long-term debt and 50% common equity" and adopted the AG's long-term debt balance (PFD at 132). DTE Gas takes exception to the PFD's

adoption of the AG's long term debt balance and modification of the Company's requested capital structure and ROE, as described and defended above. Therefore, the Company advocates for the reinstatement of its proposed long term debt balance and overall rate of return as calculated based on an ROE of 10.25% with a capital structure of 51.5% equity and 48.5% debt.

E. DTE GAS'S ADJUSTED NET OPERATING INCOME SHOULD BE ADOPTED

DTE Gas projected its adjusted Net Operating Income to be \$225,913,000 in the projected test year (DTE Gas Initial Brief Attachment A, p 3, line 29, column d). The PFD recommends \$311,133,000 (PFD Appendix A, line 2). DTE Gas takes exception to this and other matters as discussed below.

1. Throughput

a. Sales Forecast

The PFD recommends that the Commission adopt Staff's recommended disallowance of \$39,478,000 pertaining to total projected operating revenue resulting from changes in the jurisdictional average cost of gas (PFD, p 235). This increase in revenues is directly offset by an adjustment to cost of gas sold for the same amount. Therefore, there is no impact to the Company's revenue deficiency. DTE did not rebut this recommendation and does not take exception to it here.

The PFD also "agrees with the AG and MNSC, finding that DTE has significantly underestimated the gas sales volume for residential and commercial customers and the related test year revenue" (PFD, p 240). The PFD finds that the AG "has adequately supported her assertion that the incremental forecasted revenue for the projected test year is \$8,290,000" and therefore recommends that the Commission adopted the AG's forecasted revenue projection (PFD, p 240.). DTE Gas takes exception to these findings as they are incorrect.

First, the PFD states that it agrees, in part, with MNSC on the sales forecast issue. Yet the PFD completely misses the mark on MNSC's stance on this issue. The PFD cites to MNSC in support for the notion that DTE Gas has "significantly underestimated the gas sales volume for residential and commercial customers and the related test year revenue" (PFD, p 240). But, as noted in the PFD's discussion of MNSC's positions, MNSC states that DTE's demand forecast "does not fully reflect potential future changes in gas demand *and is therefore likely to be too high*" (4T 850 (emphasis added); *see also* PFD, p 239), the opposite of underestimation. The PFD also cites to MNSC's testimony describing how DTE's forecasts of proactive conversions "is inadequate to fully capture the current market trend, because adoption of electric heating has been increasing considerably over the past several years" (4T 851; *see also* PFD, p 239).

In short, everything that MNSC discussed, both as recounted in the PFD and in the record itself, indicated MNSC's support for *lower* sales—or that DTE Gas has *overestimated*, not underestimated, its sales forecast. In fact, MNSC testified about the implications of a load forecast that is too high (*See* 4T 854 (asking MNSC Witness Hopkins "What are the implications of a load forecast that is too high?")). Notwithstanding this record evidence, the PFD curiously concludes that MNSC thinks DTE gas has "significantly *underestimated* gas sales volumes" (PFD, p 240) (emphasis added). In plain terms, the PFD's analysis is contrary to the record and the Commission should view the PFD's analysis on this issue—and perhaps other issues highlighted in these Exceptions—with extreme skepticism.

Notwithstanding the above, the PFD's adoption of the AG's position on this issue is flawed, as the AG's position is contradictory and ignores evidence in the record. The AG used the years 2018–2023 to derive an average annual rate of decline in sales, and then applied the actual five-

year percentage decline trend to DTE’s actual weather-normalized sales per customer for 2023 (4T 1518). This is problematic for three reasons.

First, customer usage changed dramatically during a once-in-a-lifetime event—the COVID-19 pandemic. DTE Gas asserts that the use of *any* period of time spanning the COVID-19 pandemic is problematic from an analytical standpoint and will produce skewed results (2T 231). Additionally, the selection of these specific years, whether influenced by the COVID-19 pandemic or not, is completely arbitrary (2T 232). In contrast, the years selected by DTE Gas—2021 through 2023—is a period of time that is post-COVID-19, so DTE Gas’s analysis removes the COVID-19 pandemic. Additionally, DTE Gas consistently uses the twenty-four months prior as the timeframe in which to inform the analysis, an approach routinely approved by the Commission (2T 221).

Second, the AG criticized DTE Gas’s selected historical gas usage period as “concerning,” citing in part the “lingering effect” of the COVID-19 pandemic on customer gas usage (4T 1517). But DTE Gas presented concrete and specific data demonstrating that customer behavior had largely rebounded from the COVID-19 pandemic by August 2021 (2T 218). This was a reasonable basis from which DTE Gas could have projected demand. In contrast, the AG has presented no evidence that demand will rebound to pre-COVID-19 pandemic levels, so the AG’s analysis, which assumes pre-COVID-19 levels of customer usage, would be speculative. The irony of the AG’s “concern” over the “lingering” effects of the COVID-19 pandemic is that the AG’s own analysis uses information from during the COVID-19 pandemic. Thus, even if DTE’s analysis was impacted by the “lingering effect” of the COVID-19 pandemic, the AG’s analysis is based on information that was also severely impacted and distorted by the COVID-19 pandemic.

Third, the AG’s proposal to “apply the actual five-year percentage decline trend” attempts to represent the net effect of sales losses from Energy Waste Reduction (EWR) (4T 1518). In other words, the AG seeks to simulate changes in customer gas usage over a longer period of time than just two years (4T 1518). This approach would be improved by using actual EWR rates, ideally ones that were approved by the Commission.

DTE Gas did exactly this. The Company applied EWR factors approved by this Commission in Case No. U-21322 as part of its analysis in forecasting demand (2T 214). The AG criticized DTE Gas’s EWR factors, claiming that “the 1% EWR loss rate does not appear realistic” (4T 1516). DTE Gas referred Witness Coppola to the information provided in Case No. U-21322, in which all EWR factors were presented, litigated, and ultimately approved by this Commission (*See* 2T 233). But even if DTE Gas had not done so, the AG was a party to that case and settlement—the AG therefore should be well-versed in the events of that proceeding, including its outcome. Witness Coppola’s failure to review the pertinent information from that proceeding is not something that DTE Gas should need to account for in this case.

Ultimately, the PFD adopts the AG’s flawed and contradictory analysis, alleging that DTE Gas failed to explain changes in customer usage (PFD, p 240). But as demonstrated above, DTE Gas did explain these changes on the record, and the PFD simply adopted the AG’s position without considering the evidence. The Commission should therefore reject the PFD’s findings on this issue and adopt DTE’s position instead.

b. End-Use Transportation

DTE Gas had 539 EUT customers and 146.6 Bcf of volume in the 2022 historical test year (2T 46; Exhibit A-15, Schedules E6 and E7). DTE Gas forecasts 545 customers and 150.7 Bcf in the projected test year (2T 46; Exhibit A-15, Schedules E6 and E7). DTE Gas had \$121.9 million

of total EUT revenue in 2022, and projects \$122.8 million (at current rates) of total EUT revenue in the projected test year (2T 52; Exhibit A-13, Schedule C3.2, line 23, columns (b) and (c)).

The AG proposed to increase EUT volumes by 2.6 Bcf, to 64.1 Bcf, based on a five-year average period ending March 2024 (AG Initial Brief, p 82). The AG argued that the Company's use of a historical five-year average period ending August 2023 should be altered to include the latest gas delivery information as of March 2024 (AG Initial Brief, p 82). Accordingly, the AG recommended that the Company's forecasted EUT revenue be increased by \$503,000 (AG Initial Brief, p 84).

The PFD agrees with the AG, finding that the updated five-year average of gas deliveries should be used "as that average is based on the most recent historical information" (PFD, p 248). The PFD claims that the Company's argument that the historical five-year average methodology was adopted in Case No. U-20940 was "misleading" because the issue in Case No. U-20940 was not whether an as-filed five-year average was preferred over an updated five-year average, but rather whether a five-year or a three-year average was preferred (PFD, p 248).

The Company disagrees. The Company's methodology for forecasting EUT power generating volumes is consistent with prior practice and avoids arbitrary time selection. The Company's EUT forecast was created using the most recent data available when the instant case was filed. Given that the Company is not afforded an opportunity to update EUT volumes after filing, the Company's EUT forecast was created using the most recent twelve months of data available when this case was prepared, adjusted for known and measurable changes. Regardless of the methodologies advanced by the parties in Case No. U-20940, the fact remains that the Company's historical five-year average approach to forecasting EUT sales was adopted by the Commission in several of the Company's previous rate cases, including the most recent rate case

proceeding (*Order*, Case No. U-20940 (December 9, 2021), p 108; *Order*, Case No. U-18999 (September 13, 2018), p 62). As such, contrary to the PFD’s claim otherwise, the Company’s argument is not “misleading.”

Additionally, using a five-year historical average of deliveries to power plants is the most reasonable way to project test year gas use. As the Company has emphasized throughout this proceeding, gas deliveries to generation plants are extremely variable due to gas prices, other area plant outages, and/or weather (DTE Initial Brief, p 88; 2T 121). In Case No. U-18999, the Commission agreed that the Company’s five-year historical period best represents the Company’s use because it “captures the range of variations in generation customer volume, which can change with weather, gas prices, and power plant outages” (*Order*, Case No. U-18999 (September 13, 2018), p 62). In contrast, the AG proposed to selectively update the time period that best suited its position. Therefore, the PFD’s proposal to calculate EUT power generating volumes using an updated five-year average should be rejected.

2. Midstream Revenue

DTE Gas realizes Midstream revenue from selling storage and transportation services to off-system customers.⁸ These sales maximize the utilization of DTE Gas’s rate base assets and help mitigate rate increases (2T 53). DTE Gas projects \$111.6 million of Midstream revenue, consisting of \$38.5 million of storage revenue and \$73.2 million of transportation revenue (2T 54–55). The Company’s proposed \$73.2 million of transportation revenue consists of \$60.4 million in Off-System Transportation revenue and \$12.8 million in Exchange revenue (2T 62; Exhibit A-13, Schedule C3.3, lines 6, 7, and 8, column (d)).

⁸ An off-system customer transports gas through the DTE Gas storage and transmission system from a specified receipt point to an off-system delivery point. These customers ultimately consume gas outside the DTE Gas service territory, in contrast to GCR, GCC and EUT customers (2T 53).

The AG proposed to increase Midstream revenue by \$6,230,000 based on two adjustments (AG Initial Brief, pp 85–87). First, the AG increased Off-System Transportation revenue by \$3,398,000 based on an average of the most recent three-years of actual revenues (AG Initial Brief, p 85). The Company disagreed because it is inappropriate to use historical averages to forecast Off-System Transportation revenue because taking an average of prior years’ revenue includes transportation capacity that is no longer available for sale (DTE Gas Initial Brief, p 90). Instead, the Company properly calculated Off-System Transportation revenue by adding revenue already under contract to the estimated revenue for assets available for sale (DTE Gas Initial Brief, p 90).

Second, the AG increased Exchange services revenue by \$2,832,000 based on a three-year average ending in 2023 (AG Initial Brief, p 85). While historical averages are appropriate for calculating Exchange services revenue, the appropriate methodology, as used in Case Nos. U-20940 and U-20642, is to use the historical test period (i.e., 2022) as the last year in the average (DTE Gas Initial Brief, p 90).

The PFD agrees with the Company’s approach to calculating Off-System Transportation revenue but finds the AG’s method for calculating Exchange services revenue to be “more reliable” since it uses “more recent information [and] excludes an anomalous year (2020) adversely affected by COVID” (PFD, p 255).

The Company agrees that using a three-year average for projecting Off-System Transportation revenue is inappropriate but takes exception to the PFD’s finding regarding the calculation of Exchange services revenue. As indicated above, the Company used the same methods of calculating forecasts in this case as it used in its last three rate case proceedings in Case Nos. U-20940, U-20642, and U-18999 (2T 124). This was, and is, a workable, accepted, consistent, and otherwise appropriate practice. In contrast, the AG inappropriately mixed two methodologies,

selectively choosing the one that produced the highest result in each category (DTE Gas Initial Brief, p 90). Specifically, the AG used, and the PFD adopts, a three-year average from 2021 to 2023 instead of the Company's three-year average from 2020 to 2022, claiming that the more recent data avoids any negative impact from the COVID-19 pandemic (AG Initial Brief, p 86). In contrast, the AG accepted the Company's forecast for Midstream Park and Loan services, which is higher than the result would be if the AG used his own methodology (DTE Gas Initial Brief, p 90, n 25). Therefore, the AG's shifting methodology, which changes by category to capture the most revenue, is inappropriate, and the PFD's resulting calculations should be rejected as unlawful and unreasonable (DTE Gas Initial Brief, p 90).

3. Other Operating Revenue - Home Protection Plus Appliance Service Program

The Home Protection Plus (HPP) Appliance Service Program provides appliance repair services performed by DTE Gas field service employees and selected vendors pursuant to a one-year service agreement between DTE and residential customers (2T 82). The revenues with these programs in the projected test year are included as a reduction in the overall cost of service to customers (2T 83). To determine costs related to this program, the AG proposes to use the 2023 revenue and operating expenses associated with the program (4T 1524). The PFD agrees with the AG, reasoning that "DTE has failed to support a reasoned opposition to using the 2023 revenue and operating expenses" (PFD, p 257).

The Company disagrees and takes exception. As evidenced by the testimony of DTE Witness Decker, the HPP Appliance Service Program is subject to intense competition in the marketplace, and average contract amounts have decreased between 2022 and 2023 (2T 126). The PFD acknowledges this fact but fails to acknowledge its significance—namely, that the decrease in average contracts demonstrates the level of uncertainty associated with this business, and that

the HPP Appliance Service Program is an optional cost from a customer perspective (2T 126). Further, weather plays a significant role in the operating expenses associated with this program, as lower cooling degree days and heating degree days in any given year can decrease the cycling and overall usage of appliances and thus decrease required repairs (2T 126). Because of these factors, 2022 is a more accurate representation of a normal operating year for the HPP Appliance Service Program and is therefore more reasonable and prudent to use in calculating HPP Appliance Service Program costs and revenues (2T 126). The PFD inappropriately adopts the AG's position simply because those values are lower, without any consideration as to whether this is an accurate or reflective year of costs to use.

Moreover, the PFD entirely ignores the Company's alternative proposal to use a three-year average of the profit margin percentage (against revenue for the corresponding year) and apply this percentage to the most recent available full year revenue actual (2T 126). This methodology would smooth yearly variations in the components that make up profit margin and is consistent with other forecasted components of the Company's filing (2T 126). The PFD fails to provide any rationale as to why such an alternative method is unreasonable or inappropriate. Accordingly, the Commission should reject the PFD's adoption of 2023 revenues and operating expenses and instead adopt DTE Gas's use of 2022 revenues and operating expenses.

4. Operating and Maintenance Expenses

DTE Gas supports \$535,621,000 of O&M expenses (DTE Gas Initial Brief, Attachment A, page 3, line 8, column (d)). The PFD indicates a recommendation of \$454,410,000 (PFD, Appendix C, line 36, column (h)).⁹

⁹ Note, however, that the PFD's recommended O&M expense reflects calculation errors. As corrected, the PFD's recommended O&M expense is \$459,462,000 (DTE Gas Exceptions, Attachment A, page 3, line 8, column (e)).

a. 2023 O&M Expense Reductions

The major categories of O&M expense, as reflected on Exhibit A-13, Schedule C5, are Natural Gas Storage; Transmission; Distribution; Customer Service; Marketing; Administrative and General (A&G); and Pensions and Benefits. The Company requested:

- \$15.2 million for Natural Gas Storage (4T 1999; Exhibit A-13, Schedule C5.1, line 22, column (l));
- \$89.7 million for Transmission (4T 1999; Exhibit A-13, Schedule C5.2, line 22, column (l));
- \$141.9 million for Distribution (4T 1999; Exhibit A-13, Schedule C5.3, line 22, column (l));
- \$62.3 million for Customer Service (4T 1999; Exhibit A-13, Schedule C5.4, line 17, column (l));
- \$57.0 million for Marketing (4T 1999; Exhibit A-13, Schedule C5.5, line 7, column (l));
- \$128.9 million for A&G (4T 1999; Exhibit A-13, Schedule C5.6, page 1, line 20, column (l); and
- \$43.1 million for Pension and Benefits (4T 1999; Exhibit A-13, Schedule C5.9, line 31, column (d)).

The AG recommended a total disallowance of \$22,431,000 from DTE Gas's projected test year O&M expense for these seven O&M categories (Exhibit AG-45, line 8, column (f)). The AG argued that DTE Gas provided actual 2023 O&M expense information with significant cost savings achieved (AG Initial Brief, pp 96–98). Specifically, the AG claimed that the Company took a number of measures to reduce 2023 costs in light of financial challenges at both DTE Gas and DTE Electric that resulted in lower O&M expenses (AG Initial Brief, pp 96–98). As such, the

AG asserted that DTE Gas's projected test year O&M expense was not reasonable and was overstated by \$22,431,000 (AG Initial Brief, p 98). The AG calculated its \$22,431,000 recommended disallowance by comparing the 2023 actual O&M expenses to the 2022 actual O&M expenses, as adjusted for inflation, and recommended the disallowance of the difference (Exhibit AG-45, line 8, column (f)).

The PFD agrees with the AG, explaining:

Recognizing the known and measurable cost savings that DTE undertook (as normalized by DTE which included \$57.7 million of cost add-backs for temporary cost reductions) is appropriate in formulating projected test year expenses. Moreover, contrary to DTE's assertion, the Attorney General's proposed disallowance includes specific expense savings from all seven categories of DTE's O&M expenses.

(PFD, pp 268–69) (footnotes omitted).

However, the PFD agrees with the Company that the AG's recommended disallowance needed to be adjusted to remove \$1,755,000 for the Company's Washington 10 contract expiration and \$3,297,000 for Customer Service O&M expenses that were already reflected in the test year (PFD, p 269). Accordingly, as adjusted, the PFD adopts the AG's proposed disallowance of \$17,379,000 (PFD, p 269).

The Company disagrees with the \$17,379,000 disallowance. First, the AG's methodology is flawed and should therefore not be adopted. The AG's proposal to reset O&M using historical 2023 actuals violates the regulatory construct of using a historical test year as adjusted for known and measurable changes (4T 2048). Updating for just one item is simplistic and ignores other changes that may have occurred (DTE Gas Initial Brief, p 95).

For these reasons, the PFD's proposed disallowance should be rejected.

b. Inflation

The Company used a 2022 historical test year and assumed inflation rates of 3.2% in 2023, 2.9% in 2024, and 2.2% in 2025 (Exhibit A-13, Schedule C-5, columns (g) through (i)). The Company then calculated a composite inflation rate based on a labor factor and a non-labor factor (4T 2315). The composite labor component factor is 3% and consists of rates for represented employees and non-represented employees (DTE Gas Initial Brief, p 92). For represented employees, the Company is obligated under existing Collective Bargaining Agreements to increase pay rates by at least 3% annually through the term of the contracts (4T 2634–35). Non-represented employees also generally received an overall pay increase of 3%, based largely on pay practices of other employers, changes in the external competitive market, and internal pay equity (4T 2635). For non-labor costs, the inflation rate is based on a consumer price index (CPI)-Urban from IHS Markit in August 2023 (4T 2315). These labor-and non-labor rates were then used to calculate a composite inflation rate for 2023, 2024, and a nine-month proration for 2025 (4T 2315).

The AG applied different inflation rates using 2.6% for 2024 and 2.2% for nine months of 2025 (AG Initial Brief, p 12). The AG disagreed with the use of a blended rate and instead proposed that the Commission use CPI-Urban area inflation rates to forecast future costs (AG Initial Brief, p 98). As a result, the AG recommended removal of approximately \$4 million from forecasted O&M expense for the projected test year (AG Initial Brief, p 98).

The PFD agrees with the AG, stating:

[T]he Attorney General’s proposed adjustments are reasonable and supported. This PFD notes that the Commission customarily applies that CPI-Urban inflation rate used by the Attorney General and that the Commission does not support DTE’s use of a blended inflation rate . . . Thus, this PFD recommends that the Commission adopt the Attorney General’s proposed disallowance of \$4,001,000.

(PFD, p 266) (footnote omitted).

The Company disagrees. First, the Company fully supported the calculation of a weighted average composite inflation rate (4T 1873). Second, the Company's projected O&M expenditures in the test period were developed at a point in time (4T 1873). Therefore, it is inappropriate, as the AG suggests, to selectively update the non-labor inflation rate for the test period without also accounting for an updated labor rate for the test period (4T 1873). Moreover, the non-labor rates used by the AG are already outdated and have since increased for those respective time periods (4T 1873; Exhibit A-34, Schedule X-1).

The PFD also fails to consider the Company's rebuttal testimony revising the Company's inflation rates (4T 1873). Specifically, Witness Telang explained that, should the Commission choose to incorporate an updated non-labor inflation rate to calculate projected test period O&M expenses, it would be appropriate to use the most recent CPI-U rate and updated labor rates (4T 1873). As such, Witness Uzenski provided updated inflation factors using labor rates supported by Witness Cooper and CPI-U rates as of April 2024 (Exhibit A-34, Schedule X1). Therefore, the PFD's disallowance should be rejected.

c. Transmission Integrity Management Program

The TIMP is a federally mandated program (49 CFR, part 192, subpart O) to identify and mitigate risks to transmission pipeline systems (DTE Gas Initial Brief, p 95). The Company forecasts \$23 million of TIMP Pipeline Integrity (TIMP PI) expenses for the projected test year (DTE Gas Initial Brief, p 95).

The AG recommended a disallowance of \$6.7 million, the Company's requested expense increase from the 2022 historical test year, from the projected test year (AG Initial Brief, pp 98–100). The PFD agrees with the AG, stating:

While the amount of remediation work is difficult to predict, historical costs do provide insight as to appropriate future expenditures. Moreover, DTE has not

rebutted the Attorney General's assertion that DTE has steadily reduced pipeline inspection costs since 2021 with the number of inspections also dropping since 2021. In addition, this PFD notes that DTE started using the ILI Expansion program in 2012, such that the history of work under the program is not so limited as to be unreliable for comparison purposes. Thus, this PFD recommends that the Commission adopt the Attorney General's proposed disallowance.

(PFD, p 272)

The Company disagrees because regulations require operators to assess pipelines generally every seven years, and there are several factors that cause expenses to vary from year to year for assessments and remediation, including: (1) the number of pipelines being assessed based on assessment requirements for those pipelines; (2) the Company is increasing the number of pipelines being assessed due to the In Line Inspection (ILI) Expansion program; (3) the length and diameter of the pipelines being assessed; (4) the type of assessment being conducted, either Direct Assessment (DA) or ILI; (5) the type and number of tools utilized to perform the assessment (DTE Gas Initial Brief, p 96). The AG's proposed use of a historical average is also inappropriate to predict the amount and type of remediation, which is based on the assessments, and a significant expense for TIMP PI (DTE Gas Initial Brief, p 96). Considering the forecasted work that is planned to meet the federal regulations for the projected test year, the AG's proposed disallowance should be rejected.

d. Leak Detection and Repair

DTE Gas included costs related to compliance with the pending NOPR in O&M. Specifically, from January 1, 2023, through September 30, 2025, DTE Gas will have incurred \$10.3 million of LDAR O&M costs (4T 2040; Exhibit A-27). The \$10.3 million in LDAR O&M costs consists of: (1) \$7.5 million in leak grading and repair costs; (2) \$0.3 million in patrols and leak survey costs; (3) \$0.2 million in advance leak detection program costs; (4) \$2.0 million in pressure relief device costs; and (5) \$0.3 million in training costs (4T 2039). Additionally, over the

three-year period of 2025–2027, DTE Gas expects to spend \$44.79 million in LDAR O&M costs, consisting of \$17.72 million in 2025, \$13.53 million in 2026, and \$13.53 million in 2027 (4T 2040). Recognizing, however, that the NOPR is not yet final, if the Commission removes LDAR costs from the rate case, the Company alternatively requested that a regulatory deferral mechanism be implemented for recovery of these costs.

The AG and Staff disputed the Company’s LDAR O&M expenses, arguing that recovery of LDAR O&M expenses was premature given that the NOPR is not yet final (4T 1538–1539, 1792–1793). Therefore, the AG and Staff witnesses recommended that the Commission reject the Company’s requested approximately \$10.3 million in LDAR O&M expenses (4T 1538–39, 1792–93). However, Staff supported the Company’s alternative request for a regulatory deferral mechanism for LDAR O&M costs if the Commission did not support recovery of LDAR costs (4T 1793).

The PFD agrees with the AG and Staff that the Company’s LDAR O&M expenses are “premature and should not be recovered until such a time that the final LDAR rule is published, and the actual effective date is known” (PFD, p 276). Thus, the PFD recommends that the Commission adopt the AG’s proposed disallowance (PFD, p 276).¹⁰ However, the PFD agrees with the Company and Staff that the Commission should approve a regulatory deferral mechanism for recovery of these costs (PFD, p 276).

The Company takes exception to the PFD’s disallowance of approximately \$10.3 million in LDAR O&M expenses but does not dispute the alternative recommendation that the

¹⁰ The PFD recommends that the Commission adopt the AG’s “proposed \$20,276,000 disallowance” (PFD, p 276). However, the correct amount of the AG’s proposed disallowance is \$10,276,000 (4T 1448). Given that the \$10,276,000 adjustment is reflected in Appendix C to the PFD, the “proposed \$20,276,000 disallowance” appears to be a typographical error in the body of the PFD.

Commission approve a regulatory deferral mechanism for recovery of these costs. While the NOPR is not yet final, it is expected to go into effect during the projected test period—currently estimated for March 1, 2025 (Initial Brief, p 100). Therefore, the PFD’s recommended disallowance of \$10,276,000 should be rejected.

e. Administrative and General Expenses – Corporate Memberships

DTE Gas supports \$126.3 million in administrative and general O&M expense during the projected test period (DTE Gas Initial Brief, p 101). This includes approximately \$1.8 million in corporate membership dues under Miscellaneous General Expenses (2T 140; Exhibit A-34, Schedule X3, lines 1–14, column (d)). Of the approximately \$1.8 million in corporate membership dues, the top four corporate memberships—the American Gas Association (AGA), Gas Technology Institute-Operations Technology Department (GTI-OTD), Gas Technology Institute-Utilization Technology Development (GTI-UTD), and INGAA—account for \$1.7 million (2T 140).

The Frontline Organizations (FLO) requested that the Commission deny recovery for the Company’s corporate membership expenses, claiming that these memberships are actually harmful to ratepayers (FLO Initial Brief, p 91). The PFD agrees, stating:

This PFD agrees with FLO that DTE’s projected membership dues are problematic. Despite being repeatedly directed by the Commission to provide detailed information of projected costs associated with membership fees and justification for why these costs are in customers’ interests, DTE has failed to do so. As FLO points out, DTE’s cursory direct testimony that its Ex. A-3, Sch. C15 “identifies allowable operating expenses for corporate memberships” is false; that exhibit does not identify expenses for corporate memberships. Nor does any other DTE direct testimony or exhibit do so, let alone explain why the projected costs are in customers’ interests. Moreover, this PFD notes that DTE’s somewhat more detailed exhibit and testimony (referenced above) in support of these projected costs were offered not in its direct case but rather by way of (improper) rebuttal testimony filed after Staff and other intervenors’ testimonies were filed.

In addition, this PFD notes that DTE’s general descriptions of the benefits gained from these memberships indicate apparent overlaps and redundancies among the different memberships, with repeated references to R&D initiatives focused on safety and reliability, and mutual assistance coordination across the industry. Indeed, this PFD notes that an example of the benefit of its participation in the AGA that DTE offers is pipeline safety information sharing between AGA and INGAA (of which DTE is also a member).

(PFD, pp 278–79).

The Company disagrees. First, the PFD mischaracterizes DTE Gas’s obligations concerning membership fees. In claiming that DTE Gas has been “repeatedly directed by the Commission to provide detailed information of projected costs associated with membership fees and justification for why these costs are in customers’ interests,” the PFD cites two DTE Electric rate case orders (PFD, p 279, n. 1538). While the Commission may have directed DTE *Electric* to file an itemized list of projected membership fee costs and a justification for why these costs are in customers’ interests,¹¹ the Commission has not imposed similar obligations on DTE *Gas*. As such, the PFD’s implication that the Company has repeatedly ignored Commission directives is patently false.

Second, in response to FLO’s direct testimony, the Company filed Witness Uzenski’s rebuttal Exhibit A-34, Schedule X3 providing the costs and a description for each corporate membership included in DTE Gas’s O&M expense for the projected test year. The Company’s corporate membership expenses were further supported by Witness Decker’s rebuttal testimony, which provided, among other things, detailed descriptions of the benefits the AGA, GTI-OTD, GTI-UTD, and INGAA memberships provide to DTE Gas and its customers (2T 141–46). The PFD claims that this detailed exhibit and testimony supporting the Company’s requested corporate

¹¹ See *Order*, Case No. U-20836 (November 18, 2022), p 308 (directing DTE Electric “to file in its future rate cases an exhibit containing an itemized list of projected costs associated with membership fees and justification for why these costs are in customers’ interest”).

membership expenses is “improper” because it was filed in the Company’s rebuttal testimony (PFD, p 279). Again, however, the PFD ignores that DTE Gas is under no specific obligation to describe and justify projected costs associated with membership fees. Requiring the Company to provide this much detail for every line item in the rate case would be administratively impossible and unnecessary given that intervenors are permitted to seek discovery on specific items they find important. Moreover, as explained above, DTE Gas provided detailed information on its corporate memberships in response to FLO’s request in its direct testimony that the Company specifically identify, *in its rebuttal testimony*, its corporate membership dues and the organizations to which the Company paid those dues (4T 1019). DTE Gas’s submission of such detailed cost and membership information in its rebuttal testimony is responsive and not “improper.”

Third, the PFD claims that there are “overlaps and redundancies among the different memberships, with repeated references to R&D initiatives focused on safety and reliability, and mutual assistance coordination across the industry” (PFD, p 279). This assertion, however, is unsupported by record evidence and appears to be the PFD’s opinion. Additionally, as explained by Witness Decker, however, the Company’s corporate memberships provide a variety of benefits to ratepayers (2T 141–46). While enhanced safety and reliability, for example, may be ratepayer benefits under a few different corporate memberships, each corporate membership has a distinct purpose and unique combination of ratepayer benefits (2T 141–46). As such, the possibility of overlap between some ratepayer benefits should not be a justification for disallowing corporate membership costs.

Finally, the PFD disregards the Commission’s previous approval of DTE Gas’s request to recover membership dues for both GTI-OTD and GTI-UTD programs (2T 143, 145). Specifically, in Case No. U-20940, the Commission approved the Company’s request to recover \$600,000 per

year for membership dues in the GTI-OTD program (2T 143). Additionally, in Case No. U-18999, the Commission approved the Company's request to include \$350,000 per year for membership dues in the GTI-UTD program (2T 145). In Case No. U-18999, the Commission explicitly found that the GTI-UTD membership expense was "reasonable and prudent[] [and] beneficial to ratepayers" (*Order*, Case No. U-18999 (September 13, 2018), p 96). Accordingly, the PFD's disallowance of \$1,779,000 for corporate membership expense should be rejected.

f. Employee Benefits Expenses

i. Employee Savings Plan

DTE's Employee Savings Plan (ESP) allows eligible employees to participate in a savings matching program (4T 2613–14). Regarding the starting point for calculating ESP expense, DTE Gas witnesses testified that projected ESP expense was developed based on the 2022 expense and escalated using the most recent five-year average, or 8.40% (4T 2614). However, the PFD agrees with Staff that the historic amount for 2022 should not be escalated, and that ESP expense should use 2023 expense amounts along with a five-year average annual growth rate (AAGR) from 2019 to 2023, resulting in a \$1,683,000 disallowance (PFD, p 284–85).

The Company takes exception with this finding as it ignores additional evidence that DTE presented on this issue. The PFD fails to account for the testimony of Witness Uzenski, who testified that the abnormally high proportion of capitalized ESP costs in 2023 is "much lower than the five prior years" (4T 2341). Because the Company is returning to a more standard level of O&M in 2024 and beyond, this abnormally high rate of capitalization is inappropriate. Rather, a better forecast of capitalized benefits would be based on the capitalization rate from 2022 (4T 2341). This evidence, together with the PFD's consideration of Witness Cooper's testimony, demonstrates that DTE Gas's position is more reasonable than Staff's. The Commission should

accordingly reject the PFD's proposal to adopt Staff's position and should instead adopt DTE Gas's ESP expense for the projected test year of \$13.166 million.

ii. Active Healthcare Costs

Active Healthcare expense relates to the competitive package of active healthcare benefits offered by the Company to attract and retain a skilled workforce (4T 2615). These benefits include medical, dental, and vision for active employees, which are projected to increase by \$3.988 million from \$18.053 million in the historic test year to \$22.041 million in the projected test year (4T 2615–16).

The PFD agrees with the suggestion by AG and Staff that “DTE unreasonably inflated its historic 2022 expense basis by using a ‘constant dollar average’ and that this method of historical adjustment has been rejected by the Commission” (PFD, p 289). Accordingly, the PFD recommends that the Commission adopt the AG's proposed disallowance of \$4,884,000 for Active Healthcare costs (PFD, pp 289–90). The PFD's adoption of the AG's projected Active Healthcare Costs reflects the elimination of the Company's constant dollar adjustment, the adoption of the AG's annual escalation assumption of 2.40%, and the use of the Company's actual proportion of total Active Healthcare costs capitalized.

DTE Gas takes exception to this finding as the propriety of adopting either the constant dollar adjustment or the use of historical escalations is wholly lacking. In fact, the PFD merely cites to previous Commission orders where a different calculation method—the AAGR method—is used (PFD, p 289). The PFD fails to address evidence in the record demonstrating the reasonableness of DTE Gas's methods. For example, Witness Cooper testified that the Company's projected trend rates, which are relied upon by DTE Gas in recent years, “have matched the actual national medical trend rates,” demonstrating that the Company's projected trend rates are accurate

predictors of actual medical trends (4T 2628). Witness Cooper also directly refuted the AG's and Staff's use of historical changes as predictors of future use, as these can be "virtually worthless" due to the extreme level of volatility in healthcare costs (4T 2629). Finally, Witness Cooper addressed the flaws in the Commission's reasoning in rejecting the constant dollar adjustment, including the Commission's rationale that the constant dollar adjustment "merely recasts the Company's historical Active Healthcare costs for the impact of historical medical cost escalations," that overall inflation is an inapt measure of historical medical cost escalations, and the inaccurate characterization that normalization of Active Healthcare costs as "the compounding of inflationary pressures" (4T 2624). In short, while the flaws in the Commission's reasoning were addressed in the direct and rebuttal testimony of Witness Cooper, the PFD simply adopts the AG's position on this point.

In addition, the PFD completely ignores the Company's proposed adjustment to the AG's projected Active Healthcare costs to correct for the impact of a one-time reduction in 2023 and the unusually high proportion of Active Healthcare costs capitalized in 2023, as reflected on Exhibit A-29, Schedule S4. Specifically, in 2023, the proportion of total Active Healthcare costs capitalized was abnormally high, which understated the Company's Active Healthcare expense by \$1.283 million (DTE Gas Initial Brief, p 117). Also, in 2023, the Company received a one-time credit from its Pharmacy Benefits Manager that reduced its Active Healthcare expense by \$206,000 (DTE Gas Initial Brief, p 117). The combined effect of these corrections to the AG's projected Active Healthcare expense is to increase the AG's projection by \$1.550 million (4T 2686). While the Company disagrees with the AG's projected Active Healthcare costs as adopted by the PFD, if the Commission is persuaded by the PFD's recommendation, it should at least adopt

the corrections reflected on Exhibit A-29, Schedule S4 and increase Active Healthcare costs by \$1.550 million (4T 2686).

iii. Employee Compensation

Regarding recovery of incentive compensation for operational metrics, the PFD agrees with the AG that DTE should not recover as if it will achieve all operating measures at the 100% target level (PFD, p 300). In support, the PFD cites to the December 9, 2021, Order from Case No. U-20940, which outlined the AG's argument in that case as to why DTE Gas should not recover as if it will achieve all operating measures at the 100% target level (*See Order*, Case No. U-20940 (December 9, 2021), p 163). To that end, the PFD recommends a disallowance of \$2,864,000 (PFD, p 300).

The PFD's analysis on this point fails to account for DTE Gas's arguments outlining the flaws in the AG's approach, which were as present in the U-20940 case as they are in this case. Put simply, there appears to be a misunderstanding in how the operational incentive program works. Certain measures may produce results that are less than Target level, while others may produce results greater than Target (4T 2675). Importantly, even measures that were less than Target can still generate payouts if the actual performance was higher than a given Threshold level. Thus, while payouts vary depending on the outcome, there is nevertheless a wide range of situations where a payout of some kind can occur (4T 2675). The AG's singular focus on whether actual performance was at, above, or below Target level ignores this potential range, which is not only unreasonable but also inconsistent with the very design of these plans (4T 2676). The AG, and in turn, the PFD's analysis, fails to recognize the gradients of performance that are the basis for actual payouts (*See* 4T 2676). The Commission should accordingly reject the PFD's position on this issue and adopt DTE Gas's position instead.

Additionally, regarding savings from the Voluntary Separation Incentive Program (VSIP), the PFD agrees with the AG that cost reductions resulting from the VSIP should be recognized as a reduction to the O&M expense for the projected test year, prorated for the nine months ending September 30, 2025 (PFD, p 302). Accordingly, the PFD recommends that the Commission adopt the AG’s disallowance of \$2.35 million (PFD, p 302). DTE Gas takes exception to this finding and reiterates that this disallowance fails to account for the fact that DTE Gas continues to assess the need to fill key vacated positions (*See* DTE Initial Brief, p 122). Thus, any estimated savings will continue to evolve as positions are filled, and it would be premature to assign VSIP savings of any amount until such savings amounts can be determined with certainty. The PFD also fails to incorporate the impact of \$8 million in corresponding costs incurred by DTE Gas in connection with the VSIP, meaning that the PFD’s recommendation inappropriately accounts for alleged savings without accounting for the corresponding cost to achieve such savings. *See Michigan Consol. Gas. Co.*, 389 Mich. At 633 (“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.”). For all these reasons, the PFD’s finding on this issue fails to account for significant evidence in the record and should be rejected.

5. Uncollectible Expense

To project uncollectible expenses, DTE Gas utilized the historical three-year average of actual net write-offs plus direct expense for 2020–2022 and adjusted for revenue growth (4T 2234). This average normalizes annual variability factors that drive uncollectible expense.

Staff argued that the Company’s revenue amount used was excessive and recommended the use of total current revenue projected test year billing determinants at the current base rates

(4T 1650–51). The PFD agrees with Staff and the AG that DTE’s projected uncollectible expense is inflated and adopts Staff’s calculation as “the most accurate and reasonable estimate” because it uses current known rates in its projection (PFD, p 305). The Company disagrees and takes exception.

As evidenced in the record, the use of present rates equates to the use of stale rates (DTE Gas Initial Brief, p 125). It would be more reasonable to use a simple percent increase or other similar proxy to achieve a revenue that more closely matches the revenue that will be used in final, approved rates, and the use of current rates denies DTE Gas a reasonable chance to recover the uncollectible costs that it will be incurring (DTE Gas Initial Brief, p 125). The PFD simply chooses to use Staff’s proposed calculation merely because it “uses the current known rates in its projection,” yet fails to address anywhere in its reasoning the significant issues associated with current rates that DTE raised (PFD, p 305). Put simply, the PFD ignores the significant evidence in the record. This results in unjust rates related to uncollectible expense as it denies DTE a reasonable chance to recover the uncollectible costs that it will be incurring.

The PFD additionally ignores and fails to consider DTE Gas’s alternative position. Even if the Commission were to approve Staff’s methodology, DTE Gas proposed two necessary and appropriate adjustments to the calculation to ensure better alignment with uncollectible expense. First, Staff’s methodology needs to adjust historical revenue to also exclude any revenue Staff has excluded from projected revenue, which adjustment increases Staff’s uncollectible calculation by \$3.965 million (*See* DTE Initial Brief, pp 126–27 (discussing the inclusion of GCC cost of Gas, HPP revenue, EWR revenue, and miscellaneous revenue in historical revenues, but the exclusion of the same items from projected revenue)). Second, DTE proposes to use Staff’s proposed revenue, as opposed to present revenue, which results in an additional \$0.984 million increase to Staff’s

uncollectible expense (DTE Initial Brief, p 127). The PFD fails to address why either of these two alternative proposals are unreasonable and the Commission should therefore reject the PFD's findings.

6. Lost and Unaccounted for and Company Use Gas; Gas In Kind

DTE Gas supported 5.4 Bcf of Lost and Unaccounted for (LAUF) gas for the projected test period, based on a five-year (January 1, 2018, to December 31, 2022) average, in accordance with the methodology adopted in DTE Gas's last six contested rate cases (Case Nos. U-10150, U-13898, U-15985, U-17999, U-18999, and U-20940) (4T 2064; Exhibit A-15, Schedule E9). DTE Gas also supported the utilization of 4.5 Bcf of Company Use (CU) gas in the projected test period to operate its system and to support natural gas delivery requirements of its customers (4T 2070; Exhibit A-15, Schedule E11).

The AG disagreed with the Company's projected test year costs for CU gas and LAUF gas. The AG argued that the Company's LAUF volumes should be decreased by 529 MMcf and that the Company's O&M expense for both CU gas and LAUF gas should be reduced to reflect a lower cost of gas rate (AG Initial Brief, pp 91–92). Accordingly, the AG recommended that the Commission disallow \$4,932,000 in CU gas and LAUF gas expenses, consisting of a \$2,170,000 reduction related to lower LAUF volumes and a \$2,762,000 reduction due to a lower cost of gas rate (AG Initial Brief, p 93).

The PFD agrees with the AG, stating:

This PFD agrees with the Attorney General's approach to reduce the LAUF volume by 529 MMcf, as it is reasonable to expect progressively lower LAUF gas volumes in the coming years. As such, this PFD recommends that the Commission adopt the Attorney General's proposed disallowance of \$4,932,000.

(PFD, p 309)

The Company disagrees. First, the PFD does not explain why it is “reasonable” to expect lower LAUF volumes in the coming years. To the extent the PFD relies on the AG’s claim that such reductions are appropriate in light of the Company’s net zero goal (AG Initial Brief, pp 92–93), the Company takes exception. As the record makes abundantly clear, the Company’s net zero goal is not absolute (4T 2076; Initial Brief, p 129). In other words, the Company’s net zero carbon emissions goal is a *net goal*; that is, a goal to reduce emissions both by reducing DTE Gas’s own emissions and also balancing out remaining emissions through other means (DTE Gas Reply Brief, p 18). In contrast, an absolute goal ensures that there are no emissions created at all; emissions are simply reduced to zero (DTE Gas Reply Brief, p 18). As such, to the extent the PFD relies on this argument in recommending the LAUF disallowance, the PFD’s recommendation should be rejected as unreasonable and unsupported.

Second, the PFD completely omits any discussion of the Company’s argument that if LAUF is adjusted, Gas-in-Kind (GIK) revenue must also be adjusted (DTE Initial Brief, p 129). As the Company explained, because GIK revenue is calculated to recover costs related to LAUF and CU Gas, any changes to those costs must be reflected in adjustments to GIK revenue (DTE Initial Brief, p 129). The PFD, however, does not mention, let alone analyze, the Company’s recommendation that if LAUF and CU gas is adjusted, that GIK revenues be correspondingly adjusted. Accordingly, the PFD’s LAUF disallowance should be rejected.

7. AFUDC

The AG proposed to remove from construction work in progress (CWIP) capital expenditures related to the following projects: (1) the Fort Street Main Replacement project, (2) the Austin-Detroit A&B Lines, (3) the Oakland Resiliency (CMS Line 2700) project, and (4) the Belle River Detroit Loop Line (4T 1567). The PFD accepts this adjustment, in part, but rejects the

AG's request to exclude the Oakland Resiliency (CMS Line 2700) project because the PFD rejects the AG's proposed disallowance for that project (PFD, p 312).

As discussed previously, the Company takes exception to the exclusion of the Fort Street Main Replacement project from rate base in this case. The AG incorrectly assumed that the Fort Street Main Replacement project was in CWIP—accordingly, the AG's proposed corresponding adjustment to remove AFUDC is in error. As described earlier, DTE Gas fully expects to complete the work related to this project within the test year because no previous approvals from external municipal entities is required (4T 1981). Thus, if the Commission approves the inclusion of the Fort Street Main Replacement Project, the corresponding AFUDC amounts should be retained. As such, the Commission should reject the PFD's recommendation on this point.

8. Alternate COSS

In the Company's last rate case in Case No. U-20940, DTE Gas submitted two alternate cost of service studies (COSS) that incorporated the results of supplemental studies prepared by the Company, as required by the settlement agreement in DTE Gas Case No. U-20642 (4T 2162). At a high-level, the second alternate COSS provided in Case No. U-20940 split distribution main plant and IRM Main Replacement Program costs into high- and low-pressure (4T 2162). Staff subsequently updated the costs in the Company's second alternate COSS to reflect costs approved in Case No. U-20940 (4T 2162). In the Commission's order in Case No. U-20940, the Commission required DTE Gas, in its next rate case, to provide an alternate COSS that was consistent with Staff's adjustments to the Company's second alternate COSS (*Order*, Case No. U-20940 (December 9, 2021). p 210). Accordingly, in the instant proceeding, the Company prepared an alternate COSS as directed using the same methodology as the second alternate COSS provided

by the Company in its last gas rate case, updated for costs in the instant case, as well as updated supplemental studies (Alternate COSS) (4T 2162).

Staff proposed that the Commission require the Company to continue filing the Alternate COSS, updated for the Company's filing information, in future cases (4T 1663–64). The PFD agrees, stating:

As Staff asserts, including the additional COSS, updated for DTE's filing information, in future rate cases will allow this method to continue to be utilized and continue to explore the best way to modify rate design to directly utilize this alternate COSS. In addition, this PFD disagrees with DTE's proposal whereby the Commission allows DTE to reuse workpapers provided in this instant case to prepare the Alternate COSS in DTE's next rate case. As Staff points out in its brief, this approach would not require an update of all data necessary for the alternate COS to be useful. Thus, this PFD recommends that the Commission require DTE to continue to file the alternate COS in future cases.

(PFD, p 361)

The Company disagrees. Conducting the Alternate COSS requires considerable time and resources, and there has been no determination that this new allocation method would better align cost causation with cost allocation for all rate classes (4T 2174). Moreover, contrary to Staff and the PFD's assertions otherwise, the Company's alternative proposal—in which the Company would reuse workpapers TJK-15 (Distribution Mains – High vs. Low-Pressure Cost Study) and TJK-16 (Volumes Split by Delivery Type) provided in this case to prepare the Alternate COSS—would provide all of the data necessary for the Alternate COSS to be “useful.” Therefore, the PFD's recommendation that the Alternate COSS continue should be rejected.

9. Other Issues

a. Demand Response

Pursuant to the settlement in Case No. U-20642, the Company agreed to conduct gas demand response (DR) pilot programs to determine the effectiveness of gas DR in the Company's service territory (2T 110). As a result, DTE piloted two residential Gas DR programs: the Smart

Savers Gas pilot and a behavior DR program called Energy Action Days (2T 111). The Company also piloted one commercial pilot for GS-1, GS-2, and S-rate customers, whereby telemetry equipment was installed at no cost to participating customers (2T 112). DTE Gas was also authorized to defer costs associated with pilot implementation up to \$4.0 million over the bridge and test periods and through the end of the pilot program period as a regulatory asset, subject to a reasonableness and prudence review for recovery in a future proceeding (2T 110). Altogether, the Company deferred \$2.6 million of DR costs over the two-year period for these three pilot programs (2T 115).

The evidence and data gathered from the pilot programs indicated that they were not effective (DTE Gas Initial Brief, p 145). Accordingly, DTE Gas decided that it was reasonable and prudent to discontinue the gas DR programs (DTE Gas Initial Brief, p 145). MNSC and the Clean Energy Organizations (CEO) argued that the Smart Savers pilot should be continued because the program demonstrated large amounts of gas usage reduction during gas demand events (4T 932–933; 4T 749–52). The PFD agrees with DTE Gas that it should be allowed to recover the \$2.6 million in deferred DR costs, and the Company takes no exception to this finding (PFD, p 368). However, the PFD also supports positions taken by MNSC and CEO and suggests that the Commission direct DTE Gas “to continue offering the Smart Savers Pilot program as DTE’s evaluation showed that this pilot reduced large amounts of gas usage during gas demand events” (PFD, p 368). In support of this finding, the PFD states that “DTE has not offered any contrary evidence nor offered any explanation for why its data does not support that significant amounts of gas usage were reduced” (PFD at 368). In this respect, the PFD is entirely wrong.

DTE Gas provided ample evidence that the data from these pilot programs demonstrated the programs’ ineffectiveness (DTE Gas Initial Brief, pp 141–142). For example, DTE Gas

described how, while customers were able to decrease their gas use during the Smart Savers Gas Pilot, “each [called] event experienced a large snapback” (3T 471). CEO Witness Cebulko discussed but quickly discounted this evidence, yet even CEO recognized that “the snapback was so large in one event that it resulted in more gas being consumed throughout the entire day” (3T 471). DTE Gas further demonstrated that snapback is an issue, regardless of whether it occurs concurrently with the system peak or not—in fact, because gas peaks can last entire days, snapback that occur during gas peaks may pose *additional* issues (3T 471). In any case, snapbacks are a significant concern in the context of a pilot program, as they demonstrate that the program may not be effective enough to curtail use in a meaningful way. DTE Gas provided this important context on the record, but both CEO and the PFD entirely discount it.

Thus, to say that “DTE has not offered any contrary evidence nor offered any explanation about why its data does not support that significant amounts of gas usage were reduced” is entirely wrong. The record clearly shows that the reduction in gas usage was rendered meaningless in the full context of the pilot program. The PFD failed to account for important contextual evidence that is clearly in the record, and its recommendation should be rejected by the Commission. The Commission should therefore direct that the pilot programs be discontinued.

b. Responsibly Sourced Gas

The Company requested recovery of a Responsibly Sourced Gas (RSG) premium of approximately \$180,000 for the projected RSG purchase of 4,000,000 Dth in the projected test period (2T 81). The Company forecasted the purchase of 4,000,000 Dth of RSG gas with a premium price of \$0.045 per Dth based on current market conditions (2T 80–81; Exhibit A-22, Schedule L3). Alternatively, given the undefined nature of RSG recovery mechanisms, if the Commission disallows cost recovery of RSG in this proceeding and the corresponding Gas Cost

Recovery proceedings, the Company stated that it was open to applying regulatory accounting authority for deferral of these costs until further legislation is developed or an applicable recovery mechanism is defined (DTE Initial Brief, p 153; DTE Reply Brief, p 23).

The AG, Staff, MNSC, CEO, and FLO all argued that the Commission should disallow the Company's requested \$180,000 in RSG premiums in this rate case proceeding. The PFD agrees, stating:

This PFD agrees with Staff, the Attorney General, MNSC, CEO and FLO that that the RSG premium of \$180,000 should not be included in DTE's case. This PFD finds that DTE has not provided adequate support that the proposal to purchase RSG will make a significant contribution to DTE's total greenhouse gas reduction goals. This PFD agrees that DTE's RSG proposal is premature given the current state of this issue within the natural gas industry, the lack of industry standards for all participants to adhere to as part of routine business operations, and recent legislative and EPA initiatives on methane reductions in the gas production areas.

(PFD, pp 379–80).

The Company disagrees. Contrary to the PFD's assertion otherwise, the Company did provide support that the proposal to purchase RSG will make a significant contribution to DTE Gas's total greenhouse gas reduction goals. First, by its very nature, RSG meets specified environmental targets during production (2T 67). Moreover, Witness Decker stated that the Company's forecasted purchase of 4,000,000 Dth of RSG would prevent approximately 4,000 to 8,000 metric tons of carbon dioxide from being released into the atmosphere, depending on the methane intensity of RSG purchased (2T 81).¹² Witness Decker also cites DTE Gas's 2022 Sustainability Report, which outlines the Company's net zero goals, which include sourcing gas with lower methane intensities (e.g., RSG) (2T 127–28). Additionally, while the Company acknowledges that the recovery mechanism is undefined given that the industry and federal

¹² This was reaffirmed by Witness Decker during Cross Examination (2T 187).

initiatives and standards to achieve net zero are still emerging, this is not a reasonable basis on which to disallow recovery. As Witness Decker explained, the Company has chosen to be proactive versus reactive and the procurement of RSG is one of many steps the Company is taking to be an active participant in the decarbonization effort, and an area where the Company can have a direct impact by reducing the methane intensity of the portfolio by quantifiable amounts (2T 130). Moreover, the PFD completely fails to address the Company's alternative request to defer recovery of certain costs associated with RSG premiums until legislation is developed or a regulatory mechanism is defined (DTE Initial Brief, p 153; DTE Reply Brief, p 23). As such, the PFD's recommended disallowance should be rejected.

c. Environmental Justice and Energy Transition

The PFD made two findings regarding environmental justice and the energy transition.

First, the PFD asserts that:

DTE has not made much if any assessment or study of how any energy transition will be accomplished and at what costs. This PFD agrees that DTE's Gas Delivery Plan is a good avenue to set forth its preliminary assessment of how it expects the transition to take place and what the resultant changes or ramifications may be for the utility and the ratepayers.

PFD, p 409. Second, the PFD finds it "premature" to address issues or proposals regarding affordability and energy assistance, and that the Commission should wait for the completion of the work by the Commission's Energy Affordability and Accessibility Collaborative (EAAC) before making any determinations on these issues (PFD, pp 410–11).

The Company takes exception to both findings. These issues go hand in hand, as demonstrated by the testimony of the various witnesses on this issue. For example, Witness Koepfel argued that the ongoing energy transition presently distributes burdens and benefits inequitably, and that specific communities bear "the greatest costs and receive the lowest benefits

from the system” (4T 986). Thus, calling on DTE Gas to make an assessment or study of the transition while simultaneously finding that the Commission should await conclusion of the EAAC’s work are findings that are in conflict with one another. Effectively, the PFD’s decision grants the Commission the benefit of the EAAC’s ultimate findings but deprives DTE Gas of the same findings. In order to ensure consistency in findings and to avoid duplicative work, the Commission should defer any work on assessing the energy transition until the conclusion of the EAAC.

10. Tariff Changes

DTE Gas proposed several changes to its tariff pages under Section C of its rate book (2T 103–07; Exhibit A-16, Schedule F5 (summary of proposed tariff changes); Exhibit A-16, Schedule F5.1 (revised tariff pages)).

ABATE Witness York recommended that DTE Gas change the language under Section C3.3.D.1.a governing base period volumes for System Supply Customers to be the same as what is currently in Consumers Energy’s tariff (4T 1293). Specifically, Witness York suggests that the following language be added to the end of Section C3.3.D.1.a:

The customer shall notify the Company of any adjustment to base period volumes using any reasonable method of the customer’s choice, including but not limited to written request, phone call, or email. The Company shall notify the customer if the base period adjustment is accepted or rejected within 60 days of the request. A failure to affirmatively notify the customer shall be treated as an acceptance. If the requested adjustment is rejected, the Company shall provide the customer a written explanation detailing the reasons for the rejection. A customer may request an adjustment to its base period volumes two (2) times during a calendar year.

The PFD agrees, “finding that it is reasonable to provide DTE’s customers with the same level of flexibility with respect to adjustments to base period volumes as Consumers’ customers” (PFD, p 412). The Company takes exception to this recommendation.

As Witness Decker explained, the language proposed by Witness York would require DTE Gas to be able to administer base period volume change requests from System Supply customers—customers who are largely non-contract customers that have a simplified relationship with DTE Gas as compared to EUT customers—and spend resources to analyze, record, and recall the data upon a curtailment event for System Supply customers (2T 136). Given that most System Supply customers are the last to be curtailed, the Company believes Witness York’s proposed tariff changes would result in a poor use of resources and would ultimately provide very little real-world benefits (2T 136). The PFD fails to reconcile this discrepancy and instead summarily states, without explanation, that DTE Gas’s customers should be afforded the same level of flexibility with respect to adjustments to base period volumes as Consumers’ customers (PFD, p 412). Accordingly, the PFD’s recommendation should be rejected.

11. Proposed Monthly Customer Charges and Rate Schedule Economic Break-Even Points

DTE Gas proposed a \$17.60 monthly customer charge for residential Rate A (2T 98–99); Exhibit A-16, Schedule F2, page 2, line 2, column (c)). To maintain historical consistency, the Company proposed that the same charge should apply to the Rate 2A-Meter Class 1, and that the monthly customer charge for Rate 2A-Meter Class II and Rate GS-1 should be set at \$50.00 (2T 99; Exhibit A-16, Schedule F2, page 2, lines 7–8, and 14, column (c)). DTE Gas established the monthly customer charges for the remaining rate schedules by using the economic break-even points and the proposed Rate GS-1 monthly customer charge (2T 99). The Rate GS-2 monthly service charge is \$925.00 (2T 99; Exhibit A-16, Schedule F2, page 2, line 17, column (c)). The Rate S monthly service charge is \$275.00 (2T 99; Exhibit A-16, Schedule F2, page 2, line 11, column (c)). The monthly customer charges for EUT Rates ST, LT, XLT, and XXL are \$3,300.00,

\$9,100.00, \$20,000.00, and \$230,000.00, respectively (2T 99; Exhibit A-16, Schedule F2, page 3, lines 2, 7, 12, and 17, column (c)).

Staff disagreed with the Company's proposed residential customer charge of \$17.60. Specifically, Staff took issue with the Company's method of splitting test-year capital into separate accounts or categories using historical ratios and instead proposed to use historical adjusted costs, rather than projected test-year costs, to calculate the monthly customer charge for the residential class (Staff Initial Brief, p 76). Using this methodology, Staff calculated a residential monthly customer charge of \$14.50 (Staff Initial Brief, pp 75–76).

AG Witness Coppola recommended that the Commission instead either maintain the current residential (Rate A and 2A-1) monthly charge of \$13.50, and the current Rate GS-1 charge of \$40.00, or limit the monthly service charge increases to no more than \$1.00, to \$14.50 (AG Initial Brief, p 130).

The PFD agrees with Staff, stating:

This PFD agrees with Staff modification of DTE's calculation of customer charges using a combination of historical and projected expenses as utilizing only historical costs ensures that DTE's method of spreading projected costs does not include costs that are inappropriate for inclusion in the customer charge. Thus, this PFD recommends that the Commission adopt Staff's recommendations of the following customer charges: Residential - \$14.50, School - \$270.00, and GS-1 \$50.00, with all other customer charges being determined by rate design. This PFD notes that Staff's proposed Residential charge of \$14.50 coincides with the alternative charge proposed by the Attorney General.

(PFD, p 361).

The Company disagrees and instead maintains that the monthly residential customer charge should be increased to \$17.60. First, the Company's current method for splitting distribution plant using historical ratios is a common practice in cost-of-service and is a reasonable approach that reflects investments made in the Company's distribution system (4T 2173). Second, not all costs

embedded in the residential customer charge rely on historical ratios; customer service costs reflect test-year cost projections made at the account level (4T 2173). Third, the Company's current approach has guided Commission-approved residential customer charges going back to at least 2016 and no evidence has been provided demonstrating that the current approach results in inaccurate costs or that customers have been harmed (4T 2173). Finally, using historical costs for one subpart of rate design while otherwise using forecasted costs and determinants is broadly inconsistent (4T 2173). Therefore, the PFD's recommendation should be rejected and the Company's proposal should be adopted.

12. Revenue Deficiency Summary

The PFD calculates DTE Gas's revenue deficiency of \$97,950,000 (PFD, p 419). For reasons discussed in Section I, this calculation is in error and should be rejected. For the reasons discussed in Section II, the Company's proposed revenue deficiency of \$262,407,000, as outlined in Attachment A to these Exceptions, should be adopted.

REQUEST FOR RELIEF

DTE Gas respectfully requests that the Commission issue its final order in accordance with the PFD as modified by the discussion above:

- A. Granting DTE Gas's request for final rate relief, as further supported and explained in its Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief, and these Exceptions (including Exceptions Attachment A) approving rates that will recover the Company's revenue deficiency of approximately \$262.4 million, based on an October 1, 2024, through September 30, 2025, test year, effective as soon as possible on or after November 5, 2024;
- B. Approving recovery of DTE Gas's new rates effective no later than November 5, 2024, in the manner described in the Company's Application, testimony, exhibits, Initial Brief

(including Attachments A and B), Reply Brief, and these Exceptions (including Exceptions Attachment A);

C. Acknowledging that DTE Gas has satisfied all of the directives of the Commission's Order in Case No. U-20940, which were required components of the Company's next general rate case;

D. Approving the Company's recovery of the requested infrastructure-related capital and the associated IRM;

E. Approving the Company's capital structure and return on investment;

F. Approving the Company's recovery of projected Manufactured Gas Plant expenses;

G. Approving continuation of and changes to the Company's LIA credit pilot and RIA credit, including regulatory asset and liability treatment for LIA customer credits applied that are greater or less than those approved in rates;

H. Approving the Company's proposal to amend certain customer rate schedules and proposed tariff changes;

I. Authorizing implementation of DTE Gas's proposed accounting changes as described in the Company's Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief, and these Exceptions (including Exceptions Attachment A);

J. Approving the remainder of DTE Gas's miscellaneous proposals, and rejecting other parties' additional or inconsistent proposals, as set forth in the Company's Application, testimony, exhibits, Initial Brief (including Attachments A and B), Reply Brief, and these Exceptions (including Exceptions Attachment A); and

K. Granting such other lawful relief that the Commission deems reasonable and appropriate.

Respectfully submitted,

DTE GAS COMPANY

By: _____

Dated: September 25, 2024

Its Attorney
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DTE Gas Company
 Computation of Revenue Deficiency
 Projected 12 Month Period Ending September 30, 2025
 (\$000)

Line No.	(a) Description	(b) Company Reply Brief	(c) Adjustments	(d) Exceptions to PFD Position	(e) ALJ Proposal for Decision (5)	(f) Difference
1	Rate Base (1)	\$ 6,939,800	\$ -	\$ 6,939,800	\$ 6,805,668	\$ 134,131
2	Adjusted Net Operating Income (2)	225,635	-	225,635	319,324	\$ (93,690)
3	Rate of Return (3)	6.0425%	0.0000%	6.0425%	5.6371%	0.4054%
4	Income Requirements	419,337	-	419,337	383,643	\$ 35,694
5	Income Deficiency (Sufficiency)	193,702	-	193,702	64,319	\$ 129,384
6	Revenue Conversion Factor (4)	1.3547	-	1.3547	1.3547	0
7	Revenue Deficiency (Sufficiency)	\$ 262,407	\$ -	\$ 262,407	\$ 87,132	\$ 175,275

Sources

- (1) Attachment A, Page 2
- (2) Attachment A, Page 3
- (3) Attachment A, Page 4
- (4) Exhibit A-13, Schedule C2
- (5) Per PFD Appendices as adjusted to align with the PFD Narrative. See table included in DTE Exceptions section I.

DTE Gas Company
Rate Base - Average Net Plant
For the 13-Month Average Period Ending September 30, 2025
(\$000)

Line No.	(a) Description	(b) Company Reply Brief	(c) Adjustments	(d) Exceptions to PFD Position	(e) ALJ Proposal for Decision (1)	(f) Difference
1	Plant in Service	\$ 8,493,975		\$ 8,493,975	\$ 8,396,474	\$ 97,501
2	Plant Held for Future Use	-		-	-	-
3	Construction Work in Progress	298,542		298,542	262,558	35,983
4	Total Utility Plant	8,792,516	-	8,792,516	8,659,032	133,485
5						
6	Less: Depreciation Reserve	2,756,737		2,756,737	2,746,423	10,314
7						
8	Net Utility Plant	6,035,780	-	6,035,780	5,912,609	123,170
9						
10	Net Capital Lease Property	-		-	-	-
11	Gas Stored Underground - non current	35,303		35,303	35,303	-
12						
13	Total Utility Property and Plant	6,071,082	-	6,071,082	5,947,912	123,170
14						
15	Less: Capital Lease Obligations	-		-	-	-
16						
17	Net Plant	6,071,082	-	6,071,082	5,947,912	123,170
18						
19	Allowance for Working Capital	868,717	-	868,717	857,757	10,961
20						
21						
22	Rate Base	<u>\$ 6,939,800</u>	<u>\$ -</u>	<u>\$ 6,939,800</u>	<u>\$ 6,805,668</u>	<u>\$ 134,131</u>

(1) Per PFD Appendices as adjusted to align with the PFD Narrative. See table included in DTE Exceptions section I.

DTE Gas Company
Adjusted Net Operating Income
Projected 12 Month Period Ending September 30, 2025
(\$000)

Line No.	(a) Description	(b) Company Reply Brief	(c) Adjustments	(d) Exceptions to PFD Position (3)	(e) ALJ Proposal for Decision (1)	(f) Difference
1	Operating Revenues					
2	Distribution Revenues	\$ 974,012	\$ -	\$ 974,012	\$ 950,776	\$ (23,236)
3	Third Party Transportation & Storage	111,644		111,644	111,644	-
4	Other Operating Revenues	143,784		143,784	143,784	-
5	Net Margin	1,229,440	-	1,229,440	1,206,204	(23,236)
6						
7	Operating Expenses					
8	Operation & Maintenance	535,621		535,621	459,462	(76,160)
9	Cost of Gas Sold	-		-	(39,478)	(39,478)
10	Company Use & Lost Gas	43,209		43,209	38,277	(4,932)
11	Gas Uncollectibles	35,149		35,149	20,679	(14,470)
12	Depreciation and Amortization	243,219		243,219	226,965	(16,254)
12	Property and Other Taxes	130,938		130,938	129,598	(1,340)
13	Other Income/(Ded.)-Customer Deposit Interest	406		406	406	-
14	Total Operating Expenses	988,542	-	988,542	835,909	(152,633)
15						
16	Operating Income	240,898	-	240,898	370,295	129,397
17						
18	Other Operating Income Adjustments					
19	Allow. For Funds Used During Constr	4,680		4,680	2,566	(2,114)
20	Amortization of Loss on Reacquired Debt	(1,350)		(1,350)	(1,350)	-
21						
22	Total Operating Income Adjustments	3,330	-	3,330	1,216	(2,114)
23						
24	PreTax Adjusted Net Operating Income	\$ 244,227	\$ -	\$ 244,227	\$ 371,511	\$ 127,283
25						
26	State and Local Income Taxes	9,078	-	9,078	17,496	8,417
27	Federal Income Taxes	9,514	-	9,514	34,691	25,177
28						
29	Net Operating Income	\$ 225,635	\$ -	\$ 225,635	\$ 319,324	\$ 93,690

(1) Per PFD Appendices as adjusted to align with the PFD Narrative. See table included in DTE Exceptions section I.

DTE Gas Company
Rate of Return Summary
Projected 12 Month Period Ending September 30, 2025
Based on Average Rate Base
(\$000)

Line No.	(a) Description	(b) Amounts (\$000)	Capital Structure		(e) Cost Rate %	Weighted Costs				
			(c) Percent Permanent Capital	(d) Percent of Total Capital		(f) Permanent Capital	(g) Total Cost %	(h) Conversion Factor	(i) Pre-Tax Return	
U-21291 DTE Reply Brief (Test Period Average Basis)										
1	Long-Term Debt	\$ 2,666,714	48.50%	38.40%	4.44%	2.155%	1.71%	100.000%	1.707%	
2	Preferred Stock	0		0.00%	0.00%	0.000%	0.00%	135.469%	0.000%	
3	Common Shareholders' Equity	2,831,447	51.50%	40.78%	10.25%	5.279%	4.18%	135.469%	5.662%	
4	Total	5,498,161	<u>100.00%</u>			<u>7.434%</u>				
5										
6	Short-Term Debt	184,380		2.66%	5.89%		0.16%	100.000%	0.156%	
7										
8										
9										
10	Job Development - ITC - Debt	0		0.00%	4.44%		0.00%	100.000%	0.000%	
11	Job Development - ITC Equity	-		0.00%	10.25%		0.00%	135.469%	0.000%	
12	Total Job Development - ITC	0								
13										
14	Deferred Income Taxes (Net)	1,261,422		18.17%	0.00%		0.00%		0.000%	
15										
16	Total	6,943,963		<u>100.00%</u>			<u>6.04%</u>		<u>7.525%</u>	
U-21291 DTE Exceptions to PFD (Test Period Average Basis)										
17	Long-Term Debt	\$ 2,666,714	48.50%	38.40%	4.44%	2.155%	1.71%	100.000%	1.707%	
18	Preferred Stock	0		0.00%	0.00%	0.000%	0.00%	135.469%	0.000%	
19	Common Shareholders' Equity	2,831,447	51.50%	40.78%	10.25%	5.279%	4.18%	135.469%	5.662%	
20	Total	5,498,161	<u>100.00%</u>			<u>7.434%</u>				
21										
22	Short-Term Debt	184,380		2.66%	5.89%		0.16%	100.000%	0.156%	
23										
24										
25										
26	Job Development - ITC - Debt	0		0.00%	4.44%		0.00%	100.000%	0.000%	
27	Job Development - ITC Equity	-		0.00%	10.25%		0.00%	135.469%	0.000%	
28	Total Job Development - ITC	0								
29										
30	Deferred Income Taxes (Net)	1,261,422		18.17%	0.00%		0.00%		0.000%	
31										
32	Total	6,943,963		<u>100.00%</u>			<u>6.04%</u>		<u>7.525%</u>	

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
DTE GAS COMPANY for authority)
to increase its rates, amend its rate)
schedules and rules governing the)
distribution and supply of natural gas,)
and for miscellaneous accounting authority)
_____)

Case No. U-21291

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

CAITLIN D. MYERS states that on September 25, 2024, she served a copy of DTE Gas Company's Exceptions to the Proposal for Decision with Attachment A in the above captioned matter, via electronic mail, upon the persons listed on the attached service list.

CAITLIN D. MYERS

**MPSC Case No. U-21291
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**MPSC Case No. U-21291
Service List**

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