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May 27, 2020

***VIA ELECTRONIC CASE FILING***

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

**Re:** ***MPSC Case No. U-20642: 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.***

Dear Ms. Felice:

Enclosed for filing please find the ***Association of Businesses Advocating Tariff Equity's Redacted Initial Brief*** in this proceeding and ***Proof of Service***.

Sincerely,

**CLARK HILL PLC**

Stephen A. Campbell

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cc w/enc.: Parties of Record

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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| In the matter of the application of | ) | |
| **DTE GAS COMPANY** for authority | ) | Case No. U-20642 |
| to increase its rates, amend its rate | ) | |
| schedules and rules governing the | ) | ALJ Martin Snider |
| distribution and supply of natural gas, | ) | |
| and for miscellaneous accounting authority. | ) | |
| ______________________________________ | ) | |

**ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY'S**
**INITIAL BRIEF**

The Association of Businesses Advocating Tariff Equity ("ABATE"), by its attorneys, Clark Hill PLC, hereby files its Initial Brief in this proceeding initiated by DTE Gas Company ("DTE" or "Company") before the Michigan Public Service Commission ("Commission") in accordance with the schedule established by Administrative Law Judge ("ALJ").

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## I. INTRODUCTION

The Commission may authorize a Michigan utility to collect rates and charges that are just and reasonable considering the utility's reasonable cost of doing business. In requesting Commission approval, the applicant utility bears the burden of demonstrating that its proposed costs and rates are just and reasonable. Despite this requirement, DTE put forth several proposals in this proceeding which would result in rates that do not meet this standard and should be rejected or modified.

These proposals include the Company's class cost of service studies ("CCOSS") which would misalign costs with their causation and inequitably over-allocate distribution mains and storage costs to users which are not responsible for those expenses. The Company also proposed an inflated return on equity ("ROE") which runs counter to prevailing industry ROE, credit, and interest rates trends and is based on flawed analyses. In addition, DTE proposed operation and maintenance ("O&M") expenses based on over-estimated and unreasonable inflation rates. Lastly, the Company's proposed revenue requirement includes recovery of certain financial contributions to third-party associations and organizations which are unjustified and unconstitutional.

Given their deficiencies these Company proposals would result in rates that are excessive, inequitable, and unreasonable. As such, the Commission should reject these proposals and instead adopt the recommendations and alternatives set out in this Initial Brief.

## II. ARGUMENT

### A. The Company's class cost of service study must be altered to properly allocate costs in accordance with their causation.

A CCOSS is an analysis used to determine each customer class'[1] responsibility for a utility's costs, such that a revenue requirement may be established for each class to cover its cost of service. (4 Tr 1637, 1684-86.) To develop a CCOSS, the different types of a utility's costs are identified, their primary cause is determined, and each item of cost is then accordingly allocated to customer classes. (4 Tr 1684.) This allocation is accomplished by developing allocation factors that reflect the percentage of the total cost for which each class is responsible, meaning the degree to which each class caused the utility to incur the cost. (*Id.*)

A properly conducted gas CCOSS recognizes several key cost-causation principles. First, not all gas customers purchase gas supplied by a local distribution company (DTE, in this case), as some customers purchase and transport their own gas. (4 Tr 1685.) Second, not all customers take the same delivery service; large transportation customers may take delivery service directly from the transmission system or high-pressure distribution mains. (*Id.*) In the first instance, the local distribution company does not incur natural gas supply costs to serve these transportation customers. (*Id.*) In the second instance, the cost to deliver gas is lower for customers that are directly served from the transmission system than from the distribution system. (*Id.*) As discussed later, the costs to provide high pressure distribution service are lower than the costs to provide low pressure distribution service. Third, both the timing and rate of gas consumption (i.e. demand) are critical for determining cost causation, as the local distribution company must size

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[1] Each customer class should be comprised of customers having similar characteristics. The relevant characteristics include the type of end-use customer (e.g. residential, general service sales, transportation), average size, and load factor. Allocating costs to homogeneous customer classes ensures that the rates derived from a CCOSS are just and reasonable and reflect the actual cost to serve each customer. (4 Tr 1685.)

the delivery infrastructure, including distribution mains, to meet its customers' maximum daily gas supply needs. (4 Tr 1685-86.) Fourth, the use (and associated cost) of storage services depends on the authorized tolerance levels ("ATLs") between actual and nominated gas deliveries. (*Id*.) The smaller the ATL, the lower the amount of storage service. (*Id*.) Lastly, while the timing and rate of gas consumptions are critical, the local distribution company must construct distribution mains and other facilities to connect customers to the system and provide appropriate operating pressure to provide gas to customers. (*Id*.) The latter investment must be incurred regardless of a customer's peak demand and natural gas usage. (*Id*.)

Considering these fundamental principles, the CCOSS DTE provided in this proceeding contained three major flaws. (4 Tr 1637.) These included the following: (i) distribution facilities were allocated to those classes that take gas delivery service directly from the transmission system either in whole or in part, meaning DTE over-allocated costs to the Rate LT, XLT, Rate XXLT, and DIG customer classes; (ii) low-pressure distribution mains were allocated to Rate XLT customers despite the fact that 16 of the 18 Rate XLT customers are served only from high-pressure (i.e. at or above 100 psig) distribution mains; and (iii) despite a stronger relationship between the length of DTE's distribution mains and the number of customers served than to either peak day design or annual throughput, none of DTE's distribution mains costs were allocated based on the number of customers served. (4 Tr 1637-38.) Because of these flaws DTE's proposed CCOSS must be altered as set out below.

### 1. Gas deliveries to direct-served transmission customers should be removed in allocating distribution mains and other distribution plant.

The Company's CCOSS allocated other distribution facility[2] costs to all customer classes, including those that are partially or entirely served directly from the transmission system. (Exhibit A-16, Schedule F1.1, line 5; Exhibit AB-30 at 2, 6-7.) The CCOSS also allocated a portion of distribution mains costs, as well as other distribution facilities, to the three Rate LT and two Rate XLT customers that are directly served from the transmission system. (*Id*.) Because these allocations assess costs to customers that do not cause them, the Company's CCOSS does not comport with cost causation principles and must be revised as described below.

The fundamental basis of CCOSS development is that costs should be allocated in a manner that reflects how customers take gas delivery service. (4 Tr 1638.) For example, customers that are served directly from the transmission system should not be allocated any distribution facility costs, as they neither utilize those facilities nor cause those costs. (*Id*.) Similarly, customers which take delivery service from high-pressure distributions mains should not be allocated costs associated with low-pressure distribution mains. (*Id*.) This principle is widely recognized in analogous electric CCOSSs; customers served directly at a transmission voltage are not allocated demand-related distribution plant and related costs and customers served directly from the primary distribution system are not allocated costs associated with the secondary distribution system. (*Id*.)

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[2] "Other distribution facilities" include the following: (i) land and land rights (FERC Account No. 374); (ii) structures and improvements (FERC Account No. 375); compressor station equipment (FERC Account No. 377); and (iv) measuring and regulating station equipment (FERC Account Nos. 378, 379). (4 Tr 1640.) These same types of equipment are also found in DTE's transmission plant accounts (i.e. FERC Account Nos. 365, 366, 368, and 369), meaning it is unnecessary to allocate the corresponding distribution facilities to the direct-served transmission customers. Allocating the same type of transmission and distribution equipment to a direct-served customer class would be double-counting.

As noted above, DTE provides gas delivery service directly from the transmission system for a subset of the Rate LT, Rate XLT, and Rate XXLT customer classes, while the entire DIG class is directly served from the transmission system. (See 4 Tr 1638-39; Exhibit AB-30 at 3-5.) Specifically, direct transmission service accounts for approximately 2.8%, 14.6%, 65%, and 100% of the annual throughput of the Rate LT, Rate XLT, Rate XXLT, and DIG customer classes, respectively. (*Id*.) The Company's CCOSS did not recognize this reality and instead, as described above, allocated both other distribution facilities to customers that are partially, or entirely, served directly from the transmission system, as well as a portion of distribution mains and other distribution facilities to the three Rate LT and two Rate XLT customers that are direct-served from the transmission system. (See 4 Tr 1639; Exhibit A-16, Schedule F1.1, line 5; Exhibit AB-30 at 2, 6-7.) Such an allocation would assess costs to classes for which they are not responsible and must be rectified for DTE's CCOSS to comport with cost of service principles.

Specifically, DTE's Allocation Schedule A must be revised to remove the peak day design and annual throughput of all direct-served transmission customers. (4 Tr 1640.) These same revisions must also be made to Allocation Schedule 3A. (*Id*.) Ultimately, Allocation Schedules 3 and 3A should be identical.[3] (*Id*.) These revisions have been provided in Exhibit AB-14 and will align DTE's cost allocation with cost causation.[4] (See 4 Tr 1641.)

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[3] While the direct-served transmission customers were removed from Allocation Schedule A, DTE failed to remove the direct-served Rate LT and Rate XLT transmission customers, and it also removed the entirety of the Rate XXLT class from Schedule 3A even though one customer takes distribution delivery service. This is reflected in DTE's Response to Discovery Request ABDG-4.35 (Exhibit 30 at 4-5), which lists only four out of the five total Rate XXLT customers that take gas delivery service directly from DTE's transmission system.

[4] With regard to DTE's critique regarding Exhibit AB-14 and Table 1 of Mr. Pollock's Direct Testimony, ABATE filed an errata to this Table in this proceeding which addressed DTE's concern. (See 4 Tr 874; Filing No. U-20642-202, filed April 22, 2020; Exhibits AB-30 at 3-5.)

### 2. No low-pressure distribution mains should be allocated to classes that are served directly from high-pressure mains.

The Company's CCOSS also failed to recognize the distinction between high- and low-pressure distribution mains[5] and the customers being served thereby. (See 4 Tr 1642; Exhibit A-16, Schedule F.1.1, line 6; Exhibit AB-30 at 10.) Specifically, DTE allocated the costs of all distribution mains (both high- and low-pressure) to all transportation customers receiving gas delivery service from the distribution system, regardless of whether they are directly served from high-pressure distribution mains. (*Id.*) As this would again assess costs to customers for which they are not responsible, DTE's CCOSS must be altered as described below.

Similar to transmission system service, DTE provides different types of distribution delivery service to different customers. For those customer classes receiving gas delivery service from the distribution system, 16 of the 18 Rate XLT customers are served directly from high-pressure distribution mains while all other distribution customers are served from low-pressure distribution mains. (Exhibit AB-30 at 2.) Despite these service differences, as noted above, DTE allocated the costs of all distribution mains to all transportation customers receiving gas delivery service from the distribution system. DTE asserted that it does not have detailed accounting records which identify the costs associated with high- and low-pressure distribution mains such that it could distinguish between the transportation customers taking service from each. (Exhibit AB-30 at 11.)

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[5] DTE defines "high-pressure" as including mains that operate at pressure of 100 psig and higher, while "low-pressure" mains operate at pressures below 100 psig. (Exhibit AB-30 at 8-9.)

Notably, this lack of detail is inconsistent with the accepted practice of Michigan's other major utility, Consumers Energy Company ("Consumers").[6] Rather than indiscriminately allocating all distribution mains costs to all distribution system customers, Consumers identifies the costs of both its high-pressure and low-pressure distribution mains in its CCOSS and allocates them according to customer causation. (See Case No. U-20322, Filing No. U-20322-0193, Exhibit No. A-16 (EAD-2), Schedule F-1a at 3.) As such, Consumers does not allocate any low-pressure distribution mains costs to those customer classes that are served directly from high-pressure distribution mains.[7] (*Id.*) It is ABATE's understanding that the Commission has approved Consumers' distinguishing of high- and low-pressure distribution mains costs since Case No. U-13000 (June 2001). (4 Tr 1642-43.) Thus, the Commission has previously and recently adopted cost studies which distinguish between high- and low-pressure distribution mains costs.

As a CCOSS must fundamentally recognize the different types of gas delivery service, distinguishing between the different types of distribution delivery service is necessarily consistent with cost causation principles. Customers directly served by the transmission system or which take distribution service from DTE's high-pressure mains do not cause DTE to install low-pressure distribution mains or incur costs related thereto. (4 Tr 1643.) As such, none of

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[6] It is also generally inconsistent with the National Association of Regulatory Utility Commissioners ("NARUC") Gas Rate Design ("GRD") Manual, which notes that when determining cost of service "[a]ll items that can be directly attributed to a particular service (such as revenues from a specific service or the cost of a high pressure main constructed for a particular customer or group of customers) should be segregated and directly assigned to the appropriate customers." (NARUC, *Gas Distribution Rate Design Manual* at 20 (June 1989).)

[7] The Attorney General's contention that ABATE's proposal "dissect[s] costs to such a level that undermines the fact that the Company's transmission and distribution system is an integrated system, which works in tandem" and "would result in the operation of two utility companies with DTE Gas," one "to serve the large volume commercial and industrial customers, and another to serve the remaining customers" is therefore overstated. (4 Tr 1530-31.) ABATE's proposal

DTE's low-pressure distribution mains costs should be allocated to those customers. (*Id*.) The Company's proposed Allocation Schedule 3A must therefore be revised by removing gas deliveries to the direct-served transmission customers in the Rate LT and XLT classes, and including gas delivery to the Rate XXLT customer taking distribution service.

As stated above, the Company claimed that it does not have sufficient information to identify the cost causation related to its high-pressure and low-pressure distribution mains. At a minimum the Commission should therefore order DTE to conduct a study identifying the investment and associated expenses for its high- and low-pressure distribution mains. The results of this study should be presented in DTE's next rate case.

**3. At least 40% of distribution mains costs should be allocated on a customer basis.**

The Company's CCOSS proposed to classify the costs associated with all gas distribution mains as demand- and commodity-related; no distribution mains costs were classified as customer-related. (4 Tr 830-31.) Contrary to this proposed allocation, classifying a portion of distribution mains costs as customer-related is consistent with cost causation principles and is appropriate, accepted practice in the majority of state regulatory jurisdictions nationwide which have addressed the issue. (4 Tr 1644-52.) Thus, because the Company's proposed distribution main cost allocation failed to recognize the demonstrable connection between the number of DTE's customers and its distribution main investment, DTE's CCOSS must be modified as described below.

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simply seeks to align costs with causation in a manner already approved by the Commission.

### a. Regardless of customer demand DTE must invest in distribution mains and service laterals just to connect customers to its system.

Distribution mains are the various pipes used to deliver natural gas to end-use customers. As such, gas utilities must make minimum investments in these mains just to connect a customer to the gas delivery system, regardless of that customer's peak demand. (4 Tr 1644.) Thus, to the extent that a portion of distribution mains costs is caused by the requirement to connect the customer and support the deliverability of natural gas, regardless of the customer's size, it is appropriate and consistent with cost-causation to allocate these costs based on the number of customers.[8] (4 Tr 1645.)

This intuitive arrangement has been empirically demonstrated in this proceeding. In Exhibit AB-15, for instance, the length of distribution mains installed and the number of customers served by DTE for the period of 2008 through 2018 is plotted to demonstrate the strength of the relationship between these two variables. (See also 4 Tr 1645.) This analysis shows a definite relationship, producing a R Squared value of 0.60. (*Id.*) The relationships between the length of distribution mains and either peak day design (R Squared value of 0.39) or annual throughput (R Squared value of 0.08) are, conversely, much weaker and effectively nonexistent, respectively. (*Id.*; Exhibits AB-16, AB-17.) In other words, there is a conclusive relationship between the number of DTE's customers and its distribution mains investment,

[8] The Attorney General's argument that this contention is "subjective" is erroneous, as evidenced by the Attorney General's failure to provide any authoritative support for its claim. (4 Tr 1531.) The Attorney General focused on whether the distribution system is segregated between various customer types, which is irrelevant to the issue of whether a portion of distribution mains costs is generally customer-related. Variations in customer size, type, and density do not pertain to whether those customers cause distribution mains investment by the nature of their existence. Furthermore, the Attorney General's assertion ignored the fundamentals of a CCOSS, in which most of the costs are jointly-incurred; that is, they reflect the cost of the facilities DTE uses to serve all customers. As noted above, the claim that ABATE's proposal requires segregation of the distribution system's customer types is therefore demonstrably wrong.

while there is effectively no demonstrable relationship between the length of distribution mains and annual throughput. (4 Tr 1646.) Despite this lack of relation and the fact that no evidence has been provided in this proceeding to demonstrate that DTE relies on annual throughput to size its distribution mains, however, annual throughput was one of the drivers in the Company's proposed allocation of distribution mains costs in its CCOSS.

The allocation methodology proposed by DTE therefore lacks relative empirical support and should be rejected by the Commission. The much closer relationship between the number of the Company's customers and its distribution mains investment, conversely, demonstrates the need to allocate a portion of those costs on that basis. This result is also consistent with cost causation principles and is an accepted regulatory practice, as discussed in more detail below.

**i. Staff's disagreement with ABATE's proposal does not reflect the manner in which DTE incurs the distribution mains costs included in its CCOSS or the manner in which original distribution mains investments are collected from first customers.**

Staff objected to ABATE's overall proposal on this issue despite conceding that there is some relationship between the number of customers and distribution mains investment. Specifically, Staff acknowledged that "if a distribution main is built to serve one customer but no further main is built, then the main could be considered customer-related," but limited its admission by asserting that "the marginal customer (i.e. each additional customer beyond the first) does not cause the company to build more distribution main line, only the first customer does." (4 Tr 1115-16.) Thus, although recognizing that distribution main investment depends at least "tangentially on the *number of customers*," and "[i]t is possible that more customers will create more demand for distribution main," Staff claimed that "the existence or non-existence of the main is directly incumbent on the existence or non-existence of the single customer." (4 Tr

1116 (emphasis in original).) For the reasons set out below this claim is unreasonable and must be rejected.

Although acknowledging that DTE's CCOSS is based on allocating average, and not marginal, costs, Staff argued that DTE essentially only incurs distribution mains costs recovered through its CCOSS as a result of single first customers, and that no future customers served by that main are responsible for those costs. (See Exhibit AB-39 at 7.) This assertion ignores that a distribution main is designed to serve multiple customers and the associated costs should be allocated on that basis. A gas utility doesn't build a main line to serve just one customer; a main line is built to serve multiple customers and absent that main line customers will not have access to gas service. (See Exhibit AB-30 at 1.) Stated differently, although a single new customer may not require Consumers to install a new distribution main, 10, 50, or 100 new customers will directly result in investments in new distribution mains. After the first customer, the other 9, 49, and 99 customers are just as responsible for causing this new investment as the first customer taking service. To suggest otherwise is contrary to the physical realities of a gas distribution system and is unreasonable.

Staff also asserted that geography and customer density are more significant cost drivers than the number of customers served. (4 Tr 1116.) Though no explanation was provided,[9] to the extent that Staff's reference to geography and density related to costs associated with the impact of terrain on the physical layout of a gas distribution system, or service to urban contrasted with rural areas, these factors are fully recognized by the Company's Customer Attachment Program. This Program requires a customer contribution for extension of DTE's gas mains and service

[9] When asked to provide authoritative support for the contention that customer diversity or geography affect the length of distribution mains Staff failed to do so and noted that it "does not possess authoritative support for the statement that there is a direct relationship between

lines. (Exhibit AB-32.) These charges "include, but are not limited to, any specific license fees, inspection fees, or rights of way fees" as well as "an additional charge per foot for winter construction of all underground construction as installed, excluding conduit." (*Id.*) Also included in the customer contribution is an Excessive Service Line Fee "assessed to a customer whose service line requirement is in excess of the Service Line Limit" and, "for an individual service line shall be equal to the point at which the cost of the customer's service requirements are greater than the allowance based on the Cost of Service Model." (*Id.* at 3.) The customer contribution also encompasses a Fixed Monthly Surcharge "calculated such that the present value of the anticipated Surcharges collected from the Project will equal the net present value Revenue Deficiency."[10] (*Id.* at 4.)

In other words, if the incremental cost to serve a single new marginal customer (or customers) is higher than the average costs reflected in rates, due to differences in geography or customer density, the new customer(s) will pay the extra cost.[11] This payment ensures that there is no cross-subsidization between existing and new customers, thus addressing the incremental cost of a first new customer. This additional incremental cost does not, however, represent the entirety of the distribution mains costs at issue in DTE's CCOSS in this proceeding.

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geography and length of distribution mains." (Exhibit AB-39 at 3-4.)

[10] The net present value Revenue Deficiency is determined by using "the expected incremental revenues and incremental costs associated with the Project for each year of a twenty year period." (Exhibit AB-32 at 4.) Incremental revenues are calculated "based on current rates and a forecast of the timing and number of Customer attachments as well as Customers' annual consumption levels," while the incremental costs are calculated based on varying shifting factors including "estimated cost to construct distribution mains, Customer service lines, meters and pressure regulators or regulating facilities for the Project." (*Id.* at 5-6.)

[11] "A Project may consist of a single customer, requiring only the installation of a service line and meter, or may consist of numerous customers requiring the installation of mains, service lines and meters. A Project will generally be defined as a customer or group of customers that may be served from the contiguous expansion of new distribution facilities." (Exhibit AB-32 at 4.)

This is evidenced by Consumers Energy Company's explanation of its analogous Customer Attachment Program in Case No. U-20650, where Consumers' stated the following:

> First, the CCOSS appropriately only considers costs and revenues included in the revenue requirement that is used to set base rates; customer contributions are excluded from base rates. Second, the customer contributions . . . are for a variety of facilities including services, meters, regulators, and other equipment which is unrelated to a discussion around investment in distribution main. Third, the purpose of the minimum size study is to measure what drives investment in distribution main. A contribution paid to offset distribution main costs does not change or alter what drives investment in distribution main generally. (See Case No. U-20650, Doc. No. 183, Davis Rebuttal at 12-14.)

Thus, in addition to original incremental distribution mains costs the Company still collects distribution mains costs related to, for instance, meters, service laterals, and mains serving both previous and additional customers.[12] These costs are included in DTE's CCOSS, are caused by DTE's continued need to serve its customers (meaning they are directly related to the number of those customers), and should be classified as customer-related. As Staff acknowledged that it does "not know the precise financial mechanisms for DTE's line extension policy," Staff's basis for opposing ABATE's proposal to classify a portion of distribution mains as a customer-related cost lacks merit. (Exhibit AB-39 at 6.)

The claim that DTE's distribution mains costs are only indirectly related to the number of its customers, because essentially only the first customer causes those costs, does not reflect the manner in which customers cause the Company's distribution mains costs or how original

[12] The claim by the Citizens Utility Board ("CUB") that under DTE's Customer Attachment Program "all required revenue associated with the extension of mains and subject to recovery through this proceeding" is therefore inaccurate. (4 Tr 1618.) As previously stated, DTE's extension policy only applies when the incremental cost of extending gas delivery service exceeds the average cost of the facilities that are reflected in DTE's base rates. Thus, the fact that a new customer pays upfront for extending mains and other facilities to obtain service does not mean that no distribution mains costs are included in the CCOSS. In fact, distribution mains are a considerable portion of DTE's cost of providing gas delivery service.

incremental costs associated with new distribution mains investment are collected from new customers. Staff's argument on this point is therefore unreasonable and should be dismissed.

**b. Classifying a portion of distribution mains costs as customer-related is a common and accepted regulatory practice.**

In addition to the analytical relationship between the number of the Company's customers and the installation of its distribution mains, allocating distributions mains costs on this basis is a common regulatory practice. (*Id*.) Both the NARUC GRD and Gas Distribution Rate Design ("GDRD") manuals, for instance, discuss this allocation methodology.[13] The GDRD manual states that "[a] portion of the costs associated with the distribution system may be included as customer cost" and one argument for inclusion of distribution related items in the customer cost classification is the "zero [inch] or minimum size main theory." (NARUC, *Gas Distribution Rate Design Manual* at 22 (June 1989).) Similarly, the GRD manual indicates that the cost associated with distribution mains is typically functionalized on a demand and customer basis. (NARUC, *Gas Rate Design* at 28 (August 6, 1981).)

In addition to these NARUC manuals, there is uncontroverted testimony that a majority of state regulatory commissions throughout the country that have opined on this issue recognize both a customer- and a demand-related component of distributions mains. (See 4 Tr 1647.) These opinions have applied to utilities that serve both major urban centers and rural areas[14] (similar to DTE). To cite just two of these opinions, regulators in both New York and Connecticut have

[13] The National Association of Regulatory Utility Commissioners is a non-profit organization dedicated to representing the state public service commissions who regulate the utilities that provide essential services such as energy, telecommunications, power, water, and transportation. NARUC's members include all 50 states, the District of Columbia, Puerto Rico, and the Virgin Islands. See https://www.naruc.org/about-naruc/about-naruc/

[14] Examples of such utilities include the National Fuel Gas Distribution Corporation in New York and Yankee Gas Services Company and Connecticut Natural Gas Corporation in Connecticut. (4 Tr 1648-49.)

consistently adopted policies that classify a portion of distribution mains as a customer-related cost. See e.g. *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corp. for Gas Service,* New York State Public Service Commission Case No. 16-G-0257, Recommended Decision at 118-19 (January 23, 2017) (stating "that many portions of the Company's service territory consist of neighborhoods that are purely residential in nature" and "require a significant amount of investment in mains to serve these residential customers" such that "apportioning of some percentage of the cost of the mains in the customer charge is appropriate"); *DPUC Review of Natural Gas Companies Cost of Service Study Methodologies,* Connecticut Public Utilities Regulatory Authority Docket No. 99-03-28, Decision at 9-10 (August 9, 2000) (finding that a utility's investment was "clearly dependent upon 1) the number of customers served and 2) the maximum coincidental demand or combined demand of all customers on the peak day." Although all local gas distribution utilities may serve different geographic areas and have a distinct mix of customers, there is nothing unique to DTE that would indicate the same cost-causation principles generally applicable to all local gas distribution utilities cannot also be applied to DTE. (4 Tr 1646-47.) In other words, there is no specific demonstrable reason why cost allocation practices applicable to similar utilities are uniquely inappropriate for DTE.

Classifying a portion of distribution mains costs as customer-related is therefore not only supported by cost-causation principles and empirical evidence, it is also an accepted regulatory practice. Accordingly, this practice is both appropriate and necessary for DTE and should be adopted here.

#### i. Staff's objection to the guidance provided by other state utility regulatory bodies is contradicted by the authorities it references.

Staff claimed that the "decisions of other regulators in other jurisdictions on whether or not to classify a portion of distribution mains as customer-related is only partially informative" and the Commission must consider "the reasoning on which those determinations were made." (4 Tr 1117.) As Staff' did not rebut the reasoning of the decisions described above and instead provided "examples of the complexity of this issue" which did not reject classifying a portion of distribution mains costs as customer-related its argument should be rejected. (*Id.*)

Rather than engage with the New York and Connecticut decisions described above, Staff discussed regulatory actions from Minnesota and Illinois which support classifying a portion of distribution mains costs as customer related. (4 Tr 1118-19.) Specifically, the Minnesota Order Staff quoted stated that it found "merit in each theory" presented in that case, including the minimum-system approach which was "in line with previous cost studies approved" by the commission.[15] Minnesota Public Utilities Commission June 3, 2016 Order, Docket No. G-008/GR-15-424, p 53. Thus, it required the utility to "file a minimum-system study based on a statistically significant zero-intercept study, in addition to the two-inch pipe study it has traditionally used." *Id.*

With regard to the Illinois decisions, Staff acknowledged that the Illinois Commerce Commission "recently ruled both in favor [in 2018] and against [in 2013] classifying a portion of distribution mains as customer-related." (4 Tr 1119.) The more recent Illinois Order rejected the

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[15] Furthermore, while the Minnesota Order was ultimately "persuaded, on valid theoretical grounds, that the minimum-system studies over-allocate distribution costs to the customer component," it's important to note that ABATE's proposed customer allocation of distribution mains was reduced to half of the figure resulting from its analysis. (4 Tr 1118-19 (citation omitted); Exhibit AB-30 at 12; 4 Tr 1651-52.) In other words, the Minnesota commission's theoretical concerns are inapplicable to ABATE's proposal.

proposal to classify 100% of distribution mains as demand-related. The Illinois commission staff there "evaluated the ECOSS prepared by the Company and supported the findings of the Study" as "Staff found that the Study evaluates the allocator for gas service lines that reflects the level of service investment by customer class." Illinois Commerce Commission, January 31, 2018 Order, Docket No. 17-0124, p 115. Thus, the commission rejected the proposal "to classify 100% distribution mains as demand-related because 48% of Nicor Gas' distribution mains investment should be classified as customer-related." *Id*. at 122.

Instead of rebutting the persuasive additional authority set forth by ABATE's witness Jeffry Pollock, Staff instead referenced alternative jurisdictions, each of which found merit in classifying a portion of distribution mains costs as customer-related.[16] Staff's claim that decisions from additional state regulatory bodies are not influential should therefore be rejected.

**c. Failing to recognize a customer-related component in the cost of distribution mains misallocates costs and does not reflect their causation.**

Without allocating a portion of distribution mains costs on a customer-related basis DTE's CCOSS failed to properly allocate cost responsibility to the customer classes which cause those costs. This inequity is demonstrated via the following example provided by ABATE witness Jeffry Pollock:

[16] Contrary to the Attorney General's assertion that the "universe of gas utilities is not limited to the Northeast" and a "handful of jurisdictions using a customer-based allocation method is not a significant number that bears significant consideration," Mr. Pollock testified that his "research reveals that a majority of state regulatory commissions that have opined on this issue recognize both a customer and a demand-related component of distribution mains." (4 Tr 1532; 4 Tr 1647.) This testimony was note refuted. The Attorney General's description of ABATE's testimony was therefore inaccurate and unsupported by any reference to contravening authority. Furthermore, Staff's demonstration that additional regulatory commissions in the Midwest have favorably discussed this allocation shows that little weight should be given to the Attorney General's unsupported assertions.

> Assume there is a single industrial customer on DTE's system with a peak demand of 500 dekatherms (Dth). Further, assume that elsewhere on the system there is a neighborhood of 1,000 residential customers with an aggregated peak demand of 500 Dth. It is obvious that in order to connect all of those residential customers to the system, DTE would have to invest in far more footage of distribution mains than it would have to invest in for the one industrial customer. That extra investment in distribution mains is due solely to the number of customers on the system, not the peak demand of those customers. (4 Tr 1649.)

Thus, classifying all gas distribution mains costs as either demand- or commodity-based would drastically over-allocate these costs to extra-large transportation customers. This is illustrated by dividing the average length of distribution mains allocated to each customer class using DTE's Average and Peak ("A&P") allocation factors by the number of customers in each class. (4 Tr 1650.) This provides the average length of distribution mains allocated to each customer (*Id.*):

| Customer Class | A&P Allocation Factor* | Avg. Length per Customer (Feet)** |
|---|---|---|
| Rate GS-1/GS-2 - General | 16.99% | 203 |
| Rate A - Residential | 46.91% | 43 |
| Rate 2A - Multi-Family | 1.63% | 264 |
| Rate S - Schools | 0.66% | 3,288 |
| Rate ST Transportation | 5.03% | 11,923 |
| Rate LT Transportation | 5.20% | 57,485 |
| Rate XLT Transportation | 6.35% | 413,117 |
| Rate XXLT Transportation | 9.58% | 1,696,298 |
| DIG | 5.45% | 5,789,319 |
| Exelon | 2.21% | 2,352,585 |

**Sources:**
* Exhibit A-16, Schedule F1.2, page 3, Allocation Schedule #3.
** DTE Gas Model 2019 Rate Case (COS Markets) and MPSC 2018 Form P- 522

Contrary to Staff's claim that this analysis is of no probative value, this demonstration illustrates the unreasonableness of DTE's proposed allocation of distribution mains costs. (See 4 Tr 1120.) Without recognizing any customer-related component of distribution mains DTE's

CCOSS suggests that the Company only requires 43 linear feet of distribution mains to serve each residential customer. (4 Tr 1650.) Under its Service Line Limit, however, DTE allows up to 400 feet per installation for service lines. (*Id.*; 4 Tr 669.) The Company's proposed cost allocation would also suggest that DTE must install approximately 1 million linear feet of distribution mains to serve each extra-large transportation customer. (4 Tr 1651.) This discrepancy would directly contradict the notion that a gas delivery system is fully integrated and, for this reason alone, is obviously unreasonable. As distribution mains require a much more extensive investment than service laterals, each residential customer should require more than only 43 linear feet of mains. (*Id.*) In other words, DTE's proposed cost allocation does not reflect the physical realities of its gas distribution system. (*Id.*)

Any rates derived from the Company's CCOSS without recognizing that distribution mains costs are, in part, caused by the number of the utility's customers, would therefore be unjust and unreasonable. As such, the Commission should modify DTE's CCOSS to allocate a portion of distribution mains costs on a customer basis and thereby recognize those customers' cost of service.

#### d. The CCOSS adopted in this case should classify 40% of distribution mains costs as customer-related.

As set forth above, a proper CCOSS should classify a certain portion of distribution mains costs as customer-related. To do so the Company's CCOSS should utilize the Predominant Size allocation method. (4 Tr 1651-52.) This approach identifies the minimum sized distribution mains needed to serve customers and then classifies that portion of distribution mains as customer-related.[17] (4 Tr 1648-49.)

For DTE, the predominant size main is 2-inch plastic pipe. (Exhibit AB-30 at 12.) Over the past ten years DTE has installed about 12.7 million linear feet of distribution mains at a total cost of $728 million, which equates to an average installed cost of $57.17 per linear foot. (*Id*.; 4 Tr 1651-52.) During the same period, DTE installed 5.7 million linear feet of 2-inch plastic pipe at a total cost of $262 million, which equates to an average installed cost of $45.67 per linear foot.[18] (*Id*.) Thus, the Predominant Size method would classify approximately 80% ($45.67 ÷ $57.17) of distribution mains as customer-related. (*Id*.) As the Predominant Size method would classify such a significant percentage of distribution mains costs as customer-related, it is certainly reasonable to recognize at least some customer-related component of mains in DTE's CCOSS.

While the analysis provided in Exhibit AB-18 demonstrates that if all DTE's distribution mains were comprised of 2 inch plastic pipe, it would account for approximately 80% of the total investment in distribution mains made by DTE over the past ten years, 2 inch plastic pipe is only a subset of the totality of DTE's distribution mains. (4 Tr 1652.) As such, it is reasonable to classify 40% of distribution mains costs (which is half of the total cost of the 2 inch plastic mains

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[17] This is similar to the Zero-Intercept method, adopted in the New York and Connecticut decisions discussed above. (See 4 Tr 1647-48 (citations omitted).) This method uses regression analysis to identify the cost of a hypothetical "zero sized" main, the cost of which is necessary to serve customers connected to the system whether or not they place any demand on the system. While there may be subtle differences between the two methods, both recognize that certain distribution mains costs should be classified as customer-related and allocated based on the number of customers and not on peak demand. (4 Tr 1648-49.)

[18] This analysis demonstrates that Staff's claim that "[t]he predominant size on the Company's system is not the same as the minimum size available," and thus "Staff does not agree that the predominant-size method is equivalent to the minimum size method" is erroneous with regard to ABATE's proposal. (4 Tr 1119; 4 Tr 1648-49.) The analysis described above took into account

installed over the past ten years) as a customer-related. (*Id*.) This recommendation is consistent with the recent proposals by Consumers Energy Company to classify 43% to 44% of distribution mains as customer-related in both its pending and prior gas rate cases (Case Nos. U-20650, U-20322). The customer-related portion of distribution mains costs should be allocated based on the number of customers taking distribution level gas delivery service. (*Id*.)

As the Predominant Size method would classify such a significant percentage of distribution mains costs as customer-related, it is reasonable to recognize at least some customer-related component of mains in DTE's CCOSS. ABATE's proposal reasonably reflects DTE's distribution mains investment and is consistent with the recommendations provided by Michigan's other large gas distribution utility. As such, the Commission should modify DTE's CCOSS and allocate 40% of DTE's distribution mains costs on a customer basis.

**4. An appropriate CCOSS would remove all direct-served transmission customers from Allocation Schedule 3, remove the direct-served Rate LT and Rate XLT transmission customers from Allocation Schedule 3A, and classifying 40% of distribution mains costs as customer-related.**

Given the flaws in DTE's proposed CCOSS, a proper CCOSS was provided in Exhibit AB-19. This recommended CCOSS altered the CCOSS provided by the Company as follows: (i) revised Allocation Schedule 3 to remove all direct-served transmission customers (i.e. DIG and four of five Rate XXLT customers, three Rate LT customers, and two Rate XLT customers); (ii) revised Allocation Schedule 3A to remove the direct-served Rate LT and Rate XLT transmission customers; and (iii) classified 40% of distribution mains costs as customer-related. (See 4 Tr 1653.) Consistent with the discussion above, because DTE does not have specific cost

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the proportion of costs attributable to the relevant pipe sizes.

information regarding its customers' use of high- and low-pressure distribution mains, the CCOSS presented in Exhibit AB-19 overstated the cost to serve the Rate XLT class. (*Id.*)

An alternative CCOSS was also provided by ABATE in Exhibit AB-20. In this alternative CCOSS the costs of all distribution mains were classified to demand and allocated to distribution level classes based on peak day design. (*Id.*) This alternative recognized that distribution mains are sized to meet peak demand, as well as the fact that there is no relationship between the amount of distribution mains installed and annual throughput.[19] (*Id.*) In the event the Commission is not inclined to allocate a portion of distribution mains costs on a customer basis, this alternative approach is more reasonable than DTE's proposal and more properly reflects the design of the distribution system.

Lastly, the lower cost to provide direct transmission service to the Rate LT, Rate XLT, and Rate XXLT classes should be reflected by implementing a specific credit to those customers. (*Id.*) This would be consistent with the discounts that certain special contract customers (which are also directly served from the transmission system) currently receive. (4 Tr 1654.) Indeed, despite DTE's objection to this proposal based on the claim that "DTE Gas designs rates at the rate class level; the Company does not design different rates for individual customers or a subset of customers within a rate class," the Company acknowledged that DTE Gas does currently provide discounts to customers that take delivery service directly from the transmission system. (4 Tr 875 6; Exhibit AB-36.) DTE also acknowledged that "[i]t could be reasonable to recognize that a portion of a customer class takes service from the transmission system in determining the class's revenue requirement." (Exhibit AB-35.) Thus, while "a fundamental principle in COSS is that customers within a rate class share cost responsibility," the provision of a direct-transmission service credit to Rate LT, XLT, and Rate XXLT classes would reflect cost causation and is consistent with DTE's current practices.

### B. DTE's proposed class revenue allocation must be revised to correct the deficiencies in DTE's CCOSS.

In this proceeding the Company proposed an overall 17.4% increase in base delivery rates, excluding the cost of gas.[20] (4 Tr 1655; Exhibit AB-21.) Amongst customer classes this increase would range from a low of 12.4% (total residential services) to over 30% (total transportation services), although within the transportation category itself delivery rates would increase by between 14% to over 60%. (*Id*.) Because this cost allocation contained the flaws described above, it must be altered to properly assess costs in accordance with customer causation.

A proper class revenue allocation using the recommended CCOSS discussed above and provided in Exhibit AB-19 was provided in Exhibit AB-22. This CCOSS removed customers which are directly served by the transmission system from Allocation Schedules 3 and 3A and classified 40% of distribution mains cost as customer-related. (4 Tr 1655.) Again, this study still over-allocated costs to the Rate XLT class. (*Id*.) An alternative class revenue allocation was also provided at Exhibit AB-23. This alternative used the CCOSS provided at Exhibit AB-20, removed customers which are directly served by the transmission system from Allocation

[19] Staff noted that it was unaware of any analysis conducted by Staff in the past ten years showing a direct relationship between the cost of distribution mains and annual throughput and was unaware of whether DTE considered annual throughput when determining the size of distribution mains. (Exhibit AB-39 at 8-9.)

[20] The cost of gas was excluded from Exhibit AB-22 because this is a base rate case; i.e. the cost of gas is not at issue, although gas delivery rates are. (4 Tr 1655.) As such, gas costs are appropriately removed from current revenues to properly measure the impact of DTE's proposed delivery rate increase. (*Id*.)

Schedules 3 and 3A, and allocated distribution mains costs entirely on peak day design. (4 Tr 1655-56.) The transportation class' revenue increases were designed to approximately maintain the current economic breakeven points between Rates ST and LT (100,000 Mcf), Rates LT and XLT (700,000 Mcf), and Rates XLT and XXLT (3.9 million Mcf). (4 Tr 1656.) This is the same approach taken by DTE in this case and these breakeven points were previously approved in DTE's last rate case.[21] (*Id*.)

### C. The Company's proposed infrastructure recovery mechanism ("IRM") must be revised to reflect the customers taking service directly from the transmission system.

The Company proposed an IRM in this proceeding, the primary components of which included a Main Renewal Program. (4 Tr 728.) The capital investment associated with this program represented the vast majority of the IRM surcharge, and 94% of the capital costs in the program will be used to replace distribution mains and other distribution facilities. (See 4 Tr 1657; Exhibit AB-30 at 13.) As DTE allocated costs associated with this program to customers which do not utilize these mains or facilities, the proposed IRM must be altered to appropriately align costs with causation.

The Company proposed to allocate the capital costs of the Main Renewal Program using Allocation Schedule 3. (Exhibit A-18, Schedule H3.) Given the flaws described above, this allocation method would not account for whether an entire class (e.g. DIG) or a portion of certain customer classes (e.g. Rates LT, XLT, and XXLT) takes service directly from the transmission system. (4 Tr 1658.) It would not be appropriate to allocate costs related to distribution mains and facilities to these customers as they do not utilize the distribution system. Thus, doing so

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[21] Designing rates to maintain economic breakeven points is consistent with accepted practice. (4 Tr 1656.)

would over-allocate these costs to customers that do not cause DTE to incur them. (*Id.*) This is contrary to cost of service principles.

As explained above, Allocation Schedule 3 should therefore be adjusted to remove loads directly served from the transmission system, as set out in Exhibit AB-14. (*Id.*) The resulting adjusted IRM revenue requirement is set out in Exhibit AB-24 (Line 8). Further, for those classes in which a subset of customers are taking gas distribution delivery service, DTE's proposed IRM surcharge should apply. (*Id.*) The remaining allocated IRM revenue requirement not recovered from distribution-level customers should be recovered from transmission customers.[22] (*Id.*) These allocations are required to reflect cost causation.

### D. An appropriate ROE for DTE must be consistent with the Company's low regulatory risks, the risk-free cost of capital, and average authorized ROEs for other gas distribution utilities.

#### 1. Factors to consider when determining an appropriate ROE for DTE.

Determining a fair and reasonable ROE requires applying accepted methodologies utilizing inputs and assumptions that recognize current financial economic realities. (4 Tr 1696.) These realities include the following: (i) DTE's credit rating and financial strength; (ii) the Tax Cuts and Jobs Act ("TCJA"); (iii) the risk-free cost of capital; (iv) risk factors that affect DTE's ability to earn its authorized ROE; (v) ROEs authorized by additional state regulatory commissions across the country; (vi) stock market volatility; and (vii) the general principles used

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[22] The proposed IRM surcharges by customer class for gas delivery service provided at the transmission and distribution levels is provided at 4 Tr 1659, Table 4. The IRM surcharges are based on DTE's proposed IRM revenue requirements. (4 Tr 1659.) In addition, DTE's proposed IRM surcharges were used to set the rates for customers taking distribution gas delivery service, although an exception was made for Rate LT because the derived rate was higher than the proposed IRM surcharge. (*Id.*) The Rate LT distribution IRM surcharge was set to recognize that 94% of the Main Renewal Program costs were distribution-related. (*Id.*) The transmission IRM surcharge was designed to recover the remaining revenue costs not recovered from the distribution IRM surcharge. (*Id.*)

to determine a fair ROE. (4 Tr 1697.) Without considering these factors together the Company's ROE will not reflect its true cost of capital.

**a. The Company maintains a stable credit rating and is financially strong.**

The major credit rating agencies have assigned the Company high credit ratings, indicating its safety as an investment. Specifically, DTE has a long-term credit rating of A according to Standard & Poor's[23] ("S&P") and was assigned a credit rating of A1 by Moody's Investor Service ("Moody's").[24] (4 Tr 1696-97.)

This credit rating should remain stable, given DTE's proposed funds from operations ("FFO") to debt ratios[25] and rating agency benchmarks. In S&P's latest credit rating review, for instance, the agency [redacted] (Confidential Exhibit AB-31 at 2-4.) The Company's current FFO-to-debt ratio, without rate relief, is 17%, while the FFO resulting from its proposed ROE and equity ratio would be 25%. (4

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[23] In developing its credit ratings, S&P conducts a comprehensive review of utility business and financial risks. (4 Tr 1697-98.) In its October 31, 2019 review, [redacted] Its review stated that it [redacted]

[redacted]

[25] Credit rating agencies calculate FFO-to-debt ratios based on a utility's actual cash flows and long-term debt. (4 Tr 1700.) Cash flows are adjusted to account for other items such as interest expense, interest and dividend income, and current taxes, while long-term debt is adjusted to include such items as surplus cash, asset retirement obligations, pensions, etc. (*Id.*)

Tr 1699; Exhibit A-11, Schedule A2 at 3.) The FFO-to-debt ratio resulting from ABATE's lower ROE recommendation described below and DTE's 52% common equity ratio is 23%, which falls within S&P's current benchmark range of 13%-23%. (Exhibit AB-1; 4 Tr 1701.) The Company's FFO-to-debt ratio will therefore exceed S&P's benchmark and expectation, as set out above, meaning its credit rating will not be negatively affected as a result of ABATE's recommended ROE. In other words, DTE will be able to maintain its financial strength. (4 Tr 1701.)

The Company's credit rating will also be stabilized by the strength of Michigan's regulatory environment, even in the face of a decreased ROE. This is because a utility's credit rating is 50% attributable to a utility's regulatory environment; that is, the framework under which the Commission operates and the timeliness and sufficiency of cost recovery. (4 Tr 1700.) In other words, even if one of DTE's credit metrics falls below the optimum range, the fact that other metrics are well within or even above the recommended ranges, coupled with a strong regulatory environment, will substantially mitigate the risk of any credit downgrade. (*Id.*) Michigan's strong regulatory environment will therefore buttress DTE's credit rating, given that Michigan ranks in the top 15% of regulatory commissions across the United States. (4 Tr 1700-01.) This strength is attributable to several practices of which the Company avails itself, such as a streamlined rate case process, projected test years that reduce regulatory lag, and permitting utilities to earn a cash return on certain construction work in progress, all of which reduce the uncertainty of cost recovery. (*Id.*) This strong regulatory climate benefits utilities by reducing their risk and income variability, thereby stabilizing their credit ratings. (4 Tr 1701.)

#### b. The Tax Cuts and Jobs Act has not had a meaningful negative impact on the Company's credit rating.

The TCJA has been factored into DTE's credit ratings, which have not seen a meaningful reduction. (*Id.*) Furthermore, DTE's requested 52% common equity ratio will cushion its financial metrics, specifically its FFO-to-debt ratio, meaning an upward adjustment to its ROE is unnecessary for the Company to maintain its strong credit rating. (*Id.*) Thus, as with DTE's previous rate case, there is nothing to support an argument that the TCJA will adversely affect DTE's financials. *In the Matter of the Application of DTE Gas Co*, order of the Public Service Commission, entered September 13, 2018 (Case No. U-18999), p 43-44; cf. *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 8, 2020 (Case No. U-20561), p 173 (noting that the ALJ "found that DTE Electric failed to prove any increased risk associated with the TCJA" and "noted that the income component of the company's revenue requirements calculation will increase as the equity percentage of the ratemaking capital structure increases with the declining ADIT balance"). The impact of the TCJA should therefore not result in a higher ROE for DTE.

**c. The declining risk-free cost of capital indicates a lower ROE is appropriate.**

The 30-year U.S. Treasury bond interest rate (which represents the risk-free cost of capital) has steadily declined over the last twenty years. (4 Tr 1702.) When coupled with a historical risk premium (which measures the additional risk to a stock above the risk-free rate) a declining risk-free rate demonstrates that a lower authorized ROE is required. (4 Tr 1702-03.) This relationship is described further below.

**d. The Company's financial risk is minimal given Michigan's regulatory environment and DTE's cost recovery mechanisms.**

As noted above, a utility's financial risk is highly influenced by its regulatory climate. (4 Tr 1703-04.) Thus, for example, if a utility is authorized to set base rates using a fully projected future test year, utilize separate piecemeal cost recovery,[26] adjustment clauses,[27] and revenue decoupling that adjust rates automatically outside of base rate cases, and employ other constructive ratemaking practices, it will be less risky. (*Id.*) Again, the Commission's regulatory framework is viewed as very constructive for timely and effective utility cost recovery. (*Id.*)

DTE's cost recovery practices in particular greatly limit its risk. The Company currently recovers 37% of its costs through various surcharges and cost recovery factors, such as the Gas Cost Recovery ("GCR") factor and its IRM surcharge. (See 4 Tr 1704.) DTE also utilizes a Revenue Decoupling Mechanism ("RDM"), which reconciles distribution revenue approved in a rate case with actual weather-normalized distribution revenue. (*Id.*) These mechanisms allow DTE to receive timely recovery of these costs outside of a rate case and greatly reduce the risk that DTE will not obtain sufficient cost recovery.

Beyond these piecemeal cost recovery mechanisms, adjustment clauses, and revenue decoupling, DTE also reduces its risk by filing frequent rate cases, thereby reducing regulatory lag to recovery. (4 Tr 1705.) This is illustrated by the current proceeding, which DTE initiated just fourteen months after the Commission issued the final Order in its last rate case (Case No. U-18999). The Company also uses a projected test year, which reduces regulatory lag and lowers its risk by assuming future expenditures, rather than relying on historical incurrences. (*Id.*)

By lowering its risk, these mechanisms lower DTE's financial volatility and its associated expected cost of capital. (*Id.*) The Company has several tools available to reduce its regulatory

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[26] Piecemeal (or single-issue) ratemaking means authorizing a utility to implement adjustment clauses that permit it to change rates outside of a base rate case, while ignoring the utility's earnings. (4 Tr 1704.) Utilities can mitigate risk by implementing an adjustment clause that allows rates to change on an expedited basis and outside the context of a traditional rate case in accordance with cost changes. (*Id.*)

lag, including the several aforementioned mechanisms. As such, investors' required return for DTE will be lower. These myriad risk-reducing measures therefore support a reduction to DTE's current authorized ROE while still enabling DTE to maintain its credit rating, financial strength, and ability to attract capital. (*Id.*)

**e. Authorized ROEs continue to trend downward across the country.**

Over the past few years national average ROEs have remained below that currently authorized for DTE, dropping as low as 9.59% in 2018. (See 4 Tr 1705.) This trend indicates that utilities' financial and credit risks are generally lower than in the past. (*Id.*) This is due, in part, to the lower risk-free cost of capital and the implementation of a plethora of cost recovery mechanisms and other enhancements that have reduced regulatory lag, such as those discussed above. (*Id.*)

The impact of these mechanisms has been recognized in numerous regulatory orders nationwide, including those issued by the Massachusetts Department of Public Utilities (which found that "revenue decoupling mechanisms can act to reduce the variability of a company's revenues and, accordingly, reduce its risks") and the New Hampshire Public Service Commission (which stated that "a decoupling mechanism . . . eliminat[es] substantial revenue risks" and influenced its ROE decision). (See 4 Tr 1706 (citations omitted).) The Commission itself recently recognized this relationship as well. *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered September 26, 2019 (Case No. U-20322), p 44 ("The Commission also agrees with the ALJ that the company's previously approved RDM has reduced the company's risk"); *In the Matter of the Application of DTE Gas*

[27] Adjustment clauses shift the risk of cost recovery from shareholders to ratepayers as the utility is able to change its rates to recover costs on a current basis, without the expense and delay due to a rate case filing, which reduces regulatory lag. (4 Tr 1704.)

*Co*, order of the Public Service Commission, entered September 13, 2018 (Case No. U-18999), p 52 ("[T]here is a general reduction to risk because of the company's approved revenue decoupling mechanism and IRM, which supports a reduced ROE").

The Company's requested 10.5% ROE is 79 basis points higher than the average authorized ROE for other natural gas distribution utilities during 2019 (9.71%). (4 Tr 1706.) This is out of step with national ROE trends and cannot be reasonably considered to reflect DTE's cost of capital, given the ROEs assigned to its peers. The Commission should therefore recognize these national trends in establishing DTE's ROE.[28]

**f. General stock market volatility is typically greater than utility stock volatility.**

While the recent COVID-19 outbreak may have caused some swings in the stock market, utilities are considered defensive stocks which provide constant dividends and stable earnings regardless of the state of the overall stock market.[29] (4 Tr 1707.) Thus, "utility stocks are once again positioned as dividend-paying alternatives to bonds and often outperform[] the market." (*Id*. (citation omitted).) Indeed, as of March 13, U.S. utilities had outperformed the S&P 500 in 12 of the previous 13 Friday trading sessions. (*Id*. (citation omitted).) This is reflected in UBS' statement that given current circumstances "investors will be on the hunt for defensive stocks that offer a safe haven from market volatility," meaning stock market volatility will have less of an impact on utilities such as DTE. (*Id*. (citation omitted).)

Current circumstances may, in fact, benefit DTE's borrowing ability. The aforementioned stock market volatility has resulted in significant long-term interest rate decreases. (4 Tr 1708.) Specifically, the long-term rate on 30-year treasury bonds decreased from 2.33% on January 2,

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[28] If the Commission only set DTE's ROE at this national average the Company's projected revenue deficiency would decrease by $22 million. (4 Tr 1707; see Exhibits AB-2, AB-3.)

2020, to 1.49% on March 12, 2020, which is a reduction of 84 basis points. (*Id*. (citation omitted).) These lower interest rates will benefit DTE by providing it an opportunity to refinance its debt at a much lower cost, thus lowering its cost of capital. (*Id*.) Lower long-term interest rates will also reduce DTE's required ROE, as discussed in greater detail below.

Increased stock market volatility will have less of an impact on utilities because utility stocks are considered defensive, meaning they are safe havens for investors. This volatility has also resulted in lower long-term interest rates, allowing DTE to lower its cost of capital by refinancing its debt and, at the same time, reducing its cost of equity. As such, DTE's stock value may be less volatile than the overall market and, due to lower interest rates, the company may realize a financial benefit.

**g. General principles for establishing a fair ROE require the Commission balance investor and consumer interests.**

Determining a fair ROE generally requires "a balancing of the investor and the consumer interests" as "regulation does not insure that the business shall produce net revenues." *Federal Power Comm et al v Hope Natural Gas Co City of Cleveland*, 320 US 591, 603 (1944) (citation omitted). Thus, "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks" and "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Id*. As otherwise stated in *Bluefield Waterworks & Improvement Co v Pub Serv Comm of West Virginia et al*, 262 US 679, 692-93 (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; but it has no constitutional right to profits

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[29] The higher the volatility, the riskier the security. (*Id*.)

such as are realized or anticipated in highly profitable enterprises or speculative ventures.

The return should therefore simply "be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." *Id*.

As demonstrated below, DTE's proposed ROE goes far beyond this standard. Contrary to the Company's recommendation, an 8.9% ROE is a fair and reasonable balance of investor and customer interests that is commensurate with returns on similar utility investments having corresponding risks. This ROE will assure confidence in DTE's financial integrity and maintain its credit rating and ability to attract necessary capital.

**2. Based on empirical analyses an appropriate ROE for DTE is 8.9%.**

Considering the factors described above, a reasonable ROE for the Company can be established by applying established analytical methodologies to an appropriate proxy group of similar companies. In this case, applying two Discounted Cash Flow ("DCF") analyses (a Constant Growth and a Multi-Stage), two Capital Asset Pricing Models ("CAPM"), and a Risk Premium method to an appropriate proxy group of similar companies established a reasonable ROE range for DTE of 7.1% to 14.1%. (4 Tr 1710-28.) The average for this range is 8.9%, which represents a fair ROE for DTE in this proceeding. (4 Tr 1710.)

These analyses are standard methods for determining an appropriate ROE and were also utilized by DTE in forming its recommendation. (*Id*.) The analyses described below differ from those presented by DTE, however, with regard to the values of some inputs, the Company's risk profile, the composition of the proxy group, and, therefore, the results. (*Id*.) The overall methodological approach presented below is similar to that used by FERC and other state regulatory commissions, which rely on quantitative models and an assessment of a utility's risk profile to determine the appropriate ROE. (4 Tr 1711.) It is important to establish an appropriate balance between quantitative models and qualitative considerations when determining an appropriate ROE; i.e. while quantitative results provide a reasonable estimate of an appropriate ROE, qualitative factors, such as relative risk to a proxy group, must also be considered. (*Id.*)

#### a. The Company's proxy group included several companies which are not fundamentally similar to DTE.

In developing its proposed ROE in this proceeding the Company utilized a proxy group containing numerous companies which are not similar to DTE and do not reflect its specific risk. As such, DTE's proxy group and its ROE analyses incorporating the same should be rejected.

An appropriate proxy group includes companies involved in similar operations with similar risk to DTE. (*Id.*) By establishing such a comparative group, a cost of equity estimate for the proxy group will represent the economic opportunity costs that have an impact on DTE's ROE. (*Id.*) In other words, developing a proxy group that is fundamentally comparable to DTE will establish a ROE for DTE that is commensurate with returns on investments in enterprises having corresponding risks, as is required by the standard set out in *Hope*. (4 Tr 1712.)

Based on DTE's circumstances, an appropriate proxy group should include utilities having the following common characteristics: (i) consistently pay positive, quarterly cash dividends; (ii) are classified as a natural gas utility by Value Line Investment Survey (Value Line); (iii) are covered by more than one equity analyst; (iv) have gas revenues greater than 50% of total operating revenues; (v) have a Moody's credit rating of Baa3 or higher; (vi) have positive earnings growth reported by at least two of the following analysts: Value Line, Yahoo! Finance, or Zacks Investment Research (Zacks); and (vii) were not involved in any merger or acquisition related activities within the past six months. (*Id.*)

Using these characteristics establishes an appropriate comparative proxy group for DTE for the following reasons: (i) paying positive, quarterly cash dividends indicates that a company is growing; (ii) they establish the company is engaged in similar operations as DTE; (iii) coverage by more than one equity analyst provides a robust estimate of its earnings growth; (iv) gas revenues greater than 50% indicate the company is primarily a gas utility, with operating characteristics similar to DTE; (v) a Moody's credit rating of Baa3 or higher indicates the company is investment grade, similar to DTE; (vi) DTE has positive growth forecasts and therefore, the comparable companies should also have similar growth prospects; and (vii) utilities involved in mergers or acquisitions exhibit distorted stock prices that are not representative of "normal" operating conditions. (4 Tr 1712-13.) The inclusion of proxy group companies which diverge from these criteria will therefore ultimately result in a ROE recommendation which is divergent from DTE's actual cost of capital.

The proxy group presented in ABATE's analysis matched that provided in DTE's proposal, with the exception of several water and gas companies which were not fundamentally comparable to DTE. (4 Tr 1713-14.) These companies were included in DTE's proxy group because, in addition to the screening criteria utilized by ABATE, DTE's screening criteria admitted companies that had the following broader characteristics: (i) business operations concentrated in regulated industries or having similar lines of business and/or business environments; (ii) classified as a natural gas or water utility by Value Line; and (iii) have 50% or more of their assets dedicated to regulated utility activities in their industry. (4 Tr 914-16.) The Company acknowledged that not all of its selected proxy companies had a credit rating from the major rating agencies, but rather were assigned an average credit rating based on the rest of the proxy group if DTE determined that "if they were to be rated, they would receive an investment grade rating." (4 Tr 916.)

The Company's selected proxy group was therefore less fundamentally comparable to DTE than that utilized by ABATE. In addition to a number of incongruous utilities,[30] DTE's alternative selection criteria included five water companies, which do not have similar business operations to a natural gas utility. (4 Tr 1715.) The Commission has noted the impropriety of relying on water companies in proxy groups in DTE Gas' last rate case. *In the Matter of the Application of DTE Gas Co*, order of the Public Service Commission, entered September 13, 2018 (Case No. U-18999), p 53 ("The ALJ also correctly questioned the relevance of DTE Gas' proxy group based on the heavy reliance on the water utility industry"). The Company's proxy group is therefore fundamentally flawed and failed to meet the *Hope* standard described above (i.e., that the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks).

Proxy groups should include companies that are similar in nature to DTE's operations. Without these similarities the application of the ROE methodologies will produce distorted results which do not represent an appropriate ROE for a natural gas utility similar to DTE. (4 Tr 1716.) As the Company's proxy group contained multiple companies which are not fundamentally similar to DTE, this group and the Company's analyses utilizing the same should be rejected.

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[30] These utilities are not comparable to DTE for the following reasons: (i) Chesapeake Utilities derives more than 50% of its operating revenues from unregulated operations; (ii) only 27% of New Jersey Resources operating revenues are from natural gas distribution operations; (iii) NiSource Inc.'s subsidiary Columbia Gas was recently purchased by Eversource Energy; and (iv) South Jersey Industries derives less than 50% of its operating revenues from regulated gas operations.

### b. Discounted Cash Flow analyses.

Investors use DCF models to determine the present value of a stock based on future cash flows (i.e., dividends), which are discounted by the stock's known return and its forecast growth.[31] (*Id.*) The analyses below utilized a 30-day average for the stock prices. This ensured the results reflected stock prices over a period of time and were not overly reliant on any particular events affecting stock prices on a given day. These averages also represented capital market conditions over the past month. (4 Tr 1717.)

ABATE conducted analyses using two DCF methods: (i) a single stage DCF method based on a constant growth rate using analysts' forecast earnings growth rates; and (ii) a multi-stage DCF method using three different growth rates for the near-term, intermediate-term, and long-term. (4 Tr 1716.)

#### i. Single-stage DCF analysis.

The single-stage DCF model provided an estimated ROE range for DTE between 7.9% (low estimate), 10.3% (mean estimate), and 14.1% (high estimate). (4 Tr 1717.) The low estimate was based on the lowest forecast growth rate for each utility in the proxy group. (*Id.*) The mean estimate was based on the average forecast growth rate for each utility. (*Id.*) The high estimate was based on the highest growth estimate for each utility. (*Id.*) The results are shown in more detail in Exhibit AB-4, which includes the constant growth DCF calculations for each company in ABATE's proxy group using forecast growth rates from Value Line, Yahoo! Finance, and Zacks.

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[31] ABATE's DCF analyses utilized stock prices from February 10, 2020, through March 10, 2020, from Yahoo! Finance. The growth rates are the forecast earnings per share ("EPS") growth rates for the next five years from Value Line, Yahoo! Finance, and Zacks. The dividends are the forecast 2020 figures, also from Value Line. These were adjusted to reflect any quarterly adjustments during the year. (4 Tr 1717.)

### ii. Multi-stage DCF analysis.

Contrasted with a single-stage DCF analysis, a multi-stage DCF analysis uses three separate growth estimates, or "stages." (4 Tr 1718.) The first stage measures the near-term growth rate based on the analysts' forecast earnings growth used in the constant growth DCF analysis. The second stage (intermediate-term) growth rates are linear interpolations of the first and third stage growth rates. The third stage (long-term) is the forecast of the long-term growth rate of gross domestic product ("GDP").[32] (*Id.*) Using these inputs, the model calculates the required internal rate of return to meet these dividend growth rates, or the ROE. (*Id.*)

A multi-stage DCF is used because analysts' growth rates for the first stage may not be sustainable over the long-term. (4 Tr 1718-20.) In other words, basing a regulated utility's ROE solely on analysts' short-term forecasts may over-state (or under-state) the expected ROE. Under the multi-stage DCF method, the short-term growth rate is recognized but it does not dictate the estimated ROE for the long-term. (*Id.*) This is important, as analysts' short-term forecasts may overstate an expected ROE because they are based on a three-to-five year outlook, a period in which growth may be higher than the expected growth rate in long-term GDP. (*Id.*) Again, in the short-term, some utilities may grow faster than GDP, but this cannot happen consistently over a long period.[33] (*Id.*) Overall, analysts' growth rates should therefore be viewed in conjunction with other growth estimates to achieve a reasonable forecast of expected earnings. (*Id.*) The multi-stage model recognizes short-term growth (whether it be higher or lower than the long-

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[32]The forecast long-term GDP growth is used because the underlying assumption is that mature, established companies can grow at a rate that is similar to, or lower than, the GDP growth rate. (4 Tr 1718.) While some companies in the economy will grow faster than GDP for a while, this cannot happen consistently over a long period. (*Id.*)

[33] For example, Value Line projects a growth rate of 27% for Northwest Natural Holdings. (4 Tr 1718 (citation omitted).) This growth rate is not sustainable over the long-term and produces an unrealistically high ROE. (*Id.*)

term), but also accounts for a more realistic, long-term growth rate. (*Id.*) Thus, compared to the single stage DCF method, the multi-stage DCF method provides a more realistic expectation of growth in the short-term and in the long-term. (4 Tr 1719.)

ABATE calculated three multi-stage ROE analyses using a low, mean, and high first year growth rate based on the analysts' forecast estimates of growth, similar to the constant growth DCF analysis. (4 Tr 1718.) The estimated ROEs using this method were 7.1% (low), 7.6% (mean), and 8.8% (high). (4 Tr 1719; Exhibits AB-5, AB-6, and AB-7.)

**c. Capital Asset Pricing Model.**

A CAPM is a Risk Premium method which states that the expected return of a security equals the risk-free rate[34] plus a risk premium. (4 Tr 1720.) In other words, the model posits that investors require a premium over the risk-free rate to incent them to invest in a risker security. (*Id.*) A stock's risk premium is determined by multiplying the market risk premium ("MRP") by the stock's beta. (4 Tr 1721.) The MRP is the difference between the return on the market on average (i.e. the S&P 500) and the risk-free rate.[35] (*Id.*) Thus, it is the premium that reflects the risk on an average stock. (*Id.*) Beta is the price volatility of that stock relative to the market as a whole and measures the compensation an investor needs to take on additional risk, as compared

[34] The risk-free rate is the projected yield on 30-year U.S. Treasury bonds. (4 Tr 1721.) This rate is considered to be risk-free because the return is guaranteed by the U.S. government. (*Id.*)

[35] ABATE used two estimates to determine the MRP: the historical MRP (6.91%) and a projected MRP (9.45%). (4 Tr 1721.) The historical MRP (1926-2018) was provided by DTE, and the projected MRP was based on the projected median three-to-five year price appreciation of the 1,700 stocks from Value Line and the projected median dividend yield over the next 12 months for all dividend paying stocks. (4 Tr 921; 4 Tr 1721.) The forecast annual return was based on the forecast annual growth rate (10.03%) of the stocks plus the forecast median dividend (2.16%), which produced a projected annual return of 12.19%. (4 Tr 1722.) Subtracting the projected risk-free rate (2.74%) resulted in a projected MRP of 9.45%. (*Id.*)

to the risk-free rate.[36] (4 Tr 1721, 1723.) The risk premium for a *specific* stock therefore equals the *average MRP*[37] times the beta. (4 Tr 1721.) Since utility stocks are lower risk than the average stock, the risk premium for a utility stock is lower than the average MRP. (*Id.*) Multiplying the beta times the MRP gives the appropriate risk premium for the company (or group of comparable companies) being studied. (*Id.*)

ABATE's CAPM analysis utilized the forecast risk-free rate of 2.74%, which is based on the 2021 long-term forecast rate for the 10-Year Treasury bond, adjusted to reflect the historical basis point spread in the 10-Year Treasury bond and the 30-Year Treasury bond. (4 Tr 1724.) The projected 10-Year Treasury bond rate is [redacted] and the historical spread is [redacted] which results in a projected risk-free rate of 2.74%. (*Id.* (citation omitted); Confidential Exhibit AB-8.) It should be noted, however, that this forecast is from October 2019 and does not reflect the recent impact of reductions in the Federal Reserve's short-term rates. (*Id.*) While the MRP may be higher, the long-term risk-free rate therefore may be lower, which will reduce the estimated ROE. (*Id.*)

The beta utilized in ABATE's CAPM analysis was determined by reviewing the betas of the same group of companies used in ABATE's DCF analysis.[38] (4 Tr 1723.) These betas were calculated using a method which is based on a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE

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[36] A stock beta equal to 1.00 means that stock's price fluctuates exactly with the market as a whole. (4 Tr 1722.) A beta higher or lower than 1.00 means a stock's price is more or less volatile than the market overall, respectively. (*Id.*)

[37] A historical MRP provides a good approximation of future risk premiums as long-term data shows the MRP throughout many economic cycles, thereby providing a reasonable expectation of future performance. (4 Tr 1722.) A projected MRP, however, is also important as ROE estimates are forward-looking and should reflect anticipated performance. (*Id.*)

[38] The beta for each utility was from Value Line. (4 Tr 1723.)

Composite Index over a period of five years. (*Id*. (quotation omitted).) These betas are then adjusted to account for their long-term tendency to converge toward 1.00. (*Id*.) The Company similarly used the average of the betas for each company in its proxy group. (*Id*.)

The estimated ROE using the historical MRP is 7.2%, while the estimated ROE using the projected MRP is 8.8%. (4 Tr 1724; Exhibit AB-9.)

#### d. The Risk Premium method established a reasonable ROE for DTE of 8.36%.

A Risk Premium method estimates the ROE for a utility by summing a bond yield plus a risk premium yield. (4 Tr 1724.) The bond yield is the projected return on the long-term government bond (2.74%) plus the historical risk premium (5.62%). (*Id*.) The risk premium is a measure of the additional return an investor requires due to the additional risk of the security. (*Id*.) The risk premium is the measure of the difference between the historical authorized return on equity for natural gas distribution utilities (10.67%, in this case) and the historical yield on 30-year Treasury bonds (5.05%, in this case). (4 Tr 1725.)

Similar to DTE's analysis, ABATE's Risk Premium analysis compared authorized ROEs for gas utilities since 1990 to the risk-free rate at the time the ROEs were authorized. (*Id*.) This data was used to develop the average historical ROE and long-term risk-free rate and determine a reasonable ROE for DTE. (*Id*.) The results of this analysis are provided below:

| Description | Amount |
|---|---|
| **Historical Average Authorized ROE** | 10.67% |
| **Historical 30-Year Treasury Yield** | 5.05% |
| **Historical Risk Premium** | 5.62% |
| **Projected 30-Year Treasury Bond Yield** | 2.74% |
| **Return on Equity** | 8.36% |

As authorized ROEs are typically based on estimates of the required return at the time of the proceeding, ABATE's estimate recognized the average, expected historical risk premium for natural gas distribution utilities over the long term. (*Id.*) This analysis also provided a realistic long-term estimate of the risk premium for natural gas distribution utilities and recognized that the risk premium can fluctuate depending on market conditions and investor expectations. (*Id.*) Using the average risk premium over this time-period is therefore a reasonable method to estimate the current risk premium. (*Id.*; see Exhibit AB-10.)

**3. The recommended reasonable ROE described above will ensure DTE is financially sound and able to attract capital at reasonable rates.**

Using the Company's FFO-to-debt methodology and the recommended ROE and equity ratio described above, DTE's FFO-to-debt ratio will be 23%. (4 Tr 1726.) It's important to note, however, that the methodology DTE used to determine its financial metrics was based on ratemaking, rather than the methodology used by credit rating agencies. (*Id.*) The financial metrics provided by DTE are therefore simple approximations.[39] (*Id.*)

As noted above, a FFO-to-debt ratio of 23%, while 2% lower than the FFO-to-debt ratio resulting from DTE's recommendations, is within the credit rating agencies' benchmark range to maintain the Company's current credit ratings. (4 Tr 1727.) The Company has [redacted], as indicated in its latest credit report from S&P and, as previously stated, S&P's benchmark range for the FFO-to-Debt ratio for a utility with significant financial risk (low volatility) is 13%-23%. (*Id.* (citations omitted);

[39] Part III of the Commission's filing requirements require DTE to provide its financial metrics using the credit rating agencies' methodologies. Despite this requirement DTE provided financial metrics on a ratemaking basis, stating that "[e]ach rating agency has its own methodology for calculating financial ratios" and the "adjustments used by the rating agencies are not readily available," so DTE used the "standard methodology for calculating ratios" in the financial metric calculations. (Exhibit A-11, Scheduled A2 at 3.) Despite these assertions, the Company should be able to produce its financial metrics as required by the filing requirements. (4 Tr 1726-27.)

Confidential Exhibit AB-31 at 2-4.) Thus, the estimated FFO-to-debt ratio resulting from ABATE's recommendations falls within S&P's benchmark range, meaning DTE's credit rating should not be negatively affected. (4 Tr 1727.) As the Company's credit rating will not be adversely impacted, an 8.9% ROE will enable DTE to maintain its ability to attract capital at reasonable rates.

An 8.9% ROE therefore properly recognizes and reflects DTE's risk profile (including its adjustment clauses and reduced regulatory lag) and, while lowering the Company's requested revenue increase by $44.3 million for customers, will provide investors a return that is equivalent to the cost of capital for comparable utilities. (4. Tr 1728; Exhibit AB-11.) As such, the Commission should reject the improperly inflated and excessive ROE recommendation presented by the Company in this proceeding and adopt an 8.9% ROE as supported by the analyses described above.

**4. The Company's proposed 10.5% ROE is improperly inflated.**

DTE recommended a 10.5% ROE in this proceeding based on four methodologies (two CAPM, two Empirical Capital Asset Pricing Models ("ECAPM"), two Risk Premium methods, and two DCF methods) which used the Company's full proxy group sample (i.e., the gas utility proxy group sample and the water utility proxy group sample). (4 Tr 940.) As set out below, this recommendation was based on erroneous assumptions and improper risk adjustments which improperly increased the Company's proposed ROE. (See 4 Tr 1729-30.) As such, the Commission should reject DTE's proposal and approve a ROE of 8.9%.

**a. The use of the financial risk adjustments in DTE's CAPM is unnecessary and improper.**

The Company conducted two CAPM analyses using two estimates of the MRP and two estimates of the risk-free rate, as well as two financial risk adjustments: an overall after-tax weighted average cost of capital ("ATWACC") adjustment and what is known as the Hamada Adjustment. (4 Tr 1730-33.) Neither of these adjustments was appropriate or necessary and both served only to artificially inflate DTE's ROE recommendation.

The use of the ATWACC financial risk adjustment inflated DTE's ROE by 160 basis points by improperly comparing the estimated ATWACC using DTE's proxy groups' *market* value capital structures to DTE's *book* value capital structure. (4 Tr 1731-32.) This comparison of market value to book value capital structures is not only contrary to regulatory practice, it is inapt, as capital structures used in utility regulation are based on book, not market value. (4 Tr 1732.) Comparing the two is therefore improper. (*Id.*) This is evidenced by the fact that the ATWACC adjustment is not commonly used in regulatory proceedings when determining a utility's ROE, as has been recognized by the Commission previously. See *In the Matter of the Application of DTE Gas Co*, order of the Public Service Commission, entered September 13, 2018 (Case No. U-18999), p 48 (noting the ALJ's recognition that "neither the Commission, nor any other state regulatory commission, have adopted" the use of the ATWACC adjustment in a CAPM); *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 8, 2020 (Case No. U-20561), p 173 (explaining that the ALJ "noted that the Commission has already rejected the ATWACC method of adjusting proxy group results").

The Hamada Adjustment is a similar financial risk adjustment which adjusted the Company's proxy group betas to recognize the difference in their *market* value capital structure and DTE's *book* capital structure. (*Id.*) Specifically, the betas for the proxy companies are "unlevered," or adjusted to reflect their value if the company did not have any debt in its capital structure. (*Id.*) These unlevered betas are then *re-levered* using DTE's book value capital structure to determine the average beta for the Company's CAPM analyses. (*Id*.) The Hamada Adjustment thereby also artificially increases the beta (i.e. increases DTE's risk), which results in a higher ROE. (*Id*.) Like the ATWACC adjustment, the Hamada Adjustment was also recently rejected in a similar context. (Case No. U-20561, Proposal for Decision entered May 8, 2020, p 300-01.)

In addition to being improper and routinely rejected, these financial risk adjustments are unnecessary when considering DTE's financial risk relative to the companies in DTE's proxy group. DTE's credit rating is equal to or better than the credit ratings of the majority of the utilities included in the Company's proxy group. (4 Tr 1732; Confidential Exhibit AB-31.) Specifically, seven of the proxy group utilities have credit ratings below DTE, six have the same credit rating, and only two have credit ratings higher than DTE. (4 Tr 1733.) As credit ratings agencies consider a company's business and financial risk when determining its credit rating, DTE's credit rating demonstrates that it does not have significant financial risk compared to the companies in its proxy group. (*Id*.) Increasing DTE's risk relative to these companies is therefore unwarranted and unjustified.

The Company has not presented evidence in this case that DTE has increased financial risk relative to its proxy group. (7 Tr 1734.) These financial risk adjustments are therefore needless and only serve to artificially inflate DTE's recommended ROE. As such, the Commission should reject the Company's CAPM analysis and the Company's ROE proposal based thereon.

#### b. The Company's ECAPM is unnecessary and included inappropriate risk adjustments.

The Company's ECAPM analyses were similar to its CAPM analyses; they used the same parameters as the CAPM analyses and also applied both the ATWACC and Hamada adjustments. (4 Tr 1734-35.) Unlike DTE's CAPM analyses, however, its ECAPM analyses adjusted the formula using a component called "alpha" which improperly inflates beta. (*Id*.; see Exhibit A-14, Schedule No. D5.15.) As this adjustment is unnecessary and improperly inflated DTE's ROE recommendation, the Company's ECAPM analyses should be rejected.

This alpha component amounts to an additional adjustment used to account for the fact that over the long term the risk of companies with betas less than one can be under-estimated; that is, their risk is actually higher than the risk defined by the beta. (4 Tr 1735.) Similarly, over the long term companies with betas greater than one can be over-estimated; that is, their risk is actually lower than the risk shown by the beta. (*Id*.) The alpha adjustment therefore re-adjusts beta values, resulting in higher betas for low-risk securities and lower betas for high-risk securities. (*Id*.) In other words, the alpha adjustment produces an over-stated ROE for low-risk securities as, like the Hamada adjustment, it artificially inflates the beta value. (*Id*.)

This alpha adjustment to DTE's ECAPM analysis is unnecessary, as the betas utilized by DTE were already adjusted prior to their incorporation in the Company's analyses. (4 Tr 1735-36.) Thus, the betas already account for underestimation (or overestimation) of the ROE results. (4 Tr 1736.) There is therefore no need to readjust the beta values or perform an ECAPM analysis, as it readjusts the formula in an attempt to capture a phenomenon that the adjusted beta has already corrected. (*Id*.) The flaw in this methodology is reflected in the fact that this adjustment and the Company's ECAPM analyses have been formerly rejected in similar contexts. (See Case No. U-18999, Proposal for Decision, July 16, 2018, p 77 ("DTE Gas's ECAPM analysis, and its ATWACC adjustment, result in unreasonable and inflated ROE estimates"); Case No. U-20561, Proposal for Decision, March 5, 2020, p 301 ("Notwithstanding Dr. Villadsen's testimony asserting that the empirically-determined adjustments Value Line betas do not duplicate the empirically-determined ECAPM alpha-values, this PFD finds . . . that the two adjustments are duplicative”).)

Thus, as has been recognized previously, the Company’s ECAPM analyses and the financial risk adjustments employed therein improperly inflate DTE’s recommended ROE. The Company’s ECAPM analyses and ROE recommendation based thereon should therefore be rejected.

**c. DTE’s Risk Premium analyses failed to consider additional factors that could affect the equity risk premium.**

As explained above, the Risk Premium method estimates the ROE for a utility as the sum of a bond yield plus a risk premium yield. In essence the risk premium is a measure of the additional return an investor requires due to the additional risk of the security. (See 4 Tr 1736.) The Company created a regression analysis to estimate a predicted risk premium and purportedly demonstrate that there is an inverse relationship between equity risk premium and interest rates. (4 Tr 1736-37.) The Company’s regression analysis is flawed, however, as it did not consider other factors, such as different Federal monetary and fiscal policies, that could affect the equity risk premium. (4 Tr 1737.)

This flaw makes DTE’s risk premium analysis deficient. The risk premium analysis provided by ABATE, conversely, recognized the average, historical spread of authorized ROEs over long-term risk-free rates. (*Id.*) Specifically, therefore, the actual risk premium provided by ABATE reflected all information that may affect the spread, not just interest rates. (*Id.*) Thus, the historical risk premium utilized by ABATE was based on actual data and provided a more accurate estimate. (*Id.*) Given the flaws in DTE’s methodology and its application, the Commission should therefore reject DTE’s risk premium analysis and its inaccurate ROE estimation.

### d. The Company's DCF analyses also contained improper risk adjustments that artificially inflated its ROE recommendation.

Like ABATE, DTE performed two DCF analyses: a single stage DCF analysis and a multi-stage DCF analysis. (4 Tr 1738.) The Company's DCF analyses used data from its gas proxy group, water proxy group, and the full proxy group to estimate DTE's ROE. (*Id.*) The data included historical stock prices, dividend prices, and growth estimates for each company. (*Id.*) The Company then applied the ATWACC adjustment to determine DTE's estimated ROE. As this adjustment was flawed the Company's DCF analyses should be rejected.

For the same reasons raised above, the ATWACC adjustment, which DTE also used in its CAPM and ECAPM analyses, is inappropriate. (*Id.*) A financial risk adjustment is simply not necessary and resulted in a ROE proposal that was artificially higher than necessary. For these analyses, specifically, the ATWACC adjustment increased the ROE from 130 basis points to 380 basis points. (4 Tr 1739.) This inflation is flawed and unreasonable.

The Company's DCF ROEs are therefore based on a financial risk adjustment that results in improperly inflated ROEs. Again, the financial risk adjustment is unnecessary based on DTE's credit rating compared to the proxy group and has previously been rejected. As such, the Company's DCF analyses and resultant recommended ROE should be rejected.

### e. The Company's analysis regarding capital expenditures improperly included proxy group outliers.

The Company also provided an analysis that compared the revenues to gross property, plant, and equipment ("PP&E") for DTE and the companies in its proxy group.[40] (*Id.*) Based on

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[40] The revenue to gross PP&E ratio presents a company's capital intensity, i.e. the amount of revenue the company has for each dollar of PP&E. (4 Tr 1740.) The metric is used to compare the level of capital expenditures between DTE and the proxy companies. (*Id.*) A higher ratio, as compared to the proxy group, indicates that a company is engaged in a relatively higher capital expenditures program. (*Id.*)

its analysis, the Company concluded that DTE has more risk because it has a lower revenue to gross PP&E ratio than the proxy companies. (*Id.*) As this analysis contained errors invalidating its results it should be rejected.

The Company's analysis is not correct as it included a significant outlier in its data; thereby skewing the results. (4 Tr 1740.) The average revenue to gross PP&E for each company in DTE's proxy group, for the period 2012–2018, is 34.8%, compared to 30.7% for DTE. (*Id.* (citation omitted).) The 34.8% average results from DTE's proxy group ratios ranging from [redacted]. (*Id.*) Excluding the [redacted] outlier would reduce the average ratio to 29.3%, which is, in fact, below DTE's ratio of 30.7%. (*Id.*; Confidential Exhibit AB-12.)

Based on this corrected analysis, DTE does not have increased risk as compared to the proxy group. The Company's analysis and its recommended ROE based thereon must therefore be rejected.

**f. Based on the numerous flaws in DTE's analyses the Commission should reject its ROE recommendation.**

As set forth above, DTE's ROE recommendation was derived from various analyses containing numerous fatal flaws. These deficiencies resulted in a ROE recommendation that is unreasonable and should be rejected by the Commission.

Specifically, the Company's proxy group included companies that are not comparable in risk to DTE, such as water companies and companies that do not derive the majority of their revenues from regulated gas operations. (4 Tr 1740-41.) Furthermore, DTE's recommended 10.5% ROE did not recognize DTE's reduced risk due to regulatory mechanisms it has in place that reduce regulatory lag and income variability. (*Id.*) Regarding the methodologies and analyses which DTE applied to its flawed proxy group, the Company's two CAPM methods relied on market-to-book adjustments that produced inflated ROEs based on the inaccurate assumption that DTE has increased financial risk. (*Id*.) As DTE does not have increased financial risk as compared to the proxy group, these financial risk adjustments are unnecessary and have been previously rejected by the Commission. (*Id*.) As for DTE's further analyses, its ECAPM is not a common method and produced over-stated ROEs by improperly adjusting betas that had already been adjusted. (*Id*.) The Risk Premium analyses also relied solely on the relationship between interest rates and the risk premium, meaning it did not include other relevant factors that could impact the risk premium, such as Federal monetary and fiscal policies. (*Id*.) In addition, the Company's DCF analyses again used the ATWACC adjustment, which significantly and artificially increased its estimated ROEs. (*Id*.) Lastly, the Company's reasoning for increasing DTE's ROE due to its capital expenditures program is unfounded and should be rejected. (*Id*.)

Given these numerous flaws and deficiencies, the Commission should reject the Company's analyses and DTE's recommended ROE based thereon. Contrary to DTE's assertions, an 8.9% ROE is reasonable and should be adopted by the Commission.

#### 5. Staff and the Attorney General's recommendations are higher than their analyses support.

The Staff and Attorney General both provided ROE recommendations which, while more reasonable than DTE's, were artificially inflated and unsupported by their analyses. Specifically, the Staff and Attorney General failed to submit reasonable evidence to justify the 75 and 91 basis point premiums (respectively) their recommendations provided over the result of their analytically-determined reasonable ROEs. These empirically-derived ROEs were both more reasonable and more reflective of DTE's risk profile. (5 Tr 1837.) As the Staff and Attorney General's analyses indicate a ROE below their recommendations is more appropriate for DTE, the Commission should reject those recommendations and adopt a ROE in accordance with ABATE's proposal.

#### a. Staff's ultimate ROE recommendation incorporated improper considerations and was artificially inflated.

Staff recommended a 9.60% ROE for DTE based on a range of reasonableness of 8.90% to 9.90%, despite Staff's analyses demonstrating that a lower ROE is more appropriate. (4 Tr 1222.) As Staff failed to justify a ROE above the median of its recommended range and ignored DTE's comparatively low risk Staff's recommendation is flawed and should be rejected. (5 Tr 1832.)

Despite Staff's analyses demonstrating that its average calculated ROE was 8.85%, Staff explained that its inflated recommendation factored in DTE's "credit rating, requested 10.50% ROE and currently approved 10.00% ROE." (4 Tr 1238-39.) In other words, Staff recommended a ROE which would provide a 75 basis point premium ($21 million) over its estimated, average ROE based in part on DTE's currently authorized ROE, rather than DTE's actual cost of equity. (5 Tr 1833.) Staff's recommendation was therefore heavily influenced by improper considerations unsupported by sound financial principles. (*Id.*)

Staff also neglected to recognize several factors which indicate a lower ROE is more appropriate, including the following: (i) the current low interest rate environment; (ii) Staff's proxy group's average credit rating (BBB+) is below that of DTE (A); and (iii) the cost recovery mechanisms DTE has requested in this proceeding will mitigate its risk. (5 Tr 1834; Exhibit S-4, Schedule D-5.) Considering these factors would place an appropriate ROE at the average or lower end of Staff's estimated range. In other words, DTE's lower business risk and higher credit rating, as well as Staff's analyses overall, indicate DTE's ROE should be lower than Staff's recommendation. (5 Tr 1834.)

The improper considerations influencing Staff's ultimate ROE proposal artificially increased Staff's recommendation by 75 basis points, or $21 million, over the ROE figure supported by Staff's analyses. Given these deficiencies the Commission should reject Staff's recommendation.

**b. The Attorney General's ROE recommendation included an unsubstantiated and unwarranted risk premium.**

Like Staff, the Attorney General's ROE recommendation was artificially inflated using an improper risk premium (91 basis points, or $25 million) relative to the Attorney General's analytically-determined ROE. (5 Tr 1835; 4 Tr 1384; Exhibit AG-22.) The Attorney General based this artificial increase on increased interest rates, state-mandated energy efficiency and conservation programs, and the Commission's historic reluctance to assign a ROE that equals DTE's cost of equity. (4 Tr 1459.) As these concerns are either invalid or do not present a proper basis for providing DTE a heightened ROE, the Commission should reject the Attorney General's recommendation.

Regarding interest rates, the Attorney General's assumption of a 100 basis point increase was over-stated. (5 Tr 1836.) At the time the Attorney General completed its ROE analyses, the yield on long-term, 30-year Treasury bonds was 2.01%. (*Id.*) The Attorney General's CAPM and Risk Premium methods, however, both incorporated higher, forecast interest rates (3.10%). (4 Tr 1459; Exhibit AB-24.) While utilizing a higher interest rate itself increased the Attorney General's ROE recommendation, artificially adding an additional 91 basis point premium to the results of these analyses effectively double-counted the impact of higher interest rates. (5 Tr 1836.) Furthermore, with regard to DTE's state-mandated spending, while the Company's sales have been decreasing, its operating earnings per share have continuously grown since 2008, exceeding its guidance. (*Id.* (citation omitted).) Any risk of reduced earnings due to reduced sales by DTE is therefore unfounded. (*Id.*)

Finally, the Attorney General's "understand[ing] that the Commission would be reluctant to grant a ROE at the 8.5% true cost of capital at this time, preferring instead a more gradual reduction," is not an appropriate basis upon which to develop a ROE recommendation. (See 4 Tr 1459.) The factors underpinning ROE determinations are set forth above and focus on recognizing current financial economic realities; it is unproductive to engage in a thorough analysis of DTE's cost of equity only to adjust the results to reflect a party's presumed preference of the Commission. Furthermore, the Commission has previously noted that "gradualism" is not a concept applicable to ROE determinations. See *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered January 31, 2017 (Case No. U-18014), p 41 ("[T]he Commission is not persuaded that principles of gradualism should have any bearing on the determination of a reasonable ROE in this case"). Thus, the Attorney General's ROE recommendation was artificially increased based, in part, on a subjective assumption regarding a concept the Commission has previously rejected.

The Attorney General's ultimate ROE recommendation therefore contained inappropriate flaws which artificially increased its recommended ROE above the figure supported by its own analyses. As such, the Commission should reject the Attorney General's recommendation and adopt a ROE in line with ABATE's recommendation as described above.

**E. DTE's proposed operation and maintenance expenses included improper inflation assumptions.**

The Company projected $485.5 million in O&M expenses in the test year. (4 Tr 1742; Exhibit A-13, Schedule C5.) These projected O&M expenses were based on the actual, historical year O&M expenses, adjusted for inflation and "other adjustments." (*Id.*) These projected expenses represent an $83.3 million increase from the historical period to the projected period. (*Id.*) Of this amount, $57.1 million is attributed to "other adjustments" and $26.1 million is attributed to inflation. (*Id*.) As these projections were based on flawed assumptions they should be rejected.

While MCL 460.6a(1) provides that a utility "may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges," the Commission is not obligated to approve the same. Rather, "in the case where the company seeks approval for a projected cost, the company must not only provide sufficient evidence to demonstrate to the Commission that both the specific project and its cost are reasonable and prudent, but it must also show by a preponderance of the evidence that the cost will in fact be incurred before the end of the test period." *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered January 31, 2017 (Case No. U-18014), pp 5-9. In other words, as with its proposals generally, "in a case where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections." *In the Matter of the Application of Detroit Edison Co*, order of the Public Service Commission, entered January 11, 2010 (Case No. U-15768), p 9. Given the time constraints on rate cases, "all evidence (or sources of evidence) in support of the company's projections should be included in the company's initial filing." *Id*. If "the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data) . . . the Commission may choose an alternative method for determining the projection." *Id*.

The other adjustments noted above encompass items such as transmission operation supervision and engineering ($8.4 million adjustment for pipeline integrity) and distribution expense ($4.8 million adjustment for record remediation, transmission fitting conversion, and damage prevention). (4 Tr 1743; Exhibit A-13, Schedule C5.) Regarding inflation, the Company used a weighted average inflation rate of 2.9% for 2019 and 2020, and 2.2% for the projected year through September. (4 Tr 1743; Exhibit A-13, Schedule C12.) The Company also used a combination of a 3% wage inflation rate for labor and contractors and a 1.9% non-labor inflation rate for 2019 and 2.1% for 2020 and 2021.[41] (*Id.*) DTE estimated that 56.1% of its O&M expense is attributed to labor, 32.6% is attributed to contractors, and the remaining 11.3% is non-labor related. (*Id.*) The inflation rates were applied to the ratios to determine the weighted average rate for each year. (*Id.*)

The Company's assumption that its O&M expenses will increase annually by 2.9% is improper. As DTE noted in a November 2019 presentation at the EEI Financial Conference, it has successfully controlled these costs over the last several years. (4 Tr 1744; Exhibit AB-33.) Furthermore, its average annual increase in O&M expenses from 2008-2018 for DTE was only 1%. (*Id.*) It is not unreasonable to expect that DTE will continue to control its costs, which should be reflected in its projected year O&M expenses. (*Id.*) Indeed, the Commission recently noted its "decisions in previous rate cases rejecting the blended inflation rate" DTE employed here, as well as DTE's ability to "offset some of the inflation with productivity gains." *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 8, 2020 (Case No. U-20561), p 186.

Given the deficiencies in the Company's proposal the Commission should reject the Company's recommendation and approve a 1% growth rate for its O&M expenses in 2019, 2020,

[41] The 3% inflation rate for labor and contractors was based on DTE's existing collective bargaining agreements that obligate the utility to increase pay rates by approximately 3% annually through the term of the contracts. (4 Tr 1744; 4 Tr 540.) The 2.1% non-labor component is the Consumer Price Index-Urban rate as of July 2019. (4 Tr 1744; 3 Tr 209.)

and 2021. (4 Tr 1744.) This rate is consistent with past increases and therefore represents a reasonable increase.[42]

### F. The Company's industry association contributions should be removed from its revenue requirement.

The Company requested recovery of over $800,000 in this proceeding for industry association dues and corporate membership expenses. (See 4 Tr 1660; Exhibit AB-25.) As DTE has not adequately explained how these costs are just and reasonable or benefit ratepayers, or how it segregates costs for which it is improper to seek recovery from customers (e.g. those which finance political lobbying or other activities), its requested recovery of these costs should be rejected here.

#### 1. DTE did not demonstrate that its industry association contributions and expenses are just and reasonable.

The Company requested the Commission authorize significant cost recovery for DTE's industry association membership dues and contributions, claiming "[m]emberships in organizations that provide key operational support are allowed for ratemaking purposes." (Exhibit AB-25.) As DTE has not adequately explained how this "key operational support" benefits customers it has not established that these expenses are just and reasonable. As such, cost recovery for the same should be denied and these amounts should be removed from the Company's revenue requirement.

As a regulated utility in Michigan, DTE may not increase its rates and charges or alter, change, or amend any rate or rate schedules, the effect of which will be to increase the cost of services to its customers, without first receiving Commission approval. MCL 460.6a(1). As noted above, in granting that approval the Commission must determine just and reasonable rates

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[42] Applying the lower growth rate will reduce DTE's projected O&M costs by $17 million, to $468.4 million. (*Id.*; Exhibit AB-13.)

for the utility by determining the reasonable cost of doing business. *Ford Motor Co v Pub Serv Comm*, 221 Mich App 370, 374 (1997); *Association of Businesses Advocating Tariff Equity v Pub Serv Comm*, 208 Mich App 248, 258 (1994). As part of making that determination, the utility must demonstrate that its costs are just and reasonable. *In re Detroit Edison Co*, 296 Mich App 101, 116 (2012) (stating that the Court of Appeals would "not rubber-stamp a decision" permitting "a substantial expenditure–a cost to be borne by the citizens of this state–that is not properly supported" as "the PSC may allow recovery of a utility's costs only when the utility proves that recovery of the costs is just and reasonable").[43]

This includes costs relating to dues paid to certain organizations or associations, which the Commission has the discretion to allow or disallow. See *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 2, 2019 (Case No. U-20162), p 57; *Detroit Edison v Pub Serv Comm*, 127 Mich App 499, 524 (1983) (upholding a Commission decision disallowing an operating expense deduction for a utility's contribution to educational institutions, which Commission decision stated that "[s]ince charitable contributions are purely discretionary, and are not necessary to provide electrical service . . . [c]harging ratepayers for Edison's contributions amounts to taxing Edison's ratepayers for the benefit of Edison's favorite eleemosynary institutions and projects"); *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 8, 2020 (Case No. U-

[43] See also *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered April 18, 2018 (Case No. U-18255), pp 5, 30; *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 2, 2019 (Case No. U-20162), p 57; *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered January 31, 2017 (Case No. U-18014); *In the Matter of the Proceeding, on the Commission's Own Motion*, order of the Public Service Commission, entered March 30, 1989 (Case No. U-9346), p 2 ("The Commission hereby orders Consumers to make a complete rate case filing and also notifies Consumers that it will be required to carry its burden of proof to establish that its current or recommended rates are just and reasonable").

20561), p 200 ("[T]he Commission also adopts ABATE's request as to the need to continually justify that such fees are truly required and/or are in the interests of ratepayers, and reminds the company of its continuing obligation to identify, describe, and explain projected costs associated with membership fees in future rate cases").

Since 2014 DTE has included over $2.5 million in corporate membership expenses in its requested rate recovery, over $800,000 of which was included in the revenue requirement proposed in this proceeding. (Exhibit AB-25.) In explaining the "Impact to the Quality or Cost of DTE's Regulated Utility Service," made by the entities to which these expenses were paid, the Company effectively provided only generic organizational descriptions. (See Exhibit AB-26.) These accounts did not adequately demonstrate that these expenses directly benefit ratepayers, improve or relate to providing service, or that these costs are just and reasonable. As such, DTE failed to meet its evidentiary burden and these costs should be removed from the Company's revenue requirement.

At a minimum the Commission should require DTE to demonstrate that customers actually benefit from its corporate memberships and specifically identify the services the organizations listed above provide for DTE's customers. (See Exhibit AB-25.) The Company has not provided a sufficient basis on the record in this case to reasonably conclude that customers benefit from its corporate memberships. Further, as these costs fluctuate on a year-over-year basis, the Commission should require DTE to explain these swings and provide evidence that its projections for the test year are reasonable.

### 2. It is unclear to what extent DTE's industry association contributions are unconstitutional compelled speech.

In addition to DTE's failure to meet its burden of proof and establish these costs are reasonable, justified, or adequately related to customer benefits, it is unclear to what extent the

Company's ratepayer-funded industry association contributions are unconstitutional compelled speech. As such, they should be excluded from DTE's revenue requirement.

The United States and Michigan Constitutions ensure that "Congress shall make no law . . . abridging the freedom of speech" and "no law shall be enacted to restrain or abridge the liberty of speech," respectively. US Const, Am I; Const 1963, art 1, § 5. These constitutional provisions establish a "bedrock principle that, except perhaps in the rarest of circumstances, no person in this country may be compelled to subsidize speech by a third party that he or she does not wish to support." *Harris v Quinn*, 134 SCt 2618, 2644 (2014); see *Thomas M Cooley Law School v Doe 1*, 300 Mich App 245, 275 (2013) ("Because the right to free speech under the Michigan Constitution is coterminous with the right to free speech under the First Amendment, this Court may use federal authority to interpret Michigan's guarantee of free speech").

This concept's importance in the utility and ratepayer context has been specifically recognized. For instance, *Consolidated Edison Co of New York, Inc v Pub Serv Comm of New York*, 447 US 530, 543 (1980) concerned an order of the Public Service Commission of the State of New York which prohibited bill inserts that discussed controversial issues of public policy. The New York Commission argued that this "prohibition would prevent ratepayers from subsidizing the costs of policy-oriented bill inserts." *Id*. Ultimately the Supreme Court found that a constitutional harm could be avoided if the New York Commission could "exclude the cost of these bill inserts from the utility's rate base." *Id*. Multiple Justices went on, however, to explicitly describe the potential constitutional violation in compelling ratepayers to subsidize speech activities.[44]

While the *Consolidated Edison* case set out the importance of ensuring public policy-related speech costs were not financed by rate revenue, the First Amendment also demands that individuals not be compelled to pay for even the *non*-political activities of certain associations or professional organizations which both provide non-political services and also engage in political activities. See *Janus v AFSCME, Council 31*, 138 SCt 2448 (2018). In the context of union dues, for instance, distinguishing between "chargeable and nonchargeable" organization expenditures has been held to be "unworkable." *Id*. at 2481-82; see also *Knox v SEIU, Local 1000*, 567 US 298 (2012) (addressing the burden in determining chargeable and nonchargeable expenses in the political speech funding context). As such, utilities may not charge ratepayers the cost of utility contributions and other financial transfers to organizations which engage in political advocacy or speech activities; particularly where clearly distinguishing between "chargeable and nonchargeable" contributions proves opaque and difficult.

When asked to explain how charitable, social, or political contributions are included or excluded from its revenue requirement, the Company provided the following explanation:

> Membership descriptions are reviewed from association websites or through discussions with the department purchasing the membership to determine what activities or services are provided. Those that provide information and/or services

[44] See e.g. *Consolidated Edison*, 447 US at 549-52 (Blackmun, J., dissenting) ("Because of Consolidated Edison's monopoly status and its rate structure, the use of the insert amounts to an exaction from the utility's customers by way of forced aid for the utility's speech . . . Under the laws of New York and other States [as well as FERC], however, a public utility cannot include in the rate base the costs of political advertising and lobbying . . . These costs cannot be passed on to consumers because ratepayers derive no service-related benefits from political advertisements" and the "purpose of such advertising and lobbying is to benefit the utility's shareholders, and its cost must be deducted from profits otherwise available for the shareholders . . . If the State compelled an individual to help defray the utility's speech expenses, that compulsion surely would violate that person's First and Fourteenth Amendment rights").

> that the Company or individual employees within the Company can use to better perform tasks related to utility operations, to solve utility related challenges, and to inform tactical or strategic planning related to utility services are considered allowable for rate-making. Memberships not related to utility operations, or that are related to political activities are excluded. [Exhibit AB-28.]

This process is inadequate to effectively separate costs which are not properly assessed to ratepayers from those which may be included in DTE's revenue requirement. Indeed, several of the organizations to which DTE makes contributions or dues payments engage in political activities (e.g. HR Policy Association, American Gas Association, Energy Solutions Center Inc., Conference Board, Inc.) without apparent proper recognition from the Company. (See 4 Tr 1662-63; Exhibit AB-25 (recognizing certain amounts used for lobbying that "should have been excluded from DTE Gas operating expense").) Thus, the degree to which DTE's corporate membership expenses relate to operational support (and for which DTE has requested rate recovery) and the degree to which they finance political activity is apparently unclear even to the Company. (See Exhibit AB-29.)

This was demonstrated by the Company's own testimony, in which it agreed that $100,000 related to various organizational contributions should be removed from the revenue requirement,[45] although DTE maintained "that a portion of these association dues may be recoverable in future cases pending an analysis of what portion (if any) of the dues is spent on political activities." (3 Tr 231.) Considering the activities undertaken by the entities listed above and the overlap between proper and improper undertakings, DTE's assertions regarding its cost segregation process fail to instill confidence that DTE's corporate membership expenses, charitable and social welfare organization contributions, and costs for political activity are being

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[45] This amount included: (i) $5,400 for The HR Policy Association; (ii) $19,196 for the American Gas Association; (iii) $47,000 for Energy Solutions Center, Inc.; (iv) $25,000 for Conference Board, Inc.; and (v) $3,000 for the American Society of Employers. (3 Tr 231.)

properly excluded, and that only appropriate, recoverable costs are being recovered from customers. (See 4 Tr 1660-64.) Stated simply, the Company's ad hoc adjustments and analyses, such as they are, do not satisfy the constitutional requirements described above.

Given the deficiencies of DTE's cost segregation practices, as effectively acknowledged by the Company itself, in addition to the specific $100,000 identified by DTE the Commission should disallow any cost recovery for industry association contributions in this case. (See e.g. Exhibit AB-25.) It is unclear to what extent these contributions are "chargeable" and "nonchargeable," effectively making their recovery unconstitutional. To further aid in review of this issue in future rate cases, the Commission should also require DTE to explicitly indicate whether each industry association to which DTE makes contributions uses those funds to directly or indirectly engage in political activity, and the extent to which those contributions finance that activity. Until it does so these contributions should not be recovered from customers.

## III. RELIEF REQUESTED

**WHEREFORE,** ABATE requests the Administrative Law Judge to issue a Proposal for Decision adopting ABATE's positions as outlined in its Direct and Rebuttal Testimony as well as this Initial Brief.

Respectfully submitted,

**CLARK HILL PLC**

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**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

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| In the matter of the application of | ) | |
| **DTE GAS COMPANY** for authority | ) | Case No. U-20642 |
| to increase its rates, amend its rate | ) | |
| schedules and rules governing the | ) | ALJ Martin Snider |
| distribution and supply of natural gas, | ) | |
| and for miscellaneous accounting authority | ) | |
| ______________________________ | ) | |

**PROOF OF SERVICE**

Stephen A. Campbell certifies that, on May 27, 2020, he did cause to be served the ***Association of Businesses Advocating Tariff Equity's Redacted Initial Brief*** as well as this ***Proof of Service*** in the above docket, via electronic mail, to the persons identified on the attached service list.

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