



## CITY OF ANN ARBOR, MICHIGAN

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March 13, 2026

*VIA ELECTRONIC CASE FILING*

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

RE: MPSC Case No. U-21973

Dear Ms. Felice,

Attached please find the **Direct Testimony of Rick Brown, Dr. Melissa Stults, and Michael Walsh on behalf of the City of Ann Arbor** for the above-referenced case, along with proof of service.

Please contact me if you have any questions.

Sincerely,

Valerie Jackson  
Assistant City Attorney,  
City of Ann Arbor

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

U-21973

ALJ Christopher S. Saunders

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**DIRECT TESTIMONY OF RICK BROWN**

**ON BEHALF OF**

**THE CITY OF ANN ARBOR**

**March 13, 2026**

1       **I.       INTRODUCTION AND QUALIFICATIONS**

2       **Q.       Please state your name, title, and business address.**

3       A.       My name is Rick Brown. I am a self-employed independent engineering consultant  
4               specializing in gas system design, operation, and analysis. My office is located in San  
5               Ramon, California.

6       **Q.       Please describe your educational background and professional experience.**

7       A.       I have a Bachelor of Science degree in Mechanical Engineering from California  
8               Polytechnic State University, San Luis Obispo and I am a registered Professional  
9               Engineer in California, License M 31225. I have 36 years’ experience at Pacific Gas &  
10              Electric Co, working in the Gas System Planning Department with increasing technical  
11              expertise as a Gas Engineer, Senior Gas Engineer, and Principal Gas Engineer on  
12              hydraulic system design and operations for gas distribution and transmission systems. For  
13              the past 25 years of my career, I was in Gas System Planning leadership roles as a  
14              Manager, Senior Manager, and Director. I have developed and/or led multiple multi-  
15              million dollar gas transmission and distribution investment plans. In my leadership roles,  
16              I was responsible for ensuring that gas system investments were comprehensive, explored  
17              all alternatives in an unbiased manner, were cost-effective, and balanced affordable  
18              energy costs and reliable customer service. Under my direction, portable compressed  
19              natural gas (“CNG”) and liquified natural gas (“LNG”) was used extensively on gas  
20              transmission and distribution systems to defer gas system investments and perform  
21              system maintenance. I have 4 years of experience in gas system decarbonization,  
22              including the impacts of building electrification and hydrogen blending on gas system  
23              energy capacity. I have been a Board Member on the Pipeline Simulation Interest Group

1 (“PSIG”) for 29 years. PSIG is an international group dedicated to advancing the state of  
2 the art of pipeline simulation and hydraulic analysis. I have authored and presented 11  
3 PSIG papers on pipeline simulation, including two papers on gas system decarbonization.  
4 A more complete summary of my experience and qualifications is in my resume, Exhibit  
5 AA-1.

6 **Q. On whose behalf are you submitting your testimony in this proceeding?**

7 A. My testimony is on behalf of the City of Ann Arbor (“Ann Arbor” or “the City”).

8 **Q. Have you previously testified before this Commission or as an expert in other**  
9 **proceedings?**

10 A. I have not previously testified before this Commission. However, I have significant  
11 experience in gas related proceedings. I have testified at the California Public Utility  
12 Commission on behalf of Pacific Gas & Electric Company during my employment there  
13 for a Reasonableness Hearing for Underground Gas Storage Operations, a proceeding  
14 related to Lodi Gas Storage, and was a witness in gas transmission rate cases for both Gas  
15 Capacity programs and Gas Capital Spending programs. I testified at the Colorado Public  
16 Utility Commission as a technical expert on Public Service Company of Colorado’s  
17 (“PSCo’s”) Mountain Energy Project on behalf of the Sierra Club in Proceeding No.  
18 25A-0044EG and on PSCo’s Gas Infrastructure Plan on behalf of Natural Resources  
19 Defense Council, Rewiring America, Sierra Club, Southwest Energy Efficiency Project  
20 and Western Resource Advocates (collectively Conservation Advocates) in Proceeding  
21 No. 25A-0220G. I have also testified as a technical witness at the Nevada Public Utility  
22 Commission on Southwest Gas’s 2026-2028 Triennial Integrated Resource Plan on  
23 behalf of Clean Energy Advocates in Docket No. 25-09010. My technical witness

1 testimony has focused on gas system engineering, the prudence of gas system  
2 investments made by the gas utilities, the gas utilities' efforts and procedures for non-  
3 pipeline alternative ("NPA") adoption, and the need to include certain economic benefits  
4 for NPAs in economic analysis.

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

6 A. The purpose of my testimony is to provide analysis and recommendations, and assess the  
7 prudence of gas system investment projects proposed by DTE, including projects for a  
8 new pipeline to support In-Line-Inspections ("ILI"), pipeline replacements, compressor  
9 station upgrades, system capacity, and new business projects, and how alternatives to  
10 those projects could affect DTE's gas system and infrastructure investments.

11 **Q. What projects will you review in your testimony?**

12 A. I will review the East Petoskey Pipeline Reinforcement Project, the Fort Street Main  
13 Replacement Project, and the Carlton Main Project.

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

15 A. Yes. I am sponsoring the following exhibits:

16	Exhibit AA-1	Resume of Rick Brown
17	Exhibit AA-2	Discovery Response AADG-3.10ei
18	Exhibit AA-3	Discovery Response AADG-3.8c
19	Exhibit AA-4	Discovery Response AADG-3.11a
20	Exhibit AA-5	Discovery Response AADG-3.9a
21	Exhibit AA-6	Discovery Response AADG-3.6g
22	Exhibit AA-7	Discovery Response AADG-3.6h
23	Exhibit AA-8	Discovery Response AADG-3.9b

1	Exhibit AA-9	Discovery Response AADG-3.7b
2	Exhibit AA-10	Discovery Response AADG-3.7aiv
3	Exhibit AA-11	Discovery Response AADG-3.7aiii
4	Exhibit AA-12	Discovery Response AADG-3.8ei-evi
5	Exhibit AA-13	Discovery Response AADG-2.3a
6	Exhibit AA-14	Discovery Response AADG-2.3b
7	Exhibit AA-15	Discovery Response AADG-5.1d
8	Exhibit AA-16	Discovery Response AADG-2.1h
9	Exhibit AA-17	Discovery Response AGDG-3.113

10 **II. EAST PETOSKEY PIPELINE REINFORCEMENT PROJECT**

11 **Q. Have you reviewed the evidence presented by DTE in support of the East Petoskey**  
12 **Pipeline Reinforcement Project, including DTE witness Fedele’s testimony and**  
13 **Exhibit A-12, Schedule B5.5?**

14 A. Yes, I have reviewed this evidence, as well as discovery responses submitted by the  
15 Company regarding the East Petoskey Pipeline Reinforcement Project.

16 **Q. What is your understanding of the East Petoskey Pipeline Reinforcement Project?**

17 A. The East Petoskey Pipeline Reinforcement Project proposes to install 13.5 miles of new  
18 8” distribution pipe from a new East Petoskey Interconnect Station at Great Lakes  
19 Transmission to the existing Petoskey Gate Station. Remotely controlled valves will also  
20 be installed at the Petoskey Gate Station, the Charlevoix Tap, and the Boyne City Gate  
21 Station.<sup>1</sup> The cost of this new, redundant East Petoskey Pipeline is \$39.4 million.<sup>2</sup> The

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<sup>1</sup> Fedele, Direct Testimony, p. 36.

<sup>2</sup> Exhibit A-12, Sch. B5.5, p. 6.

1 Company claims the new pipeline is needed for two reasons: (1) as a backup during an  
2 assessment of the existing 8” Petoskey single-source pipeline under the In-Line  
3 Inspection (“ILI”) Expansion program because if the ILI tool becomes stuck in the  
4 existing pipeline, there is a risk of customer outages, and (2) if the existing 8” Petoskey  
5 Pipeline has a failure at some point in the future, the new, redundant East Petoskey  
6 Pipeline can avoid potential customer outages that may result from such failure.<sup>3</sup>

7 **Q. Please explain the scenario where the Company says the East Petoskey Pipeline is**  
8 **needed to avoid customer outages during the 2028 ILI of the existing 8” Petoskey**  
9 **Pipeline.**

10 A. The Company says there is a risk that during the ILI project, an ILI tool will become  
11 stuck in the pipeline causing the risk of 19,000 customers losing service,<sup>4</sup> including  
12 15,000 customers in Petoskey and 4,000 customers in Charlevoix.<sup>5</sup>

13 **Q. Please provide your opinion regarding the risk of the ILI project causing customer**  
14 **outages due to a stuck ILI tool.**

15 A. The Company assumes a scenario where all customers in the Petoskey and Charlevoix  
16 areas lose gas service due to the ILI project. This assumption requires multiple rare  
17 events to occur, such that, when combined, the result is a scenario of extremely low  
18 probability. The events that need to occur to produce DTE’s assumed scenario are (1)  
19 modifications to the existing 8” Petoskey Pipeline must fail in allowing an ILI tool to  
20 navigate the pipeline without getting stuck, (2) an ILI tool that is designed to identify  
21 obstructions must fail to identify the obstructions, (3) the ILI tool must get stuck, (4) the

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<sup>3</sup> Fedele, Direct Testimony, p. 36-37.

<sup>4</sup> Fedele, Direct Testimony, p. 36.

<sup>5</sup> Exhibit A-12, Sch. B5.5, p. 7.

1 stuck ILI tool must severely restrict the flow of gas to customers, (5) operations to  
2 dislodge the stuck ILI tool must fail, (6) rapid response plans to remove the stuck ILI tool  
3 before customers lose service must fail, (7) portable LNG is either not utilized or  
4 experiences a failure, and (8) a second redundant portable LNG unit is either not utilized  
5 or also fails.

6 **Q. Can modifying the pipeline reduce the risk of an ILI tool getting stuck?**

7 A. Yes. The chance of an ILI tool getting stuck is greatly reduced by performing a detailed  
8 assessment of the pipeline's physical characteristics to determine if any potential  
9 obstructions could cause the ILI tool to get stuck in the pipeline. Potential obstructions  
10 include changes in pipe diameter, elbows, fittings, valves, tees, bends, and other pipeline  
11 features. In my experience, ILI vendors who provide ILI tools and instrument data for the  
12 ILI project can leverage their expertise to help ensure a thorough review of the pipeline's  
13 features. Based on this assessment, potential physical obstructions are excavated,  
14 inspected, and, if necessary, removed from the pipeline to minimize the risk of an ILI tool  
15 becoming stuck. In the case of a single-feed pipeline, like the existing 8" Petoskey  
16 Pipeline, a more aggressive approach to inspecting and modifying the pipeline to ready it  
17 for an ILI project should be pursued; any feature in question should be replaced. Since  
18 the pipeline will need to have ILIs every seven years, the cost of this more aggressive ILI  
19 readiness approach is a good investment to help promote smooth future ILI runs. The cost  
20 for more aggressive feature replacement is very small compared to building a new \$39.4  
21 million pipeline.

22 **Q. Can ILI tools designed to identify obstructions reduce the chance that ILI tools get**  
23 **stuck in the pipeline?**

1 A. Yes. Before running the complex, instrumented ILI tool, a highly flexible poly foam ILI  
2 tool can be run through the pipeline. This tool is specifically designed as a first-pass test  
3 to assess a pipeline's viability for complex ILI tools to navigate it successfully, by  
4 identifying any obstructions. The use of a poly foam ILI tool to identify obstructions  
5 before the ILI assessment reduces the chance of an ILI tool getting stuck.

6 **Q. Has the Company raised any other reasons the ILI tool can get stuck in the**  
7 **pipeline?**

8 A. Yes, the Company raised the issue that debris in the pipeline may cause the tool to get  
9 stuck.<sup>6</sup> There is a very low possibility of this occurring. Specialized ILI cleaning tools are  
10 generally run through the line to remove debris before using more complex instrumented  
11 ILI tools, minimizing the risk of a stuck ILI tool.

12 **Q. Will a customer outage necessarily occur if an ILI tool gets stuck, or are there**  
13 **situations in which an ILI tool becomes stuck and gas can still flow?**

14 A. The customer outage risk described by the Company assumes that if an ILI tool gets  
15 stuck, it will either completely shut off or severely restrict the flow of gas, resulting in  
16 customers losing service. However, a stuck or damaged ILI tool may allow a significant  
17 amount of gas to bypass it, depending on how it gets stuck in the pipeline. In other words,  
18 there are several scenarios in which, even if the ILI tool becomes stuck, it would not  
19 cause a customer outage, so the risk of an outage caused by a stuck ILI tool is actually  
20 even smaller than the risk of an ILI tool becoming stuck in the first place, making DTE's  
21 assumed scenario even more unlikely.

22 **Q. Are there ways to prevent outages by dislodging a stuck ILI tool?**

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<sup>6</sup> Exhibit AA-2.

1 A. Yes, there are multiple operating strategies to dislodge a stuck ILI tool, including  
2 increasing the pressure behind the tool, rapidly increasing or decreasing pressure to create  
3 a “surging” effect to break the ILI tool free, and reversing the flow of the pipeline to  
4 move the ILI tool backward. In addition, a second recovery ILI tool can be used to push  
5 the stuck ILI tool.

6 **Q. If all of the above strategies are used and the ILI tool still becomes stuck and**  
7 **severely restricts the flow of gas, are there things that can be done to avoid customer**  
8 **outages?**

9 A. Yes. If the ILI tool becomes stuck and severely restricts gas flow, the downstream  
10 pressure will drop due to downstream customer demand and a lack of gas supplied  
11 downstream of the ILI tool. However, customer outages will not occur immediately. This  
12 is because there is a significant volume of gas downstream of the ILI tool due to the  
13 pipeline's diameter and length, and the high operating pressures of transmission pipelines  
14 (higher pressure means more gas in the pipeline than at lower pressure). Hydraulic  
15 analysis using pipeline simulation software can estimate the duration for which sufficient  
16 pressure will remain to maintain customer service. Depending on available time, a utility  
17 can attempt to dislodge the ILI tool, or, in a worst-case scenario, cut it out of the pipeline  
18 and restore service. In addition to hydraulic analysis, a key preparation would be to  
19 develop a rapid-response plan to minimize the time required to cut out a stuck ILI tool  
20 and restore the pipeline to service. This would include having personnel, material, and  
21 tools ready and a detailed plan in place. When asked whether the Company has an  
22 emergency response plan in place to isolate any pipeline damage and make emergency

1 repairs quickly, DTE responded, “Yes.”<sup>7</sup> However, in response to a discovery question  
2 regarding whether the Company has performed hydraulic analysis to determine how long  
3 customers can retain service in the event the 8” Petoskey Pipeline experiences a failure,  
4 DTE replied that it has not performed this type of hydraulic analysis. While this  
5 particular question was regarding a pipeline failure, it is reasonable to assume that the  
6 Company has not performed the same type of hydraulic analysis for a stuck ILI tool. This  
7 demonstrates that the Company did not pursue a thorough review of possible alternatives  
8 to installing a redundant and costly \$39.4 million pipeline. Finally, utilizing portable  
9 liquefied natural gas (“LNG”) and/or compressed natural gas (“CNG”) provides a cost-  
10 effective redundant supply if all of the above actions fail.

11 **Q. Please describe how portable LNG and portable CNG can provide a supplemental**  
12 **supply to a gas system.**

13 A. Portable LNG and CNG systems are mobile, self-contained units that store and inject gas  
14 into natural gas systems as a supplemental supply. Key location(s) on the gas system are  
15 identified where the supplemental LNG or CNG can be injected to support the gas  
16 system, and an LNG or CNG injection connection (tap) is installed on the gas pipeline.  
17 The portable LNG and/or CNG is driven to the location(s) and is connected to the  
18 injection tap(s). The portable LNG and CNG unit can be operated manually to inject gas  
19 into the pipeline, or automatically to maintain specific gas system pressures. Portable  
20 LNG and CNG are often used to increase system supply during very rare extreme cold  
21 events when demand is high. Portable LNG and CNG are ideal applications when  
22 maintenance on the gas system is needed because the maintenance typically only lasts for

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<sup>7</sup> Exhibit AA-3.

1 a few days or weeks, and the LNG and CNG units can be moved wherever maintenance  
2 is being performed. This portability and flexibility allow for rapid deployment of a  
3 supplemental supply during short timeframes at a fraction of the cost of new pipelines.  
4 Any application that needs additional supply for a short timeframe will be much lower  
5 cost using portable LNG and CNG than compared to costly new pipelines. LNG has  
6 higher injection flow rates and higher volumes than CNG, so the type of portable system  
7 depends on the application. Multiple units can be located in multiple locations or at the  
8 same location to increase flow rates or volumes as needed.

9 **Q. The Company claims it considered and rejected using LNG as a backup supply**  
10 **during the existing Petoskey Pipeline ILI assessment as an alternative to installing a**  
11 **redundant pipeline.<sup>8</sup> Please provide your opinion on the Company rejecting this**  
12 **option.**

13 A. I strongly disagree with the Company rejecting this option. In my years as an experienced  
14 gas system planning engineer and leader of the Gas System Planning Department, we  
15 successfully used portable LNG and portable CNG as both a backup supply and as a  
16 primary supply for complex ILI projects, pressure tests of pipelines, and other  
17 maintenance activities on the gas system. Portable LNG and CNG were successfully used  
18 many times each year for maintenance activities and were a critical, highly valued asset  
19 for completing complex maintenance on the gas system. Based on my experience, the  
20 existing single-feed 8” Petoskey Pipeline ILI is an ideal application for using portable  
21 LNG and/or CNG as a backup supply. Coupled with the execution of an emergency

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<sup>8</sup> Fedele, Direct Testimony, p. 38-39.

1 response plan (which DTE claims to have),<sup>9</sup> this would allow DTE to provide customers  
2 reliable service even if an ILI tool becomes stuck. I have experienced customers being  
3 successfully supported by LNG and/or CNG backup supply on single feed pipelines  
4 during ILIs and other maintenance activities many times, including some maintenance  
5 activities that lasted for weeks or even months.

6 **Q. Why did the Company claim that supporting the ILI with LNG backup was not a**  
7 **viable alternative?**

8 A. The Company claims performing the ILI with LNG backup is “costly, complex, and  
9 impractical” if an ILI tool were to get stuck, and that the LNG equipment would have to  
10 be “100% reliable without any issues to ensure [DTE does] not lose customers on the  
11 pipeline.”<sup>10</sup> The Company also claimed that LNG backup would only provide redundant  
12 supply during an ILI and would not provide redundancy if third-party damage or another  
13 failure caused an outage.<sup>11</sup> I interpret the previous sentence to refer to a failure of the  
14 existing Petoskey Pipeline other than during ILI activity, which I will address later in my  
15 testimony.

16 **Q. Please address the Company’s position that performing the ILI with LNG backup is**  
17 **not a viable alternative and is costly.**

18 A. I strongly disagree with the Company’s position. The Company does not provide any  
19 support for its claim that LNG backup is not a viable alternative for the ILI project. Based  
20 on my experience, this ILI project is an ideal application for LNG. The Company is  
21 essentially taking the position that it needs to build a new \$39.4 million pipeline in case

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<sup>9</sup> Exhibit AA-3.

<sup>10</sup> Fedele, Direct Testimony, p.39.

<sup>11</sup> *Id.*

1 modifications to eliminate obstructions in the existing pipeline fail *and* the ILI tool gets  
2 stuck *and* the ILI tool severely restricts the flow of gas *and* operational strategies fail to  
3 dislodge the ILI tool *and* the system cannot survive long enough to remove the stuck tool  
4 *and* LNG equipment fails. Yet, even this scenario, which is based on the assumption of  
5 compounding failures, can be addressed. For instance, the Company could add a  
6 redundant, second LNG unit, which could be installed in parallel with the first unit at the  
7 same location, kept on standby nearby, or at a separate injection location on the gas  
8 system. Regarding DTE’s claim that LNG is too costly, DTE's witness stated in a  
9 discovery response that the estimated cost to provide LNG in the event of a stuck ILI tool  
10 is \$5.5 million.<sup>12</sup> Thus, even if a second unit is provided as a backup and assumed to  
11 double the estimated cost of providing backup LNG, this alternative would still only be  
12 approximately one quarter of the cost of installing a new, redundant pipeline with a price  
13 tag of \$39.4 million. In my opinion, the East Petoskey Pipeline Reinforcement Project is  
14 not a prudent or reasonable way to address the stated concern, and reliable service can be  
15 delivered during the ILI assessment at far lower cost.

16 **Q. Do you agree with the Company that the \$39.4 million redundant East Petoskey**  
17 **Pipeline is needed in the event of an integrity failure of the existing Petoskey**  
18 **Pipeline? Why or why not?**

19 A. No. First, the Company has made no case that there are integrity issues with the existing  
20 pipeline that would cause the pipeline to fail. In fact, in response to a discovery request  
21 regarding the number of incidents that have occurred during the existing pipeline’s life  
22 that created a risk of failure, DTE witness Fedele responded, “There have been no

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<sup>12</sup> Exhibit AA-4.

1 incidents to date that could have led to failure.”<sup>13</sup> Moreover, DTE stated that there have  
2 been no leaks on the existing Petoskey Pipeline in the past five years,<sup>14</sup> and when asked  
3 to provide any data related to corrosion issues, witness Fedele responded, “No additional  
4 data is available.”<sup>15</sup> The fact that DTE is planning to perform an ILI to assess the  
5 pipeline’s integrity is evidence that the Company does not currently have data showing  
6 that the pipeline has integrity issues - let alone integrity issues significant enough to cause  
7 a failure. Gas companies perform ILIs to help keep pipelines in service and avoid costly  
8 pipeline replacements. The Company can use the data that results from the ILI  
9 assessment to determine whether there are any integrity issues on the existing pipeline  
10 and then address any that are discovered, which will minimize the risk of future pipeline  
11 failure, further lessening the need for a redundant pipeline. The Company simply has not  
12 provided sufficient support to justify spending nearly \$40 million to build a redundant  
13 pipeline.

14 **Q. Please address the Company’s position that the \$39.4 million new East Petoskey**  
15 **Pipeline is needed in the event of third-party damage causing a failure of the**  
16 **existing Petoskey Pipeline.**

17 A. The Company has not provided any data on third-party damage on the existing Petoskey  
18 Pipeline nor any instances of damage causing or risking customer outages. In fact, in  
19 response to a discovery request asking whether the pipeline has ever had to be isolated  
20 due to damage, DTE witness Fedele responded, “No.”<sup>16</sup> DTE witness Fedele also stated

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<sup>13</sup> Exhibit AA-5.

<sup>14</sup> Exhibit AA-6.

<sup>15</sup> Exhibit AA-7.

<sup>16</sup> Exhibit AA-8.

1 that, “To the best of my knowledge, there have been no incidents to date that could have  
2 led to a failure.”<sup>17</sup> I reviewed the approximate route of the existing Petoskey Pipeline  
3 shown on the map in Exhibit A-12, Schedule B5.5, p. 7, and compared it with Google  
4 Earth from Boyne City to Petoskey. The vast majority of the route is by open, rural,  
5 undeveloped land that appears to be mostly agricultural or natural open space. The only  
6 locations with population areas where construction activity is more likely to be present  
7 are at the start of the pipeline in Boyne City and as it approaches and terminates in  
8 Petoskey and Charlevoix. Instead of installing a costly new, redundant pipeline that  
9 increases customers’ costs for energy, a much more cost-effective approach would be to  
10 invest in proactive monitoring of the pipeline route including aerial patrol and aerial leak  
11 surveys, proactive and repetitive communications to landowners about the presence of the  
12 pipeline and the need to call 811 before excavating their land, and ensuring there are  
13 plenty of pipeline markers along the pipeline’s route - all practices that DTE already  
14 follows according to its discovery responses, though the Company could increase such  
15 efforts to help alleviate concerns over potential third party damage.<sup>18</sup> In addition, the  
16 Company could consider installing more mainline valves along the pipeline so that if a  
17 section is damaged, it can be isolated within a smaller portion of the pipeline. This will  
18 maximize the volume of gas and pipeline pressure remaining outside the isolated section,  
19 thereby maximizing the gas available to customers while repairs are made or LNG is  
20 mobilized to inject into the system. The Company could also consider installing remote  
21 controls on the mainline valves to isolate a damaged section more quickly. Another

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<sup>17</sup> Exhibit AA-5.

<sup>18</sup> Exhibit AA-9; Exhibit AA-10; Exhibit AA-11.

1 option is installing line rupture control valves, which can sense a rapid change in pressure  
2 due to pipeline damage and automatically isolate the affected section of the pipeline.  
3 Finally, there are specialized line isolation devices to minimize the length of isolating a  
4 transmission pipeline that is damaged. These methods include line stopping (stopple), hot  
5 tapping, and inflatable plugs. I expect the Company has expert engineers who can assess  
6 this option and/or consult with industry experts. All of the above potential options should  
7 be pursued. Hydraulic analysis should also be performed to determine how long the  
8 pipeline can continue to meet customer demand if a section of the pipeline is isolated  
9 under different demand conditions (the Company confirmed in discovery responses that  
10 no such analysis has been performed<sup>19</sup>). Based on the results of this analysis, rapid  
11 response plans can be developed to ensure crews, material, and other resources are  
12 available. The same portable LNG injection point(s) used for the ILI project can be used  
13 to supply LNG to the system. So, rather than spend \$39.4 million on a new, redundant  
14 pipeline, it would be prudent to spend a fraction of this cost to (1) proactively monitor  
15 activity and leaks around the pipeline, (2) proactively increase awareness and  
16 communications of the presence of the pipeline to landowners in the area, (3) invest in  
17 additional mainline valves to minimize the length of any section of the pipeline that needs  
18 to be isolated due to damage, which will increase the gas available for customers, (4)  
19 invest in installing remote controls on mainline valves so sections can be isolated more  
20 quickly, (5) develop rapid response plans to repair the pipeline, and (6) utilize portable  
21 LNG and any injection taps installed for the ILI project to support the system as needed.

22 **Q. Can you please summarize your conclusions and recommendations regarding the**

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<sup>19</sup> Exhibit AA-12.

1           **need to install a new, redundant East Petoskey Pipeline to support the ILI of the**  
2           **existing Petoskey Pipeline?**

3    A.     The expense of the new, redundant East Petoskey Pipeline is not justified by either the  
4           remote risk that backup gas will be needed during the ILI on the existing Petoskey  
5           Pipeline or as a mitigation strategy for potential future failure of the existing pipeline. As  
6           discussed above, other viable, much lower-cost alternatives exist to mitigate the risks  
7           raised by the Company. In my experience, these alternatives are regularly used by gas  
8           utilities to mitigate the risk of pipeline failure. Therefore, I recommend the Commission  
9           disallow the entire \$39.4 million expense of the East Petoskey Pipeline Reinforcement  
10          Project due to the unreasonably high cost of installing a redundant pipeline given the  
11          much less costly and prudent alternatives discussed above.

12       **III. FORT STREET MAIN REPLACEMENT PROJECT**

13    **Q.     Have you reviewed the evidence presented by DTE in support of the Fort Street**  
14           **Main Replacement Project, including DTE witness Fedele’s testimony and Exhibit**  
15           **A-12, Schedule B5.5?**

16    A.     Yes, I have reviewed this evidence, as well as discovery responses submitted by the  
17           Company regarding the Fort Street Main Replacement Project.

18    **Q.     What is your understanding of the Fort Street Main Replacement Project and the**  
19           **reasons the Company is proposing it?**

20    A.     The Fort Street Main Replacement Project involves retiring relatively old mechanically  
21           coupled steel mains operating at 50 psig and 90 psig and installing new steel and plastic  
22           mains in a dense urban environment. The Company claims that the mechanically coupled  
23           joint segments in the existing mains are subject to a higher risk of leaks from third-party

1 damage, corrosion, and ground movement due to natural forces or nearby construction  
2 activity. The Company also states that the project will create a “looped” supply operating  
3 at 145 psig, which will mitigate the risk of a potential outage of 15,000 customers in  
4 downtown and southwest Detroit. Finally, the Company states that the higher-pressure  
5 gas supply is needed in the area east of downtown Detroit to supply future 60 psig GRP  
6 projects.<sup>20</sup>

7 **Q. What is the scope and cost for the Fort Street Main Replacement Project?**

8 A. The Fort Street Main Replacement Project is a multi-year, 8-phase project of very large  
9 scope. From 2022 through 2025, the project installed 7.23 miles of steel and plastic pipes  
10 of various diameters. Pipe installed includes 24”, 20”, 16”, 12”, and 8” steel, and 12” and  
11 4” plastic. Six district regulators were installed from 2022 through 2024 along with other  
12 associated mains, valves, and fittings. For 2025 through 2027, the project installs another  
13 5.14 miles of the same diameter and material as installed in 2022 through 2025, along  
14 with 5 additional district regulators and other associated mains, valves, and fittings. The  
15 total projected cost over the entire scope of the project is approximately \$157.3 million.  
16 For the scope of the project planned for the bridge period and projected test year, the  
17 Company is requesting recovery of \$71.8 million in this case.

18 **Q. What is your opinion of the need for the Fort Street Main Replacement Project?**

19 A. The Company has provided sufficient justification for the Fort Street Main Replacement  
20 project. The old main and mechanically coupled joints are of integrity concern and  
21 replacement of the main is warranted. Since the main is being replaced it makes sense to  
22 perform the hydraulic upgrades including increasing the operating pressure to 145 psig to

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<sup>20</sup> Fedele, Direct Testimony, p. 55.

1 address customer service needs in downtown Detroit, East Jefferson, and the GRP Grid  
2 customers while providing redundancy for potential pipeline failures.

3 **Q. What is your opinion of the cost of the Fort Street Main Replacement Project?**

4 A. The Fort Street Main Replacement Project cost is extremely high. While I recognize the  
5 pipeline is being installed in a dense urban area, the costs per mile are still higher than I  
6 have ever seen in my experience. The 2025 cost is \$27 million for 2.83 miles of main, 4  
7 district regulators, and other associated mains, valves, and fittings. The 2026 and 2027  
8 costs are \$55 million for 2.32 miles of main, 1 district regulator, and other associated  
9 mains, valves, and fittings.<sup>21</sup> In an effort to calculate the cost per mile of main for this  
10 project, the City requested that DTE provide the cost for only the main replacement in  
11 2025, as well as for the 2026 and 2027 time periods. The Company responded that it  
12 could not provide the costs for the 2.83 miles of main in 2025 because “costs associated  
13 with design, materials, and other project overheads are tracked by phase and year.”<sup>22</sup> I  
14 interpret this to mean the Company did not track the actual costs of main replacement for  
15 this project. For the 2026 and 2027 time periods, the Company similarly did not provide  
16 the costs for only the 2.32 miles of main.<sup>23</sup> DTE’s inability to provide the 2026 and 2027  
17 main costs does not make sense because 2026 and 2027 costs are based on estimated, not  
18 actual costs. The estimated costs for these years should be developed based on the  
19 individual facilities planned for installation (main, district regulators, valves, etc.), so the  
20 estimated cost to install 2.32 miles of main should be available. Because the Company  
21 failed to provide the cost of main installed for 2025 or 2026/2027, I needed to make an

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<sup>21</sup> Exhibit A-12, page 4, Scope of Work

<sup>22</sup> Exhibit AA-13.

<sup>23</sup> Exhibit AA-14.

1 assumption to estimate the cost per mile of main installed. I assumed a relatively high  
2 cost of \$1.5 million per district regulator to estimate the costs of the district regulators,  
3 associated main, valves, and fittings. These costs were then subtracted from the total  
4 project cost to develop the cost to install the main alone. (The estimated costs per mile for  
5 main installation are only intended to provide a rough order of magnitude to illustrate the  
6 extraordinarily high costs of installing main for this project, given that the Company did  
7 not provide the main installation costs requested.) Based on my calculations, the  
8 estimated cost of main installation for 2025 is \$7.4 million per mile; for 2026 and 2027, it  
9 is \$23.1 million per mile, resulting in an average cost from 2025 through 2027 of \$14.5  
10 million per mile. While I recognize that some of the pipe installed is large diameter and  
11 that the project is being installed in a dense urban environment, in my experience, I have  
12 never observed such high costs for installing distribution pipe, and I have never observed  
13 transmission pipe approaching \$20 million per mile.

14 **Q. What is your recommendation for the Fort Street Main Replacement Project?**

15 A. I recommend that the Commission require DTE to provide transparency regarding the  
16 breakdown of costs for this project, including the cost for only the number of miles of  
17 pipe installed, so that the reasonableness of such costs can be evaluated.

18 **IV. CARLTON MAIN REPLACEMENT PROJECT**

19 **Q. Have you reviewed the evidence presented by DTE in support of the Carlton Main**  
20 **Replacement Project, including DTE witness Fedele's testimony and Exhibit A-12,**  
21 **Schedule B5.5?**

22 A. Yes, I have reviewed this evidence, as well as discovery responses submitted by the  
23 Company regarding the Carlton Main Replacement Project.

1 **Q. What is your understanding of the Carlton Main Replacement Project?**

2 A. The Carlton Main Replacement Project will install 4.6 miles of new 12” steel pipe that  
3 will operate at 274 psig, replacing the north half of the central section of the system. The  
4 project will abandon 5.1 miles of existing 6” 125 psig steel pipe, install six main line  
5 valves, and replace or modify three district regulator stations. The new 4.6 miles of 12”  
6 steel pipe will connect Augusta Station to the Ypsilanti and Augusta Township gas  
7 distribution systems. The total cost of this project is \$14.5 million, all of which DTE  
8 seeks to recover in this case.<sup>24</sup>

9 **Q. What reasons did the Company provide to justify this \$14.5 million expense?**

10 A. The Company claims the 6” steel section of the Carlton Main is in need of replacement  
11 due to its age, declining condition, proximity to residential homes, and its thin walls that  
12 make it difficult to maintain or repair. As with the Petoskey and Fort Street projects, the  
13 Company also claims a benefit of the proposed new pipe is that it will create a redundant  
14 supply.

15 **Q. Did the Company assess any alternatives to the Carlton Main Replacement Project?**

16 A. Yes, it considered abandoning the Carlton Main but rejected this alternative, claiming it  
17 would not be hydraulically feasible during peak winter conditions to meet customer  
18 demand without a replacement. DTE also considered lowering the operating pressure of  
19 the pipeline and integrating it into the local distribution system, but rejected this option,  
20 claiming it would “not resolve the safety and reliability issues associated with the thin-  
21 wall pipe and existing pipe conditions.”<sup>25</sup>

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<sup>24</sup> Fedele, Direct Testimony, p. 58-62.

<sup>25</sup> Fedele, Direct Testimony, p. 60.

1 **Q. What is your opinion of DTE rejecting the alternative of lowering the operating**  
2 **pressure of the pipeline and integrating it into the local distribution system?**

3 A. I disagree with rejecting this alternative. The Company did not indicate that adopting this  
4 alternative would result in insufficient system capacity, and it is therefore reasonable to  
5 conclude that sufficient system capacity would be available with this option. Rather, the  
6 Company rejected this alternative because it claims lowering the pressure will not resolve  
7 “the safety and reliability issues.”<sup>26</sup> However, lowering operating pressure will reduce  
8 stress on the pipeline, which lowers both the risk of failures and the risk of leaks, thereby  
9 *improving* safety and reliability. Also if there is a pipeline failure, the reduced force of  
10 the lower operating pressure would result in less gas escaping while the pipe is being  
11 repaired. Given the high cost of the project, I believe this alternative should be explored  
12 further as a way to safely extend the life of the existing pipeline before adding \$14.5  
13 million to the rate base for unnecessary new infrastructure.

14 **Q. Why does the Company state the Carlton Main Replacement Project is the best**  
15 **alternative?**

16 A. The Company claims the Carlton Main Replacement Project provides system  
17 redundancy, operational flexibility, capitalizes on original designs of the Augusta  
18 pipeline and two regulator stations, reduces the number of unique pressure systems, and  
19 eliminates long lead time for mechanical fittings needed to maintain and/or repair the  
20 pipeline.<sup>27</sup>

21 **Q. What is your opinion of justifying the Carlton Main Replacement Project based on**

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<sup>26</sup> *Id.*

<sup>27</sup> *Id.*

1 **system redundancy?**

2 A. System redundancy is a common theme in some costly projects the Company is  
3 proposing. In fact, it is the sole driver for the \$39.4 million East Petoskey Pipeline  
4 Reinforcement Project. Including this \$14.5 million dollar project, system redundancy is  
5 driving at least \$53.9 million in system investments. In my opinion, the Company is  
6 biased towards eliminating very low probability risks and not sufficiently considering the  
7 impact of these investments on customer affordability. Given its high cost, I am skeptical  
8 that system redundancy is a valid justification for such projects, particularly when the  
9 issues that redundancy seeks to address have a low probability of ever occurring and  
10 there are significantly less costly alternatives available that in my experience are  
11 regularly implemented and effective. In other words, using redundancy as a justification  
12 for these projects is not reasonable.

13 **Q. What is your opinion of the Company justifying the Carlton Main Replacement**  
14 **Project based on operational flexibility?**

15 A. The Company claims this project will “increase operational flexibility for maintenance,  
16 integrity assessment, or emergency response work,”<sup>28</sup> but it does not provide any specific  
17 support for these claims. Thus, it is difficult to provide my opinion on the value of this  
18 claimed justification in comparison to the \$14.5 million project.

19 **Q. What is your opinion of the Company justifying the Carlton Main Replacement**  
20 **Project based on reducing the number of unique pressure systems?**

21 A. There are valid benefits to reducing the number of unique pressure systems, however  
22 none of these benefits are necessary to the safe operation of the pipeline. For example,

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<sup>28</sup> Fedele, Direct Testimony, p. 60.

1 the risk of a regulator station failing to control pressure, which can result in either over-  
2 pressuring or under-pressuring the downstream pipeline, can be avoided with stations  
3 designed with both a regulator and monitor or dual regulators and monitors, which  
4 provides redundancy and solves for this risk at a much lower cost than installing a new  
5 pipeline. The Company also claims a benefit of operating fewer unique pressure systems  
6 is “operational flexibility for performing required maintenance and responding to  
7 emergency scenarios,”<sup>29</sup> but again there is no specific evidence to support these claims.

8 **Q. The Company is proposing a 12” diameter pipe replacement of an existing 6” pipe;**  
9 **do you believe the Company justified the higher costs associated with the larger**  
10 **pipeline?**

11 A. No. The flow area of the 12” main is 113 square inches, while the existing 6” diameter  
12 main has a flow area of 28 square inches. This means the proposed new main will have 4  
13 times the flow capacity of the existing main. The Company did not indicate that an  
14 increased flow capacity is necessary to meet the demand of the customers currently  
15 served by the 6” pipeline. Rather, in response to a discovery request asking for  
16 justification of the increase in pipe diameter and flow capacity, witness Fedele indicated a  
17 12” diameter pipe is proposed because it will provide supply redundancy.<sup>30</sup> As discussed  
18 above, I do not believe supply redundancy is a valid justification for costly projects that  
19 have feasible, less costly alternatives.

20 **Q. What is your opinion of the Company justifying the Carlton Main Replacement**  
21 **Project based on the concern that long lead time mechanical fittings will delay**

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<sup>29</sup> *Id.* at 61.

<sup>30</sup> Exhibit AA-15.

1           **repairs?**

2    A.    This issue can be addressed by ordering a variety of long lead time mechanical fittings  
3           and keeping them in stock to make timely repairs, which would be much more cost-  
4           effective and prudent than retiring the pipeline and installing a new one. In a discovery  
5           response, the Company claimed it “has included long-lead mechanical fittings in  
6           inventory for the 6-inch section identified for replacement on the Carlton Main project,”  
7           and that “these fittings are stocked for emergency use,”<sup>31</sup> thus negating this alleged  
8           concern.

9    **Q.    Has the section of the Carlton Main that is proposed for replacement had any**  
10       **integrity issues?**

11   A.    No. As the Company admits, “The section of the Carlton Main to be replaced has not  
12       had any known gas leaks or repairs performed on it in the last 5 years.”<sup>32</sup> DTE noted a  
13       low wall thickness finding in the Carlton system, but it was in a different section than the  
14       one proposed for replacement.<sup>33</sup> Therefore, the Company has not demonstrated any  
15       integrity performance issues that would justify the replacement of the existing main.

16   **Q.    What is your overall recommendation regarding the Carlton Main Replacement**  
17       **Project?**

18   A.    DTE has not justified its rejection of the lower cost alternative of downrating the pressure  
19       of the main and integrating it into the local distribution system to decrease pipeline stress,  
20       which would in turn improve pipeline integrity and reduce the potential for leaks, nor has  
21       the Company justified the need to install a new main with four times the flow capacity of

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<sup>31</sup> Exhibit AA-16.

<sup>32</sup> Exhibit AA-17.

<sup>33</sup> *Id.*

1 the existing main (other than redundancy). Further, the Company admitted to having an  
2 existing inventory of mechanical fittings for use in emergencies, so its expressed concern  
3 with the long lead time to acquire such fittings to address future integrity issues on the  
4 existing pipe is misleading.

5 I recommend the Company revisit the option to downrate the pressure of the main to  
6 decrease pipeline stress and integrate the main into the local distribution system. This  
7 would address concerns about pipeline integrity and reduce leaks.

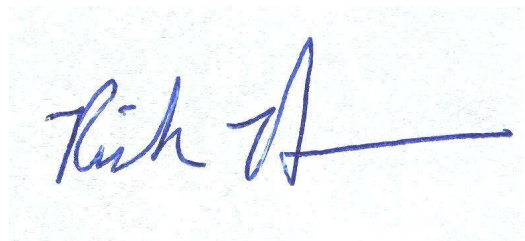
8 I also recommend that the Commission require the Company to perform hydraulic  
9 analysis to determine how long pipeline pressures would be sufficient to maintain  
10 customer service in the event of a failure on the section of pipeline it proposes to replace,  
11 and to provide estimates for the cost of injecting portable CNG to support the system  
12 while repairs are made to compare to the significant capital required to install a new  
13 pipeline. The Company should also be required to provide reasons why the 12-inch new  
14 main needs to have 4 times the flow capacity of the existing main.

15 **Q. Does this conclude your direct testimony?**

16 A. Yes.

17 **Q. Do you swear under penalty of perjury that the statements above are true to the best**  
18 **of your knowledge, information, and belief?**

19 A. Yes.



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Rick Brown

20  
21  
22

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

U-21973

ALJ Christopher S. Saunders

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**DIRECT TESTIMONY OF DR. MELISSA STULTS**  
**ON BEHALF OF**  
**THE CITY OF ANN ARBOR**

**March 13, 2026**

1       **I.       INTRODUCTION AND QUALIFICATIONS**

2       **Q.       Please state your name and business address.**

3       A.       My name is Dr. Melissa Stults. I am the Sustainability and Innovations Director for the  
4           City of Ann Arbor, Michigan. My office is located at 301 E. Huron Street, Ann Arbor,  
5           Michigan 48104.

6       **Q.       Please describe your educational background and professional experience.**

7       A.       I hold a dual doctoral degree in urban resilience from the University of Michigan. This  
8           degree is from Urban and Regional Planning and from the former School of Natural  
9           Resources and the Environment, now known as the School for the Environment and  
10          Sustainability (“SEAS”). I also hold a master’s degree in Climate and Society from  
11          Columbia University and bachelor’s degrees in Marine Biology and Environmental  
12          Sciences from the University of New England.

13          Professionally, I have spent over 20 years working directly with local and regional  
14          governments, as well as indigenous populations, to advance climate and sustainability  
15          actions. This has included work in nonprofits, for profits, academic institutions,  
16          philanthropic organizations, and local government. In this work, I have focused on  
17          translating complex scientific information into useful, usable, and understandable pieces  
18          of knowledge that can inform decision-making across scales (i.e., local, regional,  
19          statewide) and sectors (i.e., built, natural, social, cultural, economic). I have been the City  
20          of Ann Arbor’s head of Sustainability and Innovations since 2018, but have worked on  
21          sustainability and climate-related activities in Ann Arbor since moving to the City in  
22          2012.

23

1 **Q. On whose behalf are you submitting your testimony in this proceeding?**

2 A. My testimony is on behalf of the City of Ann Arbor (“Ann Arbor” or “the City”).

3 **Q. Have you previously testified before this Commission or as an expert in other**  
4 **proceedings?**

5 A. Yes. I have provided testimony on behalf of Ann Arbor in the following cases:

6 • U-20471

7 • U-20836

8 • U-21172

9 • U-21297

10 • U-21384

11 • U-21291

12 • U-21534

13 • U-21860

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

15 A. The purpose of my testimony is to discuss (1) the new franchise agreement between Ann  
16 Arbor and DTE Gas Company (“DTE” or the “Company”), (2) DTE’s updated Gas  
17 Delivery Plan (“GDP”), and (3) DTE’s failure to scenario plan.

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

19 A. Yes. I am sponsoring the following exhibits:

20 Exhibit AA-18 Resume of Dr. Melissa Stults

21 Exhibit AA-19 Discovery Response AADG-2.9gi-iv

22 Exhibit AA-20 Ann Arbor City Council Resolution # R-23-101

23 Exhibit AA-21 *Natural Gas Use Per Residential Customer*, AGA Energy  
24 Insights, Nov. 2024, Vol. 2024-10

1	Exhibit AA-22	<i>Tracking the Heat Pump &amp; Water Heater Market in the</i>
2		<i>United States</i> , RMI, available at
3		<a href="https://rmi.org/insight/tracking-the-heat-pump-water-heater-market-in-the-united-states/">https://rmi.org/insight/tracking-the-heat-pump-water-</a>
4		<a href="https://rmi.org/insight/tracking-the-heat-pump-water-heater-market-in-the-united-states/">heater-market-in-the-united-states/</a>
5	Exhibit AA-23	Attachment to Discovery Response AADG1.1
6	Exhibit AA-24	Cornelius, P., Van de Putte, A. & Romani, M. (2005).
7		Three Decades of Scenario Planning in Shell. <i>California</i>
8		<i>Management Review</i> , 48(1), 92-109
9	Exhibit AA-25	Discovery Response AADG-2.9a
10	Exhibit AA-26	Direct Testimony of Dr. Bente Villadsen from Case No. U-
11		21291 (Excerpt)
12	Exhibit AA-27	Discovery Response MECCUBDG-8.1a
13	Exhibit AA-28	Takemura, A., <i>Heat pump sales dipped in 2025. They still</i>
14		<i>beat gas furnaces</i> , Canary Media (Feb. 13, 2026)

15 **II. DTE’S FRANCHISE IN ANN ARBOR**

16 **Q. Is a franchise necessary for DTE to use existing infrastructure to serve existing**  
 17 **customers or expand service to new customers within the City of Ann Arbor?**

18 A. Yes. A franchise, in addition to allowing use of the City’s rights-of-way, gives DTE  
 19 permission to conduct business within Ann Arbor.

20 **Q. Does DTE currently have a franchise to provide fossil gas service in the City?**

21 A. Yes. In April 2025, Ann Arbor and DTE executed a new franchise agreement, which was  
 22 adopted by the Ann Arbor City Council.

23 **Q. What is the duration of the new franchise?**

24 A. Ten years. The term of this franchise agreement ends on April 22, 2035.

25 **Q. How long was DTE’s previous franchise in Ann Arbor?**

26 A. The prior franchise was for a term of 30 years.

1 **Q. In response to a discovery request, DTE witness Decker stated, “The shorter-than-**  
2 **typical term of the Ann Arbor franchise is a reflection of the challenges Ann Arbor**  
3 **faces reducing emissions to meet the City’s ambitious climate goals.”<sup>1</sup> Do you think**  
4 **that is an accurate characterization of the reason Ann Arbor granted DTE a 10-year**  
5 **franchise?**

6 A. No. The significantly shorter franchise is not a reflection of the “challenges” of meeting  
7 the City’s goals, but rather a reflection of our *commitment* to meeting the City’s goals.

8 **Q. Why didn’t Ann Arbor grant another 30-year franchise to DTE?**

9 A. On March 20, 2023, the Ann Arbor City Council unanimously passed a resolution that  
10 directed City staff to negotiate a new gas franchise that aligned with the City’s  
11 sustainability goals. The resolution specifically noted that one of the City’s strategies for  
12 reaching its overarching goal of community wide carbon neutrality by 2030 is  
13 “supporting electrification and an incremental transition from natural gas to electric  
14 transportation and building systems.”<sup>2</sup> Entering another 30-year franchise would not have  
15 aligned with this directive. The shorter, 10-year franchise demonstrates Ann Arbor’s  
16 commitment to exploring alternatives to fossil gas and its expectation that at least  
17 portions of the City will no longer need fossil gas service by 2035.

18 **Q. Is there anything else about the current franchise that you would like to highlight?**

19 A. Yes. The new franchise agreement includes an Agreement Regarding Climate Action  
20 (“ARCA”), in which DTE committed to take certain actions in cooperation with Ann  
21 Arbor to combat climate change. The ARCA is intended to lead to “opportunities for the

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<sup>1</sup> Exhibit AA-19.

<sup>2</sup> Exhibit AA-20.

1 city and its citizens, especially those citizens with low to moderate income, to gain access  
2 to energy efficiency, distributed energy resources, and evolving technology programs and  
3 funding that are made available by [DTE].”<sup>3</sup>

4 **Q. In response to a discovery request, DTE witness Decker stated, “DTE Gas views the**  
5 **current franchise agreement as an opportunity to work with the City to continue to**  
6 **evaluate different emission reduction options and identify solutions that can meet**  
7 **customer needs for affordability and reliability”<sup>4</sup> Do you agree with that view of the**  
8 **franchise agreement?**

9 A. Yes. I am hopeful that the City and DTE can work collaboratively to support each other  
10 in reaching our climate goals. However, I am not confident DTE understands that one of  
11 the implications of Ann Arbor meeting its goals is that the City will no longer need fossil  
12 gas service, and that the Company should be planning for such a future.

13 **III. DTE’S UPDATED GDP**

14 **Q. What did the Commission order regarding DTE’s Gas Delivery Plan (“GDP”) in the**  
15 **previous rate case (Case No. U-21291)?**

16 A. The Commission ordered DTE to file an updated GDP by December 31, 2025 because  
17 “[i]t is clear from the record ... that the transition away from fossil fuels and the eventual  
18 trend of declining natural gas demand will have impacts on the future of the natural gas  
19 system and that these impacts were not sufficiently considered in the company’s GDP as  
20 filed.”<sup>5</sup> The Commission clarified that the updated GDP shall include:

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<sup>3</sup> Ann Arbor City Code, Ch. 34, § 2:311.

<sup>4</sup> Exhibit AA-19.

<sup>5</sup> Case No. U-21291, Order, November 7, 2024, p. 216.

1 information pertaining to how the company intends to achieve  
2 emissions reductions as part of its corporate goals and the State's  
3 emissions reductions goals with an estimated timeline for achieving  
4 those goals and interim goals; alternatives to capital investment,  
5 such as pipeline repairs and NPAs; historical trends of natural gas  
6 demand, projected demand, and impacts of changing demand; and  
7 the projected impacts of the transition towards electrification and  
8 decarbonization, including the portion of its distribution system that  
9 DTE Gas anticipates will be most immediately impacted.<sup>6</sup>

10 **Q. Have you reviewed the updated GDP?**

11 A. Yes.

12 **Q. Do you believe it complies with the Commission's order in Case No. U-21291?**

13 A. No, I do not believe the updated GDP meaningfully addresses alternatives to capital  
14 investment, the impacts of changing demand, the impact of electrification and  
15 decarbonization, or the portion of its distribution system that it anticipates will be most  
16 immediately impacted.

17 The updated GDP includes blanket statements regarding the likelihood of reduced  
18 demand as a result of decarbonization efforts, such as, "As GHG emission reductions get  
19 more aggressive to reach Michigan's 2050 net zero goal, there is likely to be further  
20 reduction in natural gas demand,"<sup>7</sup> and, "As the state transitions to a lower-emission  
21 economy, DTE Gas understands that there may be a shift in natural gas usage that could  
22 impact the Company's investment plans."<sup>8</sup> However, despite acknowledging a  
23 foreseeable reduction in natural gas demand, DTE did not address the impact it will have  
24 on customer rates, its distribution system, or its organizational climate commitments and  
25 investments.

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<sup>6</sup> *Id.* at 216-17.

<sup>7</sup> Exhibit A-12, Sch. B5.5, p. 85

<sup>8</sup> *Id.*

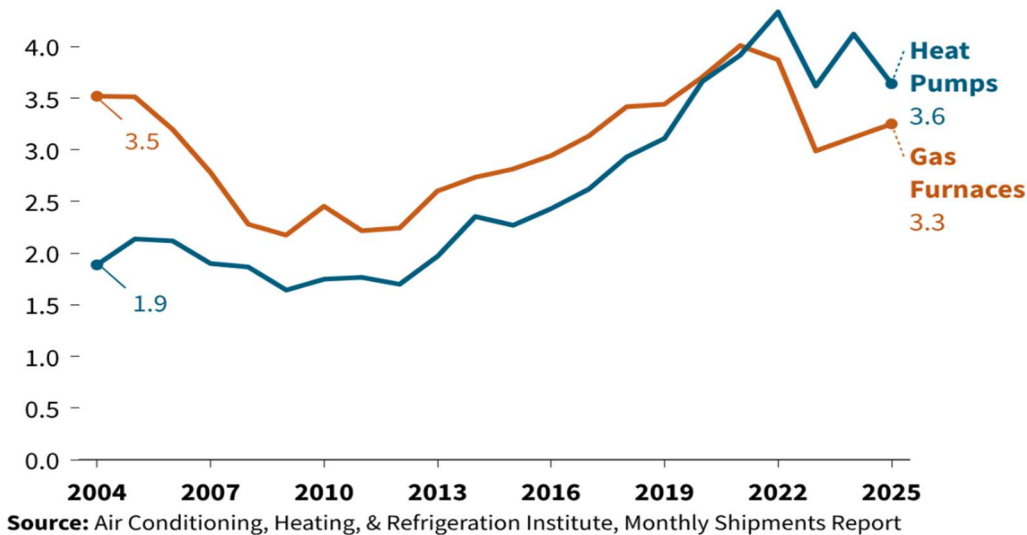
1 Q. Is there any evidence of a reduction in gas usage generally by residential and  
2 commercial customers, or that such reduction is accelerating?

3 A. Yes. Among other evidence, an American Gas Association report notes that since 2020,  
4 gas use per residential customer has declined more than twice as fast as the decline in the  
5 previous decade (1.45% from 2020 to 2023 versus 0.69% from 2010 to 2020); in 2023  
6 alone, residential gas use declined by 4.0%.<sup>9</sup> In that same time period, air source heat  
7 pumps began to outsell furnaces in the U.S., a trend that has only continued (see Figure 1  
8 below).<sup>10</sup> DTE itself predicts a decrease in gas demand from residential and commercial  
9 customers due in part to “new technology options over the next 10 years.”<sup>11</sup>

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### Annual Shipments of Gas Furnaces and Air-Source Heat Pumps

Annual # of units shipped (millions of units), 2004-2025



10

11 **Figure 1.** Illustration of relative demand for air-source heat pumps  
12 compared to gas furnaces.<sup>12</sup>

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<sup>9</sup> Exhibit AA-21.

<sup>10</sup> Exhibit AA-22, p. 1-2.

<sup>11</sup> Exhibit A-12, Sch. B5.6, p. 31.

<sup>12</sup> Exhibit AA-22, p. 3.

1 **Q. Are DTE’s own forecasts of residential and commercial customer use in line with**  
2 **these national trends?**

3 A. No. The GDP assumes a decline in weather-normalized consumption from 157.5 Bcf in  
4 2024 to 152.6 Bcf in 2030.<sup>13</sup> That equates to a decrease in demand from residential and  
5 commercial customers of 3% between now and 2030, or an average decrease of only  
6 0.5% per year.

7 **Q. Is DTE required to meet any energy waste reduction targets?**

8 A. Yes. Michigan law requires DTE to achieve incremental energy savings equivalent to  
9 0.875% of total retail sales beginning in 2026.<sup>14</sup> So, if DTE expects its reduction in total  
10 consumption to be only 0.5% per year, it must depend on customer growth to achieve the  
11 legally-mandated energy savings.

12 **Q. Does DTE’s projection of total demand for gas from residential and commercial**  
13 **customers assume a decrease or increase in its customer count in the next decade?**

14 A. DTE projects its total number of customers to grow from 1.34 million in 2024 to 1.4  
15 million in 2030 (an average annual increase of approximately 0.8%), and that growth  
16 after 2030 will be “consistent with the growth over recent years.”<sup>15</sup>

17 **Q. Do you think DTE’s projection of customer growth is reasonable?**

18 A. No. It is not consistent with DTE’s historical customer counts and does not take into  
19 account the trend toward electrification and decarbonization.

20 **Q. What is DTE’s projection for growth for the five-year period from 2025 to 2030?**

21 A. DTE projects that its total customer count will grow from 1,352,126 customers at the end

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<sup>13</sup> Exhibit A-12, Sch. B5.6, p. 32.

<sup>14</sup> MCL 460.1077(7).

<sup>15</sup> Exhibit A-12, Sch. B5.6, p. 31-32.

1 of 2025<sup>16</sup> to 1.4 million customers by the end of 2030,<sup>17</sup> which is a 3.54% increase over  
2 those five years.

3 **Q. How would a 3.54% growth rate over five years compare to DTE’s historical level of**  
4 **customer growth?**

5 A. To put it in context, between the end of 2003 and the end of 2025, DTE’s total customer  
6 count increased by 102,630 customers.<sup>18</sup> That is an 8.21% increase over 22 years, which  
7 represents approximately 0.37% growth annually. DTE is now projecting that over the  
8 next five years it will add 47,874 customers, which would be an increase of 3.54% in just  
9 five years, or an average annual growth rate of approximately 0.71%. That means DTE  
10 expects its customer count to grow in the next five years at a rate that is nearly double the  
11 rate of its historical growth since 2003.

12 **Q. Did DTE’s customer growth rate meet or exceed 0.71% in any of the last three years**  
13 **(2023, 2024, and 2025)?**

14 A. Once, in 2024.

15 **Q. How would a 3.54% increase in customers over a five-year period compare to the**  
16 **highest and lowest growth rates over five-year periods between 2003 and 2025?**

17 A. DTE’s highest customer growth rate over a five-year period occurred between 2017 and  
18 2022, when the Company experienced an overall growth rate of approximately 5% (or  
19 1% per year). DTE’s lowest growth rate over a five-year period occurred between 2005  
20 and 2010, when DTE experienced a reduction in customer count, leading to a growth rate  
21 of approximately -4.1%, or an average loss of 0.81% of its customers per year.

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<sup>16</sup> Exhibit AA-23.

<sup>17</sup> Exhibit A-12, Sch. B5.6, p. 32.

<sup>18</sup> Exhibit AA-23.

1           Therefore, in the last two decades, DTE has experienced both a period where its customer  
2           count increased at a higher rate than it is projecting for the next five years and a period of  
3           customer loss 15% higher than the rate DTE is projecting to gain customers in the  
4           coming five years.

5   **Q.   Given DTE’s historical customer counts and the trend toward electrification and**  
6           **decarbonization, do you think the customer growth and usage numbers in DTE’s**  
7           **GDP are reasonable?**

8   A.   No. I think these projections likely overpredict both future customer growth and future  
9           gas usage.

10 **Q.   What concerns you do you have regarding the impact of using unreasonably high**  
11           **customer growth and customer usage assumptions on DTE’s investment planning?**

12 A.   I am concerned that DTE is making investments in infrastructure without appreciating the  
13           rate impacts of those investments on a customer base that is likely to be much smaller in  
14           number than they are expecting. Specifically, the Company is not considering what will  
15           happen if the infrastructure it installs today is not actually used and useful for its entire  
16           depreciable life, which is a likely result of increasing decarbonization and electrification  
17           efforts in the state. I am concerned DTE is not appropriately weighing the impact of  
18           making significant investments to expand a distribution system that will likely be moving  
19           lower quantities of gas to fewer people in the future. I am also concerned that DTE is  
20           creating intergenerational inequity by continuing to make costly capital investments that  
21           will increase the rate base while more and more people choose to electrify, leaving fewer  
22           customers to cover the growing costs.

23

1 **Q. Does the City of Ann Arbor track permits associated with switching home heating**  
2 **fuels?**

3 A. Yes. A permit is required when a resident is installing a heat pump and also when a new  
4 furnace is being installed.

5 **Q. Does the City track the number of heat pumps being installed in Ann Arbor?**

6 A. Yes. The City has a public facing dashboard which draws directly from the City’s permit  
7 application portal to track the number of permits pulled for heat pump installations.

8 **Q. What does the data on heat pump installations in Ann Arbor show?**

9 A. Since the City moved to its new online permit application portal in 2023, the City has  
10 seen a steady increase in the number of permits pulled for heat pumps. Specifically, as  
11 illustrated in the table below, the percentage of all HVAC installation permits that were  
12 pulled for heat pumps has increased every year for both the residential and commercial  
13 sectors.

14 **Table 1: Heat pump adoption in Ann Arbor**

<b>Year</b>	<b>Percent of Residential HVAC Permits for Heat Pump Installation</b>	<b>Percent of Commercial HVAC Permits for Heat Pump Installation</b>
2023	6.6%	3.1%
2024	9.6%	7.6%
2025	9.7%	13.3%
2026 <sup>19</sup>	12.4%	14.1%

15  
16 Combined, this data demonstrates a growing awareness and adoption of heat pump  
17 technology in Ann Arbor. And this trend is far greater than the national trend for heat  
18 pump adoption.

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<sup>19</sup> As of March 7, 2026.

1 **Q. Does the City expect this trend to change?**

2 A. Perhaps, but if it were to change, it would almost certainly be towards greater adoption of  
3 heat pump technology.

4 **Q. Why do you think heat pump technology adoption is so high in Ann Arbor?**

5 A. The City has been actively working with consumers, contractors, and manufacturers to  
6 ensure that residents know about the viability of heat pump technology in cold climates.  
7 The City also provides incentives to support electrification, including thousands of  
8 dollars in rebates to support residents with the adoption of heat pump technology. In  
9 addition, the City is working to educate developers on the viability of air source and  
10 ground source heat pump technology in Michigan. This education includes helping  
11 developers understand the operational and upfront cost implications of electrification, as  
12 well as details on comfort, health, safety, and operational and maintenance requirements.

13 **Q. Why do you think DTE Gas should be paying attention to heat pump adoption  
14 trends in Ann Arbor?**

15 A. While Ann Arbor has one of the most aggressive climate goals in the country, making it  
16 an early adopter of policies and programs to support electrification, many other Michigan  
17 municipalities have climate goals they are working to make progress on. And achieving  
18 those goals will necessitate electrification and air and ground source heat pump adoption.  
19 In this way, Ann Arbor likely serves as a canary in the proverbial coal mine for DTE,  
20 demonstrating what kind of consumer choices and local preferences are on the horizon  
21 across a significant portion of its service territory.

22 **Q. What would you like to have seen in DTE's DGP and/or in this rate case to address  
23 your concerns?**

1 A. DTE should have included multiple scenarios in its DGP, so it could plan for the likely  
2 impact of varying levels of electrification and/or other NPAs to better understand the  
3 long-term rate impacts that will result from the expenditures proposed in this case.

4 **IV. DTE'S FAILURE TO SCENARIO PLAN**

5 **Q. What is scenario planning?**

6 A. Scenario planning is a planning approach whereby stakeholders create multiple plausible  
7 futures to review and analyze with the objective of making more informed choices based  
8 on a bevy of possible futures. Scenario planning is a technique particularly useful in the  
9 face of making decisions on complex and uncertain futures.

10 Scenario planning, as currently conceived, emerged in the 1950s from work Herman  
11 Kahn, a researcher at Rand Corporation, was doing with the U.S. government to explore  
12 possibilities for what were described as “unthinking situations.” It was later employed by  
13 Royal Dutch/Shell Oil Company to help navigate an ever changing and evolving energy  
14 system – this is largely considered the first well-known successful usage of scenario  
15 planning in the energy industry and is credited with Royal Dutch/Shell Oil Companies’  
16 ability to be more resilient in the face of the 1973 oil embargo.<sup>20</sup>

17 **Q. Why is scenario planning important?**

18 A. Scenario planning allows decision makers and key stakeholders to gather a more holistic  
19 understanding of the range of possible futures, the benefits and threats of those futures,  
20 and to make plans based on those variables. Scenario planning is particularly useful as a  
21 framework to consider novel situations in dynamic and evolving fields/areas where  
22 planning for the past is a poor predictor for the future.

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<sup>20</sup> Exhibit AA-24, p. 4-7.

1 **Q. Is scenario planning a common practice in managing a business?**

2 A. Yes. Scenario planning is regularly used by the U.S. military, energy companies, and  
3 local governments. In fact, DTE Electric Company uses scenarios as part of its Integrated  
4 Resource Planning process whereby it workshops multiple plausible futures, models  
5 implications of those futures, and then uses that information to decide which resources to  
6 procure.

7 **Q. Did DTE include scenario planning in its updated GDP or in this rate case?**

8 A. No, not in a meaningful way. Rather than model multiple scenarios to understand the  
9 potential impacts of varying levels of electrification on DTE's infrastructure investments  
10 and customer rates, DTE seems to only be planning for growth of its gas system, which is  
11 especially unreasonable considering recent history. Specifically, given that the Company  
12 experienced long periods of net customer loss (2005-2011), and in fact did not recover to  
13 2003 levels of customer numbers until 2016,<sup>21</sup> combined with the electrification adoption  
14 rates being seen in Ann Arbor, DTE should have a plan that considers multiple plausible  
15 futures, including a future of significantly reduced gas consumption and fewer gas  
16 customers.

17 DTE's failure to scenario plan is demonstrated by its response to a discovery request  
18 asking DTE to provide any studies or analyses assessing the risk of investments  
19 becoming stranded or underutilized due to climate policy, customer electrification, and  
20 declining gas demand, in which DTE failed to provide any such studies or analyses.  
21 Rather, DTE witness Decker repeated three points from his testimony: (1) "DTE Gas is  
22 not currently aware of any proposed legislation or regulations that would materially

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<sup>21</sup> Exhibit AA-23.

1 impact its current business, including the utilization of existing assets;” (2) “DTE has  
2 considered customer electrification but at this time does not foresee any impact on asset  
3 utilization given the limited number of customers expected to fully electrify;” and (3)  
4 “even if gas demand declines, the expected impact on asset utilization is expected to be  
5 minimal.”<sup>22</sup>

6 **Q. What is your response to witness Decker’s first point (“DTE Gas is not currently  
7 aware of any proposed legislation or regulations that would materially impact its  
8 current business, including the utilization of existing assets”)?**

9 A. First, Ann Arbor’s discovery request did not ask whether DTE had assessed the risk of  
10 “proposed legislation or regulations,” but rather whether it had assessed the risk due to  
11 “climate policy.” Ann Arbor has at the very least made DTE aware of its climate policy  
12 and intention to transition away from relying on fossil gas service. The City’s decision to  
13 grant a franchise for a much shorter term than in the past is indicative of the risk of exit.  
14 Over time, Ann Arbor’s exit from the gas system will certainly result in stranded assets  
15 and impact DTE’s business.

16 Second, this point should be read in context with the Company’s testimony in the last rate  
17 case, in which DTE’s own witness made the following statements, all of which highlight  
18 the risks the gas industry faces due to climate policy:

- 19 • “In the current regulatory and policy environment focused on decreasing  
20 greenhouse gas (‘GHG’) emissions, there is some uncertainty about the future of  
21 natural gas.”
- 22 • “To the extent that decarbonization risks continue, the business risk of the gas

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<sup>22</sup> Exhibit AA-25.

1 LDC industry would increase substantially.”

- 2 • “DTE Gas is facing increasing risk from state decarbonization policies.”<sup>23</sup>

3 **Q. What is your response to witness Decker’s second point (“DTE has considered**  
4 **customer electrification but at this time does not foresee any impact on asset**  
5 **utilization given the limited number of customers expected to fully electrify”)?**

6 A. First, claiming DTE has “considered customer electrification” is not the same as  
7 modeling varying electrification scenarios. Acknowledging electrification as a possibility  
8 and then failing to plan for any potential impact is illustrative of DTE’s tendency to turn a  
9 blind eye to inconvenient truths, like the growing popularity of heat pumps compared to  
10 conventional furnaces. Moreover, Ann Arbor’s experience with heat pump adoption is  
11 public – meaning that this information was easily discoverable should DTE have wanted  
12 to see what kind of electrification adoption rates are likely in the near future.

13 Second, a decade ago DTE had not yet recovered from years of sustained customer losses  
14 following a sustained recession in Michigan. Even if DTE does not believe a reduction in  
15 customer numbers will result from electrification, it should consider the possibility of an  
16 economic downturn and make sure the Company’s plans could be successfully executed  
17 if the Company faced a similar situation again.

18 In summary, even if DTE does not consider a reduction in customers to be the most likely  
19 scenario for the future, planning only for high levels of growth and ignoring the  
20 possibility of customer loss is not only imprudent, but it also places ratepayers at risk of  
21 holding the bag should DTE’s linear assumptions prove incorrect.

22  

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<sup>23</sup> Exhibit AA-26.

1 **Q. What impacts on asset utilization is DTE failing to consider by ignoring the**  
2 **possibility of a reduction in its customer count?**

3 A. A key impact DTE is failing to consider is the fate of the ratepayers who will be left to  
4 pay for infrastructure investments that the Company made under the assumption that their  
5 costs would be spread over a greater number of customers. When fewer customers remain  
6 to pay down the rate base, it leads to increasing rates. Increasing rates are likely to  
7 increase the number of customers taking advantage of efficiencies and new technologies,  
8 exacerbating the problem. Continuing to invest in assets at a rate that is only supportable  
9 if the current customer count grows ignores this foreseeable risk of lower future customer  
10 counts. For instance, it is foreseeable that an anticipated small percentage of customers  
11 electrifying in the very near future is likely to snowball into a large percentage of  
12 customers electrifying in the longer term. That means a growing number of customers  
13 will exit the system every year, and assets that have yet to reach the end of their useful  
14 lives will remain in system with fewer people to cover their costs. And even this scenario  
15 ignores external pressures that might lead people to leave the system sooner, such as  
16 incentives for electrification offered by governments, technology advancements which  
17 bring electrification options to cost parity with gas options, wars and conflicts that disrupt  
18 gas systems and lead to price increases, and the potential for growing customer concern  
19 with the health implications of burning fossil gas in homes and businesses. Regardless,  
20 DTE's failure to explore the very real possibility of declining gas demand and a shrinking  
21 customer base represents a dangerous gamble.

22 **Q. What is your response to witness Decker's third point ("even if gas demand declines,**  
23 **the expected impact on asset utilization is expected to be minimal")?**

1 A. I'll echo my concern from above. This point does not take into consideration the fact that  
2 as gas demand declines and customers electrify, there will be fewer customers left to  
3 share the cost of DTE's assets, which means DTE will have to continue increasing rates  
4 for those who remain dependent on the gas system. Planning investments based only on  
5 growth scenarios is likely to disproportionately impact low-income customers who may  
6 not be able to afford the upfront costs of electrifying, especially if they are grappling with  
7 rising bills.

8 But, if the Company believes this statement made by witness Decker to be true and acts  
9 accordingly, then the Commission should hereby put DTE on notice that any financial  
10 implications of customers leaving the system and/or reduced gas demand must be borne  
11 by DTE shareholders and not the ratepayers. Put another way, DTE Gas should not be  
12 granted permission to blindly plan for one future scenario but be protected from all future  
13 scenarios – especially when prudent and affordable planning frameworks, such as  
14 scenario planning, are available to help manage the reality of an uncertain future.

15 **Q. Did DTE otherwise address the potential impacts of electrification?**

16 A. In response to a discovery request asking whether DTE analyzed the potential impact of  
17 electrification on its business, DTE witness Decker responded affirmatively, pointing to a  
18 single question and answer in his testimony. Based on that testimony, it appears the  
19 extent of DTE's "analysis" was reviewing a handful of studies that concluded heat pumps  
20 are more expensive than gas furnaces (including a 2022 study commissioned by DTE)  
21 and conducting a customer survey, which led the Company to conclude that it "would  
22 expect only about 4% of customers to choose an electric heat pump over a natural gas

1 furnace.”<sup>24</sup> The discovery response further stated, “Due to the small percentage of  
2 customers likely to switch, DTE Gas did not do additional analysis.”<sup>25</sup>

3 **Q. Did you review the study that resulted from the survey referenced by witness**  
4 **Decker, which is DTE’s Exhibit A-25, Schedule O1?**

5 A. Yes.

6 **Q. Do you believe DTE’s expectation that only about 4% of customers would choose a**  
7 **heat pump over a furnace is a reasonable conclusion based on the results of that**  
8 **survey?**

9 A. No. It is unreasonable to make any conclusions about DTE customers as a whole based  
10 on the referenced survey because it was conducted only on homeowners outside metro  
11 Detroit/Southeast Michigan who currently use propane for heating.<sup>26</sup> Thus, the resulting  
12 data are not representative of the energy preferences of customers throughout DTE’s  
13 territory, nor of DTE customers who currently heat their homes with gas. Concluding that  
14 only 4% of customers throughout DTE’s service territory would choose a heat pump over  
15 a furnace based on this non-representative survey is unreasonable and misleading and  
16 does not mirror the lived reality appearing in Ann Arbor where heat pump adoption is  
17 rapidly rising.

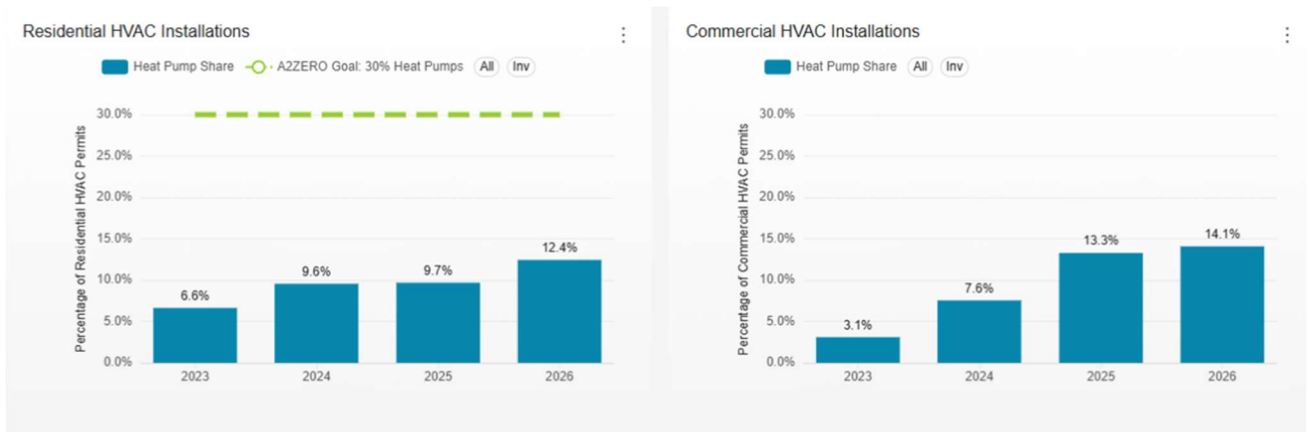
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<sup>24</sup> Decker, Direct Testimony, p. 14.

<sup>25</sup> Exhibit AA-27.

<sup>26</sup> Exhibit A-25, Sch. O1, p. 2

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2

3

**Figure 2.** *Percentage of HVAC permits for heat pump installation in Ann Arbor.*<sup>27</sup>

4

5 **Q. Is DTE’s conclusion that only about 4% of customers would choose a heat pump**  
 6 **over a furnace supported by heat pump sales trends?**

7 A. No. As shown in Figure 1 in section III, air-source heat pumps have outsold furnaces in  
 8 the U.S. in each of the past four years, and as shown in Figure 2 above, Ann Arbor has  
 9 seen a sustained increase in heat pump installations since 2023, both of which are “a  
 10 testament to Americans’ sustained appetite for the zero-emissions appliances crucial to  
 11 weaning buildings off planet-warming fossil fuels.”<sup>28</sup>

12 **Q. Do you have any recommendations regarding DTE’s failure to meaningfully**  
 13 **consider scenarios involving reduced reliance on the gas system?**

14 A. Yes. I recommend DTE be required to model multiple scenarios with varying levels of  
 15 electrification adoption in order to understand the potential impacts on DTE’s  
 16 infrastructure investments and customer rates. I also recommend that the Commission

<sup>27</sup> Exhibit AA-22, p. 3.

<sup>28</sup> Exhibit AA-28.

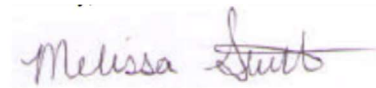
1 initiate a Future of Gas proceeding, requiring utilities to begin seriously engaging in and  
2 planning for a future in which we do not rely on fossil gas for heating.

3 **Q. Does this conclude your direct testimony?**

4 A. Yes.

5 **Q. Do you swear under penalty of perjury that the statements above are true to the best**  
6 **of your knowledge, information, and belief?**

7 A. Yes.

8 

9  
10

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Melissa Stults

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

U-21973

ALJ Christopher S. Saunders

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**DIRECT TESTIMONY OF MICHAEL WALSH, Ph.D.**

**ON BEHALF OF**

**THE CITY OF ANN ARBOR**

**March 13, 2026**

1       **I.       INTRODUCTION AND QUALIFICATIONS**

2       **Q.       Please state your name, title, and business address.**

3       A.       My name is Michael J. Walsh. I am the Managing Partner of Groundwork Data, Inc. My  
4       business address is 51 Lockeland Avenue, Arlington, Massachusetts 02476.

5       **Q.       Please describe your educational background and professional experience.**

6       A.       I hold an A.B. in Chemistry from Colby College, and a Ph.D. in Environmental  
7       Engineering from Cornell University. My doctoral research and education focused on  
8       marine biogeochemistry. I conducted postdoctoral research as a fellow at the Bentley  
9       University Center for Integration of Science and Industry on the topics of integrated  
10      macro-energy system modeling, lifecycle and technoeconomic assessment, and  
11      technology transitions in the bioenergy industry.

12      From 2017 to 2019, I served as the technical lead of the Carbon Free Boston Study at the  
13      Boston University Institute for Sustainable Energy, overseeing a comprehensive technical  
14      analysis and stakeholder engagement exercise. In 2019, I was hired by the Cadmus  
15      Group, where my primary responsibility was as project director for the Massachusetts  
16      2050 Decarbonization Roadmap Study (“2050 Roadmap”), a comprehensive technical  
17      analysis and stakeholder engagement exercise that served as the foundational research for  
18      the Executive Office of Energy and Environmental Affairs’ (“EEA”) decarbonization  
19      planning.

20      In 2021, I launched an independent practice that evolved into Groundwork Data focused  
21      primarily on the future of gas and future of heat. In this role, I have overseen several  
22      studies and projects on the “future of gas” and the “future of heat” in Massachusetts and  
23      other jurisdictions. To date, Groundwork Data has worked only with governmental or

1 nonprofit public-interest organizations.

2 **Q. On whose behalf are you submitting your testimony in this proceeding?**

3 A. My testimony is on behalf of the City of Ann Arbor (“Ann Arbor” or “the City”).

4 **Q. Have you previously testified before this Commission or as an expert in other**  
5 **proceedings?**

6 A. My usual role in testifying before public utility regulatory agencies is in an advisory  
7 capacity as a buildings and gas sector decarbonization expert. In the Commonwealth of  
8 Massachusetts, I have testified before the Massachusetts Department of Public Utilities  
9 on behalf of the Attorney General’s Office on the Massachusetts gas companies’ Climate  
10 Compliance Plans (D.P.U. 25-41 through 25-44/45); and, on behalf of the Conservation  
11 Law Foundation (“CLF”) on Liberty Utility’s petition for approval of an agreement to  
12 purchase renewable natural gas from Fall River RNG, LLC (D.P.U. 22-32). I have also  
13 acted as a non-testimonial expert in other dockets as a consulting expert and commenter,  
14 notably in the Department of Public Utilities’ “Future of Gas Investigation” D.P.U. 20-80  
15 on the topics of Pathways Analysis, Line Extension Allowances, and Renewable Natural  
16 Gas.

17 I have also testified before the Rhode Island (“R.I.”) Public Utilities Commission  
18 (“P.U.C.”) on behalf of the CLF on Rhode Island Energy’s 2024 and 2025 infrastructure,  
19 safety, and reliability proceedings (R.I. P.U.C. 23-49-NG and R.I. P.U.C. 24-55-NG). I  
20 have also participated as a technical expert in the R.I. “Future of Gas” investigation (R.I.  
21 P.U.C. 22-01-NG) on behalf of the CLF and Sierra Club. And I have recently testified  
22 before the Colorado Public Utilities Commission on Xcel Energy’s 2025-2030 Gas  
23 Infrastructure Plan (CO. P.U.C. 25A-0220G) on behalf of Rewiring America.

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

2 A. The purpose of my testimony is to provide the Commission with an independent  
3 assessment of DTE Gas Company's ("DTE," "DTE Gas," or "the Company") proposed  
4 investments and business strategies in light of the converging challenges facing gas  
5 distribution systems. Specifically, my testimony: (1) identifies four structural disruptors  
6 facing DTE's gas system – growing infrastructure costs, state and local climate action,  
7 increasing competition from heat pump technology, and Michigan population decline –  
8 and demonstrates that these challenges are independently validated by the Michigan  
9 Department of Environment, Great Lakes, and Energy; (2) evaluates DTE's response to  
10 the Commission's November 2024 directive to consider energy transition pathways in its  
11 Gas Delivery Plan, and finds it insufficient; (3) presents a revenue requirement model  
12 projecting residential bills and per-customer costs through 2050 under seven demand  
13 scenarios, demonstrating that even modest declines in gas demand materially increase  
14 costs for remaining ratepayers and that neither renewable natural gas nor hybrid heating  
15 presents a viable path to system-wide decarbonization; (4) examines the limitations of  
16 DTE's emissions-factor-based approach to methane mitigation and recommends a  
17 transition to measurement-based strategies; (5) evaluates DTE's claims regarding  
18 renewable natural gas ("RNG"), demonstrating that RNG is fundamentally supply-  
19 constrained, driven by distortive federal subsidies, and an inferior use of limited  
20 bioenergy resources; (6) describes the growing field of non-pipeline alternatives ("NPA")  
21 and recommends that DTE be directed to systematically identify and evaluate NPA  
22 opportunities across its system; (7) analyzes DTE's Customer Attachment Program,  
23 demonstrating that existing ratepayers finance approximately 94% of new service

1 connection costs system-wide and that the program's revenue projections are based on  
2 assumptions contradicted by DTE's own Gas Delivery Plan; and, (8) summarizes how  
3 five peer states are addressing "Future of Gas" issues through regulatory proceedings and  
4 policy changes, including lessons from the Peoples Gas experience in Illinois.

5 Throughout these reviews, I offer recommendations that the Commission: (1) reform line  
6 extension allowances; (2) direct DTE to begin non-pipeline alternative evaluation; and  
7 (3) initiate a comprehensive Future of Gas proceeding with four defined workstreams and  
8 twelve-month deliverables.

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

10 A. Yes. I am sponsoring the following exhibits:

11	Exhibit AA-29	Resume of Michael Walsh
12	Exhibit AA-30	State Future of Gas Proceeding Matrix
13	Exhibit AA-31	DTE Gas Revenue Requirement Model
14	Exhibit AA-32	Discovery Response MECCUBDG-5.2b
15	Exhibit AA-33	Discovery Response STDG-2.13
16	Exhibit AA-34	Discovery Response AGDG-6.221
17	Exhibit AA-35	Discovery Response MECCUBDG-5.12a-b
18	Exhibit AA-36	EGL E Report: <i>Clean, Safe, and Affordable</i> (Excerpts)
19	Exhibit AA-37	Michigan Population Projections Through 2050 (Excerpt)
20	Exhibit AA-38	Michigan Population Growth Domestic Gains (Excerpt)
21	Exhibit AA-39	Discovery Response MECCUBDG-3.16g
22	Exhibit AA-40	DHInfrastructure & CUB, <i>Potential Bill Impacts of</i>
23		<i>Business-as-Usual in Michigan</i> (Excerpt)
24	Exhibit AA-41	ICF, Michigan Renewable Natural Gas Study (Excerpt)

1	Exhibit AA-42	Discovery Response AADG-1.6
2	Exhibit AA-43	MPSC Form P-522, p. 305B and 306C
3	Exhibit AA-44	Olaguer, E.P. et al., <i>The Michigan-Ontario Ozone Source</i>
4		<i>Experiment (MOOSE): An Overview</i>
5	Exhibit AA-45	Sargent, M.R. et al., “Majority of US urban natural gas
6		emissions unaccounted for in inventories”
7	Exhibit AA-46	Direct Testimony of Robert Ackley from Case No. U-
8		21291 (Excerpt)
9	Exhibit AA-47	American Gas Foundation, <i>Renewable Natural Gas Supply</i>
10		<i>Assessment</i> (Excerpt)
11	Exhibit AA-48	EPRI, <i>Net-Zero Scenarios 2.0</i> (Excerpt)
12	Exhibit AA-49	Cole Rosengren, “How the EPA’s Renewable Fuel
13		Standard program changes could be boon for landfill and
14		AD operators,” <i>Waste Dive</i>
15	Exhibit AA-50	Jacob Wallace, “Biogas groups, lawmakers jockey for
16		changes as EPA nears final rule on eRIN market,” <i>Waste</i>
17		<i>Dive</i>
18	Exhibit AA-51	New York State Energy Plan, <i>Low-Carbon Alternative</i>
19		<i>Fuels</i> (Excerpt)
20	Exhibit AA-52	New York State Energy Research and Development
21		Authority, <i>Considerations for Low-Carbon Alternative</i>
22		<i>Fuel Use in New York State</i> (Excerpt)
23	Exhibit AA-53	Attachment to Discovery Response MECCUBDG-3.12a
24		(Heat Pump Emissions tab)
25	Exhibit AA-54	Attachment to Discovery Response MECCUBDG-3.12a
26		(GHG Emissions Factors tab)
27	Exhibit AA-55	RMI & National Grid, <i>Non-Pipeline Alternatives:</i>
28		<i>Emerging Opportunities in Planning for U.S. Gas System</i>
29		<i>Decarbonization</i> (Excerpt)
30	Exhibit AA-56	Discovery Response MECCUBDG-3.8a

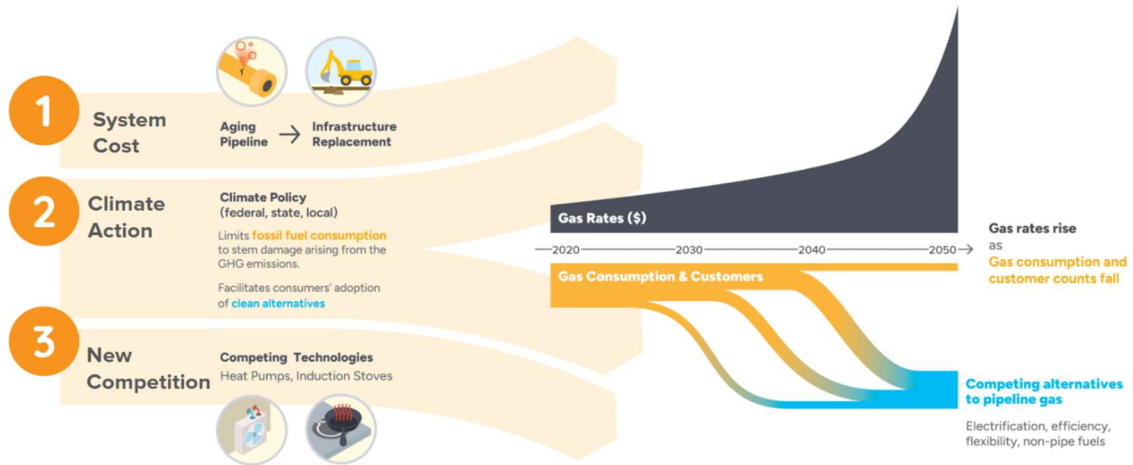
1	Exhibit AA-57	Discovery Response FLODG-4IV2bii
2	Exhibit AA-58	Discovery Response AADG-2.7a
3	Exhibit AA-59	Discovery Response AADG4.4a-f
4	Exhibit AA-60	U.S. Energy Information Administration, Natural Gas
5		Annual 2024, Table 15
6	Exhibit AA-61	U.S. Energy Information Administration, Natural Gas
7		Annual 2024, Table 19
8	Exhibit AA-62	Discovery Response AADG-2.8a
9	Exhibit AA-63	Discovery Response AADG-2.9fi-iii
10	Exhibit AA-64	RMI, “Cutting These Subsidies Could Save States Millions
11		of Dollars”
12	Exhibit AA-65	National Regulatory Research Institute, <i>Line Extensions for</i>
13		<i>Natural Gas: Regulatory Considerations</i> (Excerpt)
14	Exhibit AA-66	California Energy Commission, <i>The Challenge of Retail</i>
15		<i>Gas in California’s Low-Carbon Future</i> (Excerpt)
16	Exhibit AA-67	Citizens Utility Board of Illinois & Groundwork Data,
17		<i>Peoples Gas: Escalating Business Risk in a Changing</i>
18		<i>Energy Landscape</i> (Excerpt)
19	Exhibit AA-68	Stephanie Zimmerman, “Peoples Gas Pipe Replacement is
20		Costing Chicagoans More,” Chicago Sun-Times (Feb. 16,
21		2021)
22	Exhibit AA-69	Robert Channick, “Peoples Gas Pipeline Program Will Cost
23		Another \$12.8 Billion to Complete,” Chicago Tribune (Oct.
24		29, 2024)

25 **II. CHALLENGES FACING THE GAS SYSTEM**

26 **Q. What are the key challenges facing natural gas distribution systems in Michigan**  
27 **and nationally?**

28 A. Natural gas distribution systems across the country, including DTE’s, face three

1 converging disruptors that are fundamentally changing the economics and long-term  
 2 viability of the gas utility business model (Figure 1). These are: (1) growing costs of  
 3 maintaining and expanding gas distribution infrastructure; (2) mounting climate action  
 4 not just from governments, but also from customers; and (3) increasing competition from  
 5 non-gas technologies, particularly electric heat pumps.



6  
 7 **Figure 1.** *Illustration of how increasing gas costs concentrate on a*  
 8 *declining customer base as the gas system is disrupted.*  
 9 *Groundwork Data figure.*

10 In Michigan, gas utilities face a fourth challenge: statewide population decline that  
 11 threatens to reduce the gas customer base even without attrition to other fuels.  
 12 The combined and accelerating effect of these trends demands careful regulatory  
 13 attention. As I describe below, each is clearly present in Michigan. Whether gas demand  
 14 ultimately declines modestly or substantially, these trends create material risk for existing  
 15 ratepayers who fund the system's fixed costs. This risk justifies heightened regulatory  
 16 scrutiny of DTE's investment plans.

- 17 **Q. What are the consequences of these combined disruptors for gas ratepayers?**  
 18 **A.** The fundamental problem is that gas distribution is a high-fixed-cost system. The vast  
 19 majority of costs are incurred regardless of the amount of gas flowing through the

1 system. When gas consumption declines, whether through efficiency, electrification, or  
2 customer departure, those fixed costs must be spread over fewer units of gas consumed  
3 and ultimately fewer customers. This concentrates costs on the customers who are unable  
4 to reduce their gas usage, a group that is likely to be increasingly constrained in their  
5 ability to manage their gas use.

6 Regulators in other states have recognized this dynamic and have begun to address it  
7 through formal proceedings and policy changes. This is discussed in detail in Section IX.  
8 The Michigan Public Service Commission (“MPSC” or “the Commission”) has taken  
9 initial steps in this direction through the updated Gas Delivery Plan (“GDP”)  
10 requirements established in Case No. U-21291,<sup>1</sup> but as I discuss in subsequent sections,  
11 DTE’s response to these requirements has been insufficient.

## 12 **II-A. Growing Costs for Gas Distribution Infrastructure**

### 13 **Q. How are gas distribution infrastructure costs changing?**

14 A. Gas distribution infrastructure costs are rising significantly, both nationally and at DTE  
15 specifically. This is driven by multiple factors: aging infrastructure requiring accelerated  
16 replacement, increasingly stringent federal pipeline integrity mandates, escalating  
17 contractor and labor costs, and the inherent difficulty of working on increasingly complex  
18 system management projects. These cost pressures are largely structural and will persist  
19 regardless of whether gas demand grows, stagnates, or declines.

20 At DTE, the evidence of cost escalation is pervasive in this proceeding. The Company’s  
21 Gas Renewal Program (“GRP”) cost per installed mile has increased sharply, from \$1.08

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<sup>1</sup> Case No. U-21291, Order, November 7, 2024, p. 216-17.

1 million in 2023 to \$1.69 million in 2025 (a 56% cumulative increase).<sup>2</sup> The GRP itself is  
2 ramping up from 127 miles per year in 2026 to an average of 196 miles per year from  
3 2027 through 2037.<sup>3</sup> Pipeline integrity operations and maintenance (“O&M”) costs are  
4 nearly tripling, from an average of approximately \$14.5 million per year over 2019–2024  
5 to projected levels of \$30 million in 2026 and \$42 million in 2027.<sup>4</sup> The Company has  
6 introduced a new Regulator Station Replacement Program (“RSRP”), but with  
7 approximately 2,100 legacy regulator stations remaining and a current pace of roughly 15  
8 per year, complete replacement would take approximately 140 years.<sup>5</sup>

9 Additional testimony is being submitted by Rick Brown, who provides a detailed  
10 engineering assessment of several specific large capital projects proposed in this case,  
11 including the Carlton Main Replacement Project, Fort Street Main Replacement Project,  
12 and the East Petoskey Pipeline Reinforcement Project. The cost trajectories of these  
13 projects illustrate the broader pattern: gas infrastructure spending is growing at rates that  
14 exceed general inflation, and this trend is expected to continue for decades.

## 15 **II-B. Climate Action at the State and Local Level**

### 16 **Q. What climate policies are relevant to gas demand in Michigan?**

17 A. Michigan has established a clear policy direction toward decarbonization that directly  
18 impacts the gas distribution system. The state released the MI Healthy Climate Plan in  
19 2022, which establishes a target of economy-wide carbon neutrality by 2050. Specifically  
20 relevant to this proceeding, the MI Healthy Climate Plan targets a 17% reduction in

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<sup>2</sup> Janness, Direct Testimony, p. 28-29.

<sup>3</sup> Exhibit AA-32.

<sup>4</sup> Exhibit AA-33; *see also*, Exhibit AA-34.

<sup>5</sup> Exhibit AA-35.

1 emissions from heating homes and businesses by 2030, relative to a 2005 baseline.<sup>6</sup>  
2 Additionally, Public Act 229 of 2023 increased energy-efficiency requirements for  
3 Michigan utilities, further reducing natural gas consumption.<sup>7</sup> The Commission itself has  
4 recognized the need for gas utilities to begin planning for the energy transition, requiring  
5 DTE to file an updated Gas Delivery Plan in the last rate case incorporating, among other  
6 things, how changing customer demand, electrification, and decarbonization will impact  
7 the distribution system.<sup>8</sup>

8 DTE’s own witness, Mr. Decker, acknowledges that “State or Federal legislative and  
9 regulatory developments could impact natural gas demand and DTE Gas’s capital  
10 plans.”<sup>9</sup> Yet the Company also claims that it is “not currently aware of any proposed  
11 legislation or regulation that would materially impact its current business.”<sup>10</sup> This posture  
12 is internally contradictory: in its most recent prior rate case, DTE’s own return-on-equity  
13 witness cited decarbonization risk – including the City of Ann Arbor’s franchise  
14 negotiations – as a basis for seeking a higher equity return.<sup>11</sup> The Company cannot  
15 credibly invoke climate risk when seeking higher shareholder returns and then dismiss it  
16 when the question is whether to plan prudently for that same risk.

17 **Q. Is climate action also occurring at the local level in Michigan?**

18 A. Yes. The City of Ann Arbor, on whose behalf I submit this testimony, adopted its  
19 A<sup>2</sup>ZERO Carbon Neutrality Plan in June 2020, committing the community to achieving

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<sup>6</sup> [MI Healthy Climate Plan](#); *see also*, Exhibit A-12, Schedule B5.6, p. 81 (Figure 72).

<sup>7</sup> *See* MCL 460.1077; *see also*, Decker, Direct Testimony, p. 22.

<sup>8</sup> Case No. U-21291, Order, November 7, 2024, p. 216-17.

<sup>9</sup> Decker, Direct Testimony, p. 17.

<sup>10</sup> *Id.*

<sup>11</sup> Exhibit AA-26.

1 carbon neutrality by 2030.<sup>12</sup> Transitioning away from fossil gas is a core strategy of this  
2 plan.

3 Ann Arbor’s building electrification goals are backed by dedicated funding, established  
4 programs, and active projects. The City’s Community Climate Action Millage generates  
5 roughly \$7 million annually to fund A<sup>2</sup>Zero decarbonization initiatives.<sup>13</sup> The City’s Heat  
6 Pump Concierge program provides streamlined incentives, free system design,  
7 guaranteed price estimates, and contractor vetting for residents<sup>14</sup> – and the City has seen  
8 HVAC permits for heat pump installation increase substantially in the past two years,  
9 from 6.6% of residential HVAC permits and 3.1% of commercial HVAC permits in 2023  
10 to 9.7% of residential permits and 13.3% of commercial permits in 2025.<sup>15</sup> The City’s  
11 Sustainable Energy Utility, launching in 2026, will further promote progress.<sup>16</sup> Both the  
12 City and the University of Michigan are already actively developing large networked  
13 geothermal systems.

14 Ann Arbor’s rapid progress demonstrates that its residents, which make up roughly 4% of  
15 DTE customers, cannot be expected to remain in DTE’s customer base in 2050 at current  
16 levels. The results of the revenue requirement model detailed in Section IV of my  
17 testimony demonstrate that even this 4% departure represents an increasing risk that  
18 DTE’s investment planning should, but does not, account for.

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<sup>12</sup> City of Ann Arbor, [A<sup>2</sup>ZERO Carbon Neutrality Plan](#) (adopted June 2020).

<sup>13</sup> City of Ann Arbor, [2022 Community Climate Action Millage](#).

<sup>14</sup> City of Ann Arbor, [A<sup>2</sup>ZERO Heat Pump Concierge](#).

<sup>15</sup> City of Ann Arbor, [A<sup>2</sup>ZERO Dashboard](#).

<sup>16</sup> City of Ann Arbor, [Sustainable Energy Utility](#).

1           **II-C. Increasing Competition from Non-Gas Technologies**

2   **Q.    What non-gas technologies are emerging as competitors to gas heating?**

3    A.    The most significant competitive threat to the gas distribution system is the electric air-  
4           source heat pump. Modern cold-climate heat pumps can operate efficiently at  
5           temperatures well below zero degrees Fahrenheit, a capability that was not commercially  
6           viable a decade ago. These systems offer several advantages over gas heating that are  
7           relevant to this proceeding.

8           First, heat pumps are *modular*. A homeowner can install a single mini-split unit to heat  
9           and cool a primary living space for a few thousand dollars, without the need for ductwork  
10          or gas piping. Second, heat pumps provide *both heating and cooling*, eliminating the need  
11          for a separate air conditioning system. Third, heat pumps can operate in *hybrid*  
12          *configurations* alongside existing gas or propane heating equipment. This hybrid  
13          approach significantly reduces gas consumption (potentially by 50–80% depending on  
14          design) while retaining gas backup for the coldest hours of the year.

15   **Q.    Are there particular consumer segments where heat pump adoption may be**  
16          **especially beneficial?**

17    A.    Yes. Consumers currently using propane for heating are a particularly promising segment  
18          for full or dual-fuel/hybrid heat pump adoption. The EGLE building decarbonization  
19          roadmap notes that Michigan ranks first in the nation in residential propane consumption,  
20          with over 400,000 homes heated by delivered fuels, and finds that the average Michigan  
21          propane household would save approximately \$660 per year by switching to a heat pump

1 – and significantly more under improved rate design.<sup>17</sup>

2 This observation has direct implications for DTE’s Customer Attachment Program  
3 (“CAP”). DTE attributes much of its new customer growth to “increased demand by  
4 homeowners for conversion from the higher cost of propane to natural gas, particularly in  
5 the community expansion space.”<sup>18</sup> But if these propane customers could achieve  
6 substantial heating cost savings through a hybrid heat pump/propane configuration,  
7 without requiring millions of dollars in ratepayer-funded gas main extensions, then the  
8 economic justification for these extensions is weaker than the Company represents.  
9 Moreover, from a system-wide perspective, encouraging hybrid heat pump adoption  
10 among propane customers could deliver benefits to the electric grid (higher winter  
11 utilization of electric infrastructure) that benefit all electricity ratepayers, without  
12 imposing new costs on gas ratepayers. Section VIII of my testimony will detail concerns  
13 with DTE’s CAP.

14 **Q. How competitive are heat pumps with natural gas?**

15 A. Michigan’s relatively low natural gas prices create a cost structure that currently favors  
16 gas heating on an operational basis. The cost of an electrification retrofit can be  
17 substantial, given the need for new equipment and the installation of enabling building  
18 envelope improvements. In contrast, in new construction, installing ducted heat pumps or  
19 ductless mini-split heat pumps can avoid the cost of gas piping, which is especially  
20 advantageous if cooling is desired.

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<sup>17</sup> [Clean, Safe, and Affordable: A Policy Roadmap for Efficient and All-Electric Homes in Michigan](#) (March 2026), prepared by Institute for Energy Innovation, Michigan Energy Innovation, and 5 Lakes Energy for the Michigan Department of Environment, Great Lakes, and Energy (Relevant excerpts at Exhibit AA-36).

<sup>18</sup> Huffman, Direct Testimony, p. 39.

1 The fact that gas is cheaper *today* also does not mean that gas will remain the lowest-cost  
2 option over the 20-to-50-year lifetime of the infrastructure investments this Commission  
3 is being asked to approve. Gas distribution costs are escalating rapidly, as described  
4 above. Heat pump technology continues to improve in both efficiency and cost.  
5 Electric rate design could further affect the economics of heat pump adoption. A March  
6 2026 EGLE-commissioned study found that under existing Michigan electric tariff  
7 structures, a natural gas customer switching to a heat pump would see annual energy  
8 costs increase, but that an alternative tariff incorporating seasonal volumetric delivery  
9 charges—lower distribution rates in winter when system capacity is abundant, higher in  
10 summer—produces annual bill savings when paired with building envelope  
11 improvements, without shifting costs to non-adopters.<sup>19</sup> Several states have already begun  
12 addressing this barrier: In Massachusetts, all investor-owned utilities offer a Residential  
13 Heat Pump Rate that reduces per-kilowatt-hour distribution charges during winter  
14 months, reflecting the lower cost of serving heating load when distribution system  
15 capacity is abundant. The EGLE report recommends that the MPSC require Michigan  
16 utilities to implement similar heat pump-specific rate plans and adopt time-differentiated  
17 pricing that reflects seasonal cost-of-service differences.<sup>20</sup> Notably, DTE's own  
18 Guidehouse Heat Pump Breakeven Analysis did not account for seasonal electricity  
19 pricing in its evaluation of heat pump economics.<sup>21</sup> Further, climate policies may impose

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<sup>19</sup> [Clean, Safe, and Affordable: A Policy Roadmap for Efficient and All-Electric Homes in Michigan](#) (March 2026), prepared by Institute for Energy Innovation, Michigan Energy Innovation, and 5 Lakes Energy for the Michigan Department of Environment, Great Lakes, and Energy, (Relevant excerpts at Exhibit AA-36).

<sup>20</sup> *Id.*

<sup>21</sup> Exhibit A-29. Schedule 1.

1 costs on gas consumption that do not exist today.

2 **II-D. Population Decline in Michigan**

3 **Q. How can we expect Michigan population change to impact DTE business?**

4 A. Gas companies in Michigan face the added challenge of a flat or declining population.

5 The Michigan Center for Data and Analytics projects that the state’s population will  
6 decrease by approximately 2% from 2025 to 2050. Population decline is most severe in  
7 Wayne County, the most populous county in DTE Gas service territory, whose  
8 population is projected to decline 184,000 people (10.6%) by 2050.<sup>22</sup> DTE is unlikely to  
9 maintain indefinite customer growth under these conditions, especially if it is unable to  
10 attract new customers in propane-heated homes.

11 **II-E. Conclusion**

12 **Q. Is there a historical precedent for declining gas consumption in Michigan?**

13 A. Yes. DTE’s own Gas Delivery Plan reports that the Company has achieved an 18%  
14 reduction in weather-normalized demand per customer since 2005 and projects continued  
15 1% annual energy-efficiency savings.<sup>23</sup> This is consistent with a long-standing structural  
16 trend: building energy codes have grown more stringent over time, appliances have  
17 become more efficient, and utility energy waste reduction (“EWR”) programs have  
18 steadily reduced per-customer consumption. Public Act 229 of 2023 will accelerate this  
19 trend by increasing EWR targets.<sup>24</sup>

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<sup>22</sup> Michigan Center for Data and Analytics, “[Statewide Population Projections through 2050 Report](#)” (April 2024) (Relevant excerpt at Exhibit AA-37); Michigan Center for Data and Analytics, “[Michigan Shows Population Growth and Slight Domestic Gains in 2025](#),” (January 2026) ( Relevant excerpt at Exhibit AA-38).

<sup>23</sup> Exhibit A-12, Schedule B5.6, p. 85.

<sup>24</sup> See MCL 460.1077.

1 What is new is that these historical structural efficiency gains can now be significantly  
2 *accelerated* by the emergence of heat pump technology. Where efficiency improvements  
3 historically reduced gas consumption incrementally, heat pump adoption can reduce a  
4 customer’s gas consumption by 50–80% (in a hybrid configuration) or eliminate it  
5 entirely. This means the trajectory of declining per-customer consumption that DTE itself  
6 acknowledges could steepen materially, even if the timing and pace remain uncertain.  
7 These impacts could be further magnified by population decline.

8 **Q. Has a Michigan state agency independently validated the challenges to the gas**  
9 **system described in this section?**

10 A. Yes. In March 2026, the Michigan Department of Environment, Great Lakes, and Energy  
11 ("EGLE") released “Clean, Safe, and Affordable: A Policy Roadmap for Efficient and  
12 All-Electric Homes in Michigan,” prepared by the Institute for Energy Innovation,  
13 Michigan Energy Innovation Business Council, and 5 Lakes Energy.<sup>25</sup> The report models  
14 the impacts of building electrification and energy efficiency policies consistent with the  
15 MI Healthy Climate Plan's goal of carbon neutrality by 2050.

16 The EGLE report's findings are consistent with and reinforce each of the disruptors I  
17 describe above. On growing infrastructure costs, the report cites projected increases in  
18 monthly gas delivery charges across Michigan's three major gas utilities, including an  
19 increase at DTE from approximately \$80 to \$177 per month by 2050 — a projection  
20 independently corroborated by my own revenue requirement model. On climate action,

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<sup>25</sup> [Clean, Safe, and Affordable: A Policy Roadmap for Efficient and All-Electric Homes in Michigan](#) (March 2026), prepared by Institute for Energy Innovation, Michigan Energy Innovation, and 5 Lakes Energy for the Michigan Department of Environment, Great Lakes, and Energy, (Relevant excerpts at Exhibit AA-36).

1 the report recommends that the MPSC conduct a study evaluating the role of natural gas  
2 in Michigan's clean energy future, that the Commission consider non-pipeline  
3 alternatives, and that line extension allowances be eliminated – each of which I  
4 independently recommend in this testimony. On competition from non-gas technologies,  
5 the report's building inventory model finds that Michigan must install approximately 2.8  
6 million heat pumps by 2040 to meet the state's decarbonization targets, and models  
7 delivered fuel customers as an attractive early market for fuel switching. On population  
8 and demand decline, the report's Energy Policy Simulator modeling projects the  
9 elimination of residential building sector Scope 1 emissions by 2050, with natural gas  
10 consumption declining sharply after 2035.

11 The convergence of the EGLE report's findings with the analysis presented in my  
12 testimony is significant. When EGLE, the state agency charged with climate planning,  
13 commissions a study reaching the same conclusions as I present in this testimony — that  
14 the gas system faces structural decline, that electrification is the primary decarbonization  
15 pathway, and that regulatory reform is necessary – it underscores that these are not  
16 speculative concerns but recognized realities of Michigan's energy landscape.

17 **Q. What are the implications of these challenges for the Commission's review of DTE's**  
18 **rate case?**

19 A. The convergence of rising costs, climate action, growing competition from alternatives,  
20 and declining population creates a fundamentally different planning environment than the  
21 one in which gas utility regulation was traditionally conducted. For decades, the gas  
22 system operated in a growth paradigm: new customers meant new revenue that helped  
23 cover system costs, and per-customer consumption was relatively stable. The four

1            disruptors I have described are eroding each element of that paradigm.

2            This does not mean that the gas system will disappear by 2050. But it does mean that the  
3            Commission should apply increased scrutiny to DTE’s proposed investments, particularly  
4            those that expand the system’s reach and add long-lived assets to the rate base, to ensure  
5            that existing ratepayers are not bearing disproportionate risk from investments premised  
6            on optimistic assumptions about future gas demand. The Commission should also play a  
7            more significant role in gas system planning, as the MPSC has begun to do through the  
8            GDP process. The adequacy of DTE’s planning in this regard is the subject of the next  
9            section of my testimony.

10           **III. DTE IS NOT SUFFICIENTLY PLANNING FOR THESE CHALLENGES**

11           **Q. What did the Commission direct DTE to do regarding energy transition planning?**

12           A. In its November 7, 2024 order in Case No. U-21291, the Commission found that "the  
13           transition away from fossil fuels and the eventual trend of declining natural gas demand  
14           will have impacts on the future of the natural gas system and that these impacts were not  
15           sufficiently considered in the company's GDP as filed."<sup>26</sup> The Commission directed DTE  
16           to file an updated Gas Delivery Plan demonstrating how it has “considered various  
17           energy transition pathways and the associated costs and risks of each.” The Commission  
18           further directed DTE to address specific elements including: how the Company intends to  
19           achieve emissions reductions under both its corporate goals and the State's goals, with an  
20           estimated timeline; alternatives to capital investment, including pipeline repairs and non-  
21           pipeline alternatives; historical trends, projected demand, and impacts of changing  
22           demand; the projected impacts of the transition toward electrification and

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<sup>26</sup> Case No. U-21291, Order, November 7, 2024, p. 216.

1 decarbonization, including the portions of its system that will be most immediately  
2 impacted; and meaningful engagement with interested persons.

3 **Q. How has DTE responded to this directive?**

4 A. DTE's response takes two forms. First, the Company filed an updated Gas Delivery Plan  
5 in Case No. U-21291, which is included in this case as Exhibit A-12, Schedule B5.6 and  
6 includes a seven-page section titled "Energy Transition." Second, Company Witness  
7 Decker's direct testimony addresses the GDP's energy transition content and describes the  
8 Company's climate-related strategies, including its positions on renewable natural gas,  
9 methane emissions reductions, and non-pipeline alternatives. Mr. Decker acknowledges  
10 the Commission's directive and claims that DTE has complied by including the Energy  
11 Transition section in the GDP.

12 **Q. Has DTE adequately responded to the Commission's directive?**

13 A. No. DTE has failed to plan for the challenges I described in the preceding section in two  
14 fundamental respects. First, the Company has not analyzed the financial consequences of  
15 declining gas demand for its ratepayers. In Section IV, I use a revenue requirement model  
16 to demonstrate that even modest declines in gas demand will materially increase costs for  
17 remaining ratepayers, and that more aggressive but plausible transition scenarios produce  
18 bill impacts that are unsustainable. Second, the Company's Gas Delivery Plan and  
19 supporting testimony do not satisfy the specific elements the Commission identified. I  
20 address deficiencies on methane mitigation, renewable natural gas, and non-pipeline  
21 alternatives in sections V, VI, and VII, respectively.

22 **Q. Did DTE meaningfully engage stakeholders in the development of the GDP as the**  
23 **Commission directed?**

1 A. The Commission directed DTE to “take steps to meaningfully engage interested persons  
2 in the development of its updated GDP.” DTE’s engagement was minimal. Discovery  
3 revealed that DTE held a single stakeholder meeting during the GDP development  
4 process and took no notes.<sup>27</sup>

5 **Q. How should the Commission view these findings?**

6 A. The Commission’s 2024 order in Case No. U-21291 clearly stated that “the transition  
7 away from fossil fuels and the eventual trend of declining natural gas demand will have  
8 impacts on the future of the natural gas system and that these impacts were not  
9 sufficiently considered in the company’s GDP as filed” and directed DTE to demonstrate  
10 a consideration of various energy transition pathways and their associated costs and risks.  
11 The record shows that DTE has not delivered on this directive. The absence of utility  
12 planning for these scenarios does not make the risk go away – it ensures that when  
13 change arrives, it arrives without mitigation. The Commission should require DTE to  
14 deliver on its 2024 directive and increase its scrutiny of future gas investments.

15 **IV. INSIGHTS FROM REVENUE REQUIREMENT MODELING**

16 **Q. Have you analyzed the financial consequences of reduced gas demand for DTE Gas  
17 ratepayers?**

18 A. Yes. I developed a simplified revenue requirement model for DTE Gas that projects  
19 delivery costs, residential bills, and per-customer infrastructure costs through 2050 under  
20 a range of demand scenarios. The model replicates standard utility revenue requirement  
21 methodology using DTE’s own capital expenditure data from its Gas Delivery Plan, P-  
22 522 annual reports filed with the Commission, and authorized financial parameters from

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<sup>27</sup> Exhibit AA-39. DTE Gas Response to MECCUBDG-3.16g.

1 recent rate proceedings.<sup>28</sup> The model’s baseline results are independently corroborated by  
2 a separate analysis prepared by DHInfrastructure for the Citizens Utility Board of  
3 Michigan, which projected a nearly identical 2050 monthly residential bill of \$177.22  
4 under comparable assumptions.<sup>29</sup> This model is provided in Exhibit AA-31.

5 **Q. What scenarios did you model?**

6 A. I modeled seven core scenarios spanning the range of plausible futures for the gas  
7 system. Two scenarios provide alternative baselines: one with a continuation of DTE’s  
8 projected growth in customer base, and one with a flat customer base. Scenario 1 assumes  
9 4% customer attrition by 2050, a number that corresponds to Ann Arbor’s current share  
10 of DTE Gas customers. Scenario 2 assumes that all DTE customers adopt hybrid heating  
11 systems to reduce gas consumption. Scenarios 3-6 model alternative pathways to  
12 decarbonizing today’s gas heating by 2050: one with a combination of customer attrition,  
13 hybrid heating, and RNG; one with an equal mix of electrification and RNG; one with  
14 100% electrification; and one with 100% RNG.

15 These scenarios vary across four dimensions: per-customer consumption trends, customer  
16 count trajectories, capital expenditure growth rates, and commodity cost assumptions.

17 Table 1 summarizes the core assumptions defining each scenario.  
18  
19

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<sup>28</sup> The model uses a depreciation rate of 2.79%, weighted average cost of capital of 8.78%, retirement rate of 0.89%, and property tax rate of 1.17%, consistent with DTE's most recent filings. Operating costs are inflated at 2.3% per year based on CBO CPI-U projections.

<sup>29</sup> [Investor-Owned Utility Gas Distribution Capital Expenditure A Study on the Potential Bill Impacts of Business-as-Usual Investment in Michigan](#), prepared by DHInfrastructure for Citizens Utility Board of Michigan (March 2025) (Relevant excerpt at Exhibit AA-40).

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**Table 1. Revenue Requirement Model Scenario Assumptions**

Scenario	Demand Decline	Customer Trend	CAPEX Growth	Commodity
<b>0A: Baseline w/ Growth</b>	-1%/yr	DTE-projected growth	GDP values 2025-2035, then tracks inflation	Conv. gas
<b>0B: Baseline w/o Growth</b>	-1%/yr	Flat	GDP values 2025-2035, then tracks inflation	Conv. gas
<b>1: Mild Decline</b>	[Same as baseline]	-4% over 25 yr	[Same as baseline]	Conv. gas
<b>2: Hybrid Heating</b>	-3%/yr	Flat	[Same as baseline]	Conv. gas
<b>3: Mild Decline + Hybrid Heating + RNG</b>	-3%/yr	-4% over 25 yr	[Same as baseline]	RNG blend
<b>4: 50% Electrification, 50% RNG</b>	[Same as baseline]	-50% over 25 yr	GDP values 2025-2035, then flat	50% RNG
<b>5: 100% Electrification</b>	[Same as baseline]	-50% by 2040 and -100% by 2050	GDP values 2025-2035, then flat	Conv. gas
<b>6: 100% RNG</b>	[Same as baseline]	Flat	[Same as baseline]	100% RNG

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The model is very sensitive to assumptions regarding inflation and relative growth in costs among different categories. The analysis was conducted in nominal terms to ensure consistency with historical data and the nominal basis of the WACC. Results were then deflated using a 2.3% compounded inflation rate to convert them to 2025 dollars.

Ultimately, the key drivers of costs remain increasing infrastructure spending, the concentration of costs on remaining customers, and the high cost of renewable natural gas. The analysis is used to demonstrate these cost drivers.

10 **Q. What do the baseline scenarios show?**

11 A. Even under the most favorable assumptions, real monthly residential gas bills increase.

12 Under Scenario 0A, which assumes DTE's own customer growth projections continue to materialize, real monthly bills (in 2025 dollars) rise from \$96 in 2025 to \$110 in 2050.

14 However, customers see more significant impacts if that assumption changes. If customer growth stalls (Scenario 0B), bills rise to \$127, or 15% above the growth baseline. Under

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1 Scenario 1, which assumes a mild decline of just 4% of the customer base over 25 years,  
2 bills reach \$131—a 36% increase, or a 19% premium over the growth baseline.

3 Table 2 presents the real monthly bill projections for these baseline-adjacent scenarios.

4 **Table 2.** *Real Monthly Residential Bills (2025\$) – Baseline Scenarios*

Year	Scenario 0A: Baseline w/ Growth	Scenario 0B: Baseline w/o Growth	Scenario 1: Mild Decline
2025	\$96.18	\$96.18	\$96.18
2030	\$103.37	\$106.54	\$107.13
2035	\$107.97	\$114.26	\$115.60
2040	\$110.45	\$120.16	\$122.37
2045	\$111.07	\$124.30	\$127.46
2050	\$110.28	\$127.02	\$131.17

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6 These results demonstrate that without proactive planning, even a flat or modest decline  
7 in customer base will drive up the bills of remaining gas ratepayers. As I detail in section  
8 II of my testimony, these declines could be caused by a variety of factors including  
9 growing gas infrastructure costs, programs and legislation in support of state and local  
10 climate goals, increasing technology competition and customer preferences, and  
11 population decline.

12 **Q. What happens under scenarios that reflect climate action or accelerated  
13 electrification?**

14 A. Without proactive planning efforts, remaining gas customers face sharply escalating bills  
15 under any climate-aligned scenario. Under Scenario 5, which models a transition to full  
16 electrification by 2050, real monthly bills rise from \$96 in 2025 to \$393 by 2045 – more  
17 than quadrupling over that timeframe. Under Scenario 3, which pairs modest customer  
18 attrition with hybrid systems and RNG commodity costs, bills reach \$275 by 2050, or  
19 149% above baseline.

**Table 3. Real Monthly Residential Bills (2025\$) – Climate-Action Scenarios**

Year	Scenario 3: Mild Decline + Hybrid + RNG	Scenario 4: 50% Elec + 50% RNG	Scenario 5: 100% Electrification	Scenario 6: 100% RNG
2025	\$96.18	\$96.18	\$96.18	\$96.18
2030	\$113.24	\$124.49	\$121.15	\$169.60
2035	\$140.22	\$194.84	\$155.48	\$234.20
2040	\$172.25	\$242.35	\$207.43	\$291.25
2045	\$262.05	\$288.98	\$392.96	\$341.24
2050	\$275.07	\$337.88	N/A	\$384.91

Per-customer infrastructure costs escalate most dramatically under Scenario 5, where the remaining customer base shrinks to approximately 312,000 by 2045, and each bears a real annual distribution cost of \$4,370 – a 343% premium over the growth baseline. Over this time, costs per therm delivered begin to exceed those of delivered fuels.

**Q. Does RNG offer a path to mitigate these cost pressures?**

A. No. RNG commodity costs rise rapidly across all blending scenarios. Our analysis incorporates price curves developed for the Michigan Renewable Gas Study, which show steep price increases as more RNG is consumed.<sup>30</sup> The comparison with Scenario 5 is particularly instructive: even under unmanaged full electrification, where 50% of customers depart the system over 15 years, remaining gas customers face lower monthly bills than under 100% RNG. This demonstrates that even the most disruptive electrification scenario produces better outcomes for remaining gas customers than RNG-based decarbonization. I detail additional concerns with RNG as a proposed solution to gas system decarbonization in Section VI of my testimony.

**Q. What about hybrid heating, which DTE has promoted as a lower-cost alternative?**

<sup>30</sup> [Michigan Renewable Natural Gas Study](#), prepared by I.C.F. Resources, L.L.C. for the Michigan Public Service Commission (Sept. 23, 2022) (Relevant excerpts at Exhibit AA-41).

1 A. Hybrid heating that still relies on gas infrastructure but reduces gas consumption also  
2 creates a cost concentration situation. Assuming that per-customer demand decreases by  
3 75% in hybrid heated homes does reduce gas utility bills—but this benefit yields just a  
4 9% bill savings in 2050 compared to a baseline scenario. This happens because per-therm  
5 delivery costs increase 158% in real terms by 2050 under hybrid deployment (Scenario  
6 2), a 111% incremental increase over the baseline scenario.

7 The fundamental reason for this trend is that reduced per-customer consumption does not  
8 proportionally reduce the fixed infrastructure costs embedded in gas delivery rates.

9 Customers operating two heating systems continue to bear both the ongoing gas  
10 infrastructure costs and the capital cost of heat pump installation, making the net  
11 economic impact more adverse than gas bill figures alone suggest. In other words, while  
12 any individual customer could realize value from converting to a hybrid system today, the  
13 benefits of this strategy are almost completely diluted as system-wide deployment forces  
14 DTE to raise rates to meet its revenue requirements. This could potentially reach levels  
15 that exceed propane costs, leading savvy customers to further opt out of the gas system.

16 This model demonstrates that, while a hybrid strategy reduces emissions, it exacerbates  
17 the cost concentration challenges.

18 **Q. What does your model suggest about the potential impact of more proactive**  
19 **planning efforts to prepare for reduced demand scenarios?**

20 A. While more precise modeling of the impact of proactive planning for gas system decline  
21 would require collaboration with DTE, my analysis demonstrates that proactive planning  
22 and management efforts have the power to materially reduce the cost burden on  
23 remaining customers. Under a 100% electrification scenario, remaining customers would

1 save \$31 per month in real terms by 2045 (an 8% reduction) if DTE's capital additions  
2 decline at 5% per year after 2035. Remaining customers see \$92 per month savings  
3 (24%) in a more aggressive management scenario where DTE holds capital expenditures  
4 at 2025 levels through 2035 and then reduces them 5% annually afterward. These results  
5 show that the Commission's capital expenditure decisions today directly determine how  
6 costly the energy transition will be for the customers who remain on the gas system.

7 **Q. What is the significance of these projections for the Commission?**

8 A. Four findings are critical from this analysis. First, even a static customer base or a modest  
9 decline in customer base can have measurable negative impacts for gas ratepayers.

10 Second, any foreseeable path toward reducing gas usage will lead to cost increases for  
11 gas ratepayers without proactive planning. Third, both RNG and hybrid heating increase  
12 customer costs, potentially leading to customer defection. Fourth, proactive planning and  
13 management can materially reduce the cost burden on remaining customers.

14 The financial consequences of gas system disruption are not a mystery. The delivery of  
15 gas relies on large, fixed-cost assets that are financed by spreading those costs across  
16 high consumption volumes over annual utilization and decade-long customer  
17 commitment periods. If that annual usage pattern changes or customers leave the system,  
18 those fixed costs become concentrated on remaining customers. The scenarios I model  
19 apply straightforward revenue-requirement analysis to a range of demand trajectories that  
20 span from DTE's own planning assumptions to outcomes consistent with declining gas  
21 usage (and Michigan's climate objectives). It is not possible to know what Michigan's gas  
22 system will look like in 2050—but prudent business practice demands consideration of  
23 all potential outcomes. The results of my analysis demonstrate the importance of the

1 Commission’s 2024 order to assess the impacts of declining demand on DTE’s business.  
2 Given the various headwinds facing DTE Gas in the near future, it is imperative that the  
3 Commission have the information necessary to weigh proposed DTE investments in light  
4 of the risks of declining demand.

5 **V. LIMITATIONS OF METHANE MITIGATION**

6 **Q. What claims does DTE Gas make regarding its methane mitigation efforts?**

7 A. DTE Gas claims significant progress in reducing its internal (“Scope 1”) emissions. In the  
8 direct testimony of Company Witness H.J. Decker, DTE Gas states that it has “reduced  
9 the majority of its internal emissions via methane leak reductions, which the Company  
10 has primarily achieved through replacing leak-prone pipe with modern plastic via the  
11 Company’s Gas Renewal Plan.”<sup>31</sup> The GDP further claims a 44 percent reduction in  
12 annual Scope 1 emissions attributed to distribution mains and services since 2011,  
13 amounting to approximately 269,000 metric tons of CO<sub>2</sub>e.<sup>32</sup>

14 **Q. How does DTE Gas calculate these claimed Scope 1 emissions reductions?**

15 A. DTE Gas calculates Scope 1 emissions for distribution mains and services “in accordance  
16 with the Greenhouse Gas Mandatory Reporting Rule as specified in 40 CFR Part 98  
17 Subpart W.”<sup>33</sup> The Company’s own GDP acknowledges in a footnote that “DTE does not  
18 use direct measurement to determine the Scope 1 Emissions for this category; rather, they  
19 utilize the total miles, type of pipe, and emission factors to determine the emission

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<sup>31</sup> Decker, Direct Testimony, p. 8.

<sup>32</sup> Exhibit A-12, Schedule B5.6, p. 6.

<sup>33</sup> *Id.* at 82.

1 quantity.”<sup>34</sup> I will address this “emissions factor” approach<sup>35</sup> below, noting that DTE’s  
2 claimed emissions reductions are based entirely on changes in pipe material inventory,  
3 not on observed or measured reductions in methane reaching the atmosphere.

4 **Q. Does DTE Gas also suggest that its Gas Renewal Program could be accelerated to**  
5 **achieve even greater emissions reductions?**

6 A. Yes. Witness Decker testifies that “although the Company believes it is on track to meet  
7 its internal (Scope 1) emission reduction target, this target could be achieved sooner with  
8 an accelerated, or increased, Gas Renewal Program.”<sup>36</sup> This statement is notable because  
9 it uses claimed emissions reductions as an additional justification for increased capital  
10 expenditure on pipe replacement. Again, these claimed reductions are based on emissions  
11 factors rather than direct measurement; the actual climate benefit of such acceleration is  
12 uncertain and may be substantially overstated. Moreover, DTE admits that the climate  
13 impacts are not a factor in determining what pipelines are repaired.<sup>37</sup>

14 **Q. What are the key characteristics of methane as a greenhouse gas that are relevant to**  
15 **evaluating DTE’s claims?**

16 A. Methane (CH<sub>4</sub>) is a short-lived but potent greenhouse gas. On a per-molecule basis,  
17 methane has a greater warming effect than carbon dioxide (CO<sub>2</sub>), but this effect fades  
18 rapidly. Methane contributes to intense warming for roughly a decade before decaying in  
19 the atmosphere, whereas CO<sub>2</sub>, once emitted, mostly persists for centuries.

20 The standard comparison tool is the Global Warming Potential (“GWP”), which

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<sup>34</sup> *Id.*

<sup>35</sup> For example, methane emissions are calculated as the product of the miles of pipe and a material-based per-mile emissions factor.

<sup>36</sup> Decker, Direct Testimony, p. 8.

<sup>37</sup> *See*, Exhibit AA-42. AADG 1.6.

1 compares the impacts of different greenhouse gases over a defined timescale, typically 20  
2 or 100 years. Standard GWP values have been regularly updated with each successive  
3 Intergovernmental Panel on Climate Change Assessment Report. For instance, DTE’s  
4 own GDP notes that “in 2024, the Global Warming Potential emission factor for the  
5 methane component increased thus causing an arbitrary increase in carbon dioxide  
6 equivalent emissions despite the methane emissions continuing to decrease.”<sup>38</sup> This  
7 statement reveals an important point: when the metric used to convert methane to CO<sub>2</sub>e  
8 changes, the Company’s reported emissions change even if physical methane volumes  
9 remain constant. Such a change is not “arbitrary” – it reflects improving scientific  
10 understanding to inform decision-making. The next several questions will address how  
11 the scientific understanding of methane leaks is improving.

12 **Q. How do methane leaks occur in a gas distribution system?**

13 A. Methane escapes from the gas distribution system through leaks in mains and service  
14 lines, meter and regulator stations, customer meters, post-meter equipment, and during  
15 maintenance activities such as blowdowns. The rate of leakage from distribution pipe  
16 depends on several factors, including: pipe material (older cast iron and bare steel pipes  
17 have higher leak rates than modern plastic); pipe age and installation date; soil conditions  
18 (including corrosivity, moisture content, and ground movement); operating pressure  
19 within the system; temperature fluctuations; the quality of pipe joints and fittings;  
20 maintenance history; and external factors like construction activity. Not all these  
21 influencing attributes are captured by the standard emissions factors that DTE uses to  
22 calculate its claimed reductions.

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<sup>38</sup> Exhibit A-12, Schedule B5.6, p. 82, fn. 1.

1 **Q. What is the relative significance of methane leaks compared to other gas system**  
2 **emissions?**

3 A. Estimated methane emissions from gas distribution systems are a relatively small  
4 component of the total greenhouse gas footprint associated with natural gas service. For  
5 example, the GDP implies that in 2024 fugitive methane emissions were 342 thousand  
6 tons CO<sub>2</sub>e. Emissions from the combustion of DTE's delivered gas in 2024 were  
7 approximately 7.3 million tons CO<sub>2</sub>e.<sup>39</sup> The emissions from customer combustion of  
8 natural gas represent the overwhelming majority of the climate impact of the gas system.

9 **Q. What are emissions factors, and how are they used to estimate methane emissions**  
10 **from gas distribution systems?**

11 A. Emission factors are standardized multiplier coefficients that assign a rate of methane  
12 emissions per unit of infrastructure, typically per mile of main or per service line, based  
13 on the pipe's material classification. These factors were derived from sampling studies  
14 and represent average emissions across a population of pipes of each material type. They  
15 do not reflect the actual emissions from any specific pipe segment.

16 **Q. Are these emission factors accurate representations of actual methane emissions**  
17 **from individual pipe segments?**

18 A. No. There is a fundamental difference between the certainty of emissions estimates  
19 derived from gas consumption (CO<sub>2</sub> from combustion) and those estimated from  
20 infrastructure inventories (fugitive CH<sub>4</sub>). Calculating combustion emissions is  
21 straightforward: CO<sub>2</sub> emissions per unit of energy are predictable and consistent, and gas

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<sup>39</sup> Based on combined sales of 137 BCF to conventional and Customer Choice customers in 2024 as reported in MPSC Form P-522 (Pages 305B and 306C, excerpted at Exhibit AA-43).

1 consumption is precisely metered. In contrast, quantifying fugitive methane emissions  
2 from leaky pipes is subject to considerable uncertainty. Leaks are stochastic. They occur  
3 irregularly throughout the system, can vary widely in size, and are influenced by multiple  
4 interacting factors that change over both seasonal and multi-year time scales.

5 A critical issue is the role of “super-emitters” which are a small number of leaks that are  
6 responsible for a disproportionate share of total emissions. Methane emissions follow  
7 extreme (“fat-tailed”) distributions. Under such a distribution, the bulk of methane  
8 emissions is driven by abnormal conditions.

9 Such distributions are observed in DTE’s service territory. In 2021, researchers from the  
10 University of Michigan School of Public Health deployed a mobile monitoring laboratory  
11 equipped with high-sensitivity Picarro CH<sub>4</sub> analyzers across southwest Detroit as part of  
12 the Michigan-Ontario Ozone Source Experiment (MOOSE).<sup>40</sup> Over 20 sampling days  
13 and approximately 1,100 km of driving, the researchers detected 534 distinct methane  
14 peaks, roughly one elevated reading every two kilometers. Nine locations showed  
15 repeated large peaks across multiple sampling days, suggesting sizable, persistent  
16 pipeline leaks or other concentrated CH<sub>4</sub> sources. The study area encompassed a mix of  
17 residential, commercial, and industrial land uses served by DTE's gas distribution  
18 infrastructure. These direct measurements from DTE's own service territory underscore  
19 why factor-based emissions estimates, which assume uniform leak rates across pipe  
20 categories, cannot reliably characterize actual methane emissions from a complex urban  
21 distribution system.

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<sup>40</sup> Exhibit AA-44.

1 **Q. What does this variability mean for the accuracy of DTE’s claimed emissions**  
2 **reductions?**

3 A. It means that DTE’s claimed 44 percent reduction in Scope 1 emissions from distribution  
4 mains and services may not correspond to an actual 44 percent reduction in methane  
5 reaching the atmosphere. Consider two segments of cast iron pipe: one with a large,  
6 active leak and one that does not leak. Under the emissions factor approach, both  
7 segments are assigned the same emissions based on their material classification and  
8 length. Replacing the non-leaking pipe receives full credit for eliminating its assigned  
9 emissions, even though it was not contributing meaningful methane to the atmosphere.  
10 Replacing the actively leaking pipe receives the same credit, even though its actual  
11 emissions may have been many times higher than the factor assumed. Notably, non-  
12 replacement mitigation (patching, relining) does not receive any credit under this  
13 accounting approach.

14 **Q. Has atmospheric monitoring confirmed that emissions-factor-based claims of**  
15 **reduction are accurate?**

16 A. Evidence from other jurisdictions suggests caution toward a reliance on emissions  
17 factors. A 2021 study by Sargent et al.<sup>41</sup> found that total methane emissions in the Boston  
18 urban area were approximately six times higher than those estimated by bottom-up  
19 inventory methods (inclusive of behind-the-meter sources) over an eight-year study  
20 period, and showed no observable reduction in methane emissions during the first six  
21 years of an active pipe replacement program. While this study addressed a different gas  
22 system than DTE’s, the fundamental measurement challenges are the same. The activity-

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<sup>41</sup> Exhibit AA-45.

1 based emissions factors that DTE relies upon can be systematically wrong.

2 **Q. Does DTE Gas acknowledge any limitations in its emissions accounting**  
3 **methodology?**

4 A. The Company's GDP contains a notable footnote that partially acknowledges this issue:  
5 "DTE does not use direct measurement to determine the Scope 1 Emissions for this  
6 category, rather, they utilize the total miles, type of pipe, and emission factors to  
7 determine the emission quantity. In 2024, the Global Warming Potential emission factor  
8 for the methane component increased thus causing an arbitrary increase in carbon dioxide  
9 equivalent emissions despite the methane emissions continuing to decrease."<sup>42</sup> This  
10 footnote demonstrates that the Company's reported emissions are a function of regulatory  
11 accounting conventions rather than observed atmospheric conditions. The Company  
12 characterizes a GWP update as causing an "arbitrary" increase, yet the same accounting  
13 methodology underlies its claimed 44 percent reduction. If the Company considers  
14 updates to the GWP as "arbitrary," the Commission should consider whether the  
15 underlying factor-based methodology itself provides a reliable basis for assessing the  
16 climate benefits of the Gas Renewal Program.

17 **Q. Are emissions factors likely to remain reliable over the long term, even as DTE**  
18 **replaces older pipe materials with modern plastic?**

19 A. No. The premise of DTE's emissions accounting is that replacing cast iron, bare steel, and  
20 other legacy materials with modern plastic pipe results in a permanent reduction in  
21 fugitive methane emissions. But this framing assumes that plastic pipe is perfectly leak-  
22 free at install and does not develop leaks over time. That assumption is not supported by

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<sup>42</sup> Exhibit A-12, Schedule B5.6, p. 81.

1 the evidence. While new plastic pipe has significantly lower average leak rates than aged  
2 cast iron or bare steel, plastic pipe is not immune to deterioration. Over the multi-decade  
3 service life of distribution infrastructure, soil movement, freeze-thaw cycles, and ground  
4 settlement can stress plastic pipe and its connections. The emissions factors used assign a  
5 fixed, low emission rate to plastic pipe and treat that rate as permanent. As the installed  
6 base of plastic pipe ages, actual emissions from those segments may diverge from the  
7 factors currently assigned to them, just as the factors assigned to older materials may not  
8 reflect actual leak conditions for any given pipe segment today.

9 This has a compounding effect on the reliability of DTE's claimed reductions over time.  
10 The Company's 44 percent Scope 1 reduction is calculated entirely from the difference  
11 between the emission factor assigned to removed pipe and the factor assigned to new  
12 plastic pipe. If the plastic factor understates long-term leak rates, the claimed reduction  
13 overstates the actual atmospheric benefit. The overstatement will grow with each year of  
14 aging. The fundamental problem is the same one that afflicts factor-based accounting for  
15 legacy materials: a statistical average applied to a pipe category cannot capture what is  
16 actually happening at any given location in the system. The emissions factor approach is  
17 not actionable and should have limited relevance in regulatory proceedings.

18 **Q. Has direct measurement of methane been conducted in DTE's service territory, and**  
19 **what is the current state of DTE's own measurement capabilities?**

20 A. Yes, direct measurement has been conducted. Independent researchers (discussed above)  
21 and DTE itself have deployed high-sensitivity Picarro CH<sub>4</sub> analyzers in the Detroit area,  
22 and their findings underscore the gap between factor-based accounting and actual field  
23 conditions. A similar leak measurement analysis was also performed in the Ann Arbor

1 area and discussed in the prior rate case's testimony, which found similar results.<sup>43</sup>  
2 Notably, DTE Gas has operated the same Picarro technology since 2021 and is seeking  
3 \$6.0 million in this proceeding to renew its Picarro Survey units. Company Witness  
4 Bolda testifies that Picarro “utilizes more sensitive gas detection technology (parts per  
5 billion vs parts per million), which has increased DTE Gas's ability to accurately identify  
6 existing leaks.”<sup>44</sup> Witness Bolda further states that Picarro deployment “resulted in the  
7 identification and ultimately the remediation of hundreds of large emitting leaks in off-  
8 cycle survey areas that would have otherwise gone unidentified until the upcoming leak  
9 survey cycle.” The Company also plans to use Picarro to conduct pre- and post-  
10 construction drives to compare area emissions before and after infrastructure  
11 replacement, “with the resulting decrease being attributed to the newly installed  
12 infrastructure and therefore supporting the effectiveness of the Gas Renewal Program.”<sup>45</sup>  
13 DTE's own Picarro testimony is revealing in two respects. First, it confirms that  
14 traditional leak survey methods, the same methods underlying the Company's historical  
15 leak data, have systematically failed to identify large emitting leaks. Witness Bolda  
16 describes Picarro as transforming “the outdated manual process that is so dependent on  
17 human performance to identify leaks.”<sup>46</sup> If DTE's prior survey methods missed hundreds  
18 of large leaks that Picarro subsequently found, then the historical leak data informing the  
19 Company's emissions factor calculations has been incomplete. Second, DTE's plan to use  
20 Picarro for pre- and post-construction emissions comparison represents an implicit

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<sup>43</sup> Exhibit AA-46.

<sup>44</sup> Bolda, Direct Testimony, p. 27-28.

<sup>45</sup> *Id.* at 28.

<sup>46</sup> *Id.* at 27.

1 acknowledgment that direct measurement is necessary to verify whether pipe replacement  
2 actually reduces atmospheric methane.

3 **Q. Given these findings, would investment in direct measurement and advanced mobile**  
4 **leak detection provide a more robust methane reduction strategy than the current**  
5 **emissions-factor-based approach?**

6 A. Yes. The fundamental limitation of DTE's current approach is that it measures activity  
7 (miles of pipe replaced) rather than outcomes (methane actually prevented from reaching  
8 the atmosphere). A measurement-based strategy built around advanced mobile leak  
9 detection (“AMLD”) technology and instruments like the Picarro analyzers used in the  
10 Batterman et al. study would enable DTE to identify and prioritize the specific locations  
11 that are actually emitting significant quantities of methane. This is a fundamentally  
12 different and superior approach because it: (1) identifies super-emitters; (2) is verifiable;  
13 and (3) is adaptive over time.

14 DTE's own Gas Delivery Plan states that the Company "has also invested in advanced  
15 leak detection equipment" and identifies “Advanced Leak Detection”<sup>47</sup> among the  
16 solutions it is considering to meet its 2040 and 2050 climate targets (and also make the  
17 system safer and more efficient by preventing fugitive methane). The Company should be  
18 commended for seeking to better understand leaks – acknowledging the limitations of  
19 conventional strategies. However, the contrast between DTE's current reliance on  
20 emission factors for its claimed 44 percent Scope 1 reduction and the availability of  
21 measurement technologies that have already been deployed in DTE's own service  
22 territory by independent researchers calls into question whether these techniques are

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<sup>47</sup> Exhibit A-12, Schedule B5.6, p. 82.

1 successfully eliminating lost gas and the associated costs and climate impacts of methane  
2 emissions. Despite the improvement in data offered by AMLD, it still has some  
3 limitations. For example, it may be limited in the ability to quantify methane emissions or  
4 identify behind-the-meter leaks beyond the platform’s field of view. Air-borne  
5 measurement may address some of these limitations, but may face other cost,  
6 measurement, and operational tradeoffs.

7 **Q. What are the implications of these limitations for DTE’s Gas Renewal Program as a**  
8 **strategy to prevent methane emissions?**

9 A. The implications are significant. The emissions factor approach creates a systematic bias  
10 in favor of pipe replacement as the primary – and effectively sole – mechanism for  
11 demonstrating reductions in fugitive methane. Because the metric is based solely on pipe  
12 material, it does not recognize methane emissions reductions achieved through other  
13 means, such as direct leak repair, pipeline relining, or robotic joint sealing. A repair of a  
14 large leak on a cast-iron main would not be “credited” as a method to reduce methane  
15 emissions, while replacement of a non-leaking main would be assumed to be a literally  
16 perfect solution. This misalignment between accounting credit and actual emissions  
17 reduction is a fundamental flaw that creates a prejudice for new capital over improved  
18 maintenance.

19 **Q. Is leak-prone pipe replacement a cost-effective strategy for reducing methane**  
20 **emissions?**

21 A. When evaluated through the lens of mitigating methane leaks, pipe replacement is an  
22 extraordinarily expensive strategy that delivers uncertain emissions reductions. Assuming  
23 the emissions factors are representative, the cumulative social cost of methane leaked

1 from a mile of cast-iron pipe over 20 years is on the order of \$156,000, based on EPA's  
2 social cost of methane and standard emissions factors. The cost to replace that mile of  
3 pipe averages \$1.6 million in DTE's territory. From a pure emissions mitigation  
4 perspective, the cost of pipe replacement far exceeds the climate damage it prevents.

5 While the Gas Renewal Program serves legitimate safety purposes, its reductions in  
6 fugitive emissions (and the climate benefits) are incidental and provide no weight toward  
7 accelerated capital expenditure in lieu of more aggressive maintenance of existing  
8 infrastructure.

9 **Q. What are your recommendations to the Commission regarding DTE's methane**  
10 **emissions claims and the Gas Renewal Program?**

11 A. The uncertainty associated with how methane evolves within the gas system impedes  
12 quantification; it should not be used as a justification for delaying efforts to reduce actual  
13 emissions, especially at a time when detection technology is improving identification and  
14 classification, if not quantification. As implementers of such technology and custodians  
15 of methane-emitting assets, utilities such as DTE can play an important role in advancing  
16 effective methane mitigation strategies. To achieve this outcome, I offer the following  
17 recommendations:

18 First, the Commission should recognize that DTE's claimed Scope 1 emissions  
19 reductions are based on changes in pipe material inventory, not on measured or observed  
20 reductions in atmospheric methane. The Commission should afford these claims limited  
21 weight as evidence of a reduction in fugitive methane when evaluating the Gas Renewal  
22 Program and any proposals to accelerate it.

23 Second, if a reduction in lost gas is assumed as part of the cost justification for the

1 program, the Commission should require support for that figure through use of a  
2 measurement technology, not a blanket assumption. For instance, more verifiable  
3 methods include advanced mobile leak detection (“AMLD”) or aerial survey methods—  
4 appropriate to its system. DTE should be required to propose and implement a pilot study  
5 covering a representative portion of its distribution system to establish baseline emissions  
6 data. Such data would provide the Commission with a more reliable basis for evaluating  
7 the actual climate impact of infrastructure investments.

8 Third, the Commission should require DTE Gas to develop and submit enhanced  
9 reporting on methane emissions, including: geocoded leak data with standardized  
10 formatting; summaries of leak repairs by material type and repair method employed  
11 (replacement, patching, relining, etc.); and, where AMLD or similar data become  
12 available, comparisons of estimated versus measured emissions. This information would  
13 support long-term tracking of actual emissions performance.

14 Fourth, given the high potency but short atmospheric lifetime of methane, and the fat-  
15 tailed distribution of emissions across the system, cost-effective methane leak mitigation  
16 should be targeted at the largest emitters rather than based on broad replacement of  
17 infrastructure by material type. Methane mitigation may be larger via non-replacement  
18 strategies, including advanced leak repair, pipeline relining, and robotic joint sealing.

19 Such approaches can address the highest-emitting leaks, and thus reduce the cost impacts  
20 of lost gas, at a fraction of the cost of replacement of the pipes.

21 Fifth, the Commission should assess how the Company’s infrastructure investment  
22 strategy (e.g., the GRP) would impact ratepayers if overall gas consumption shrinks  
23 instead of grows. Pipe replacement in areas likely to be targeted for electrification or

1 decommissioning may represent an imprudent investment. To minimize the risk of  
2 stranded costs to ratepayers, the Commission should both scrutinize proposals to add  
3 large amounts of capital to the system, and consider adjusting depreciation rates to  
4 mitigate for the risk of large future rate impacts from investments that appear reasonable  
5 and prudent today.

6 **VI. RENEWABLE NATURAL GAS**

7 **Q. Please describe DTE Gas’s interest in and use of Renewable Natural Gas (“RNG”).**

8 A. DTE Gas has identified RNG as a central element of its emissions-reduction strategy,  
9 both in its current operations and in its vision for meeting future climate requirements.

10 The Company’s engagement with RNG operates on two levels.

11 First, DTE Gas has established 21 operational interconnections with RNG producers  
12 across Michigan. The Gas Delivery Plan describes these efforts as part of DTE’s broader  
13 investment in “actions beyond natural gas.”<sup>48</sup> This section will highlight the fact that  
14 RNG production is limited and a poor use of bioenergy resources and that recent growth  
15 reflects distortive environmental attribution markets which the Commission should avoid  
16 further influencing.

17 Second, and more consequentially for this proceeding, DTE Gas presents RNG blending  
18 as the most cost-effective pathway for achieving deeper emissions reductions in the built  
19 environment. Witness Decker testifies that DTE Gas conducted “internal analysis on  
20 RNG blending” and concluded that “using RNG for 14% of a customer’s usage reduced  
21 emissions nearly as much as full electrification when considering the carbon intensity of

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<sup>48</sup> Exhibit A-12, Schedule B5.6, p. 84.

1 the grid.”<sup>49</sup> This section illustrates flaws in DTE’s simplistic analysis here.

2 DTE’s advocacy for RNG ignores the realities of the attractiveness and effectiveness of  
3 this strategy as a way to continue use of the current system in the face of increasing  
4 customer or regulatory pressures to decarbonize, and thus the importance of regulatory  
5 action to manage that increasing risk.

6 **Q. What is Renewable Natural Gas?**

7 A. Renewable Natural Gas is methane produced from biomass feedstocks<sup>50</sup> that is upgraded  
8 to pipeline quality and injected into the pipeline gas distribution system. The term  
9 “renewable” distinguishes it from fossil methane by its biogenic origin: the carbon in  
10 RNG was recently captured from the atmosphere through biological processes, rather  
11 than extracted from geological deposits. Importantly, however, the end-use combustion  
12 product is identical: both RNG and fossil gas produce CO<sub>2</sub> when burned in a furnace or  
13 boiler. The claimed climate benefit of RNG rests not on eliminating combustion  
14 emissions but on the need to use limited bioenergy resources to produce it.

15 **Q. Is RNG a scalable decarbonization strategy for the building sector?**

16 A. No. RNG is fundamentally limited by the availability of biomass feedstocks, which are  
17 constrained in quantity and face competing demands from higher-value applications. This  
18 is not a contested point; even industry-sponsored assessments acknowledge these  
19 limitations. The American Gas Foundation’s 2025 Renewable Natural Gas Supply  
20 Assessment explicitly states that its feedstock inventory “does not estimate resource  
21 availability—in a competitive market, resource availability is a function of factors,

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<sup>49</sup> Decker, Direct Testimony, p. 17.

<sup>50</sup> Landfills, wastewater treatment facilities, animal manure, and agricultural residues.

1 including but not limited to demand, feedstock costs, technological development, and the  
2 policies in place that might support RNG project development.”<sup>51</sup> This means that many  
3 forecasts of RNG availability make the tenuous assumption that feedstocks are solely  
4 available for RNG production and other uses such as electricity generation, sustainable  
5 aviation fuel, or carbon capture and sequestration.

6 **Q. What do these constraints mean in the context of Michigan’s resources?**

7 A. The Michigan-specific evidence on scalability is particularly relevant to this proceeding.  
8 The Michigan Public Service Commission’s own 2022 Renewable Natural Gas Study,  
9 prepared by ICF,<sup>52</sup> found that Michigan consumed an average of 673 trillion Btu (tBtu) of  
10 natural gas annually in the residential, commercial, industrial, and vehicle sectors from  
11 2016 to 2020. Under ICF’s “Achievable” scenario, which represents a low but realistic  
12 level of feedstock utilization, Michigan could produce only 57.2 tBtu of RNG per year by  
13 2050, equivalent to just 8.5% of the state’s average annual natural gas consumption. Even  
14 under the more aggressive “Feasible” scenario, which assumes higher feedstock  
15 utilization rates and the commercial deployment of thermal gasification technology not  
16 expected to be cost-competitive until the 2040–2050 timeframe, Michigan’s RNG  
17 production would reach only 148 tBtu per year by 2050 (22% of current consumption).  
18 The theoretical maximum, utilizing 100% of all available feedstocks with no constraints,  
19 yields 313.4 tBtu; less than half of Michigan’s current gas demand.

20 These figures have direct implications for DTE’s RNG blending strategy. If even a 14%

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<sup>51</sup> [Renewable Natural Gas Supply Assessment](#), prepared by ICF for American Gas Foundation (Jul. 2025) (Relevant excerpt at Exhibit AA-47).

<sup>52</sup> [Michigan Renewable Natural Gas Study](#), prepared by I.C.F. Resources, L.L.C. for the Michigan Public Service Commission (Sept. 23, 2022) (Relevant excerpts at Exhibit AA-41).

1 blend rate across DTE’s residential customer base were to be sourced from Michigan-  
2 produced RNG, it would consume a substantial share of the state’s total achievable RNG  
3 production, leaving little or no supply for other gas utilities, commercial and industrial  
4 customers, or higher-value applications such as transportation fuel or electricity  
5 generation. The Commission’s own study thus undermines the premise that RNG  
6 blending can serve as a meaningful, scalable strategy for the building sector.

7 **Q. Are there other factors influencing the scalability of RNG?**

8 A. Several additional characteristics make RNG poorly suited as a building decarbonization  
9 strategy at scale. First, RNG supply curves demonstrate increasing costs with growing  
10 consumption. Unlike solar panels or batteries, which benefit from manufacturing scale,  
11 biorefineries are constrained by feedstock availability and transportation distances. The  
12 MPSC’s ICF study confirms this, showing RNG production costs ranging from less than  
13 \$10/MMBtu for the most favorable landfill gas sites to upwards of \$50/MMBtu for  
14 smaller or less favorable facilities, compared to commodity natural gas prices below  
15 \$5/MMBtu.<sup>53</sup> Second, the current RNG market represents the lowest-cost feedstocks;  
16 growth requires tapping progressively more expensive sources, including energy crops  
17 that carry their own emissions from cultivation and land-use change. Third, and most  
18 importantly, limited bioenergy resources should be directed toward applications where  
19 electrification is not a viable alternative, such as sustainable aviation fuel, renewable  
20 diesel, marginal electricity generation, and high-temperature industrial processes.  
21 Pipeline RNG for building heat is an inferior use of these resources because electric  
22 heating is a mature and developed pathway; alternatively, few options exist for

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<sup>53</sup> *Id.*

1 decarbonizing aviation beyond low-carbon fuels.

2 Multiple independent analyses—including industry-sponsored research—have  
3 consistently found RNG to be an inferior building decarbonization strategy. Studies  
4 conducted by the Low Carbon Resources Initiative, a joint effort of the Electric Power  
5 Research Institute and the Gas Technology Institute, showed negligible low-carbon fuel  
6 use in the building sector under most scenarios evaluated.<sup>54</sup> In nearly all “net zero”  
7 scenarios modeled, residual fossil gas in the building sector was preferred over RNG to  
8 manage remaining emissions—meaning it is more cost-effective to continue limited fossil  
9 gas use rather than incur the high cost of substituting RNG.

10 **Q. DTE Gas highlights its 21 operational RNG interconnections as evidence of a**  
11 **growing market. What is driving this growth?**

12 A. The growth of the RNG market (including DTE Gas’s 21 interconnections) is largely  
13 driven by federal and state subsidy programs that create outsized financial incentives  
14 specifically for upgrading biogas to pipeline-quality RNG, while providing little or no  
15 comparable incentive for alternative uses of the same biogas feedstocks. These incentive  
16 structures place a thumb on the scale in favor of RNG over other, superior, uses of the  
17 same biological resource.

18 The two most influential programs are the Federal Renewable Fuel Standard (“RFS”),  
19 established in 2005, and the California Low Carbon Fuel Standard (“LCFS”), established  
20 in 2007. Both were explicitly designed to increase the adoption of low-carbon fuels at a  
21 time when the outlook for electric vehicles was far less favorable than it is today. RNG

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<sup>54</sup> [Net-Zero Scenarios 2.0: Sensitivity Analysis and Updated Scenarios for LCRI Net-Zero 2050](#), prepared by EPRI (December 2024) (Relevant excerpt at Exhibit AA-48)

1 used as compressed natural gas in vehicles is an established compliance pathway under  
2 both programs. Critically, because these programs generate credits valued against the  
3 compliance costs of expensive liquid fuels, they create an enormous subsidy for RNG  
4 relative to the commodity cost of fossil methane. RNG attribute prices have at times  
5 exceeded \$80 per MMBtu, while the commodity price of natural gas is below \$5 per  
6 MMBtu. RNG producers can stack credits from both the RFS and the LCFS,  
7 compounding the subsidy.

8 A regrettable and unintended consequence of this market design is that it systematically  
9 favors the RNG pathway over electric uses of the same biogas. An RNG producer can  
10 earn both RFS and LCFS credits from a facility located anywhere in the United States.  
11 By contrast, a facility that burns the same biogas directly to generate electricity can only  
12 earn LCFS credits, and only if the facility is interconnected with the California electric  
13 grid. The RFS has never included an electric compliance pathway. This asymmetry is not  
14 a reflection of the relative environmental merits of the two pathways; it is an artifact of  
15 policy design that predates the modern era of competitive electric technologies.

16 The distortive effect of these incentives is visible in the development patterns of the  
17 broader biogas industry and is documented in the MPSC's own 2022 Michigan RNG  
18 Study. ICF found that Michigan's biogas-to-electricity investment slowed markedly after  
19 2013, coinciding with the EPA's 2014 determination that RNG qualifies as an eligible  
20 renewable fuel under the RFS and the subsequent 2015 determination that landfill-  
21 sourced RNG qualifies as a cellulosic biofuel.<sup>55</sup> The ICF study documents a concrete

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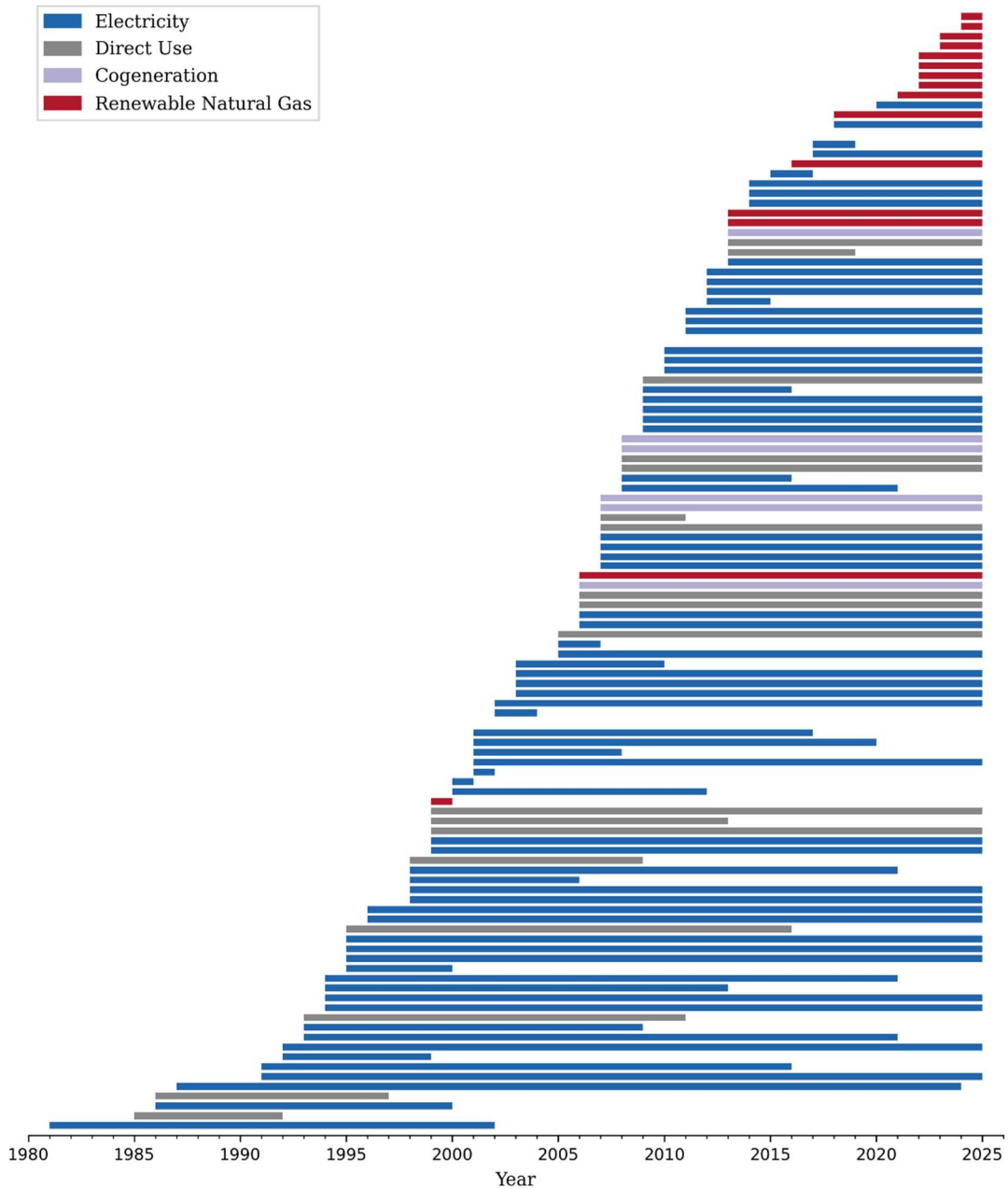
<sup>55</sup> [Michigan Renewable Natural Gas Study](#), prepared by I.C.F. Resources, L.L.C. for the Michigan Public Service Commission (Sept. 23, 2022) (Relevant excerpts at Exhibit AA-41).

1 Michigan example of this market distortion: in February 2022, the City of Riverview  
2 voted to convert its Riverview Land Preserve—Michigan’s oldest biogas-to-electricity  
3 project, operational since 1987—from electricity generation to RNG pipeline injection  
4 and use as a transportation fuel.<sup>56</sup> This trend is further depicted in Figure 2 using my  
5 analysis of EPA methane management project data.

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<sup>56</sup> *Id.*

### Michigan Agricultural & Landfill Biogas Projects Operational Timeline



1  
2 **Figure 2.** *Timeline of landfill or agricultural biogas energy*  
3 *projects in Michigan by energy product. Source: EPA AgSTAR Life*  
4 *Stock Anaerobic Digestion Database and Landfill Methane*  
5 *Outreach Program Database*

6 The American Biogas Council inventories over 2,200 biogas-producing sites in the  
7 United States. The vast majority of these are older facilities that produce heat or

1 electricity through direct combustion of biogas. The roughly 338 pipeline-quality RNG  
2 facilities represent a much smaller subset, yet this is the segment that is growing, driven  
3 by the distortive financial incentives described above. Some of these new RNG facilities  
4 represent conversions of existing direct-burn electricity facilities, meaning the subsidy  
5 structure is pulling biogas away from electricity generation and toward pipeline injection.  
6 This dynamic was further illustrated in 2023 when the EPA explored developing an  
7 electric compliance pathway for the RFS. In response to this potential change, WM  
8 (formerly Waste Management) announced that it would maintain two landfill electricity  
9 generation sites rather than convert them to RNG as previously planned. The RNG  
10 Coalition and American Biogas Council supported the inclusion of an electric pathway.  
11 The proposal ultimately did not proceed, but WM's response demonstrates that  
12 development decisions in this sector are driven primarily by the subsidy structure rather  
13 than by the inherent environmental or economic merits of one pathway over another.<sup>57</sup>  
14 Therefore, when evaluating whether increased investments in the gas distribution system  
15 have risk mitigation due to the possibility of RNG blending to meet customer or  
16 regulatory demands, the Commission should recognize that RNG may not be available,  
17 especially if the tax credit structure is changed to eliminate this likely unintended  
18 consequence. The Commission should understand DTE Gas's 21 RNG interconnections  
19 in this context. These interconnections are not evidence that RNG is the most efficient or  
20 cost-effective use of Michigan's bioenergy resources. They are evidence that current  
21 federal and state incentive structures disproportionately reward pipeline injection of  
22 upgraded biogas while providing little or no comparable incentive for direct electricity

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<sup>57</sup> Exhibit AA-49; Exhibit AA-50.

1 generation from biogas. DTE’s characterization of these interconnections as reflecting a  
2 “commitment to sustainable energy solutions” obscures the role that distorted incentive  
3 structures play in driving these investment decisions. The RNG market is growing not  
4 because pipeline injection is the best use of biogas, but because it is heavily subsidized.

5 **Q. Do other states that have evaluated RNG as a risk-mitigation factor find it to be**  
6 **attractive?**

7 A. No. Notably, the NYS Energy Plan<sup>58</sup> and its technical support document, Considerations  
8 for Low-Carbon Alternative Fuel Use in New York State,<sup>59</sup> comprehensively evaluate  
9 renewable fuels across multiple sectors and take the position that pipeline RNG for  
10 building heat is an inferior use of limited bioenergy resources.

11 The Plan discusses how bioenergy feedstocks should be prioritized to specific fuels and  
12 end uses, noting the inferiority of pipeline RNG. The Plan’s technical support document  
13 states: “Wastewater, for instance, may be able to produce RNG at a lower cost than  
14 [sustainable aviation fuel] or renewable diesel; however, injecting RNG into the gas  
15 distribution system does not directly advance the State’s long-term goals, whereas using  
16 it to produce [sustainable aviation fuel] or renewable diesel does.”<sup>60</sup> The Plan ultimately  
17 concludes that “Electrification should remain the first decarbonization solution and the  
18 use of low-carbon alternative fuels should be directed toward end-uses to maximize GHG  
19 emissions reductions while minimizing the cost of the energy transition, ensuring net co-  
20 pollutant emission reductions, and avoiding impacts associated with co-pollutant

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<sup>58</sup> [Low-Carbon Alternative Fuels](#), New York State Energy Plan, Volume II Our Energy Systems (Dec. 16, 2025) (Relevant excerpt at Exhibit AA-51)

<sup>59</sup> [Considerations for Low-Carbon Alternative Fuel Use in New York State](#), New York State Energy Research and Development Authority (July 2025) (Relevant excerpt at Exhibit AA-52)

<sup>60</sup> *Id.*

1 emissions”<sup>61</sup> and recommends designing infrastructure for liquid fuel production rather  
2 than pipeline injection, because liquid fuels serve higher-value applications with fewer  
3 alternatives.

4 **Q. Does DTE’s comparison of RNG and electrification reflect these concerns?**

5 A. No. DTE's analysis relies on an RNG cost assumption that is not scalable and ignores its  
6 own commissioned data on supply constraints. The Company assumes an RNG cost of  
7 \$18 per MMBtu. According to the Michigan Renewable Natural Gas Study  
8 commissioned by the MPSC, approximately 40 tBtu of RNG supply is available in  
9 Michigan at or below this price point. This represents approximately 4% of Michigan's  
10 total natural gas consumption. The study further identifies an "Achievable" production  
11 limit of 57.2 tBtu, beyond which costs rise sharply, reaching \$50 per MMBtu or more for  
12 less favorable feedstocks. DTE's assumed price, therefore, reflects only the cheapest  
13 tranche of a severely supply-constrained resource.

14 **Q. Are there other flaws with DTE’s comparison of RNG and Electrification?**

15 A. DTE's cost-effectiveness comparison is highly sensitive to the grid emissions forecast  
16 used to evaluate heat pump performance. The Company's analysis<sup>62</sup> uses a conservative  
17 MISO PROMOD forecast that assigns high carbon intensity to grid electricity, making  
18 heat pumps appear less effective at reducing emissions than they will be in the future  
19 under both Michigan’s historical trend and new regulatory requirements. However,  
20 climate-conscious customers are already showing a nationwide attraction for heat pumps  
21 and less of an attraction for RNG.

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<sup>61</sup> [Low-Carbon Alternative Fuels](#), New York State Energy Plan, Volume II Our Energy Systems (Dec. 16, 2025) (Relevant excerpt at Exhibit AA-51).

<sup>62</sup> Exhibit AA-53.

1 DTE's own model workbook contains an alternative scenario — labeled “DTE  
2 Environmental Target”<sup>63</sup> that reflects grid decarbonization consistent with Michigan's  
3 clean energy trajectory, including the requirements of Public Act 235 of 2023. DTE does  
4 not explain why it disregards this scenario in favor of the more pessimistic forecast  
5 regarding the effectiveness of heat pumps for customers who wish to decarbonize.  
6 Electrification becomes more effective as an emissions-reduction strategy as the electric  
7 grid decarbonizes, and Michigan law now requires that it do so. Using a grid forecast that  
8 ignores these requirements systematically understates the emissions benefit of  
9 electrification and overstates the relative attractiveness of RNG for climate-conscious  
10 customers or as a likely pathway for future regulatory compliance. When the analysis is  
11 corrected using DTE's own “DTE Environmental Target” scenario, heat pump  
12 electrification achieves an estimated 63% reduction in heating-related emissions.  
13 While DTE makes conservative assumptions for electrification, it treats emissions  
14 reductions from RNG uncritically. DTE's analysis assumes zero greenhouse gas intensity  
15 for RNG, but the energy required for biogas purification results in an effective emissions  
16 intensity of approximately 0.015 tons of CO<sub>2</sub> per MMBtu, reducing RNG's climate  
17 benefit to roughly 72% of the Company's claimed value. Correcting for this factor would  
18 require approximately 38% more RNG to achieve the same emissions reductions using  
19 the MISO PROMOD forecast, further straining an already constrained supply and  
20 increasing costs proportionally of a disfavored mitigation pathway.

21 **Q. Does DTE's climate strategy also rely on hydrogen blending or carbon offsets?**

22 **A.** Yes. DTE's Gas Delivery Plan identifies hydrogen blending and offsets among the

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<sup>63</sup> Exhibit AA-54.

1 strategies it is considering to meet its longer-term climate targets, but does not provide  
2 any material detail for how these will play a role.

3 **Q. What are your recommendations regarding DTE Gas’s RNG claims?**

4 A. The Commission should not assume RNG use will mitigate the risks associated with  
5 DTE’s proposals for increased investment in the existing gas distribution system.

6 **VII. NON-PIPELINE ALTERNATIVES**

7 **Q. How does DTE Gas characterize non-pipeline alternatives in this proceeding?**

8 A. In his direct testimony, DTE Gas Witness Decker dismisses non-pipeline alternatives as  
9 limited to “niche projects” that are not scalable.<sup>64</sup> Specifically, Mr. Decker cites a single  
10 study co-authored by National Grid and RMI examining nine NPA cases across the  
11 United States and Europe,<sup>65</sup> and concludes that NPAs are “only truly effective in niche  
12 projects ‘serving 1-5 customers, under the 100% persuasion model.’”<sup>66</sup> Based on this  
13 characterization, Mr. Decker testifies that “DTE Gas does not foresee a material impact  
14 on the need for natural gas infrastructure in realistic electrification scenarios.”<sup>67</sup>

15 Mr. Decker’s characterization of NPAs is incomplete, outdated, and misleading in several  
16 respects. First, the National Grid-RMI report Mr. Decker cites was published in May  
17 2024, and the NPA landscape has evolved substantially since that time. Since that  
18 publication, Massachusetts has established a comprehensive NPA evaluation framework  
19 requiring all gas capital investments to be screened for NPA viability;<sup>68</sup> California has

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<sup>64</sup> Decker, Direct Testimony, p. 19.

<sup>65</sup> [Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization](#), RMI and National Grid (May 2024) (Executive Summary at Exhibit AA-55)

<sup>66</sup> Decker, Direct Testimony, p. 19

<sup>67</sup> *Id.*

<sup>68</sup> Massachusetts Department of Public Utilities, Order 20-80-B, December 2023.

1 enacted Senate Bill 1221, authorizing up to 30 targeted electrification pilot projects;<sup>69</sup>  
2 Colorado has selected five gas planning pilot communities;<sup>70</sup> and Consolidated Edison in  
3 New York has implemented its Energy Exchange Program offering \$10,000–\$20,000 per  
4 customer for electrification of customers served by pre-1971 service connections.<sup>71</sup>

5 Second, the National Grid-RMI report itself does not conclude that NPAs should be  
6 abandoned – it concludes that the *approach* to NPAs must evolve beyond individual  
7 customer persuasion toward utility-led, system-level planning.<sup>72</sup> The report identifies  
8 systemic barriers to scaling, including the lack of utility incentive structures and the  
9 absence of holistic gas system planning—barriers that other states are now actively  
10 addressing through the programs I describe below.

11 Third, and most importantly, Mr. Decker’s testimony fails to acknowledge the  
12 fundamental reason NPAs are receiving increasing attention in other jurisdictions: the  
13 growing recognition that continued investment in gas infrastructure carries significant  
14 asset continuation risk: the risk that ratepayers will bear the cost of infrastructure that  
15 does not generate sufficient revenue over its useful life.

16 **Q. What is a non-pipeline alternative?**

17 A. A non-pipeline alternative is an investment or set of measures that enables a gas utility to  
18 avoid, defer, or reduce a traditional pipeline infrastructure project – such as main  
19 replacement, main extension, or system reinforcement – by reducing or eliminating gas  
20 demand on a targeted segment of the distribution system. The concept is analogous to

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<sup>69</sup> California Senate Bill 1221 (2024).

<sup>70</sup> *See*, Colorado House Bill 24-1370.

<sup>71</sup> *See*, ConEdison, [Energy Exchange Program](#).

<sup>72</sup> [Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization](#), RMI and National Grid (May 2024) (Executive Summary at Exhibit AA-55)

1 demand-side management on the electric system, or to “non-wires alternatives” that  
2 electric utilities use to defer transmission and distribution investments. DTE Gas’s own  
3 Gas Delivery Plan acknowledges that “some utilities, such as those in New York, are  
4 emphasizing Non-Pipeline Alternatives (NPAs) in areas where system constraints require  
5 new capital investment” and defines NPAs as “alternative investments that allow a utility  
6 to eliminate or delay the implementation of a traditional pipeline project.”<sup>73</sup>

7 NPAs can take several forms: they may involve converting all customers on a targeted  
8 pipe segment to alternative heating sources, thereby enabling the utility to retire the pipe  
9 rather than replace it; they may involve reducing demand on a constrained segment  
10 sufficiently to avoid a reinforcement project; or they may involve avoiding the extension  
11 of gas mains to serve new development by ensuring that development is served by  
12 electric alternatives from the outset.

13 In DTE Gas’s service territory, the most relevant NPA applications involve avoiding or  
14 deferring capital expenditures for main replacement and new customer extensions by  
15 transitioning customers to alternative heating technologies such as heat pumps, or hybrid  
16 heating arrangements with delivered fuels.

17 **Q. What cost and risk dynamics do non-pipeline alternatives address?**

18 A. NPAs address two interrelated economic concerns that are central to the long-term  
19 interests of DTE Gas ratepayers: transition costs and asset continuation risk.

20 *Transition cost* refers to the net investment required to enable a gas system segment to be  
21 retired rather than replaced. This includes the cost of customer-side measures –  
22 electrification equipment, building upgrades, delivered fuel conversion, or other

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<sup>73</sup> Exhibit A-12, Schedule B5.6, p. 85–86.

1 alternatives – minus the avoided cost of the pipeline infrastructure investment that would  
2 otherwise occur. Transition costs can be positive, when customer-side investment  
3 exceeds avoided infrastructure costs, or negative, when avoiding the infrastructure  
4 generates net savings. Transition costs can be assessed in upfront capital terms or from a  
5 longer-term net-present-value perspective that incorporates ongoing energy costs and  
6 other utility costs.

7 *Asset continuation risk* refers to the cost borne by ratepayers of continuing to invest in  
8 and maintain infrastructure that may not generate sufficient revenue over its useful life  
9 relative to a counterfactual in which it is retired and not replaced. This risk arises when  
10 expensive infrastructure serves customers who may reduce or eliminate their gas  
11 consumption within the investment’s useful life. The costs of that infrastructure do not  
12 disappear when customers depart the system. They are reallocated to remaining  
13 ratepayers through the ratemaking process, creating a cycle of rising rates and further  
14 customer departures.

15 These two concepts interact in important ways. A segment with high asset continuation  
16 risk may justify accepting higher transition costs, because avoiding the infrastructure also  
17 avoids the ongoing risk of cost concentration on remaining ratepayers. Conversely, a  
18 segment with low asset continuation risk may not warrant NPA investment even where  
19 technically feasible, because the infrastructure is likely to remain well-utilized throughout  
20 its useful life.

21 **Q. How are other states approaching non-pipeline alternatives?**

22 A. Several states have moved well beyond the conceptual stage and are implementing NPA  
23 programs of direct relevance to Michigan. I highlight three that illustrate the range of

1 approaches.

2 *Consolidated Edison (New York)*. Con Edison operates 4,500 miles of gas mains serving  
3 1.1 million gas customers in New York City and Westchester County. The utility spends  
4 approximately \$400 million annually to replace approximately 1,200 miles of leak-prone  
5 pipe installed before 1972. Con Edison has developed two NPA programs of particular  
6 relevance. First, its “Electric Advantage Program” eliminates select main replacement  
7 investments by electrifying all affected customers on a targeted segment. Second, its  
8 “Energy Exchange Program” offers individual customers served by pre-1971 service  
9 connections electrification incentives of \$10,000–\$20,000, tiered by building type and  
10 disadvantaged community status. Con Edison recovers NPA costs as a regulatory asset,  
11 and utilizes a performance incentive structure that makes NPA investment revenue-  
12 neutral or preferable for the utility.

13 *Massachusetts NPA Framework*. In December 2023, the Massachusetts Department of  
14 Public Utilities issued Order 20-80-B, establishing that all gas capital investments must  
15 be evaluated for an NPA prior to proceeding. In April 2025, the state’s Local Distribution  
16 Companies filed Climate Compliance Plans with proposed NPA frameworks that include  
17 a sequential gated evaluation process: initial viability screening, gas system integrity  
18 review, customer viability assessment, electric system review, and benefit-cost analysis.  
19 National Grid filed a Targeted Electrification Demonstration Program Implementation  
20 Plan (Massachusetts D.P.U. 24-194) proposing to cover 100% of customer conversion  
21 costs and provide bill credits to offset differential operating costs. Four additional gas  
22 utilities are filing pilot proposals. The Massachusetts legislature has also adopted changes  
23 to the obligation to serve that allow utilities to “vary the uniformity of service,” providing

1 legal authority for managed transitions.

2 *Targeted Electrification Pilots (California and Colorado)*. California enacted Senate Bill  
3 1221 in 2024, establishing a framework for neighborhood-scale decarbonization  
4 including authorization for up to 30 pilot projects for gas decommissioning coordinated  
5 with building electrification. The law requires gas utilities to publish maps of pipeline  
6 replacement projects that could be candidates for targeted electrification. In Colorado,  
7 House Bill 24-1370 directed the Colorado Energy Office to solicit interest from  
8 municipalities in becoming “gas planning pilot communities.” Five communities were  
9 selected in 2025, and Xcel Energy proposed the “Mountain Energy Project,” described as  
10 the largest at-scale NPA portfolio in the United States, affecting approximately 33,500  
11 customers with a projected cost savings of approximately \$170 million compared to the  
12 traditional pipeline approach.

13 The common thread across these states is recognition that the question is no longer  
14 whether NPAs are viable, but how to source, evaluate, and implement them  
15 systematically. DTE Gas’s position that NPAs are limited to niche projects is  
16 increasingly at odds with the direction of utility regulation nationally.

17 **Q. How should DTE Gas identify and source NPA opportunities on its system?**

18 A. Effective NPA sourcing requires a long-term, systematic approach to limiting new  
19 investment in the gas system and identifying segments where infrastructure avoidance is  
20 both feasible and cost-effective. The National Grid-RMI report that Mr. Decker cites  
21 recommends that utilities proactively and systematically scan their asset bases for

1 favorable areas for gas decommissioning.<sup>74</sup> I recommend three elements.

2 First, NPA identification must be embedded in long-term gas system planning, not treated  
3 as an ad hoc response to individual projects. The fundamental question is: how does DTE  
4 Gas limit future investment in the gas system in a manner that protects ratepayers from  
5 asset continuation risk? This requires the Company to evaluate its entire system, not just  
6 individual project proposals, to identify where infrastructure avoidance yields the greatest  
7 benefit. Currently, DTE Gas's Gas Delivery Plan evaluates capital investments project-  
8 by-project without a holistic assessment of how those investments interact with the long-  
9 term trajectory of gas demand and the risk of underutilization.

10 Second, DTE Gas should conduct a holistic gas system analysis to identify severable,  
11 leak-prone pipe segments (including service lines) that are candidates for retirement  
12 rather than replacement. This analysis should evaluate the hydraulic severability of pipe  
13 segments (i.e., whether a segment can be retired without compromising service to  
14 remaining customers), the condition and leak history of the pipe, the cost of replacement  
15 versus the transition cost of converting affected customers, and the number and  
16 characteristics of customers served. The results of this analysis should be shared with the  
17 Commission in the form of detailed maps and data that enable the Commission and  
18 intervenors to evaluate the Company's capital investment decisions in the context of NPA  
19 potential.

20 Third, DTE Gas should analyze the potential for individual customer conversions to  
21 contribute to broader infrastructure avoidance opportunities. Even where a full segment-

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<sup>74</sup> [Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization](#), RMI and National Grid (May 2024) (Executive Summary at Exhibit AA-55)

1 level NPA is not immediately feasible, individual customer departures from a targeted  
2 segment can improve the economics of future retirement by reducing remaining load. A  
3 customer departing a pipe segment reduces the revenue that segment must generate, but  
4 also reduces the demand that must be served, which may render the segment  
5 hydraulically severable in the future. Con Edison's Energy Exchange Program takes this  
6 approach: by offering individual customers on aging service connections incentives to  
7 electrify, the utility reduces the number of service connections requiring replacement and  
8 brings targeted main segments closer to retirement eligibility. DTE Gas should evaluate  
9 which segments of its system are approaching a tipping point where modest customer  
10 reductions would enable infrastructure avoidance.

11 **Q. How should customers be involved in NPA planning?**

12 A. Successful NPA implementation depends fundamentally on customer participation,  
13 which in turn depends on customer access to information about the gas system and the  
14 costs they face. Customers cannot make informed decisions about their energy future if  
15 they do not understand the trajectory of the gas system that serves them.

16 DTE Gas should publish gas system data that indicates to customers the condition of the  
17 infrastructure serving their properties and the planned capital investments in their area.

18 This should include, at minimum, the age and material of the pipe serving their  
19 neighborhood, whether the pipe is scheduled for replacement or major maintenance, the  
20 expected cost of that work and its impact on delivery rates, and whether the segment has  
21 been identified as an NPA candidate. This information should be provided through a  
22 publicly accessible web portal and map interface.

23 Transparency about gas system conditions serves two purposes. First, it enables

1 customers to evaluate their own options with full knowledge of the costs and risks  
2 associated with each path. Second, it enables third-party organizations, municipalities,  
3 and community groups to identify NPA opportunities and facilitate customer  
4 participation. The experience in other states has shown that utility-controlled NPA  
5 identification, without external input, tends to be conservative and slow. Transparent data  
6 enables a broader set of actors to participate in identifying and advancing cost-effective  
7 alternatives.

8 **Q. Do you have additional recommendations for how NPA efforts should begin?**

9 A. I recommend that the Commission direct DTE Gas to publish maps identifying customers  
10 served by leak-prone pipe, including pipe age, material, condition, and planned  
11 replacement timeline. These maps should be made available through a publicly accessible  
12 web portal and should include sufficient detail for the Commission, intervenors,  
13 municipalities, and customers to identify potential NPA opportunities. The maps should  
14 be updated regularly as part of the Company's Gas Delivery Plan filing. Publication of  
15 this data is a prerequisite for meaningful NPA evaluation and is consistent with the  
16 direction of regulatory proceedings in New York, Massachusetts, California, and Illinois.  
17 Without this information, the Commission and stakeholders cannot evaluate whether  
18 DTE Gas's capital investment program is prudent in light of available alternatives.

19 **VIII. EXISTING CUSTOMERS BEAR THE RISK OF NEW CUSTOMERS**

20 **VIII-A. Overview of DTE Gas's Customer Attachment Program**

21 **Q. What is DTE Gas's Customer Attachment Program, and what level of investment  
22 does the Company propose?**

23 A. DTE Gas's Customer Attachment Program ("CAP") provides a method for expanding the

1 gas distribution system to serve new customers. In this proceeding, the Company  
2 proposes \$262.0 million in capital expenditures for New Market Attachments from  
3 January 1, 2025, through September 30, 2027.<sup>75</sup> New Market Attachments represent the  
4 Company’s multi-customer community expansion efforts that seek to add a cohort of  
5 customers over several years through the addition of new infrastructure. This represents  
6 an average of \$95.7 million per year, approximately \$12 million per year higher than the  
7 2024 historical spend of \$83.7 million.<sup>76</sup> Two New Market Attachment projects meet the  
8 threshold to be included in Schedule B5.5 DTE Highest Cost Top 25 Capital Projects:  
9 Austin Area Expansion Project and the US-2 project. The Company attributes this  
10 increase primarily to “increased demand by homeowners for conversion from the higher  
11 cost of propane to natural gas, particularly in the community expansion space.”<sup>77</sup> DTE is  
12 actively targeting propane-to-gas conversions, with \$324,000 budgeted annually for  
13 proactive gas expansion marketing.<sup>78</sup>

14 **Q. How does the CAP model determine costs borne by new customers versus existing**  
15 **ratepayers?**

16 A. Each CAP project uses a discounted Net Present Value (“NPV”) analysis of the revenue  
17 deficiency anticipated over a 20-year payback period. If projected revenues from the new  
18 customers are insufficient to cover the cost of the expansion, the new customer pays a  
19 Contribution in Aid of Construction (“CIAC”) – typically collected as a Fixed Monthly  
20 Surcharge over five years. The remainder of the construction cost – the “allowance” – is

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<sup>75</sup> Huffman, Direct Testimony, p. 38.

<sup>76</sup> *Id.* at 39.

<sup>77</sup> *Id.*

<sup>78</sup> Exhibit AA-56; Exhibit AA-57.

1 capitalized by DTE Gas and enters the rate base, where it is recovered from all ratepayers  
2 through distribution rates. The utility’s investors earn a rate of return on this capitalized  
3 allowance.<sup>79</sup>

4 **Q. How is the CAP model designed to protect existing customers?**

5 A. The fundamental regulatory principle underlying the design of the CAP is that existing  
6 customers should not subsidize new customers. As the MPSC website states, a CAP’s  
7 purpose is “to provide gas utilities with a method of expanding their systems to new  
8 customers without such expansions being subsidized by existing customers.”<sup>80</sup> Whether  
9 this principle is being upheld depends entirely on whether the model’s revenue  
10 projections and the assumptions underlying them are reasonable.

11 **Q. Does the current approach to determining CIACs and allowances sufficiently**  
12 **protect existing customers?**

13 A. No. The remainder of this section will show that existing customers are currently  
14 financing a significant portion of new construction costs and emphasize that they bear the  
15 burden of increasing risk associated with under recovery of CIACs.

16 **VIII-B. Analysis of DTE’s CAP Project Models**

17 **Q. Did you examine DTE’s individual CAP project models?**

18 A. Yes. DTE provided 74 CAP model workbooks covering Area Expansion Projects from  
19 2024 through 2026.<sup>81</sup> These workbooks used two distinct spreadsheet templates. I  
20 examined the design of these model templates in detail. I also extracted and analyzed the

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<sup>79</sup> Huffman, Direct Testimony, p. 40-45. *See also*, DTE Gas Rate Book, Sections C8.2 and C8.6.

<sup>80</sup> Michigan Public Service Commission, [Customer Attachment Program](#); *see also*, Huffman, Direct Testimony, p. 44-45.

<sup>81</sup> Exhibit AA-58.

1 construction costs, customer targets, consumption assumptions, financial parameters, and  
2 20-year revenue projections embedded in every workbook.

3 **Q. What are the aggregate results across all 74 projects?**

4 A. The 74 projects target a combined 13,340 new customers at a total construction cost of  
5 \$104.4 million. Of this total, new customers pay \$32.8 million in CIACs (31.4%), while  
6 existing ratepayers finance \$71.6 million in allowances that enter rate base (68.6%).

7 Table 4 summarizes these results:

8 **Table 4. New Market Attachments**

	2024	2025	2026	Total
Number of projects	28	18	28	74
Target customers	3,949	3,140	6,251	13,340
Total construction cost	\$29.8M	\$24.1M	\$50.5M	\$104.4M
CIAC (customer pays)	\$9.1M	\$8.1M	\$15.6M	\$32.8M
Allowance (ratepayer-funded)	\$20.7M	\$16.0M	\$34.9M	\$71.6M
Allowance as % of total	69.6%	66.3%	69.2%	68.6%
Avg. cost per customer	\$7,535	\$7,680	\$8,081	\$7,828
Avg. allowance per customer	\$5,242	\$5,093	\$5,588	\$5,370

9 On average, existing ratepayers finance \$5,370 per new customer—more than double the  
10 \$2,458 CIAC paid by the new customer. Per-customer costs are also rising: from \$7,535  
11 in 2024 to \$8,081 in 2026, an increase of 7.2%.

12 **Q. Did you obtain system-wide data on DTE Gas’s new customer connection costs to  
13 corroborate your analysis of the 74 CAP project models?**

14 A. Yes. In response to Ann Arbor’s Fourth Discovery Request, DTE Gas provided five years  
15 of aggregate data on new *service* installations, including gross costs, CIACs collected,  
16 and net amounts added to rate base. This data apparently captures the costs incurred with

1 individual service connections. These system-wide figures independently confirm that  
 2 existing ratepayers finance the vast majority of the costs of connecting new customers.  
 3 Table 5 below summarizes DTE Gas’s system-wide new service installation data for  
 4 2021 through 2025.

5 **Table 5. DTE Gas System-Wide New Service Installation Costs, 2021–2025<sup>82</sup>**

Year	Gross New Service Cost	CIAC Collected	Net Cost to Rate Base	Attachments	Ratepayer Subsidy Rate
2021	\$36.3 M	\$1.7 M	\$34.6 M	10,219	95.3%
2022	\$41.2 M	\$1.7 M	\$39.5 M	10,358	95.9%
2023	\$38.5 M	\$1.9 M	\$36.6 M	9,990	95.1%
2024	\$39.5 M	\$1.6 M	\$37.9 M	11,068	95.9%
2025	\$39.1 M	\$4.0 M	\$35.1 M	9,446	89.8%
<b>Total</b>	<b>\$194.6 M</b>	<b>\$10.9 M</b>	<b>\$183.7 M</b>	<b>51,081</b>	<b>94.4%</b>

6 Over the five-year period, DTE Gas spent \$194.6 million on new service installations and  
 7 collected only \$10.9 million in CIACs—a system-wide CIAC recovery rate of just 5.6%.  
 8 The remaining \$183.7 million was added to rate base, where it earns a guaranteed return  
 9 for DTE’s investors and is recovered from all existing ratepayers.

10 **Q. What proportion of DTE’s new customer connections receive a line extension**  
 11 **allowance covering 100% of the connection cost—meaning the new customer pays**  
 12 **zero CIAC?**

13 A. Approximately half. DTE Gas provided data for 2024 and 2025 showing the number of  
 14 connections that required zero CIAC versus those that required some customer  
 15 contribution (Table 6).

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<sup>82</sup> Exhibit AA-59

1 **Table 6. Zero-CIAC vs. CIAC-Required Connections, 2024–2025<sup>83</sup>**

Year	Zero-CIAC Connections	CIAC-Required Connections	Total Connections	% Zero-CIAC
2024	5,403	5,665	11,068	48.8%
2025	4,817	4,627	9,444	51.0%

2  
3 **Q. What is the significance of these zero-CIAC connections for the risk analysis you**  
4 **presented earlier?**

5 A. For approximately 5,000 customers per year, the entire capital cost of connection enters  
6 rate base with no upfront contribution from the customer who caused the cost. These  
7 customers have no financial commitment to the gas system beyond their monthly bill. If  
8 they reduce consumption existing ratepayers have no recourse to recover the stranded  
9 investment.

10 **VIII-C. DTE’s CAP Model Fails to Account for Increasing Risk to Gas**  
11 **Consumption**

12 **Q. What consumption assumption does the CAP model use?**

13 A. Each of the 74 CAP models assumes that each new customer will consume gas at a  
14 constant rate over the full 20-year evaluation period. The average assumed consumption  
15 for residential customers is 121 Mcf per year. This figure is assumed to be static over 20  
16 years. There is no efficiency improvement, no fuel-switching, and no attrition modeled in  
17 any project.

18 **Q. Is 121 Mcf per year a reasonable starting assumption?**

19 A. It is above average but may be defensible as a starting point for the specific population  
20 being served. The Michigan statewide average residential natural gas consumption was

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<sup>83</sup> *Id.*

1 approximately 80 Mcf per customer in 2024, according to EIA data.<sup>84</sup> CAP customers  
2 tend to be in rural areas with older homes currently heated with propane, so above-  
3 average starting consumption may be plausible. However, given that 121 Mcf is 52%  
4 above the statewide average, continuing with the assumption that usage will remain  
5 constant for two decades is unreasonable, especially in light of trends in building energy  
6 use declining due to efficiency improvements made at various time points in an  
7 ownership cycle.

8 **Q. Does DTE’s own testimony support the assumption of constant consumption over 20**  
9 **years?**

10 A. No. DTE’s own Gas Delivery Plan directly contradicts the constant-consumption  
11 assumption used in every CAP model. On page 85 of the Gas Delivery Plan, DTE states:  
12 “DTE Gas saw an 18% reduction in weather-normalized demand per customer in 2024  
13 compared to 2005.”<sup>85</sup> The GDP further states: “DTE Gas expects to continue to achieve  
14 1% energy efficiency savings annually.”<sup>86</sup>  
15 The Company’s planning witness projects ongoing 1% annual demand decline, while its  
16 investment models assume zero decline for 20 years. If the Gas Delivery Plan’s  
17 assumptions are sound, then every CAP model systematically overstates the revenue  
18 these new customers will generate, and the allowances funded by existing ratepayers are  
19 correspondingly understated.

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<sup>84</sup> Exhibits AA-60 and AA-61 (273,737 million cubic feet delivered to 3,441,467 residential consumers in Michigan).

<sup>85</sup> Exhibit A-12, Schedule B5.6, p. 85.

<sup>86</sup> *Id.*

1 **Q. What is the impact of applying DTE’s own 1% annual demand decline to the CAP**  
2 **models?**

3 A. The impact is material. At 1% annual decline, a customer cohort starting at 121 Mcf per  
4 year consumes 109 Mcf in Year 10 and 99 Mcf in Year 20. This represents a \$275  
5 potential 20-year NPV under recovery. Because the CAP model calculates the allowance  
6 based on the assumption that revenue remains constant, any decline in actual  
7 consumption means the revenue will fall short of projections, and the allowance will not  
8 be fully “earned back” by the new customers. The shortfall is borne by existing  
9 ratepayers. Rising rates may offset this, but it illustrates that the CIAC calculation used to  
10 protect existing ratepayers rests on assumptions that are at risk of change.

11 **VIII-D. The Allowance Structure Creates Asymmetric Risk**

12 **Q. Who bears the risk if the CAP model’s consumption assumptions prove optimistic?**

13 A. Existing ratepayers bear the entire downside risk. The allowance enters the rate base and  
14 earns a guaranteed return for DTE’s investors regardless of whether the new customers  
15 actually consume gas at the projected levels.<sup>87</sup> If a new customer reduces consumption,  
16 installs a heat pump, or leaves the system entirely, the infrastructure investment is already  
17 in rate base and continues to be recovered from all remaining customers. The new  
18 customer, meanwhile, has no obligation beyond the surcharge period (typically 5 years)  
19 and no penalty for reducing consumption. DTE’s investors earn their authorized return  
20 regardless. The only party exposed to the risk of optimistic assumptions is the existing  
21 ratepayer.

22

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<sup>87</sup> Exhibit AA-62.

1 **Q. Does DTE perform any sensitivity analysis on these assumptions?**

2 A. No. In response to discovery, DTE confirmed that it “does not perform formal sensitivity  
3 analysis on customer attachment projections.”<sup>88</sup> The Company has not modeled any  
4 scenario in which demand declines, customers attrit, or fuel-switching occurs—despite its  
5 own Gas Delivery Plan projecting exactly these outcomes. No CAP model includes any  
6 alternative scenario. Every one of the 74 models presents a single, maximally optimistic  
7 forecast as the basis for committing \$71.6 million of existing ratepayer capital.

8 **VIII-E. The Emerging Heat Pump Threat to CAP Revenue Projections**

9 **Q. You mentioned fuel-switching as a risk. Can you describe a specific scenario?**

10 A. Yes. The most significant near-term risk to CAP revenue projections is the hybrid heat  
11 pump scenario. A customer who connects to natural gas through a CAP project but  
12 subsequently undertakes energy efficiency measures or installs a cold-climate heat pump  
13 as a supplemental heating system could reduce their gas consumption from the modeled  
14 121 Mcf per year significantly, depending on design. This is not hypothetical. DTE’s own  
15 Guidehouse analysis, evaluates this exact hybrid heating configuration and acknowledges  
16 it as a viable and growing option.<sup>89</sup>

17 **Q. Should ratepayers bear this risk?**

18 A. No. Long-term revenue forecasts are increasingly uncertain. Over a 20-year horizon, a  
19 model that ignores efficiency improvements, DTE’s own 1% annual demand decline  
20 projection, customer fuel-switching, and the emergence of competitive heat pump  
21 technology is not a model that prudently protects existing ratepayers. If gas service is

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<sup>88</sup> *Id.*

<sup>89</sup> Exhibit A-29, Schedule 1. *See also*, Decker, Direct Testimony, p. 4-5; 13-14.

1 genuinely the best option for new customers, they should be willing to bear a larger share  
2 of the connection cost. The current structure allows new customers to capture the full  
3 benefit of low gas prices while shifting most of the infrastructure risk to existing  
4 ratepayers who had no part in the decision to extend service.

5 **VIII-F. DTE’s Posture on Decarbonization Risk Is Internally Contradictory**

6 **Q. How does DTE characterize the risk that decarbonization policies pose to CAP**  
7 **investments?**

8 A. DTE’s position is inconsistent. In direct testimony, the Company stated that it is “not  
9 currently aware of any proposed legislation or regulation that would materially impact its  
10 current business” while acknowledging “that State or Federal legislative and regulatory  
11 developments could impact natural gas demand and DTE Gas’s capital plans.”<sup>90</sup> The  
12 Company further acknowledges that “as GHG emission reductions get more aggressive to  
13 reach Michigan’s 2050 net zero goal, there is likely to be further reduction in natural gas  
14 demand.”<sup>91</sup> The Company also acknowledged municipal climate commitments, including  
15 the City of Ann Arbor’s A<sup>2</sup>ZERO Carbon Neutrality Plan.<sup>92</sup> When asked to quantify the  
16 financial risks to its gas distribution investments from state and local decarbonization  
17 policies, DTE objected to the question entirely.<sup>93</sup>

18 This posture is untenable. DTE simultaneously filed a Gas Delivery Plan that  
19 acknowledges ongoing demand decline and emerging decarbonization risk, while asking  
20 the Commission to approve \$262 million in expansion investments premised on a model

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<sup>90</sup> Decker, Direct Testimony, p. 17.

<sup>91</sup> Exhibit A-12, Schedule B5.6), p. 85.

<sup>92</sup> Exhibit AA-19

<sup>93</sup> Exhibit AA-63.

1 that assumes neither and puts existing ratepayers at risk of paying for stranded assets at  
 2 worst and under-recovering the already-insufficient CIAC due to lower than projected  
 3 gas usage at best.

4 **VIII-G. Regulatory Actions in Other Jurisdictions**

5 **Q. Have other states reformed or eliminated gas line extension allowances?**

6 A. Yes, as shown in Table 7 below.

7 **Table 7. Status of line extension allowances in selected states.**

State	Action	Year	Key Features
<i>California</i>	Eliminated LEAs	2022	CPUC order; exceptions require a petition demonstrating no feasible alternative to gas service
<i>Colorado</i>	Eliminated LEAs	2023	Legislation (SB 23-291); immediate implementation for new gas connections
<i>Washington</i>	Reduced LEAs	2021	Shortened payback period to 7 years; reduced allowance amounts
<i>Oregon</i>	Reduced LEAs	2022	Set maximum fixed allowance by customer class; reduced from historical levels
<i>New York</i>	Eliminated the 100-foot rule.	2025	Allowances eliminated via Legislation (S.8417/A.8888)
<i>Massachusetts</i>	Under consideration	Pending	DPU has drafted a straw proposal for the elimination of line extension allowances.
<i>Maryland</i>	Eliminated LEAs	2025	Commission order (No. 91683)

8  
 9 Across the country, regulators and legislators in at least seven states have taken action to  
 10 reduce or eliminate gas line extension allowances, recognizing that these subsidies  
 11 expose existing ratepayers to unacceptable risks and are inconsistent with climate policy  
 12 objectives.<sup>94</sup>

13 *California.* In September 2022, the California Public Utilities Commission issued a

<sup>94</sup> RMI, [Cutting These Subsidies Could Save States Millions of Dollars](#), by Mike Hennen and Joe Dammel (August 27, 2025) (Provided at Exhibit AA-64).

1 decision phasing out gas line extension allowances for all gas utilities across the state.<sup>95</sup>  
2 The CPUC found that continued subsidization of gas system expansion was inconsistent  
3 with the state’s climate goals and posed stranded asset risks for ratepayers.  
4 *Colorado.* In 2023, the Colorado legislature directed the state’s Public Utilities  
5 Commission to eliminate line extension allowances, recognizing the growing risk that gas  
6 infrastructure investments would not be recovered from new customers as the state  
7 pursues its emissions reduction targets.<sup>96</sup>  
8 *New York.* On December 19, 2025, Governor Hochul signed legislation repealing New  
9 York’s statutory “100-foot rule,” which had required utilities to provide free gas  
10 connections to any customer within 100 feet of an existing gas main.<sup>97</sup> The repeal is  
11 estimated to save New York ratepayers approximately \$600 million annually.  
12 *Maryland.* In June 2025, the Maryland Public Service Commission issued Order No.  
13 91683, directing that new gas customers pay the full connection cost upfront.<sup>98</sup> The  
14 Maryland Office of People’s Counsel estimated that eliminating line extension  
15 allowances will save BGE and Washington Gas customers approximately \$1 billion  
16 through 2035. The Maryland PSC noted that “current natural gas policies may no longer  
17 be compatible with the state’s greenhouse gas emissions reduction targets” and that  
18 existing policies “expose all ratepayers to the risk of stranded gas infrastructure costs.”  
19 *Massachusetts.* The Massachusetts Department of Public Utilities has been conducting a  
20 multi-year investigation into line extension policies through its D.P.U. 20-80 proceeding.

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<sup>95</sup> California Public Utilities Commission, Decision 22-09-026 (September 2022).

<sup>96</sup> Colorado SB 23-291 (2023).

<sup>97</sup> New York S.8417/A.8888 (2025).

<sup>98</sup> Maryland Public Service Commission, Order No. 91683 (June 13, 2025).

1 In August 2025, the Department issued a Revised Straw Proposal for the elimination of  
2 line extension allowances, with limited exceptions for commercial and industrial loads  
3 where no technically feasible electric alternative exists.<sup>99</sup>

#### 4 **VIII-H. Options & Recommendations**

5 **Q. What policy options are available to the Commission to reform line extension**  
6 **allowances?**

7 A. Several options exist along a spectrum from incremental reform to the full elimination of  
8 allowances:

9 First, the Commission could prohibit line extension allowances entirely, requiring new  
10 customers to pay the full cost of connection. This is the approach adopted or being  
11 implemented in California, Colorado, New York, and Maryland. Under this approach,  
12 new customers would still be able to connect to the gas system, but the cost of the  
13 connection would be borne by the new customer rather than socialized across all  
14 ratepayers.

15 Second, the Commission could shorten the payback period used to calculate the  
16 allowance. DTE Gas currently uses a twenty-year payback period, which assumes that  
17 new customers will use gas at projected levels for two decades. Shortening this period to  
18 seven years, as adopted in Washington, would result in smaller allowances and  
19 correspondingly larger customer contributions, better reflecting the increasing uncertainty  
20 of long-term gas revenues.

21 Third, the Commission could establish a minimum CIAC, ensuring that every new

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<sup>99</sup> Massachusetts Department of Public Utilities, Interlocutory Order D.P.U. 20-80-E (August 8, 2025).

1 customer pays at least a specified portion of the actual connection cost regardless of  
2 projected revenues. This would provide a floor of cost recovery for each connection and  
3 reduce the risk of unrecovered allowances.

4 Fourth, the Commission could require new customers to guarantee revenues supporting  
5 their allowance calculation, for example through a clawback provision. Under this  
6 approach, if a customer substantially reduces gas consumption or disconnects from the  
7 gas system within a specified period, the customer would be responsible for repaying the  
8 unamortized portion of the allowance.

9 **Q. What approach do you recommend?**

10 A. I recommend that the Commission take decisive action to protect existing ratepayers from  
11 the growing risks of line extension allowances. Specifically, I recommend the following:  
12 *Primary Recommendation:* The Commission should eliminate line extension allowances  
13 for residential new construction. New residential customers should be required to pay the  
14 full cost of connecting to the gas distribution system. This approach is consistent with the  
15 actions taken in many other states, and reflects the fundamental ratemaking principle that  
16 costs should be borne by the customers who cause them. Eliminating residential  
17 allowances does not prohibit new gas connections; it simply requires new customers to  
18 assume the risks associated with the actual cost of the connection rather than socializing  
19 those risks across all existing ratepayers.

20 *Commercial and Industrial Exception:* The Commission should provide a limited  
21 exception for specific commercial and industrial loads where gas service is required for  
22 process heating or other applications for which no technically feasible electric alternative  
23 exists. Any allowance granted under this exception should be calculated using a

1 shortened payback period of no more than ten years and should include a clawback  
2 provision requiring repayment if the customer substantially reduces gas consumption or  
3 disconnects within ten years of connection.

4 *Alternative Recommendation:* If the Commission determines that a full elimination of  
5 residential allowances is premature at this time, it should, at a minimum, (a) shorten the  
6 CAP model’s payback period from twenty years to ten years; (b) establish a minimum  
7 CIAC for all new connections, ensuring that new customers pay at least 75% of the actual  
8 connection cost; and (c) require the Company to file an annual report on the performance  
9 of the CAP, including actual versus projected revenues from new customer cohorts, to  
10 enable the Commission to assess whether existing customers are being subsidized.

11 As the National Regulatory Research Institute observed in its comprehensive evaluation  
12 of line extension practices, allowances may be “bad policy” when, “in the absence of  
13 large-scale public benefits or utility internal efficiencies, subsidies funded by a utility’s  
14 existing customers come across as both unfair and economically inefficient.”<sup>100</sup> The  
15 growing risks to existing ratepayers, the actions taken in peer jurisdictions, and  
16 Michigan’s own climate objectives all point toward the need for reform.

17 Every year that allowances continue without reform, DTE Gas ratepayers finance tens of  
18 millions of dollars in new connections with no assurance that the projected benefits will  
19 materialize. The Commission has both the authority and the obligation to protect  
20 ratepayers from this growing risk. At a minimum, it should investigate how such  
21 connection programs operate and differ among utilities.

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<sup>100</sup> [Line Extensions for Natural Gas: Regulatory Considerations](#), National Regulatory Research Institute (February 2013) (Relevant excerpt at Exhibit AA-65)

1 **IX. HOW OTHER STATES ARE ADDRESSING THE FUTURE OF GAS ISSUES**

2 **Q. Why is a review of other states' approaches relevant to this proceeding, if Michigan**  
3 **does not have legislation requiring a transition away from gas?**

4 A. The challenges identified throughout this testimony are systemic challenges facing gas  
5 utilities nationwide, as market trends show. Multiple state commissions, including those  
6 in politically and geographically diverse jurisdictions, have independently concluded that  
7 existing regulatory frameworks threaten to create a severe financial burden on future  
8 ratepayers. In the absence of an MPSC investigation or other state-initiated review of the  
9 future of gas, such a review is important for highlighting future risks that DTE faces  
10 relevant to the investments proposed in this proceeding.

11 **Q. Which states have launched dedicated Future of Gas proceedings, and what have**  
12 **they accomplished?**

13 A. Since 2020, at least 14 proceedings addressing the future of the gas system have been  
14 opened across 13 states and the District of Columbia. The National Association of  
15 Regulatory Utility Commissioners recognized the need for comprehensive gas utility  
16 planning as a priority issue in 2023, establishing a Task Force on Natural Gas Resource  
17 Planning with 21 member states. The Task Force's May 2025 report reviews gas utility  
18 planning requirements across nine states and provides a resource library for commissions  
19 considering action.

20 Notably, while electric utility integrated resource planning has been standard practice  
21 since the 1980s, with over 40 states requiring electric IRPs, gas utility planning  
22 requirements are far newer and less widespread. Most of the states reviewed by NARUC  
23 adopted gas planning requirements within the last five years.

1 While each state has taken a different approach reflecting its own policy context,  
2 common elements include: multi-scenario demand-forecasting requirements; evaluation  
3 of non-pipeline alternatives; stranded asset and depreciation review; and equity  
4 protections for vulnerable customers. I summarize the approach and key insights from  
5 five leading states in this section of testimony: Massachusetts, New York, California,  
6 Colorado, and Illinois. A detailed state-by-state comparison is provided in Exhibit AA-  
7 30.

8 *Massachusetts.* The Massachusetts Department of Public Utilities opened its "Future of  
9 Gas" investigation (D.P.U. 20-80) in October 2020. After a multi-year process that  
10 included an independent consultant study analyzing eight decarbonization pathways,  
11 extensive stakeholder engagement, and technical sessions, the DPU issued its landmark  
12 Order 20-80-B in December 2023. The order declared the Commonwealth's future  
13 "beyond gas" and established a comprehensive new regulatory framework. Key elements  
14 include a requirement that gas utilities demonstrate non-pipeline alternatives were  
15 adequately considered before recovering costs for new infrastructure; five-year Climate  
16 Compliance Plans with performance metrics; a prohibition on cost recovery for gas  
17 marketing and promotion; an order directing all gas utilities to study the potential  
18 magnitude of stranded investments and the impacts of accelerated depreciation; and a  
19 requirement for integrated gas-electric planning. Massachusetts is particularly relevant to  
20 Michigan's gas system challenges: the state has among the nation's highest  
21 concentrations of leak-prone pipe and has created a framework that requires evaluating  
22 alternatives before defaulting to pipeline replacement, a dynamic directly pertinent to  
23 DTE's Gas Renewal Program.

1 *New York.* The New York Public Service Commission opened its gas planning  
2 proceeding (Case 20-G-0131) in March 2020, triggered by a crisis in which National Grid  
3 imposed a moratorium on new gas connections in downstate New York, exposing the  
4 inadequacy of existing gas planning. The PSC’s May 2022 order requires all gas utilities  
5 to file comprehensive Long-Term Plans with a 20-year planning horizon. Three scenarios  
6 are mandatory: business-as-usual, a low-carbon transition scenario, and a no-  
7 infrastructure scenario. Plans must include demand forecasts, supply analysis, NPA  
8 evaluation, and capital investment justification tied to each scenario. Annual compliance  
9 reports are required, and an Avoided Cost of Gas Working Group was established to  
10 evaluate depreciation and stranded asset approaches.

11 *California.* California’s approach began with a foundational analytical study, the E3  
12 California “Retail Gas Study” published in 2020 for the California Energy Commission,  
13 which established that building electrification is the lower-cost, lower-risk  
14 decarbonization pathway compared to renewable natural gas or hydrogen for buildings.<sup>101</sup>  
15 The state has since produced the most concrete operational results of any jurisdiction.  
16 The CPUC eliminated gas line extension allowances effective July 2023. In 2024, the  
17 legislature enacted SB 1221, authorizing up to 30 neighborhood-scale targeted  
18 electrification pilot projects.

19 *Colorado.* Colorado’s PUC gathered information and engaged stakeholders on gas  
20 transition issues through a pre-rulemaking investigatory docket even before legislation  
21 established binding GHG reduction targets to be implemented through Gas Infrastructure

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<sup>101</sup> [The Challenge of Retail Gas in California’s Low-Carbon Future](#), California Energy Commission, (April 15, 2020) (Executive Summary at Exhibit AA-66).

1 Plans. Colorado demonstrates the value of non-adjudicated investigatory proceedings to  
2 lay the groundwork for robust decision-making, and the state’s gas system characteristics  
3 and emphasis on city-oriented pilot programs are directly relevant to Michigan’s context.  
4 *Illinois*. The Illinois Commerce Commission opened its Future of Gas proceeding  
5 (Docket 24-0158) after simultaneous rate cases from all three major gas utilities revealed  
6 systemic problems in 2023. The Peoples Gas System Modernization Program was  
7 launched in 2011 as a comprehensive pipe replacement program with an initial cost  
8 estimate of \$1.4 billion, the program escalated dramatically. An independent analysis  
9 found completing the program would cost \$12.8 billion.<sup>102</sup> The ICC found that Peoples  
10 Gas had not prioritized removal of the highest-risk pipes and that cast iron and ductile  
11 iron retirement rates actually slowed over time despite massive spending increases. The  
12 customer impact has been large: a record \$303 million rate hike in November 2023, with  
13 nearly one in five customers more than 30 days delinquent on their bills and \$74.5  
14 million in total customer debt. In February 2025, the ICC rejected Peoples Gas’s \$7.2  
15 billion proposal and ordered an accelerated but risk-focused approach targeting only the  
16 highest-risk pipe. The parallels between the Peoples Gas System Modernization Program  
17 and DTE’s Gas Renewal Program, which accounts for approximately 40 percent of  
18 DTE’s 10-year capital plan, warrant consideration by this Commission.

19 **Q. What are the key lessons from these proceedings?**

20 A. Three categories of lessons emerge: what has worked, what has not, and what Michigan  
21 can improve upon.

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<sup>102</sup> [Peoples Gas: Escalating Business Risk in a Changing Energy Landscape](#), prepared by Citizens Utility Board of Illinois and Groundwork Data (October 2024) (Executive Summary at Exhibit AA-67).

1        *What has worked.* States that have acted decisively on discrete, well-defined issues have  
2        produced measurable results. California’s elimination of line extension allowances,  
3        effective July 2023, immediately changed the economics of gas system expansion.<sup>103</sup>  
4        Colorado’s rejection of hydrogen, certified gas, and carbon offsets as Clean Heat Plan  
5        compliance tools—based on rigorous cost-effectiveness analysis—prevented ratepayer  
6        resources from being directed toward strategies that would not achieve meaningful  
7        emissions reductions.<sup>104</sup> Consolidated Edison’s Energy Exchange Program in New York,  
8        which offers \$10,000–\$20,000 per customer for electrification of customers served by  
9        aging service connections, has demonstrated that non-pipeline alternatives can be  
10       implemented at the individual customer level without requiring resolution of system-wide  
11       planning questions.<sup>105</sup>

12       *What has not worked.* Several states have experienced significant delays, analytical  
13       detours, and procedural bottlenecks that Michigan should learn from. Massachusetts  
14       opened its Future of Gas investigation in October 2020 and did not issue its framework  
15       order until December 2023 – over three years later – during which time gas utilities  
16       continued to invest billions in system expansion without the guardrails the proceeding  
17       was designed to establish. A central source of delay in multiple jurisdictions has been  
18       extended debate over the role of renewable natural gas and hydrogen in building  
19       decarbonization. These debates consumed substantial regulatory resources despite the  
20       fact that, as I have demonstrated in Section VI of this testimony, RNG is fundamentally  
21       supply-constrained and hydrogen is thermodynamically inferior to direct electrification

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<sup>103</sup> California Public Utilities Commission, Decision 22-09-026 (September 2022).

<sup>104</sup> Colorado PUC, Decision No. C24-0485, Proceeding No. 23AL-0267G (June 2024).

<sup>105</sup> See, ConEdison, [Energy Exchange Program](#).

1 for building heating. Oregon provides a further cautionary example: the state opened a  
2 natural gas fact-finding investigation in 2021 but closed it in January 2023 without  
3 issuing a binding order, illustrating the risk that investigatory proceedings without clear  
4 regulatory direction may not produce actionable results.<sup>106</sup> Finally, any forecasting should  
5 not be performed only by a utility, but should be conducted within parameters *approved*  
6 by MPSC.

7 *Delay incurs costs.* Illinois provides the most directly relevant lesson for Michigan. The  
8 Peoples Gas System Modernization Program was originally estimated at \$1.4 billion in  
9 2007 and launched in 2011.<sup>107</sup> By the time the program formally received legislative  
10 authorization through a ten-year rider in 2013, the estimate had grown to \$2.6 billion.<sup>108</sup>  
11 The rider enabled automatic pass-through of costs to customers without the scrutiny of  
12 individual rate case review. By the time independent analysis was conducted in 2024, the  
13 projected completion cost had reached \$12.8 billion.<sup>109</sup> The ICC found that Peoples Gas  
14 had not prioritized removal of the highest-risk pipes, that cast iron and ductile iron  
15 retirement rates actually slowed over time despite massive spending increases, and that  
16 the company had not complied with multiple investigation orders. The critical failure was  
17 not the decision to replace pipe – it was the absence of rigorous, independent oversight  
18 during the years when the program was building inertia. By the time the ICC intervened

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<sup>106</sup> Oregon PUC, Order No. 23-005, Docket UM 2178 (January 2023).

<sup>107</sup> Exhibit AA-68 (Stephanie Zimmermann, “Peoples Gas Pipe Replacement Is Costing Chicagoans More,” Chicago Sun-Times (Feb. 16, 2021).

<sup>108</sup> Exhibit AA-69 (Robert Channick, “Peoples Gas Pipeline Program Will Cost Another \$12.8 Billion to Complete,” Chicago Tribune (Oct. 29, 2024).

<sup>109</sup> [Peoples Gas: Escalating Business Risk in a Changing Energy Landscape](#), prepared by Citizens Utility Board of Illinois and Groundwork Data (October 2024) (Executive Summary at Exhibit AA-67).

1 in February 2025, the program had consumed \$3.3 billion in ratepayer funds and  
2 generated political and contractual momentum that made course correction far more  
3 difficult and costly than early intervention would have been.

4 DTE's Gas Renewal Program exhibits early warning signs of a similar trajectory:  
5 escalating per-mile costs, absence of independent risk assessment, reliance on  
6 renegotiated rather than competitively rebid contracts, and no engineering studies in the  
7 past five years assessing whether underlying safety risks have increased or decreased.  
8 The GRP accounts for approximately 40 percent of DTE's ten-year capital plan. The  
9 Commission should not wait until these dynamics are entrenched to establish the  
10 oversight frameworks that Illinois lacked.

11 **Q. What is your primary recommendation for action beyond this rate case?**

12 A. The Commission should initiate a comprehensive Future of Gas proceeding and establish  
13 defined deliverables within twelve months of opening the docket. The issues identified  
14 throughout this testimony – declining gas demand, rising infrastructure costs, stranded-  
15 asset risk, the absence of evaluation of non-pipeline alternatives, the lack of integrated  
16 gas-electric planning, and the need for customer equity protections – cannot be  
17 adequately resolved within a single rate case. But neither should they be consigned to an  
18 open-ended investigation. The lesson of other states is that proceedings without clear  
19 deliverables and timelines produce delay, not results.

20 **Q. What specific deliverables should the proceeding produce?**

21 A. I recommend five defined workstreams, each with a deliverable within twelve months.  
22 *First: End line extension allowances.* If the Commission does not act on this issue in the  
23 present rate case, it should be the first order of business in a Future of Gas proceeding. As

1 detailed in Section VIII and as demonstrated by the actions of at least six peer states, the  
2 evidence supporting reform is conclusive. The deliverable should be a Commission order  
3 eliminating or substantially reforming line extension allowances for residential new  
4 construction, with a limited commercial and industrial exception subject to shortened  
5 payback periods and clawback provisions.

6 *Second: Provide guidance to investments that are likely to be approved as part of an*  
7 *electrification plan.* Under Michigan law, utilities may recover expenses related to an  
8 efficient electrification plan, but without a clear precedent regarding the types of  
9 programs that may be approved, utilities may be reluctant to commit the effort to develop  
10 such a plan. The Commission should provide guidance on the likelihood of approval for  
11 certain types of programs or efforts. For instance, the Commission could evaluate  
12 programs modeled on Consolidated Edison’s Energy Exchange approach, offering  
13 electrification incentives to customers served by leak-prone infrastructure for which the  
14 cost of conversion is competitive with that of pipe replacement. The deliverable should  
15 be a clear statement from the Michigan Commission about the type of program proposal  
16 likely to be approved: one with identified target segments, incentive structures, and cost-  
17 recovery mechanisms.

18 *Third: Open an investigation into coordinated non-pipeline alternatives.* The  
19 Commission should initiate a focused investigation into how non-pipeline alternatives  
20 can be systematically identified, evaluated, and implemented across the gas system—not  
21 on a project-by-project basis, but as a component of long-term infrastructure planning.  
22 The Commission should use this proceeding to describe the kind of projects that are  
23 unlikely to be deemed prudent or reasonable unless accompanied by an analysis showing

1 NPAs are not cost-effective compared to the traditional pipeline investment, based on  
2 system condition data and planned replacement maps that enable the Commission,  
3 intervenors, and the public to identify places where NPAs can provide cost savings.

4 Finally, the Commission can set forth a framework for pilot programs at the  
5 neighborhood and pipe-segment levels that is likely to be approved.

6 *Fourth: Open a financial pathways investigation.* The Commission should initiate a  
7 focused investigation into the financial and rate impacts of different gas system transition  
8 pathways. This is where a pathways analysis adds genuine value—understanding the  
9 financial consequences for ratepayers of different system configurations and management  
10 strategies. The investigation should model the rate and bill impacts of hybrid heating  
11 scenarios (in which customers retain gas backup but use heat pumps for most heating),  
12 managed electrification scenarios (in which targeted segments are transitioned off the gas  
13 system), and various capital expenditure trajectories. Critically, it should also evaluate  
14 financial management tools: rate design approaches that maintain affordability as per-  
15 customer consumption declines; securitization mechanisms that could reduce the cost of  
16 retiring undepreciated gas assets; accelerated depreciation schedules that reduce stranded  
17 asset risk; and transition financing strategies that spread costs equitably across time and  
18 across customer classes. The deliverable should be an independent analysis—scoped to  
19 answer these specific questions under Michigan-specific conditions—and a Commission  
20 order establishing the planning framework and financial tools that will govern gas utility  
21 capital decisions going forward.

1 **Q. Why is it important that the Commission act now and incorporate consideration of**  
2 **these risk factors in a Future of Gas proceeding or in individual gas rate case and**  
3 **depreciation proceedings?**

4 A. Every year that a major infrastructure program operates without rigorous oversight,  
5 independent assessment, and alternatives analysis, it builds financial and contractual  
6 constraints and risks that make course correction more difficult and more expensive.  
7 DTE’s Gas Delivery Plan outlines approximately \$9.6 billion in capital investment over  
8 the next ten years. The Gas Renewal Program alone accounts for roughly 40 percent of  
9 that plan. These expenditures are proceeding without NPA evaluation, without demand  
10 decline modeling, and without integrated gas-electric planning. The Commission has both  
11 the authority and the obligation to establish the planning frameworks, oversight  
12 mechanisms, and transition strategies that will determine whether Michigan’s gas system  
13 transition is managed proactively—at lower cost and with greater equity—or reactively,  
14 after the costs have already been incurred. It will also offer key risk metrics to utilities  
15 when they weigh investments they will undertake.  
16 Michigan’s position among states with climate goals but without a proceeding to attempt  
17 to consider the impacts of following those goals for the gas system is increasingly  
18 anomalous. Moreover, even if the state of Michigan renounced its climate goals,  
19 individual customer choices are already reducing usage and that trend is likely to  
20 continue. The Commission has the opportunity to design a proceeding that is more  
21 strategic, more focused, and more protective of ratepayers than any other state has taken  
22 to date. It should do so.

1       **X.     CONCLUSION**

2       **Q.     Does this conclude your direct testimony?**

3       A.     Yes.

4       **Q.     Do you swear under penalty of perjury that the statements above are true to the best**  
5       **of your knowledge, information, and belief?**

6       A.     Yes.

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Michael Walsh

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

U-21973

ALJ Christopher S. Saunders

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**PROOF OF SERVICE**

On the date below, an electronic copy of the **Direct Testimony of Rick Brown, Dr. Melissa Stults, and Michael Walsh on behalf of the City of Ann Arbor** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

Dated: March 13, 2026

**CITY OF ANN ARBOR**



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