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

DIRECT TESTIMONY OF RICK BROWN

ON BEHALF OF

THE CITY OF ANN ARBOR

March 13, 2026

I. INTRODUCTION AND QUALIFICATIONS

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

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

Q. Please describe your educational background and professional experience.

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

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

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

A. My testimony is on behalf of the City of Ann Arbor ("Ann Arbor" or "the City").

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

A. I have not previously testified before this Commission. However, I have significant experience in gas related proceedings. I have testified at the California Public Utility Commission on behalf of Pacific Gas & Electric Company during my employment there for a Reasonableness Hearing for Underground Gas Storage Operations, a proceeding related to Lodi Gas Storage, and was a witness in gas transmission rate cases for both Gas Capacity programs and Gas Capital Spending programs. I testified at the Colorado Public Utility Commission as a technical expert on Public Service Company of Colorado's ("PSCo's") Mountain Energy Project on behalf of the Sierra Club in Proceeding No. 25A-0044EG and on PSCo's Gas Infrastructure Plan on behalf of Natural Resources Defense Council, Rewiring America, Sierra Club, Southwest Energy Efficiency Project and Western Resource Advocates (collectively Conservation Advocates) in Proceeding No. 25A-0220G. I have also testified as a technical witness at the Nevada Public Utility Commission on Southwest Gas's 2026-2028 Triennial Integrated Resource Plan on behalf of Clean Energy Advocates in Docket No. 25-09010. My technical witness testimony has focused on gas system engineering, the prudency of gas system investments made by the gas utilities, the gas utilities' efforts and procedures for non-pipeline alternative ("NPA") adoption, and the need to include certain economic benefits for NPAs in economic analysis.

Q. What is the purpose of your testimony?

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

Q. What projects will you review in your testimony?

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

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit AA-1	Resume of Rick Brown
Exhibit AA-2	Discovery Response AADG-3.10ei
Exhibit AA-3	Discovery Response AADG-3.8c
Exhibit AA-4	Discovery Response AADG-3.11a
Exhibit AA-5	Discovery Response AADG-3.9a
Exhibit AA-6	Discovery Response AADG-3.6g
Exhibit AA-7	Discovery Response AADG-3.6h
Exhibit AA-8	Discovery Response AADG-3.9b

Exhibit AA-9	Discovery Response AADG-3.7b
Exhibit AA-10	Discovery Response AADG-3.7aiv
Exhibit AA-11	Discovery Response AADG-3.7aiii
Exhibit AA-12	Discovery Response AADG-3.8ei-evi
Exhibit AA-13	Discovery Response AADG-2.3a
Exhibit AA-14	Discovery Response AADG-2.3b
Exhibit AA-15	Discovery Response AADG-5.1d
Exhibit AA-16	Discovery Response AADG-2.1h
Exhibit AA-17	Discovery Response AGDG-3.113

II. EAST PETOSKEY PIPELINE REINFORCEMENT PROJECT

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

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

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

A. The East Petoskey Pipeline Reinforcement Project proposes to install 13.5 miles of new 8" distribution pipe from a new East Petoskey Interconnect Station at Great Lakes Transmission to the existing Petoskey Gate Station. Remotely controlled valves will also be installed at the Petoskey Gate Station, the Charlevoix Tap, and the Boyne City Gate Station.[1] The cost of this new, redundant East Petoskey Pipeline is $39.4 million.[2] The

[1] Fedele, Direct Testimony, p. 36.
[2] Exhibit A-12, Sch. B5.5, p. 6.

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

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

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

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

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

[3] Fedele, Direct Testimony, p. 36-37.
[4] Fedele, Direct Testimony, p. 36.
[5] Exhibit A-12, Sch. B5.5, p. 7.

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

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

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

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

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

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

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

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

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

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

[6] Exhibit AA-2.

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

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

A. Yes. If the ILI tool becomes stuck and severely restricts gas flow, the downstream pressure will drop due to downstream customer demand and a lack of gas supplied downstream of the ILI tool. However, customer outages will not occur immediately. This is because there is a significant volume of gas downstream of the ILI tool due to the pipeline's diameter and length, and the high operating pressures of transmission pipelines (higher pressure means more gas in the pipeline than at lower pressure). Hydraulic analysis using pipeline simulation software can estimate the duration for which sufficient pressure will remain to maintain customer service. Depending on available time, a utility can attempt to dislodge the ILI tool, or, in a worst-case scenario, cut it out of the pipeline and restore service. In addition to hydraulic analysis, a key preparation would be to develop a rapid-response plan to minimize the time required to cut out a stuck ILI tool and restore the pipeline to service. This would include having personnel, material, and tools ready and a detailed plan in place. When asked whether the Company has an emergency response plan in place to isolate any pipeline damage and make emergency repairs quickly, DTE responded, "Yes."[7] However, in response to a discovery question regarding whether the Company has performed hydraulic analysis to determine how long customers can retain service in the event the 8" Petoskey Pipeline experiences a failure, DTE replied that it has not performed this type of hydraulic analysis. While this particular question was regarding a pipeline failure, it is reasonable to assume that the Company has not performed the same type of hydraulic analysis for a stuck ILI tool. This demonstrates that the Company did not pursue a thorough review of possible alternatives to installing a redundant and costly $39.4 million pipeline. Finally, utilizing portable liquified natural gas ("LNG") and/or compressed natural gas ("CNG") provides a cost-effective redundant supply if all of the above actions fail.

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

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

[7] Exhibit AA-3.

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

Q. The Company claims it considered and rejected using LNG as a backup supply during the existing Petoskey Pipeline ILI assessment as an alternative to installing a redundant pipeline.[8] Please provide your opinion on the Company rejecting this option.

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

[8] Fedele, Direct Testimony, p. 38-39.

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

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

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

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

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

[9] Exhibit AA-3.
[10] Fedele, Direct Testimony, p.39.
[11] *Id.*

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

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

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

[12] Exhibit AA-4.

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

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

A. The Company has not provided any data on third-party damage on the existing Petoskey Pipeline nor any instances of damage causing or risking customer outages. In fact, in response to a discovery request asking whether the pipeline has ever had to be isolated due to damage, DTE witness Fedele responded, "No."[16] DTE witness Fedele also stated

[13] Exhibit AA-5.
[14] Exhibit AA-6.
[15] Exhibit AA-7.
[16] Exhibit AA-8.

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

[17] Exhibit AA-5.
[18] Exhibit AA-9; Exhibit AA-10; Exhibit AA-11.

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

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

[19] Exhibit AA-12.

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

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

III. FORT STREET MAIN REPLACEMENT PROJECT

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

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

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

A. The Fort Street Main Replacement Project involves retiring relatively old mechanically coupled steel mains operating at 50 psig and 90 psig and installing new steel and plastic mains in a dense urban environment. The Company claims that the mechanically coupled joint segments in the existing mains are subject to a higher risk of leaks from third-party damage, corrosion, and ground movement due to natural forces or nearby construction activity. The Company also states that the project will create a "looped" supply operating at 145 psig, which will mitigate the risk of a potential outage of 15,000 customers in downtown and southwest Detroit. Finally, the Company states that the higher-pressure gas supply is needed in the area east of downtown Detroit to supply future 60 psig GRP projects.[20]

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

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

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

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

[20] Fedele, Direct Testimony, p. 55.

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

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

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

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[21] Exhibit A-12, page 4, Scope of Work
[22] Exhibit AA-13.
[23] Exhibit AA-14.

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

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

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

IV. <u>CARLTON MAIN REPLACEMENT PROJECT</u>

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

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

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

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

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

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

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

A. Yes, it considered abandoning the Carlton Main but rejected this alternative, claiming it would not be hydraulically feasible during peak winter conditions to meet customer demand without a replacement. DTE also considered lowering the operating pressure of the pipeline and integrating it into the local distribution system, but rejected this option, claiming it would "not resolve the safety and reliability issues associated with the thin-wall pipe and existing pipe conditions."[25]

[24] Fedele, Direct Testimony, p. 58-62.
[25] Fedele, Direct Testimony, p. 60.

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

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

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

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

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

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[26] *Id.*
[27] *Id.*

system redundancy?

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

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

A. The Company claims this project will "increase operational flexibility for maintenance, integrity assessment, or emergency response work,"[28] but it does not provide any specific support for these claims. Thus, it is difficult to provide my opinion on the value of this claimed justification in comparison to the $14.5 million project.

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

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

[28] Fedele, Direct Testimony, p. 60.

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

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

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

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

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[29] *Id.* at 61.
[30] Exhibit AA-15.

repairs?

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

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

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

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

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

[31] Exhibit AA-16.
[32] Exhibit AA-17.
[33] *Id.*

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

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

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

Q. Does this conclude your direct testimony?

A. Yes.

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

A. Yes.

Rick Brown