

March 13, 2026

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

Via E-File

RE: MPSC Case No. U-21973

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Public Direct Testimony and Exhibits of Alice Napoleon on behalf of Michigan Environmental Council (MEC-1 through MEC-28); and
- Proof of Service.
- Please note that there is a confidential version of this testimony, and Exhibits (MEC-9C, MEC-10C, and MEC-14C) which are only being served to those with an executed nondisclosure certificate pursuant to the Protective Order.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,



Digitally signed by
Christopher M. Bzdok
Date: 2026.03.13
18:08:15 -04'00'

Christopher M. Bzdok
chris@tropospherelegal.com

CC: Parties to Case No. U-21973

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21973

DIRECT TESTIMONY OF ALICE NAPOLEON
ON BEHALF OF
MICHIGAN ENVIRONMENTAL COUNCIL

PUBLIC VERSION

March 13, 2026

TABLE OF CONTENTS

I.	Introduction and purpose of testimony	1
II.	Findings and recommendations	5
III.	DTE’s gas delivery plan is not aligned with Commission directives, state policies, or market trends	12
	i. DTE does not sufficiently evaluate alternatives and emission reduction strategies, or the costs and viability of each.....	17
	ii. DTE has not adequately accounted for the uncertainty of future gas demand	29
	iii.DTE has not sufficiently consider alternatives to capital investments	33
IV.	DTE’s new Customer Attachment Program is likely being subsidized by existing ratepayers.....	36
	i. Customer Attachment Program.....	40
	ii. Area Expansion Projects	50
V.	DTE’s IRM proposal is problematic and does not reflect prudent capital planning .	62
	i. Background and overview of current proposal	62
	ii. Concerns with the IRM.....	67
VI.	DTE has not demonstrated that it considered reasonable alternatives to its proposed Large capital projects	81

TABLE OF TABLES

Table 1. Summary of CAP disallowance calculations.....	61
Table 2. Total IRM Proposed Capital Expenditures through 2031 (\$Millions)	66

TABLE OF FIGURES

Figure 1. Adjusted forecasted household HVAC costs over 15-year appliance lifecycle	27
Figure 2. Historical and projected average monthly customers.....	30
Figure 3. Historical and projected use per customer (in thousand cubic feet or MCF), residential customers	31
Figure 6. Historical and projected target IRM capital expenditures	70
Figure 7. Actual capital cost of IRM compared to targeted levels, 2016–2024	72

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **I. INTRODUCTION AND PURPOSE OF TESTIMONY**

2 **Q Please state your name and occupation.**

3 A My name is Alice Napoleon. I am a Principal Associate at Synapse Energy
4 Economics, Inc. (“Synapse Energy Economics”) located at 485 Massachusetts
5 Avenue, Suite 3, Cambridge, MA 02139.

6 **Q Please describe Synapse Energy Economics.**

7 A Synapse Energy Economics is a research and consulting firm specializing in
8 electricity and gas industry regulation, planning, and analysis. Our work covers a
9 range of issues, including economic and technical assessments of demand-side and
10 supply-side energy resources, energy efficiency policies and programs, integrated
11 resource planning, electricity market modeling and assessment, renewable resource
12 technologies and policies, and climate change strategies. Synapse works for a wide
13 range of clients, including state attorneys general, offices of consumer advocates,
14 trade associations, public utility commissions, environmental advocates, the U.S.
15 Environmental Protection Agency, U.S. Department of Energy, U.S. Department
16 of Justice, the Federal Trade Commission, and the National Association of
17 Regulatory Utility Commissioners. Synapse’s staff includes over 35 professionals
18 with extensive experience in the electricity and gas industries.

19 **Q Please summarize your work experience and educational background.**

20 A Since joining Synapse in 2005, I have provided economic and policy analysis of
21 electric and gas systems and emissions regulations on behalf of a diverse set of
22 clients throughout the United States and in Canada. I have co-authored several

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 reports and comments on the role of energy efficiency in New York State, as well
2 as two white papers on natural gas regulatory reforms needed if New York is to
3 meet its decarbonization targets. I have provided policy analysis and technical
4 support on issues related to the future of natural gas utilities in many other states,
5 including Hawaii, Maryland, Rhode Island, Colorado, Massachusetts, Nevada, and
6 California.

7 I have provided expert advice on demand-side management programs in numerous
8 states and Canadian provinces regarding a range of issues including incentive-
9 setting methodologies, cost-benefit analysis, avoided costs, load forecasting, and
10 locational demand-side management. I also co-authored a manual for regulators on
11 designing performance incentive mechanisms for utilities, which has been highly
12 utilized by many states.

13 Before joining Synapse, I worked at Resource Insight, Inc., where I supported
14 investigations of electric, gas, steam, and water resource issues, primarily in the
15 context of reviews by state utility regulatory commissions.

16 I hold a Master's in Public Administration from the University of Massachusetts at
17 Amherst and a Bachelor's in Economics from Rutgers University. My resume is
18 attached as Exhibit MEC-1.

19 **Q On whose behalf are you testifying in this case?**

20 **A** I am testifying on behalf of Michigan Environmental Council.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Have you previously testified before the Michigan Public Service Commission**
2 **(“the Commission”)?**

3 A Yes. I submitted testimony on behalf of Michigan Environmental Council and
4 Sierra Club in the rate case for Consumers Energy Company, U-21806 in 2025. I
5 also submitted testimony on behalf of Michigan Environmental Council, Natural
6 Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan in
7 the rate case for DTE Gas Company, U-21291 in 2024.

8 **Q What is the purpose of your testimony?**

9 A The purpose of my testimony is to review and critique DTE Gas Company’s
10 (“DTE” or the “Company”) gas system planning and investment strategy, as
11 reflected in DTE’s gas rate case filing, in light of Commission directives from
12 docket U-21291 and uncertainty associated with the energy transition.

13 **Q Are you sponsoring any exhibits in this proceeding?**

14 A Yes, I am sponsoring the following exhibits:

- 15 • Exhibit MEC-1: Resume of Alice Napoleon
- 16 • Exhibit MEC-2: Company Response to MECCUBDG-5.19a, b
- 17 • Exhibit MEC-3: Company Response to MECCUBDG-3.13
- 18 • Exhibit MEC-4: Company Response to FLODG-3.31g
- 19 • Exhibit MEC-5: Company Response to MECCUBDG-5.16a, b, c and Att
- 20 • Exhibit MEC-6: Company Response to MECCUBDG-3.16f, g and Att
- 21 • Exhibit MEC-7: Company Response to MECCUBDG-3.22b
- 22 • Exhibit MEC-8: Company Response to MECCUBDG-5.17ai-iii

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

- 1 • Exhibit MEC-9C: MECCUBDG-3.9a, NDA U-21973 MECCUBDG-3.9a
- 2 Att.- Historical & Projected by Category -07.2025 Rate Case Update
- 3 Excerpt
- 4 • Exhibit MEC-10C: NDA Company Response to NDA MECCUBDG-3.21
- 5 & Att.
- 6 • Exhibit MEC-11: Company Response to MECCUBDG-7.1ai, aii, bi, bii
- 7 • Exhibit MEC-12: Company Response to MECCUBDG-3.23d, f
- 8 • Exhibit MEC-13: Company Response to MECCUBDG-8.49
- 9 • Exhibit MEC-14C: Company Response to NDA MECCUBDG-3.29ci-xviii
- 10 & Att
- 11 • Exhibit MEC-15: Company Response to MECCUBDG-3.28a, b
- 12 • Exhibit MEC-16: Company Response to MECCUBDG-8.53a
- 13 • Exhibit MEC-17: Company Response to MECCUBDG-3.31a and
- 14 attachment
- 15 • Exhibit MEC-18: Company Response to MECCUBDG-9.4
- 16 • Exhibit MEC-19: Company Response to MECCUBDG-11.4a-f and
- 17 attachment
- 18 • Exhibit MEC-20: Company Response to MECCUBDG-8.9
- 19 • Exhibit MEC-21: Company Response to MECCUBDG-8.21a and 8.22a
- 20 • Exhibit MEC-22: Company Response to MECCUBDG-8.25a-c
- 21 • Exhibit MEC-23: Company Response to AGDG-3.107a
- 22 • Exhibit MEC-24: Company Response to MECCUBDG-8.31
- 23 • Exhibit MEC-25: Company Response to MECCUBDG-8.34a

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

- Exhibit MEC-26: Company Response to MECCUBDG-8.37a, b
- Exhibit MEC-27: Company Response to AADG-2.2bvi
- Exhibit MEC-28: Company Response to AGDG-3.126

II. FINDINGS AND RECOMMENDATIONS

Q Please summarize your primary conclusions.

A My findings include the following:

- Gas Delivery Plan, Exhibit A-12, Schedule B5.6 (GDP)
 - The GDP does not seriously consider the range of demand-side alternatives (such as energy efficiency, demand response, and electrification), and supply-side alternatives (such as renewable natural gas, hydrogen, synthetic natural gas, etc.) for decarbonizing its system.
 - DTE’s proposed strategies—renewable natural gas (RNG), energy efficiency, and carbon offsets—are vague, not concrete, and may not be the most effective or affordable strategies to serve customers and comply with state policy and Commission requirements.
 - DTE’s modeling of customer HVAC choice options—its reason for ignoring electrification—is flawed.
 - DTE did not sufficiently address the Commission’s directives in Case U-21291.

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

1 ○ The GDP has limited value and is incomplete as a planning
2 document because it does not seriously account for the likely
3 reductions in demand due to electrification, nor does it consider the
4 associated risks and potential impacts on affordability and stranded
5 costs.

6 ○ In the GDP, DTE takes a business-as-usual approach to forecasting
7 load. DTE has not adjusted its load forecast and customer count
8 forecast methodology to account for the energy transition.

9 ○ DTE has not adjusted its capital planning to account for this risk,
10 and it did not adequately consider alternatives to capital
11 investments, such as non-pipeline alternatives (NPA), to avoid gas
12 system investments.

13 • Customer Attachment Program (CAP)

14 ○ DTE's new attachments forecast is unrealistically high considering
15 historical averages.

16 ○ DTE's CAP forecast methodology and customer contributions in aid
17 of construction (CIAC) calculations do not account for declining
18 sales or the energy transition.

19 ○ DTE has not adequately assessed whether it is appropriate to revise
20 its assumptions and methodology to develop charges for new
21 customer connections, and the current calculations use problematic
22 assumptions that likely lead to subsidization by existing customers.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 ○ DTE’s 400-foot line extension allowance is excessive, incentivizes
2 connections to the system, and may be subsidized by existing
3 customers.

4 • Infrastructure Recovery Mechanism (IRM)

5 ○ Budget and actual spending on IRM programs has increased
6 substantially since the Commission first approved the programs, and
7 DTE’s IRM expenditures have consistently exceeded budget. DTE
8 is planning for increasingly large IRM programs, which it is likely
9 to overspend based on its historical track record.

10 ○ There is limited evidence that the IRM is mitigating risk in the most
11 cost-effective manner. DTE targets achievement of a certain level of
12 spending on the IRM, and tracks miles renewed, which are not
13 directly related to risk mitigation. DTE does not justify risk
14 mitigation and prioritization effectively.

15 ○ The criteria for what types of projects qualify for the IRM are
16 unclear, and the utility has incentives to include routine projects in
17 the IRM. The IRM includes minimal guardrails.

18 ○ DTE is seeking to expand the bounds of the IRM by adding new
19 programs and new activities within existing programs. DTE is
20 proposing two new programs and is adding activities under the Gas
21 Renewal Program (GRP). However, it does not provide sufficient
22 justification as to why it cannot meet its safety and reliability

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 requirements through normal distribution capital, rather than the
2 IRM.

3 ○ DTE does not adequately consider NPAs to IRM expenditures.

4 • Large Capital Projects

5 ○ DTE tends to opt for solutions that provide system redundancy over
6 alternatives without redundancy.

7 ○ DTE makes claims about the superior reliability benefits of its
8 chosen solution without clearly demonstrating that it considered a
9 reasonable range of alternatives or that it considered costs and
10 benefits and the risk of stranded costs. DTE's approach for assessing
11 alternative solutions is not transparent.

12 ○ DTE is not considering demand-side alternatives that could
13 potentially mitigate capacity concerns for less money. Nor does
14 DTE consider relining pipes.

15 **Q Please summarize your recommendations.**

16 **A** Based on my findings, I offer the following recommendations:

17 • Gas infrastructure investment practices that assume continuity with the past
18 are no longer reasonable or justified. In light of uncertainty about future
19 demand and DTE's ability to collect revenue, the Commission should
20 require the Company to carefully consider, and demonstrate consideration,
21 of the near-term and long-term tradeoffs of continued gas system
22 investments. In doing so, the Company should account for the likely limited
23 lifetime of pipe replacements. The Commission should require DTE to

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

1 carefully weigh the costs and benefits of demand-side and supply-side
2 alternatives including but not limited to repair, relining, energy efficiency,
3 electrification, and retirement, to the extent that these resources are
4 available, reliable, and affordable. The Commission should not approve
5 capital investments unless DTE shows that such investments were superior
6 to alternatives at the time the Company made the investments. DTE should
7 bear the full costs and risks of any of its decisions that are based on flawed,
8 incomplete planning.

9 • NPAs

10 ○ The Commission should require DTE to include NPA evaluation in
11 its gas planning process. Further, the Company should be required
12 to prove it has considered NPAs before capital investment is
13 approved. The Commission should require DTE to consider a range
14 of demand- and supply-side alternatives to capital investments.

15 ○ The Commission should require DTE to determine criteria or plans
16 for NPAs.

17 • Customer Attachment Program (CAP):

18 ○ DTE should reduce the number of total potential customers used to
19 calculate CIACs for Area Expansion Projects (AEPs) to 77 percent.

20 ○ DTE should update its gas consumption assumptions for individual
21 CAP attachments and AEPs to reflect weather-normalized customer
22 consumption from the last five years. Specifically, DTE should
23 revise its consumption per customer assumption for residential

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 customers to 90 Mcf annually and adjust this assumption each year
2 according to the most recent five-year average residential
3 consumption (weather-normalized). Further, DTE should not be
4 allowed to collect anything related to new customer attachments
5 until it resolves the issues. DTE should adjust its revenue calculation
6 for new customers to reflect declining future consumption,
7 consistent with 20-year historical trends.

8 ○ DTE investors should be held accountable for overruns rather than
9 having ratepayers shoulder the burden for costs that do not benefit
10 them.

11 ○ The Commission should encourage DTE to reconsider its line
12 extension allowance policies and whether it is reasonable to
13 continue socializing these costs.

14 ○ The Commission should disallow \$18,182,063 in total from this
15 program: \$14,576,000 for New Market Attachments, \$3,063,821 for
16 the Austin AEP, and \$542,242 for the US-2 AEP. 576

17 ○

18 • IRM:

19 ○ The Commission should not approve inclusion of the two new
20 proposed programs in the IRM, nor should the Commission approve
21 DTE's proposal to include new activities in the GRP.

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

1 ○ Given the high likelihood of cost recovery for IRM-approved
2 programs, there should be more stringent guidelines for IRM
3 program eligibility.

4 ○ Furthermore, the Commission should require changes to the
5 existing, problematic framework of the IRM by implementing
6 spending caps requiring justification of overspending, mandating
7 that the utility provide evidence it is prioritizing investments based
8 on a risk-per-dollar spent metric, and requiring DTE to demonstrate
9 that it considered NPAs in place of IRM expenditures.

10 ○ The Commission should implement spending caps on IRM. IRM
11 spending should be capped at \$300 million, roughly equivalent to
12 2024–2025 IRM spending.

13 • Large Capital projects:

14 ○ The Commission should disallow inclusion in rate base of projected
15 bridge and test year expenditures for the East Petoskey, Carlton
16 Main, and Taggart Compressor Station projects until and unless
17 DTE adequately demonstrates consideration of alternatives and
18 provides robust quantitative analysis comparing the proposed
19 solutions with a reasonable set of alternatives.

20 ○ The Commission should require DTE to consider NPAs wherever
21 possible.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

**III. DTE’S GAS DELIVERY PLAN IS NOT ALIGNED WITH COMMISSION
DIRECTIVES, STATE POLICIES, OR MARKET TRENDS**

Q Please describe the Company’s Gas Delivery Plan.

A The Gas Delivery Plan (GDP) is the primary document DTE uses to communicate about its gas system planning and investment strategy. The Gas Delivery Plan provides a 10-year overview of DTE’s gas infrastructure investment plans, including transmission, distribution, storage and compression investments.¹ According to DTE, “The GDP explains how the Company’s capital investments promote safe and reliable natural gas service and is an important tool in evaluating the necessity and prudence of future cost recovery requests.”² DTE states that the three key objectives of the Gas plan involve safety and reliability, affordability, and environmental responsibility, including greenhouse gas (GHG) emissions.³ This is DTE’s third GDP.⁴

Q Summarize your concerns with DTE’s approach to gas system planning as presented in the Gas Delivery Plan.

A DTE presents a business-as-usual approach to gas system planning and investments. DTE does not sufficiently consider the implications of the energy transition, nor does it adequately account for the uncertainty of future gas demand as a result of electrification. Further, it does not properly evaluate alternatives to capital investments or the risk that the Company may have difficulty recovering the

¹ Direct Testimony of Kelly M. Fedele p. 15.

² Fedele Direct, p. 19.

³ Exhibit A-12, Schedule B5.6, p. 3.

⁴ Fedele Direct, p. 16.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 cost of these investments in the future in light of state emission targets and changes
2 in future demand.

3 **Q What do you mean by “energy transition”?**

4 A The energy transition is the transition away from fossil fuel energy sources toward
5 zero-carbon energy sources driven by increased market competition from efficient,
6 clean technologies and by policies to reduce GHG emissions. This transition is
7 underway across the country, especially in states with mandated emission reduction
8 targets, including Michigan.

9 **Q Please describe Michigan’s emission reduction targets.**

10 A In September 2020, Governor Whitmer signed Executive Directive 2020-10, which
11 requires Michigan to achieve economy-wide carbon neutrality by 2050, and net-
12 negative GHG emissions thereafter.⁵ Through this Order, the Governor also
13 directed the creation of the Michigan Healthy Climate Plan to provide strategies
14 and recommendations for reducing GHG emissions and achieving carbon
15 neutrality. The Michigan Healthy Climate Plan was issued in April 2022; this
16 document includes a roadmap to 52 percent GHG reductions from 2005 baselines
17 by 2030, including a 17 percent reduction in emissions related to heating Michigan
18 buildings.⁶

⁵ Governor Gretchen Whitmer. Executive Directive 2020-10. September 23, 2020. Available at: <https://www.michigan.gov/whitmer/news/state-orders-and-directives/2020/09/23/executive-directive-2020-10>.

⁶ Michigan Department of Environment, Great Lakes, and Energy. *Michigan Healthy Climate Plan*. April 2022. Available at: <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=cba6e0a9ff4c4a8297b0e39446bd1bc1>.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Will these targets impact DTE’s gas distribution business?**

2 A Yes. DTE Gas has a role in helping the state achieve the 17 percent reduction in
3 emissions target for Michigan’s built environment. In its Final Order in Case U-
4 21291, the Commission found that “the transition away from fossil fuels and the
5 eventual trend of declining natural gas demand will have impacts on the future of
6 the natural gas system and that these impacts were not sufficiently considered in
7 the company’s GDP as filed.”⁷

8 **Q Are there other factors driving change in the gas distribution sector?**

9 A Yes. Alongside state emission reduction targets, increasing competition from
10 efficient electric technologies is driving change to natural gas consumption in
11 Michigan and the country as a whole. DTE itself acknowledges the declining trends
12 in consumption per customer, as discussed further in Section i.a.ii.

13 **Q What is the important take-away regarding the energy transition for this case?**

14 A As market competition and climate policy drive declines in demand for natural gas,
15 future gas demand and asset utilization will not look the same as they did in the
16 past. Given long lives of utility assets, practices relating to those assets will need to
17 change during their lifetimes, even if near-term changes in sales are small.

18 Utilities have a responsibility to undertake prudent planning and investment actions
19 to adapt to the energy transition. They should account for the timeframe of that
20 transition and how it relates to the lifetime of gas assets. Failure to make prudent
21 capital decisions increases the risk of stranded assets (that is, assets whose costs are

⁷ Case No. U-21291, Order, November 7, 2024, p. 216.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 not recoverable from customers due to market shifts or policy changes, or because
2 assets are uneconomic). The costs of stranded assets may be borne by customers
3 and/or investors.

4 **Q Did concerns regarding how DTE handled the energy transition in planning**
5 **arise in DTE’s last rate case?**

6 A Yes. Dr. Asa Hopkins and I raised this concern in testimony in Case U-21291, and
7 the Commission issued several related directives to DTE in its November 7, 2024,
8 Order.

9 **Q Summarize the Commission’s directives to DTE in the Order in Case U-21291.**

10 A Regarding DTE’s GDP filing from Case U-21291, the Commission found that DTE
11 did not sufficiently account for the impacts of declining demand. The Commission
12 directed DTE to consider “various energy transition pathways and the associated
13 costs and risks of each.”⁸ Specifically, the Commission directed DTE to include the
14 following in its next GDP:⁹

- 15 i. information pertaining to how the Company intends to achieve emissions
16 reductions with an estimated timeline for achieving those goals (including
17 interim goals);
- 18 ii. alternatives to capital investment, such as pipeline repairs and NPAs;
- 19 iii. historical natural gas demand, projected demand, and the impacts of
20 changing demand; and

⁸ Case No. U-21291, Order, November 7, 2024, p. 216.

⁹ *Id.*

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 iv. anticipated impacts of the transition towards electrification and
2 decarbonization, including the portion of its distribution system that DTE
3 anticipates will be most immediately impacted.

4 **Q How did DTE address the energy transition in the current GDP?**

5 A DTE includes a section on the energy transition at the end of its GDP. In this
6 section, DTE discusses the sector-specific emission reductions targets from the
7 Michigan Healthy Climate Plan, the Company's progress toward reducing
8 emissions and its plans for future emission reductions by scope,¹⁰ and the limited
9 opportunity for NPAs.

10 **Q Do you believe DTE's GDP as filed in Case U-21973 addresses the**
11 **Commissions orders from Case U-21291?**

12 A No. From my review of the filing and discovery, I find that DTE's recent GDP does
13 not meet the Commission's directives. There are a few shortcomings that are
14 particularly concerning. These include the following:

- 15 • DTE does not sufficiently evaluate alternatives and emission reduction
16 strategies, or the costs and risks of each.
 - 17 ○ DTE's proposed strategies (RNG, energy efficiency, and carbon
18 offsets) are vague, not concrete, and may not be the most effective,
19 cost-effective, or affordable strategies to serve customers and
20 comply with state policy and Commission requirements.
 - 21 ○ DTE's modeling of customer HVAC choice options is flawed.

¹⁰ Scope 1, 2, and 3 emissions are defined by WRI's Greenhouse Gas Protocol,
<https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf>.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

- DTE has not adequately accounted for the uncertainty of future gas demand and has not considered the impact on rates of reduced throughput or smaller customer base. Further, it did not sufficiently consider alternatives to capital investments.

- DTE maintains relatively business-as-usual load forecasts that do not include impacts of electrification. DTE has not seriously considered the uncertainty of future gas demand and the potential impacts on its system in a future with increasing electrification.

- The uncertainty around future gas demand raises stranded cost risk concerns if sales are lower than expected.

- DTE has not adjusted its capital planning to account for this risk, and it did not adequately consider alternatives to capital investments such as NPAs to avoid gas system investments.

i. DTE does not sufficiently evaluate alternatives and emission reduction strategies, or the costs and viability of each

Q What strategies has DTE identified for reducing internal emissions?

A DTE's GDP outlines several actions by which it will reduce emissions from its customers and utility operations. Through 2040, DTE expects to reduce internal emissions by 52 percent relative to 2020 levels, primarily through the reduction of leaks on distribution mains and services through its infrastructure replacement programs.¹¹ However, strategies from 2040 through 2050 are much more uncertain.

¹¹ U-21973 Company response to MECCUBDG-5.18 – Gas Delivery Plan Figure 73 Data.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 DTE states internal emissions reductions will come from “New Technologies /
2 Carbon Offsets / Operational Improvements.”¹² DTE describes “new technologies”
3 as including investments in RNG, hydrogen, gas heat pumps, carbon capture, and
4 geothermal systems.¹³ However, DTE “has not studied the total potential of all new
5 technologies to reduce emissions.”¹⁴

6 **Q What strategies has DTE identified for reducing emissions from customer gas**
7 **usage?**

8 A DTE discusses reducing customer emissions (scope 3), through RNG, carbon
9 offsets, and continued energy efficiency. DTE includes an analysis comparing the
10 customer cost of three different HVAC scenarios for decarbonizing customer end-
11 use emissions, including RNG blending, hybrid heating, and full electrification.
12 Drawing on this analysis, DTE determines that electrification is not a viable
13 emission reduction strategy or future risk.

14 **Q Do you have concerns with DTE’s emission reduction strategies?**

15 A Yes. DTE relies heavily on infrastructure replacement and alternative fuels for
16 reducing emissions, which entrench reliance on the gas system and continued
17 methane emissions from its use. DTE does not consider electrification or other
18 NPAs as emission reduction strategies, which have the potential for significant

¹² Exhibit A-12 Schedule B5.6 (GDP), Figure 73 p. 83.

¹³ Ex MEC-2, Company Response to MECCUBDG-5.19a-b, response a.

¹⁴ *Id.*, response b.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 emission reductions and affordability benefits resulting from avoided infrastructure
2 investments.

3 Overall, DTE has not provided sufficient detail about its plans for achieving state
4 emission reduction targets, as required by the Commission’s Final Order in Case
5 U-21291.

6 I further describe my concerns with DTE’s strategies below.

7 **DTE has not sufficiently evaluated its proposed strategies**

8 **Q What does DTE claim regarding RNG as a decarbonization strategy?**

9 A DTE argues that “blending of RNG into the natural gas distribution system is the
10 lowest cost option to reduce emissions from customers’ use of natural gas.”¹⁵

11 **Q Do you have concern with RNG as a decarbonization strategy?**

12 A Yes. RNG is more expensive than traditional fossil gas, and customers will pay
13 higher bills for RNG. DTE acknowledges this in the GDP, saying, “Today, RNG is
14 more expensive than natural gas, and would increase costs to DTE Gas customers
15 to incorporate into the Company’s existing natural gas supply.” DTE then describes
16 its strategy of purchasing small quantities of RNG through the customer opt-in
17 Natural Gas Balance (NGB) program to “support further growth in the market,
18 drive down costs, and establish a long-term view of the viability and application of
19 RNG.”¹⁶

¹⁵ Direct Testimony of Henry J. Decker, p. 18

¹⁶ Exhibit A-12 Schedule B5.6 (GDP), p. 84.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Is this strategy likely to drive down RNG costs?**

2 A It may in the short run, if these purchases are substantial enough to encourage
3 potential suppliers to make needed investments to enter the market. However, the
4 availability of RNG is constrained. Even assuming maximum in-state feasible
5 potential of 148 tBtu per year¹⁷ , there would only be enough RNG to displace at
6 most 13 percent of Michigan's 2025 gas consumption.¹⁸ Furthermore, there will
7 likely be competition to secure RNG from other utilities, industry, and
8 transportation sectors in Michigan and elsewhere, especially for hard-to-
9 decarbonize end-users, for example some industrial processes.

10 **Q Do you have other concerns with RNG?**

11 A Yes. Emissions from RNG vary considerably based on the feedstock and process
12 used to make it. Some types of RNG have GHG emissions that are similar to fossil
13 gas. The GDP does not specify what types of RNG DTE is pursuing in the future.
14 If DTE is planning to pursue sources such as landfill gas or thermal gasification
15 projects, for example, then RNG may offer little to no emissions reductions for
16 higher cost.¹⁹

¹⁷ ICF. September 23, 2022. *Michigan Renewable Natural Gas Study: Final Report*. Prepared for the Michigan Public Service Commission. <https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/RenewableNaturalGas/MI-RNG-Study-Final-Report-9-23-22.pdf>. Page 4.

¹⁸ U.S. EIA. Natural Gas Consumption by End Use. https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SMI_A.htm

¹⁹ ICF. September 23, 2022. *Michigan Renewable Natural Gas Study: Final Report*. Prepared for the Michigan Public Service Commission. <https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/RenewableNaturalGas/MI-RNG-Study-Final-Report-9-23-22.pdf>.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q What other decarbonization strategies does DTE consider?**

2 A DTE also considers energy efficiency and carbon offsets as strategies for reducing
3 or offsetting carbon emissions. However, DTE makes only cursory mention of these
4 strategies in its GDP. Further, the Company did not conduct a thorough analysis or
5 cost-effectiveness evaluation to determine the best options for customers.

6 **Q Do you have further comments on incorporation of energy efficiency into**
7 **DTE's plan?**

8 A Yes. DTE assumes that some emission reductions will be realized through its
9 energy efficiency programs, however DTE does not appear to expand energy
10 efficiency efforts beyond historical levels.

11 Energy efficiency is an important part of a strategy to reduce emissions, but it
12 should also be considered as part of a strategy to avoid investments in the gas
13 system for capacity expansion or pipeline replacements. DTE is not doing so or
14 proposing to do so, as I discuss in Section III.ii.

15 Furthermore, providing incentives for the installation of gas appliances through
16 efficiency programs locks in a household's gas consumption for decades, making
17 it more challenging to achieve building decarbonization goals. Many gas
18 appliances, including measures incentivized through gas energy efficiency
19 programs, have long useful lives. For example, a new natural gas furnace typically
20 lasts 20 years or longer. Replacing a gas measure in-kind removes the opportunity
21 for customers to switch their systems and extends reliance on the gas system.

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

1 **Q Do you have comments on carbon offsets?**

2 A My testimony in this case does not focus on carbon offsets as a decarbonization
3 strategy. However, I briefly summarize some points I raised in my testimony in the
4 last rate case below.

5 • To ensure credibility and environmental integrity, carbon offsets should be
6 permanent, additional, verifiable, enforceable, and real.²⁰ Without adequate
7 oversight to ensure that offsets meet these criteria, offsets may not actually
8 contribute to carbon reductions.

9 • Many verified carbon offset registries lack transparency regarding the
10 actual impacts of their carbon offset projects.²¹

11 Thus, inclusion of offsets as a component of a decarbonization strategy should be
12 avoided.

²⁰ *Permanent* means that emissions reductions or removals should not be reversible; a reduction in emissions now will not be followed by an equivalent increase in emissions later. *Additional* means that the offset project should represent new emissions reductions. Offsets are additional if they enable carbon reduction to occur that would not otherwise occur without the offset funding. *Verifiable* means that emissions reductions from offsets should be monitored and regularly verified by an independent third party. *Enforceable* means that only one credit can be claimed for the offset. *Real* means that offsets should represent one ton of carbon emissions reduced as the result of the offset project without carbon displacement occurring, which occurs when the offset results in the same emissions occurring elsewhere rather than actually reducing overall emissions. (World Resources Institute. 2010. The Bottom Line on Offsets. <https://www.wri.org/research/bottom-line-offsets>.)

²¹ For example, see Coffield, Shane and James Randerson. 2022. "Satellites detect no real climate benefit from 10 years of forest carbon offsets in California." The Conversation. December 1. Available at: <https://theconversation.com/satellites-detect-no-real-climate-benefit-from-10-years-of-forest-carbonoffsets-in-california-193943>; Coffield, S.R., Vo, C.D., Wang, J.A, Badgley, G. Goulden, M.L., Cullenward, D., Anderegg, W.R.L, & Randerson, J.T. 2022. "Using remote sensing to quantify the additional climate benefits of California forest carbon offset projects." Global Change Biology (Vol. 28, Issue 22). Available at: <https://onlinelibrary.wiley.com/doi/10.1111/gcb.16380>.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **DTE does not sufficiently analyze the cost-effectiveness and potential for**
2 **electrification**

3 **Q What arguments does DTE make around the risk of declining demand or**
4 **number of customers due to electrification?**

5 A DTE argues that electrification is not a cost-effective emission reduction strategy
6 for customers, and that RNG or hybrid solutions are cheaper for customers while
7 still providing emission reductions. DTE cites a 2022 Guidehouse study of the
8 relative costs of different home heating technologies and fuel choices, including
9 high efficiency natural gas furnaces, central and split electric air-source heat pumps,
10 propane, and electric ground-source heat pumps.²² DTE claims that Guidehouse's
11 analysis shows that both a natural gas furnace and central air conditioning (A/C) or
12 a natural gas boiler and room A/C cost less than air-source heat pumps, over a 15-
13 year period.²³

14 Based on this study, DTE states that it only expects a small number of customers
15 to choose an electric heat pump over a natural gas furnace.²⁴

16 **Q Describe DTE's household HVAC cost analysis for its three emission reduction**
17 **scenarios.**

18 A DTE presents a brief analysis of three scenarios for achieving deep decarbonization
19 in the built environment. These scenarios include RNG blending, hybrid heating,
20 and full electrification. The analysis compares forecasted household HVAC costs

²² Decker Direct, p.13.

²³ *Id.*

²⁴ Company response to MECCUBDG-8.1a.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 of each scenario based on a 15-year appliance lifecycle. The RNG blending
2 scenario assumes that 35 percent of supply will come from RNG and the rest will
3 come from natural gas.²⁵ The hybrid heating scenario assumes customers primarily
4 use electric heat pumps but retain a natural gas furnace as a back-up fuel source.
5 The full electrification scenario appears to assume that customers fully electrify
6 their end uses. In each scenario, DTE assumes continued use of the natural gas
7 distribution system.²⁶ DTE determined that the most affordable option for
8 customers to reduce GHG emissions is the RNG blending scenario, stating that
9 “developing more RNG and using it in home heating is currently the best approach
10 for Michigan residents.”²⁷ According to DTE’s analysis, the hybrid scenario is the
11 next most affordable option, lastly followed by the full electrification scenario.²⁸

12 **Q Do you agree with DTE’s conclusions and the results of the Guidehouse study?**

13 A No. As I will describe below, DTE gas’s comparison of customer costs of
14 electrification alternatives that continue use of gas is flawed because it substantially
15 underestimates the total installed cost of a gas furnace. In addition, it appears that
16 DTE did not consider the cost impact of continued capital spending on the gas
17 distribution system in its analysis²⁹ and did not incorporate the impacts of future
18 heat pump efficiency improvements in its modeling.³⁰

²⁵ Attachment MECCUBDG-8.2a-01 HVAC Cost Model 2025 Rates, “GDP_Summary_Slide” tab.

²⁶ GDP at 85, “In each of these scenarios, safe and reliable natural gas distribution system is required to provide critical energy delivery during the coldest days of the year.”

²⁷ GDP at 86.

²⁸ GDP at 85, Figure 75.

²⁹ Ex MEC-3, Company Response to MECCUBDG-3.13.

³⁰ Ex MEC-4, Company Response to FLODG-3.31g.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 Based on these deficiencies, I expect that the HVAC breakeven analysis
2 underestimates the costs of continued gas heating and may overestimate the costs
3 for heat pumps.

4 **Q Please expand on your concerns with the equipment costs included in the**
5 **Guidehouse study.**

6 A The Guidehouse study underestimates gas furnace equipment costs and
7 overestimates cold-climate air-source heat pump (ccASHP).

8 The Guidehouse study bases its cost estimates for furnaces on U.S. EIA equipment
9 cost data from 2018.³¹ The model assumes \$1,685 for a gas furnace and \$5,105 for
10 a central air conditioner, which results in total installed costs, in 2022 dollars, of
11 \$6,790 for baseline household heating with natural gas and cooling with a central
12 air conditioner. For a hybrid heating household, Guidehouse assumes the cost of
13 the dual-fuel heat pump system to be the cost of a standard air-source heat pump
14 (ASHP) plus \$1,685 for a gas furnace. This total cost appears to be too low. A
15 recent study from LBNL analyzing project cost data found that the median installed
16 cost for gas furnaces was \$5,025 and the median cost of a central air conditioner
17 was \$5,930.³²

18 The Guidehouse study also calculates the cost of a ccASHP by multiplying the cost
19 of the standard ASHP by 1.45, without a source or justification for this, resulting in

³¹ Navigant. 2018. Final EIA Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case. Presented to U.S. Energy Information Administration. <https://www.eia.gov/analysis/studies/buildings/equipcosts/archive/2018/pdf/appendix-a.pdf>

³² Less et al. 2021. *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes*. Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/final_walker_-_the_cost_of_decarbonization_and_energy.pdf. Page 74.

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

1 a ccASHP cost of \$18,815. This estimate appears to be too high. The same LBNL
2 study found that on average ccASHP installed equipment costs were \$192 more per
3 ton than a standard ASHP, or only 4 percent.³³ Applying this assumption to the
4 Guidehouse estimate results in an adjusted ccASHP cost of \$13,500—\$5,315 less
5 than Guidehouse assumes.

6 **Q How would the results of Guidehouse study change if the study used correct**
7 **cost assumptions?**

8 A Based on these adjustments mentioned above, I calculate a revised estimate of the
9 lifecycle costs³⁴ for space heating using Guidehouse's model³⁵ (Figure 1). My
10 adjustments increase the cost of gas space conditioning equipment and decrease the
11 cost of ccASHP. As a result, using the same assumptions around RNG blending
12 discussed above, I find that the all-electric household sees overall lower lifecycle
13 costs than a household continuing to use gas with RNG blending or a hybrid
14 household heating with an ASHP with gas furnace backup.

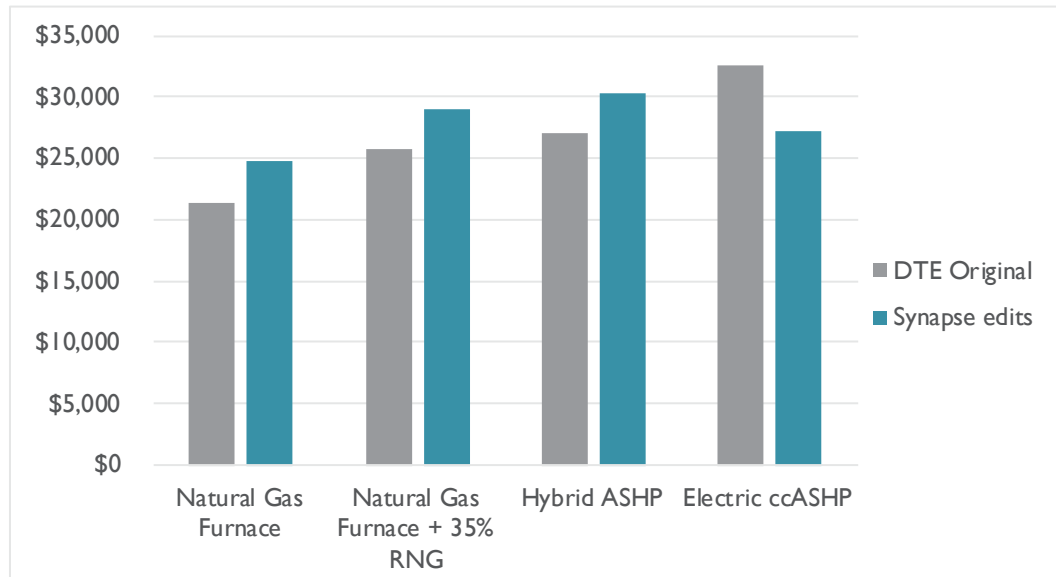
³³ Less et al. 2021. *The Cost of Decarbonization and Energy Upgrade Retrofits for US Homes*. Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/final_walker_-_the_cost_of_decarbonization_and_energy.pdf. Figure G 21.

³⁴ This includes the upfront equipment cost, any incentives, and the operating and maintenance costs over a 15-year appliance lifetime.

³⁵ Attachment MECCUBDG-8.2a-01 HVAC Cost Model 2025 Rates.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

Figure 1. Adjusted forecasted household HVAC costs over 15-year appliance lifecycle



1 **Q Why isn't DTE pursuing opportunities for electrification?**

2 A In the GDP, DTE states that one of the reasons it is not pursuing opportunities for
3 electrification is because of a “strong customer preference for natural gas.”³⁶ When
4 asked to justify this statement in discovery, DTE referred to a survey that Sparks
5 Research conducted on propane customers' heating preferences.

6 **Q Describe the survey DTE hired Sparks Research to conduct on the heating
7 preferences of propane customers.**

8 A DTE hired Sparks Research to conduct a survey of Michigan propane customers to
9 understand their energy preference between natural gas and electricity. The study
10 indicated that “propane users preferred gas over electricity at a ratio of four to one.

³⁶ GDP, p. 86.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 The main reason for this preference was cost.”³⁷ DTE relies on this survey for its
2 position that there is a strong customer preference for natural gas.³⁸

3 **Q Do you have concerns with the propane customer survey?**

4 A Yes. The survey included only a subset of the potential customers who could
5 potentially switch to gas, and this subset shared a common characteristic: they are
6 all propane customers. Propane prices are generally quite high, and so it is not
7 surprising that propane customers would favor a switch to gas. In contrast with this
8 incomplete, biased sample, the universe of potential customers (that are currently
9 using other energy sources like solar, wood or oil) may be less amenable to
10 switching to natural gas. Thus, the survey does not support DTE’s broad statements
11 about customer preference for natural gas.

12 Additionally, the survey contains questions that are phrased in a manner that casts
13 doubt on the neutrality of the survey . One question asks: “How likely would you
14 be to switch to electric if your monthly energy bills doubled and there would be
15 additional costs to switch your current appliances to electric?”³⁹ This question is
16 biased against electric equipment since it does not mention the equipment costs
17 associated with converting to natural gas (appliances that burn propane cannot
18 necessarily burn natural gas). Further, the premise that energy bills will be higher

³⁷ Direct Testimony of Julia L. Huffman, p. 48.

³⁸ Ex MEC-5, Company Response to MECCUBDG-5.16a-c and attachment 01, specifically responses b and c.

³⁹ *Id.*, question 5b.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 with electric equipment relative to gas-fired equipment is not supported and is
2 unlikely to be true, as discussed in section III.i.

3 **Q What do you conclude regarding DTE’s arguments about electrification as it**
4 **relates to its gas system planning processes?**

5 A DTE’s assumption that it will not see material impacts due to electrification is not
6 supported. DTE relies on faulty HVAC cost analyses and biased assumptions about
7 customer heating preference, as demonstrated above. Further, DTE has not
8 coordinated efforts with DTE Electric to evaluate the impacts of electrification.⁴⁰

9 **ii. DTE has not adequately accounted for the uncertainty of future gas**
10 **demand**

11 **Q What does DTE assume about future gas sales?**

12 A DTE does not plan for sufficient reductions in demand. DTE forecasts modest
13 demand reductions based on and consistent with historical trends (i.e., due to
14 efficiency gains).⁴¹ However, DTE does not forecast escalation in reductions in gas
15 demand due to electrification or decarbonization over the next 10 years.⁴²

⁴⁰ Ex MEC-6, Company Response to MECCUBDG-3.16f.

⁴¹ Witness Decker states, “Based on DTE Gas historical sales, weather normalized natural gas demand has decreased by 12% over the past years, or on average, 0.67% per year. Continuing this through 2050 would be a further 17% reduction, or a total reduction of about 30% by 2050 from 2005.” Decker Direct, p. 16.

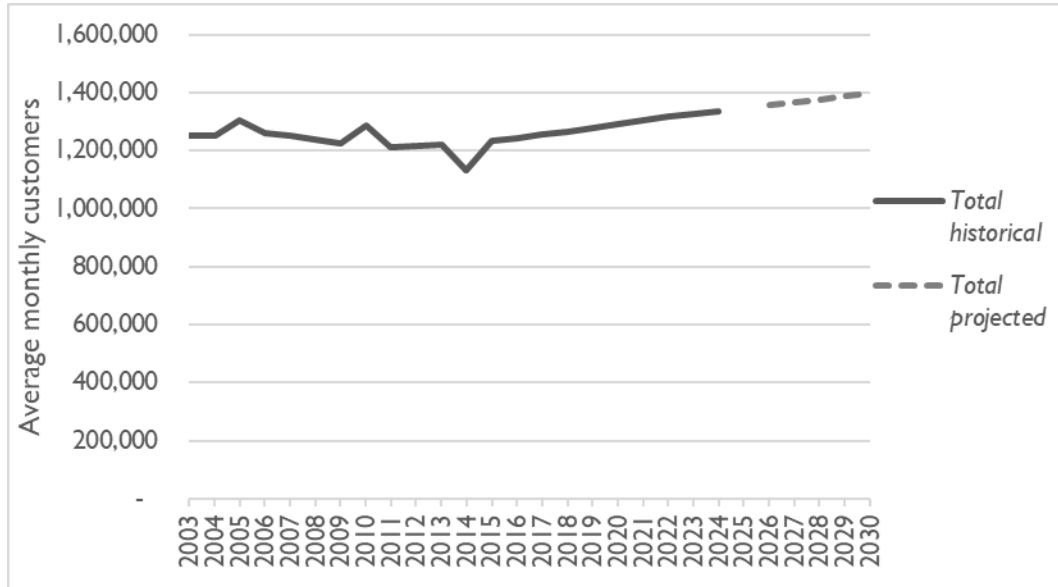
⁴² Witness Decker’s testimony indicates that “DTE Gas does not anticipate material impacts to demand from electrification, decarbonization, or NPAs over the next 10 years and therefore believes the forecast included in GDP is the most reasonable and prudent forecast to incorporate in the GDP 10-year period.” Decker Direct, p. 19.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q How does DTE develop load forecasts for its gas customers?**

2 **A DTE develops its load forecasts primarily based on its projected number of**
3 customers and average gas usage per customer. DTE projects a gradual increase in
4 its number of customers over the next 5 years, as shown in Figure 2.

5 **Figure 2. Historical and projected average monthly customers**



6

7 *Source: U-21973 KH-1 Audit Response For Submission, KH-1.1-02 to KH-1.1-24, Exhibit*
8 *A-15 Schedule E2.*

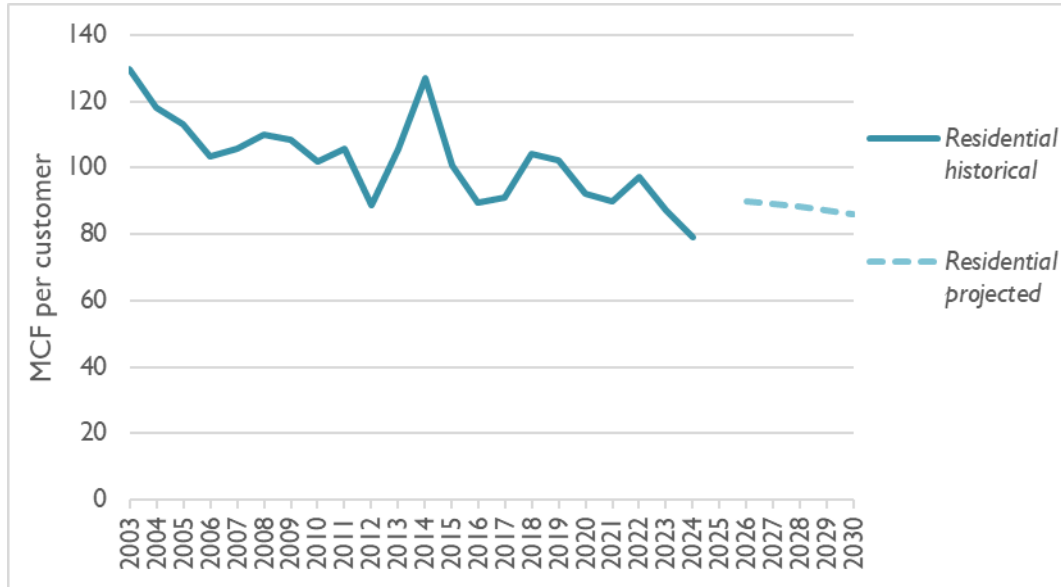
9 At the same time, DTE projects declining sales per customer. On average, DTE's
10 residential (Rate A) weather-normalized sales per customer have declined about 21
11 percent over the 21-year period from 2004 to 2025,⁴³ as shown in Figure 3.
12 Similarly, DTE's commercial (Rate GS-1) average sales per customer has declined
13 20 percent over the same time period.⁴⁴ DTE projects continuing declines in gas
14 usage per customer.

⁴³ Exhibit A-15 Schedule E4.

⁴⁴ *Id.*

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

Figure 3. Historical and projected use per customer (in thousand cubic feet or MCF), residential customers



Source: Historical use per customer based on historical average monthly customers and billed sales from U-21973 KH-1.1-02 to KH-1.1-24, projected use per customer based on projected average number of customers and weather normalized sales projections from Exhibit A-15 Schedule E2.

1 **Q Does this mean that DTE’s load forecast is too high?**

2 A Yes, it appears to be too high, which gives rise to several concerns. First, DTE has
3 not adequately considered the risk of higher levels of electrification or steeper
4 declines in gas use. With declines in gas use, the fixed costs of serving each
5 customer will need to be recovered over lower sales than in the past. Also, a high
6 load forecast may appear to support continued or increasing investment in the gas
7 pipeline system, encouraging system overbuilding. A high forecast may also
8 discourage the utility and stakeholders from considering retirements of gas
9 pipelines in some segments of its service territory where a majority of customers
10 may leave the system (e.g., switch to electric heating) to choose cleaner, more
11 efficient heating options. Such overbuilding of gas pipeline systems driven by a

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 flawed load forecast could result in unduly high gas system costs and gas bills for
2 consumers.

3 **Q Does DTE demonstrate appropriate consideration of these risks associated**
4 **with uncertainty about future gas demand?**

5 A No, it has not. As discussed in this testimony, DTE has not adjusted its load forecast
6 methodology, customer count forecast methodology, or its analysis of customer
7 attachments and community expansion to account for the energy transition. Further,
8 DTE has not demonstrated that it has taken seriously the Commission's directives
9 from Case U-21291 to consider the impacts of changing demand on its system in a
10 future with increasing electrification. As discussed in Section IV, DTE did not
11 change any inputs, methods, or assumptions to its model for setting new customer
12 attachment contributions to reflect uncertain or changing gas demand, despite the
13 Commission Order in Case No. U-21291 that highlighted the potential for shortfalls
14 in recovery from new customers due to the impacts of the energy transition or
15 declining gas demand.⁴⁵ Relatedly, DTE has not considered the impact on rates of
16 reduced throughput or smaller customer base. The failure to make these
17 considerations is unreasonable and imprudent, and DTE should bear the costs and
18 risks of its decisions in this regard.

⁴⁵ Ex MEC-7, Company Response to MECCUBDG-3.22b.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

iii. DTE has not sufficiently consider alternatives to capital investments

Q What are non-pipeline alternatives?

A NPAs are solutions that meet customer energy needs and are alternatives to traditional infrastructure investments. NPAs could include demand-side measures such as electrification, energy efficiency, and other measures that reduce or eliminate customers' demand for natural gas.

Q Does DTE consider NPAs?

A DTE states that it considers NPAs when assessing project solutions. However, DTE "does not specify types of NPAs it considers."⁴⁶ Furthermore, DTE does not have "set criteria for the type of projects that explore alternative solutions" and DTE "does not track the number of projects where alternative investment options were considered."⁴⁷

From this, I conclude that DTE has not meaningfully considered and does not meaningfully consider opportunities for NPAs to avoid gas system investments, as required by the Commission's Final Order in Case U-21291. For instance, DTE does not appear to consider NPAs when presenting capital expenditure forecasts. There is limited discussion of NPAs in the GDP, and not much detail on the types of NPAs considered or the method for evaluating.⁴⁸

⁴⁶ Ex MEC-8, Company Response to MECCUBDG-5.17aii-iii.

⁴⁷ *Id.*

⁴⁸ Exhibit A-12 Schedule B5.6 (GDP), pp. 85-86.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q** **What is DTE’s rationale for not meaningfully considering NPAs to avoid gas**
2 **system investments?**

3 A Witness Decker states that “[e]lectrification would reduce the demand for natural
4 gas, but elimination of existing pipelines would require every customer served by
5 that line to be converted to full electric.” Mr. Decker cites a 2024 study by RMI
6 and National Grid, which he claims finds that NPAs are “only truly effective in
7 niche projects ‘serving 1-5 customers, under the 100% persuasion model,’ meaning
8 all customers agree to the change and the utility covers all costs of transition.”⁴⁹

9 **Q** **Is this an accurate characterization of the study’s findings?**

10 A No. The study recommends that “[u]tilities should advance efforts to pursue the
11 *most achievable NPAs under existing frameworks* (e.g., projects serving 1-5
12 customers, under the 100% persuasion model, *and projects to avoid capacity*
13 *expansions*)”⁵⁰ (emphasis added). The language from the RMI study merely
14 describes where NPAs are most likely to be successful *at first*, while utilities learn
15 how to target, develop, and implement them. The language also recognizes the
16 potential for NPAs to avoid capacity expansion, which DTE is seeking to do with
17 some of its large capital project proposals. Further, while acknowledging that
18 challenges remain with implementing NPAs, the study recognizes the potential to
19 use NPAs for gas system decarbonization and for achieving ratepayer savings.⁵¹

⁴⁹ Decker Direct, p. 19.

⁵⁰ RMI and National Grid. 2024 (May). Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization, p. 24.

⁵¹ *Id.* at p. 1.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Do you have comments about the relevance and applicability of the RMI**
2 **study?**

3 A Yes. The study is somewhat dated at this point. Some utilities have made progress
4 and are successfully implementing NPAs.

5 **Q Can you provide an example?**

6 A Yes. New York gas utility Consolidated Edison has three NPA programs: one
7 aimed at avoiding the replacement of leak-prone radial (i.e. terminal, end-of-
8 branch) mains, one aimed at avoiding the replacement of vintage services, and one
9 aimed at reducing demand to avoid capacity-related projects. As of November
10 2025, Con Edison had electrified over 100 customers in 63 buildings and avoided
11 the installation of nearly 3,000 feet of gas main and associated services.⁵²

12 **Q Did DTE take steps to meaningfully engage interested persons in the**
13 **development of its updated GDP, as directed by the Commission on page 217**
14 **of the Final Order in Case No. U-21291?**

15 A No. Discovery indicates that DTE held one meeting with stakeholders on April 10,
16 2025, about five months after the U-21291 Order. The presentation from the
17 meeting contains one slide on this topic: slide 22. That slide recounts that the
18 Commission directed DTE to update the GDP to consider “Energy Transition and
19 Emission Reductions,” “Investment Alternatives,” and “Historical and Forecasted
20 Natural Gas Demand.”⁵³ The slide provides no information regarding how DTE did

⁵² Consolidated Edison Company of New York, Inc. Non-Pipes Alternatives Annual Expenditures & Program Report, November 2025, Case 22-G-0065.

⁵³ Ex MEC-6, Company Response to MECCUBDG-3.16g and attachment, slide 22.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 or did not consider these issues relative to its GDP in the five months after the U-
2 21291 Order. Instead, it states that DTE “will take steps to meaningfully engage
3 interested persons” on those topics. However, discovery reveals no further meetings
4 or communications of any kind with interested persons on these topics over the next
5 seven months leading up to the filing of the new GDP with this case.

6 **Q What are your recommendations?**

7 A The Commission should require DTE to prove it has considered NPAs before
8 approving capital investments. Specifically, the Commission should require DTE
9 to consider a range of demand- and supply-side alternatives to capital investments
10 and further require DTE to determine criteria or plans for NPAs.

11 **IV. DTE’S NEW CUSTOMER ATTACHMENT PROGRAM IS LIKELY**
12 **BEING SUBSIDIZED BY EXISTING RATEPAYERS**

13 **Q Describe the Company’s new attachment programs.**

14 A DTE expands gas service to new customers through the Customer Attachment
15 Program (CAP). The CAP has four sub-categories of attachments including the
16 following:

- 17 • New Construction refers to attachments to newly built structures with no
18 prior fuel source.
- 19 • On-Main Conversions refers to customers who convert to natural gas from
20 another fuel source, whose property is already fronted by an existing gas
21 main.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

- 1 • Main Extensions refers to attachments where DTE extends the gas main to
- 2 reach a small group of new customers (10 or fewer).
- 3 • Community Expansion refers to large-scale projects that extend gas service
- 4 to new neighborhoods or territories, also called Area Expansion Projects
- 5 (AEP).

6 The discussion in this section applies to the entire CAP (including all four
7 categories of attachments) unless otherwise specified. I refer to New Construction,
8 On-Main Conversions, and Main Extensions collectively as “individual, non-AEP
9 attachments” in places.

10 **Q What are Area Expansion Projects?**

11 A Area Expansion Projects (AEP) are large-scale attachment projects that extend
12 service to 50 or more customers in a new area.⁵⁴ AEPs fall under the Community
13 Expansion category of the CAP. DTE seeks rate recovery for two AEPs in this rate
14 case, the Austin AEP in the Greater Grand Rapids service area and the US-2 AEP
15 in the Escanaba area. Both projects are discussed in Witness Huffman’s testimony.

16 **Q How many new attachments is DTE projecting under the CAP, and at what**
17 **cost?**

18 A DTE projects 11,000–12,000 new attachments each year through 2035⁵⁵ including
19 New Construction, On-Main Conversion, Main Extension, and Community
20 Expansion projects. DTE projects \$97,298,000 in test year capital spending on

⁵⁴ Company response to MECCUBDG-3.9b.

⁵⁵ Exhibit A-12 Schedule B5.6 (GDP), p 32.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 New Market Attachments, a significant increase from 2025 spending-levels of
2 \$82,722,000 or the five-year historical annual average of \$81,820,000.⁵⁶

3 **Q What were the Commission’s directives to DTE regarding new customer**
4 **attachments from its November 7, 2024, Order in Case U-21291?**

5 A In its order in Case U-21291, the Commission expressed concern about how DTE
6 determines new customers’ contributions in aid of construction (CIAC). The
7 Commission found that “the record in this case indicates that there is potential for
8 shortfalls in recovery from CAP participants, which the company is then proposing
9 to later include in base rates.”⁵⁷ Specifically, the Commission stated that “DTE Gas
10 has not sufficiently considered the impacts of the energy transition or declining gas
11 demand in the assumptions used to arrive at the CIAC amounts used in the CAP
12 tariff,” and directed DTE to “provide a thorough justification for its CIAC and CAP
13 methodology, including whether it is appropriate to revise its assumptions to
14 include declining gas demand, customer adoption rates for the CAPs based on
15 historical experience when calculating new attachment surcharges, and how the
16 company intends to avoid subsidization by existing customers.”⁵⁸

17 **Q Do you believe that DTE has adequately complied with the Commission’s**
18 **directives from Case U-21291?**

19 A No. DTE has not meaningfully demonstrated how it has complied with the
20 Commission’s directives from Case U-21291 and continues to follow a business-

⁵⁶ Exhibit A-12, Schedule B5.1, page 2 of 2, line 13, column g.

⁵⁷ Case No. U-21291, Order, November 7, 2024, p 246.

⁵⁸ Case No. U-21291, Order, November 7, 2024, p 247.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 as-usual approach for new customer attachments. When asked in discovery whether
2 DTE has changed any CAP model inputs, methods, or assumptions in response to
3 the Commission Order in Case No. U-21291, the company described updates for
4 rates and charges based on the Order, but no changes to inputs, methods, or
5 assumptions responsive to the Order's directives regarding the CAP model.⁵⁹ The
6 Commission approved the CAP as part of a settlement agreement in 1995.⁶⁰ I am
7 not aware of efforts by DTE to evaluate how well the model approximates actual
8 new customer behavior since the program was established.

9 **Q Please summarize your concerns with DTE's approach to new customer**
10 **connections.**

11 **A** I have numerous concerns with DTE's Customer Attachment Program, which lead
12 me to recommend that the Commission disallow DTE from recovering certain
13 costs, as described more below. My concerns are as follows:

- 14 • DTE's new attachments forecast is unrealistically high considering the
15 historical average number of new attachments.
- 16 • DTE has not adequately assessed whether it is appropriate to revise its
17 CIAC assumptions and CAP methodology to include declining gas demand
18 and historical customer adoption rates, and how it avoids subsidization by
19 existing customers, as required by the Commission in U-21291.

⁵⁹ Ex MEC-7, Company Response to MECCUBDG-3.22b.

⁶⁰ Case No. U-10745, Order, June 5, 1995.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

- 1 • DTE’s CIAC calculation uses the following problematic assumptions that
2 likely lead to subsidization by existing customers:

3 ○ For all attachments, DTE assumes that consumption per customer
4 will remain unchanged over the course of 20 years, despite historical
5 trends that show declining consumption per customer due to energy
6 efficiency.

7 ○ For all attachments, DTE assumes that all new customers will
8 remain on the gas system for at least 20 years, which does not
9 account for uncertainty related to electrification.

10 ○ For all attachments, DTE assumes unrealistically high residential
11 customer consumption levels above recent historical average
12 consumption.

13 ○ DTE overestimates the number of new customers that will connect
14 to AEPs, despite historical data showing fewer actual connections
15 than originally expected.

- 16 • DTE’s 400-foot line extension allowance is excessive, incentivizes
17 connections to the system, and may be subsidized by existing customers.

18 I discuss each of these concerns at greater length below.

19 **i. Customer Attachment Program**

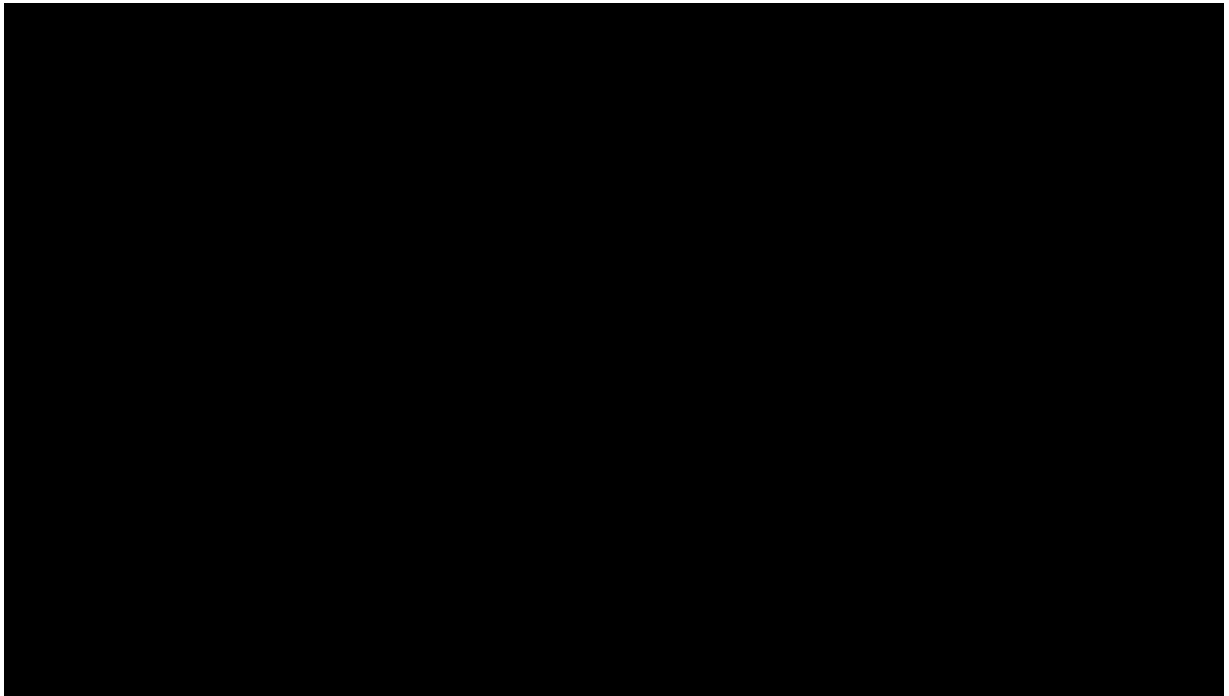
20 **Q How does DTE’s new customer attachment forecast compare to historical**
21 **levels?**

22 **A DTE projects an average of [REDACTED] new attachments each year from 2026 through**
23 **2035, even though DTE only completed an average of [REDACTED] attachments**

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

annually over the last five years (2020–2024). DTE projects declining New Construction attachments from 2026–2035, and a stable number of On-Main Conversion and Main Extension attachments consistent with historical 3-year averages (2022–2024). However, forecasted growth in the Community Expansion, or AEP, category results in an overall increase in the projected number of attachments. Within the Community Expansion category, the 3-year historical average annual attachments was [REDACTED] and the 8-year historical average was [REDACTED]. However, DTE projects an annual average of [REDACTED] Community Expansion attachments over the next 10 years, which is [REDACTED] times the historical average (relative to a 3-year and 8-year historical comparison).

Figure 4. DTE historical and projected number of new attachments



Source: MECCUBDG-3.9a, “NDA U-21973 MECCUBDG-3.9a Attachment - Historical and Projected by Category -07.2025 Rate Case Update.”

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Are DTE’s projections for new customer attachments reasonable?**

2 **A No.** DTE assumes a decline in the number of attachments stemming from new
3 construction, however DTE assumes a stable or increasing number of attachments
4 in other categories. Notably, DTE assumes an additional [REDACTED]
5 attachments in the Community Expansion category above historical levels
6 beginning in 2026 – roughly doubling the recent historical actual numbers.⁶¹ DTE’s
7 only justification for this unprecedented increase is “anticipated growth driven by
8 sustained community interest and continued high demand for natural gas.”⁶²
9 However, DTE does not provide evidence or analysis supporting this projection.

10 Additionally, DTE’s New Construction forecast methodology leads to potentially
11 optimistic assumptions about the number of new construction attachments. DTE
12 forecasts New Construction attachments by averaging Global Insights’ forecast of
13 new housing starts with DTE’s historical average New Construction attachments
14 from 2020 to 2024.⁶³ This approach increases the number of New Construction
15 attachments predicted by the Global Insights forecast by 10 to 30 percent. The
16 Global Insights’ forecast alone predicts a [REDACTED] percent cumulative average growth
17 rate (CAGR) of new housing starts from 2026 to 2035. However, DTE’s adjusted
18 forecast predicts a [REDACTED] percent CAGR over the same time period. DTE states that
19 housing data has historically underpredicted new construction in its service

⁶¹ Ex MEC-9C, MECCUBDG-3.9a, “NDA U-21973 MECCUBDG-3.9a Attachment - Historical and Projected by Category -07.2025 Rate Case Update,” “Projected Attachment Data” tab.

⁶² Company response to MECCUBDG-7.5d.

⁶³ Ex MEC-9C, MECCUBDG-3.9a, “NDA U-21973 MECCUBDG-3.9a Attachment - Historical and Projected by Category -07.2025 Rate Case Update,” “Forecast Summary 2025” tab.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 territory,⁶⁴ but provides no further justification for this methodology or the size of
2 the adjustment.

3 DTE also assumes that natural gas penetration (the share of households' with
4 natural gas as their primary heating source) remains at [REDACTED] percent through 2035.⁶⁵

5 This assumption appears to be inconsistent with the Commission's findings from
6 U-21291 that "the transition away from fossil fuels and the eventual trend of
7 declining natural gas demand will have impacts on the future of the natural gas
8 system."⁶⁶ DTE is likely overestimating the future market share of gas equipment
9 and creating unrealistic projections of new customer attachments.

10 **Q Does DTE charge new customers for gas attachments?**

11 A Yes, in certain cases DTE requires new customers to pay a CIAC to contribute to
12 the cost of installing a new gas connection.

13 **Q Does DTE require all new connecting customers to pay a CIAC?**

14 A No. DTE completes new attachments at no charge to the customer if the length of
15 the connection is less than 400 feet. For projects over 400 feet, DTE requires
16 customers to pay a CIAC in the form of a fixed monthly surcharge or an upfront
17 payment.

⁶⁴ Ex MEC-9C, MECCUBDG-3.9a, "NDA U-21973 MECCUBDG-3.9a Attachment - Historical and Projected by Category -07.2025 Rate Case Update," "Assumptions" tab.

⁶⁵ Ex MEC-9C, MECCUBDG-3.9a, "NDA U-21973 MECCUBDG-3.9a Attachment - Historical and Projected by Category -07.2025 Rate Case Update," "Forecast Summary 2025" tab.

⁶⁶ Case No. U-21291, Order, November 7, 2024, p. 216.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Describe how DTE calculates CIACs for the Customer Attachment Program.**

2 A DTE lays out its cost and revenue estimation and allocation approach in Section C8
3 of its Rate Book. DTE calculates the CIAC based on the revenue deficiency of the
4 anticipated project. To calculate the revenue deficiency, DTE estimates the cost to
5 construct and maintain the assets required to serve new customers. DTE then
6 estimates the incremental revenues associated with the new customers (not
7 including the commodity cost of fuel), assuming constant gas consumption per
8 customer over time. The revenue deficiency is the difference between the 20-year
9 present value of the costs and the 20-year present value of the revenues. DTE
10 requires that new customers pay for the revenue deficiency, either up front or over
11 time. Note that this payment does not cover the full capital cost of the expansion:
12 costs more than 20 years after installation are not reflected in the calculation. DTE
13 applies the same general approach to both individual attachments and community
14 expansions, although community expansions have greater uncertainty regarding the
15 number of customers that will connect.

16 **Q What are your concerns with the 20-year time period DTE uses to calculate**
17 **the revenue deficiency?**

18 A DTE assumes that new customers will remain connected to the gas system,
19 contributing to revenues for at least 20 years. However, there is reason to believe
20 that future gas demand might look different from historical gas demand, for the
21 reasons discussed in Section III. In particular, competition from more efficient
22 electric alternatives to natural gas may cause customers to leave the gas system
23 earlier than DTE currently anticipates based solely on historical data. By failing to

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 account for this risk, DTE may be overestimating expected revenues from new
2 customers and causing existing ratepayers to subsidize the cost of new attachments.

3 **Q What level of consumption does DTE assume over the 20-year CIAC**
4 **calculation period?**

5 A DTE assumes that new customer consumption will remain at the same level over
6 the entire 20-year time span of the CIAC calculation. Specifically, DTE assumes
7 that, for individual, non-AEP CAP attachments, residential customers will consume
8 [REDACTED] Mcf per year.⁶⁷

9 **Q What are your concerns with this assumption?**

10 A DTE assumes that new customers will consume the same amount of gas each year
11 for 20 years. This contradicts DTE's observations about declining use per customer
12 over the last 20+ years. As discussed by Witness Chapel, residential consumption
13 per customer has been stable or declining since before 2000, despite increases in
14 customer count from 2012 to 2024 (see Figure 2 and Figure 3, above).⁶⁸

15 Further, DTE's assumption of constant consumption levels for new customers does
16 not consider the impacts of energy efficiency. Witness Huffman argues that
17 customers who convert to natural gas "invest in new, high efficiency appliances or
18 invest in retrofitting existing appliances that have a substantial remaining life," and
19 that "these customers are unlikely to make another investment to switch fuels again
20 or see declining demand from EWR."⁶⁹ Even if Huffman is correct that new

⁶⁷ Ex MEC-10C, NDA Company Response to MECCUBDG-3.21 & Att.

⁶⁸ Direct Testimony of George H. Chapel, p. 21.

⁶⁹ Huffman Direct, p. 50.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 construction is unlikely to experience energy savings over 20 years, 50 percent of
2 DTE's forecasted attachments are for customers in *existing* structures, which are
3 likely to have potential for energy savings through energy efficiency.

4 DTE's assumption of constant consumption levels for new customers also fails to
5 account for the potential impact of partial electrification, such as the electrification
6 of water heating, dryers, stoves, etc., or that new construction may depend on gas
7 for fewer end uses than it did 20 years ago.

8 DTE should revise this assumption to account for the impact of energy efficiency
9 and electrification on annual customer consumption. At the very least, DTE should
10 adjust new customer consumption for attachments to existing structures to reflect
11 long-term historical consumption trends. While this approach will not capture the
12 impact of partial electrification, it will capture the impacts of historical energy
13 efficiency.

14 **Q What amount of consumption per customer does DTE assume for the purpose**
15 **of calculating CIACs?**

16 A For individual attachments within the CAP (New Construction, On-Main
17 Conversions, and Main Extensions) DTE assumes [REDACTED] Mcf per customer annually
18 for residential, non-seasonal homes. For the Austin AEP and US-2 AEP, DTE
19 assumed [REDACTED] Mcf per customer annually for residential, non-seasonal homes.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q What are your concerns with DTE’s assumptions about annual consumption**
2 **per customer for individual, non-AEP attachments?**

3 **A**Historical data from DTE’s filing shows that, from 2020 to 2024, residential space
4 heating customers in DTE’s territory on average consumed 90 Mcf annually
5 (weather normalized).⁷⁰ The last time residential customers consumed 100 Mcf (in
6 weather normalized terms) was 2008.⁷¹

7 DTE uses outdated consumption data to perform CIAC calculations which
8 contradicts DTE’s findings that consumption per residential customer has
9 declined.⁷² Further, DTE does not justify this methodological decision, which
10 directly violates the Commission’s directives in Case U-21291. The Commission
11 specifically directed the Company to “provide a thorough justification for its CIAC
12 and CAP methodology, including whether it is appropriate to revise its assumptions
13 to include declining gas demand, customer adoption rates for the CAPs based on
14 historical experience when calculating new attachment surcharges, and how the
15 company intends to avoid subsidization by existing customers.”⁷³ Yet, there is a tab
16 in the CAP model presenting usage data that was last updated in 2010.⁷⁴ In
17 discovery, DTE stated that the usage values from this tab reflect 15 years of
18 weather-normalized usage for the years 1995 to 2009.⁷⁵ When asked why DTE has
19 not updated these values since 2010, the Company responded: “Following a

⁷⁰ Exhibit A-15, Schedule E4.

⁷¹ Exhibit A-15, Schedule E4.

⁷² Chapel Direct, p. 21.

⁷³ Case No. U-21291, Order, November 7, 2024, p. 247.

⁷⁴ Ex MEC-10C, NDA Company Response to MECCUBDG-3.21 & Att., Mcf Tables sheet.

⁷⁵ Ex MEC-11, Company Response to MECCUBDG-7.1ai, aii, bi, and bii.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 reasonable and diligent review of available records, the Company did not locate
2 any documentation reflecting later revisions or providing an explanation for the
3 absence of further updates. Accordingly, DTE is not in possession of additional
4 information regarding the rationale for the lack of updates to this tab after 2010.”⁷⁶

5 It is not clear if DTE still relies on the consumption values from this tab, however
6 DTE has not indicated otherwise.

7 Additionally, DTE does not appear to distinguish between new construction and
8 existing building conversions in its consumption assumptions. New construction is
9 generally more energy-efficient than existing buildings, and customers in new
10 construction may have lower energy needs than existing buildings. DTE’s
11 modeling does not capture this nuance, and it may overestimate revenues from new
12 construction attachments.

13 With regards to non-AEP attachments, DTE should revise its consumption per
14 customer assumption for residential customers to 90 Mcf annually and adjust this
15 assumption each year according to the most recent five-year weather-normalized
16 average residential consumption. (I will discuss my concerns with DTE’s
17 assumptions for the Austin and US-2 AEPs further down in this testimony.)

⁷⁶ *Id.*, response aii.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Does DTE track whether actual usage and revenue conform to or are even**
2 **within range of the assumptions?**

3 A No.⁷⁷ This is problematic because, without tracking actual usage and revenue from
4 new customers, there is no way for DTE, the Commission, or intervenors to verify
5 the accuracy of DTE's CIAC assumptions for new attachments.

6 **Q You mentioned earlier that DTE provides a new attachment at no charge to**
7 **the customer if the length of the connection is less than 400 feet. Has DTE**
8 **provided any analytical support for the 400 feet service line limit?**

9 A No. The 400 feet service line limit has remained 400 feet since the CAP model was
10 implemented and has not been revised.⁷⁸ When asked for the assumptions and
11 methods used to calculate the service line for each geographic location and category
12 of customers, such that the Service Line Limit equals the "point at which the cost
13 of the customer's service requirements are greater than the allowance based on the
14 Cost of Service Model," DTE responded that it applies the limit uniformly and does
15 not have any analysis.⁷⁹ Furthermore, compared to other utility footage allowances,
16 400 feet appears to be excessive.

⁷⁷ Ex MEC-12, Company Response to MECCUBDG-3.23d and f, response f.

⁷⁸ Ex MEC-13, Company Response to MECCUBDG-8.49.

⁷⁹ Ex MEC-12, Company Response to MECCUBDG-3.23d d and f, response d.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Are you aware of other states that have eliminated or reduced line extension**
2 **allowances?**

3 A Yes. In states such as California and Colorado, Commissions have eliminated these
4 subsidies entirely for residential customers, partly because of concerning
5 assumptions about continued gas demand.^{80,81}

6 **Q What is your recommendation?**

7 A Based on the failure to follow Commission directives, the lack of support for the
8 projected number of new attachments, and the lack of support for the usage
9 assumptions in the CAP model, at a minimum the Commission should disallow
10 inclusion in rate base of any increase in New Market Attachments capital
11 expenditures over the \$82,722,000 amount for 2025 – this translates to a
12 disallowance of \$10,969,937, excluding the additional \$3,606,063 disallowance I
13 recommend below for the Austin and US-2 AEPs. I have additional
14 recommendations related to this subject matter below.

15 **ii. Area Expansion Projects**

16 **Q Describe the Austin AEP.**

17 A The Austin AEP expands service to new customers in the Greater Grand Rapids
18 area, adding 67 miles of new pipe to DTE’s service territory.⁸² DTE is requesting

⁸⁰ California Public Utility Commission, Decision 22-09-026 in Rulemaking 19-01-011, September 15, 2022, available at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K987/496987290.PDF>.

⁸¹ Colorado Senate Bill 23-291, Section 5, 40-3.2-104.3, available at: https://leg.colorado.gov/sites/default/files/2023a_291_signed.pdf.

⁸² “We will be installing 107,224 of 2", 7,700' of 3", 151,339' of 4", 76,852' of 6" and 11,810' of 8" new main” (Exhibit A-12, Schedule B5.5, page 11). This adds up to 354,925 feet of new pipe, or 67.2 miles.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 approval to include \$12.5 million in rate base for the Austin AEP for the 2025–
2 2027 period. At the time of the filing, DTE reported that construction for the project
3 was underway, with an expected in-service date of December 2025.⁸³

4 **Q Describe the US-2 AEP.**

5 A The US-2 AEP expands gas service to new customers in the Escanaba area,
6 extending the gas system by 12 miles and adding 224 service lines (installing 208
7 and renewing 16).⁸⁴ DTE is requesting approval to include \$4.6 million in rate base
8 for the US-2 AEP for the 2025–2027 period. Customers began attaching in June
9 2025.⁸⁵

10 **Q How does DTE calculate CIACs for AEPs?**

11 A With some noteworthy differences, DTE calculated CIACs for AEPs using the
12 same general approach as for individual CAP attachments (described above). DTE
13 uses the same assumptions for the calculation time period (20 years) and
14 consumption level (held constant throughout the 20 years) for both individual
15 attachments and AEPs. The usage tab in the CEP model has also not been updated
16 since 2010.⁸⁶ And as with individual attachments, DTE does not track or reconcile
17 usage for AEPs, stating that the 1995 settlement agreement that originally approved
18 the program does not require the Company to do so.⁸⁷

⁸³ Exhibit A-12, Schedule B5.5, p. 11.

⁸⁴ “Installed 30,013 of 2", 22' of 3", 9,045 of 4" and 26,818 of 6" new main. We renewed 140' of 2" and 6,083 of 6" main.” (Exhibit A-12, Schedule B5.5, page 31.) Totalling 65,898 feet of new main, or 12.48 miles.

⁸⁵ Exhibit A-12, Schedule B5.5, page 31.

⁸⁶ Ex MEC-14C, Company Response to NDA MECCUBDG-3.29ci-xviii & Att, tab Mcf tables.

⁸⁷ Ex MEC-15, Company Response to MECCUBDG-3.28a-b.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 One notable difference between DTE’s CIAC calculation for Austin and US-2
2 compared to its CIAC calculation for individual CAP attachments is that, for Austin
3 and US-2, DTE assumes residential customers will consume [REDACTED] Mcf per year,
4 which is greater than the [REDACTED] Mcf assumed for individual attachments.

5 Another difference between CIAC calculation methods for these AEPs and for
6 individual, non-AEP CAP attachments has to do with the expected number of
7 attachments. In both cases, DTE calculates the CIACs based on the expected
8 number of new attachments. For individual CAP attachments, DTE knows the
9 number of new attachments with more certainty. For AEPs, the exact number of
10 attachments is harder to know.

11 **Q Describe DTE’s process for estimating the number of attachments for AEPs.**

12 **A DTE states that it “identifies new attachments by first defining the project scope**
13 **based on the proposed gas main installation. All premises within the feasible service**
14 **area of the proposed main are identified as potential customers, representing the**
15 **maximum number of customers the project could serve.”⁸⁸ DTE then conducts**
16 **outreach to individual customers within the project area to assess interest and**
17 **determine the number of committed customers (committed customers are those that**
18 **sign a gas application).⁸⁹**

⁸⁸ Ex MEC-16, Company Response to MECCUBDG-8.53a.

⁸⁹ *Id.*

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q How does DTE use its estimated number of attachments to calculate CIACs**
2 **for AEPs?**

3 A DTE does not assume that all potential customers will connect to service in the
4 same year; instead, it spreads out the number of attachments over multiple years.
5 For Austin and US-2, DTE assumes that [REDACTED] percent of customers will connect in
6 the first year, [REDACTED] percent in the next year, [REDACTED] percent in the three following years,
7 and none after that. This reflects 90 percent of the total potential customers DTE
8 identified in the project area. DTE calculates CIACs based on the expectation that
9 90 percent of total potential customers will connect over the span of the project (in
10 other words, CIACs are calculated by dividing the revenue deficiency by 90 percent
11 of the potential customers).

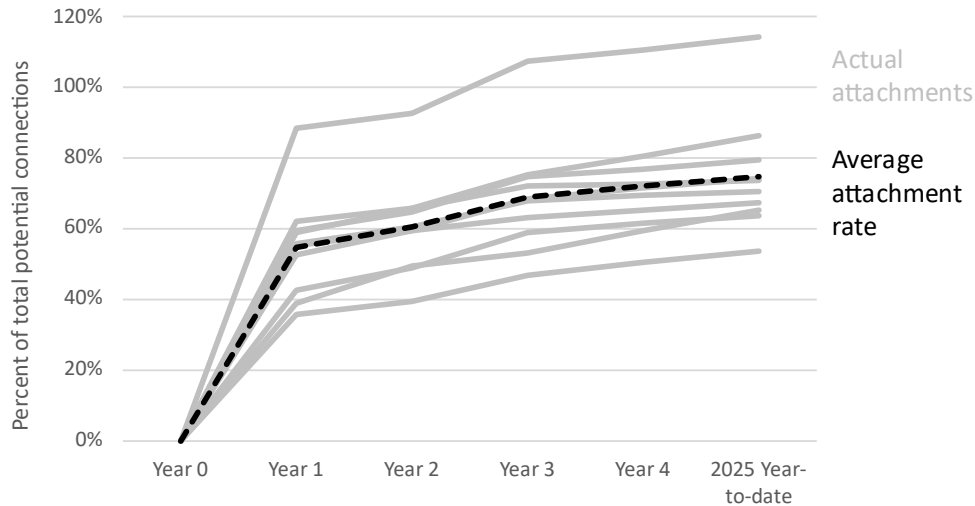
12 **Q What do historical trends indicate about the number of actual attachments for**
13 **AEPs?**

14 A Looking at the ten AEPs that started in 2020, only 77 percent of the total potential
15 attachments for these projects have materialized.⁹⁰ At this point, these projects have
16 been operational for six years and their growth has significantly slowed, as shown
17 in Figure 5.

⁹⁰ Ex MEC-17, Company Response to MECCUBDG-3.31a AEP Projects YTD Attachments 2020-2025.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

Figure 5. Customer attachments for 2020 AEPs



Source: MECCUBDG-3.31a AEP Projects YTD Attachments 2020-2025.

Similarly, the fifteen AEP projects that started in 2021 have only reached 70 percent of their potential attachments after five years.⁹¹ To the extent that the Austin and US 2 AEP attachment timelines (described above) are representative of DTE's typical assumed attachment timeline, I would expect that the AEPs started in 2020 and 2021 should have reached about 90 percent of their total potential attachments by now; however, both are well below target.

Q Does DTE's assumption about connecting 90 percent of potential customers align with historical trends?

A No. DTE consistently over-projects the number of new attachments for AEPs as explained above.

⁹¹ *Id.*

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q What does Witness Huffman say about attachment rates for the AEPs started**
2 **in 2024?**

3 A Witness Huffman states, “Across all AEP projects started in 2024, the year-to-date
4 target (as of August 31, 2025) used in the CAP models was 2,368 attachments. The
5 year-to-date actual as of the same date was 2,404, which is 36 attachments ahead
6 of target.”⁹²

7 **Q What can you say about the attachment rate for the 2024 AEPs relative to their**
8 **total potential?**

9 A While the 2024 AEPs have achieved 102 percent of their year 1 target, as described
10 by Witness Huffman, they have only reached 61 percent of their total potential of
11 3,937 attachments. As demonstrated with the 2020 and 2021 AEPs, progress in the
12 first year does not necessarily indicate that long-term targets will be met.

13 **Q What does Witness Huffman say about the Peach Ridge AEP?**

14 A Witness Huffman states, “The forecasted adoption rate that was included in the
15 CAP model for Peach Ridge was 369 through August 31, 2025. The actual adoption
16 rate through August has been 353, which is only 16 lower than forecasted. This
17 reflects approximately 96% of the original forecast for the time period.”⁹³
18 Witness Huffman goes on to argue that “the disallowance based on an 80% or less
19 adoption assumption was inappropriate, and all capital expenditures related to the

⁹² Huffman Direct, p. 46.

⁹³ Huffman Direct, p. 48.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 project, including the \$912,000 previously disallowed, should be approved in this
2 case.”⁹⁴

3 **Q Do you believe that DTE should be able to recover the \$912,000 previously**
4 **disallowed?**

5 A No. The Peach Ridge AEP achieved 96% of its 2025 target, however it has only
6 achieved 72 percent of its total potential. Moreover, the rate of attachments has
7 slowed significantly: 335 customers connected to Peach Ridge in the first year, 5
8 customers connected the next year, and 13 customers connected in the first half of
9 2025.⁹⁵ Peach Ridge has not reached the 80 percent total adoption target that the
10 disallowance was based on, nor has DTE provided evidence that Peach Ridge will
11 reach its full adoption target. Therefore, the Commission should not approve the
12 \$912,000 previously disallowed.

13 **Q Based on DTE’s experience with customer attachment rates over the last few**
14 **years, is it reasonable for DTE to assume that 90 percent of total potential**
15 **customers will connect to the Austin and US 2 AEP project within five years?**

16 A No. If historical data is a predictor of AEP attachments rates, then it is likely that
17 the Austin and US 2 AEP will fall short of their 90 percent attachment targets in
18 five years’ time.

⁹⁴ Huffman Direct, p. 48.

⁹⁵ Ex MEC-18, Company Response to MECCUBDG-9.4.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Who bears the risk of additional costs if DTE’s estimate of the number of**
2 **customers that connect proves too high?**

3 A Unless the Commission orders that existing ratepayers be insulated from these
4 costs, existing ratepayers will bear the risk of additional costs. If DTE’s estimated
5 number of connecting customers proves to be too high, DTE will overestimate
6 expected revenues from new customers in the project area. Since CIACs are
7 calculated based on the difference between revenues and costs, overestimating the
8 number of customers, and thus revenues, will result in CIACs that are too low.

9 **Q What is a more reasonable assumption about share of total potential**
10 **customers that will actually connect to gas service?**

11 A For the purpose of calculating CIACs, I believe it is more reasonable to assume that
12 77 percent of total potential customers will actually connect. This estimate is
13 grounded in DTE’s actual experience, but even that may be optimistic given that
14 customers have cost-effective, more efficient choices with electrification.

15 **Q If the Austin AEP project realizes an average number of attachments, how**
16 **much will other DTE ratepayers be subsidizing the customers served by the**
17 **project?**

18 A Using DTE’s CAP model, I estimate that existing ratepayers will be subsidizing
19 \$1,965,756 for the Austin AEP.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Could you please describe how you calculated the present value of the expected**
2 **shortfall to be about \$1,965,756 for the Austin AEP?**

3 A To calculate this value, I adjusted the number of expected Austin AEP customers
4 in DTE's CAP model from 1372 to 1056, a reduction consistent with the 77 percent
5 historical average attachment rate. I did not adjust any other variables. If DTE
6 charges its projected amount for CIAC (\$ [REDACTED] month for residential customers),
7 this will result in a revenue deficiency of \$1,965,756. This calculation assumes that
8 the remainder of DTE's assumptions hold, including the average use per customer
9 and that usage stays constant over 20 years.

10 DTE has used unreasonable assumptions regarding customer connections to this
11 project, and the resulting rates are therefore not just and reasonable.

12 **Q If the US-2 AEP project realizes an average number of attachments, how much**
13 **will other DTE ratepayers be subsidizing the customers served by the project?**

14 A I estimate that existing ratepayers will be subsidizing the customers served by the
15 project \$346,961 for the US-2 AEP.

16 **Q Could you please describe how you calculated the present value of the expected**
17 **shortfall to be about \$346,961 for the US-2 AEP?**

18 A I calculated this value using the same approach described for the Austin AEP.
19 Specifically, I adjusted the number of expected customers for the US-2 AEP from
20 245 to 188, a reduction consistent with the 77 percent historical average attachment
21 rate. If DTE charges its projected amount for CIAC (\$ [REDACTED] /month for residential
22 customers), this will result in a revenue deficiency of \$346,961.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q If the Austin AEP project customers consume an average amount of gas, how**
2 **much will other DTE ratepayers be subsidizing the customers served by the**
3 **project?**

4 A If Austin AEP residential customers consume an average amount of gas (90 Mcf
5 per year), I estimate that existing ratepayers will be subsidizing the new customers
6 \$1,425,535 for the Austin AEP.

7 **Q Could you please describe how you calculated the present value of the expected**
8 **shortfall to be about \$1,425,535 for the Austin AEP?**

9 A To calculate this value, I adjusted DTE's assumption for average annual
10 consumption per residential customer in the CAP model from [REDACTED] Mcf to 90 Mcf,
11 which is a reduction consistent with DTE's reported annual average consumption
12 for this group of customers from 2020 to 2024. I did not adjust any other variables
13 in the model. Importantly, I maintained DTE's assumptions about the number of
14 expected customers. If DTE charges its projected amount for CIAC
15 (\$ [REDACTED] /month for residential customers), this will result in a revenue deficiency
16 of \$1,425,535. This calculation assumes that usage stays constant over 20 years.

17 **Q If the US-2 AEP project customers consume an average amount of gas, how**
18 **much will other DTE ratepayers be subsidizing the customers served by the**
19 **project?**

20 A If US-2 AEP residential customers consume an average amount of gas (90 Mcf per
21 year) I estimate that existing ratepayers will be subsidizing \$253,925 for the US-2
22 AEP.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Could you please describe how you calculated the present value of the expected**
2 **shortfall to be about \$253,925 for the US-2 AEP?**

3 A I calculated this value using the same approach described for the Austin AEP.
4 Specifically, I adjusted DTE's assumption for average annual consumption per
5 residential customer in the CAP model from [REDACTED] Mcf to 90 Mcf, which is a
6 reduction consistent with DTE's reported annual average consumption for this
7 group of customers from 2020 to 2024. If DTE charges its projected amount for
8 CIAC (\$ [REDACTED]/month for residential customers), this will result in a revenue
9 deficiency of \$253,925.

10 **Q If the Austin and US-2 AEPs experience both an average number of**
11 **attachments and average level residential of consumption, how much will**
12 **other DTE ratepayers be subsidizing the customers served by the projects?**

13 A By adjusting DTE's assumptions about *both* the customer attachment potential *and*
14 annual consumption according to the adjustments described above, I estimate that
15 existing ratepayers will be subsidizing \$3,063,821 for the Austin AEP and
16 \$542,242 for the US-2 AEP.

17 **Q What are your findings?**

18 A DTE's projections of number of customers connecting to AEPs and consumption
19 assumptions, which underpin the determination of new customer charges, are
20 overly optimistic. Therefore, the new customer charges are unlikely to cover the
21 full cost of the Austin and US-2 AEPs. Excess costs not covered by AEP customers
22 are ultimately socialized to existing ratepayers.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

Table 1 summarizes the results of my disallowance calculations and highlights my recommended disallowance for the Austin and US-2 AEPs.

Table 1. Summary of CAP disallowance calculations

Disallowance amount			
	Adjusted customers	Adjusted consumption	Adjusted customers and consumption*
Austin AEP	\$1,965,756	\$1,425,535	\$3,063,821
US-2 AEP	\$346,961	\$253,925	\$542,242
Total	\$2,312,717	\$1,679,460	\$3,606,063

Note: () reflects my recommended disallowance*

Q What do you recommend to the Commission regarding the risk of project under-subscription and customer under-consumption?

A In addition to recommending that the Commission disallow \$10,969,937 for New Market Attachments, \$3,063,821 for the Austin AEP, and \$542,242 for the US-2 AEP, I recommend the following:

- DTE should reduce the number of total potential customers used to calculate CIACs for Area Expansion Projects (AEPs) to 77 percent.
- DTE should update its gas consumption assumptions for individual CAP attachments and AEPs to reflect actual customer consumption from the last five years. Specifically, DTE should revise its consumption per customer assumption for residential customers to 90 Mcf annually and adjust this

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 assumption each year according to the most recent five-year average
2 residential consumption (weather-normalized). Further, DTE should not be
3 allowed to collect anything related to new customer attachments until it
4 resolves the issues.

- 5 • DTE should adjust its revenue calculation for new customers to reflect
6 declining future consumption, consistent with 20-year historical trends.
- 7 • DTE investors should be held accountable for overruns rather than having
8 ratepayers bear the burden of investments that do not benefit them.
- 9 • The Commission should encourage DTE to reconsider its line extension
10 allowance policies and whether it is reasonable to continue socializing these
11 costs.

12 **V. DTE’S IRM PROPOSAL IS PROBLEMATIC AND DOES NOT REFLECT**
13 **PRUDENT CAPITAL PLANNING**

14 **i. Background and overview of current proposal**

15 **Q What is the IRM?**

16 **A**The IRM is a cost recovery mechanism that allows DTE to seek pre-approval of
17 costs for select programs. DTE submits a five-year plan for capital expenditure and
18 project activity to be recovered through customer surcharges.⁹⁶ In testimony,
19 Witness Janness states that capital investments under the IRM programs are

⁹⁶ Direct Testimony of Eric. D. Janness, p. 15.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 “necessary to ensure the safety and reliability of the Company’s natural gas
2 system.”⁹⁷

3 **Q How are IRM costs recovered from customers?**

4 A DTE recovers IRM costs through a surcharge that is determined annually based on
5 approved investment plans, minus any budget underruns from the previous year.
6 Each calendar year, DTE calculates the IRM surcharge based on the predetermined
7 cumulative incremental revenue requirement associated with the incremental
8 capital investment for the five-year investment period.⁹⁸ In the first quarter of each
9 year, DTE files with the Commission an annual reconciliation for the capital
10 invested in the prior year. IRM investments incur pre-tax rate of return,⁹⁹ while
11 regular rate-based investments earn an after-tax rate of return.

12 **Q Please describe the original IRM.**

13 A The Commission approved MichCon’s original IRM in 2013 in Case No. U-
14 16999.¹⁰⁰ This IRM funded the 10-year Main Removal Program (MRP) (now called
15 the Gas Renewal Plan, or GRP) and Meter Move Out (MMO) programs, which the
16 Commission had approved in other dockets in 2011.¹⁰¹ The initial IRM also
17 included spending on the Pipeline Integrity (PI) program, based on a finding that
18 the program was “required under federal and state safety standards and is an integral

⁹⁷ *Id.* at p. 11.

⁹⁸ *Id.* at p. 15.

⁹⁹ Direct Testimony of Kirk M. Vangilder, p. 18.

¹⁰⁰ Case No. U-16999, Order, April 16, 2013.

¹⁰¹ Case No. U-16999, Order, April 16, 2013, p. 2, citing Case No. U-16451, Orders dated September 13, 2011, and November 10, 2011, and Case No. U-16407, Order, September 13, 2011.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 part of the company's overall effort to improve the safety and reliability of its
2 system.”¹⁰²

3 The Commission approved the initial IRM at a spending level of \$77.4 million per
4 year, including \$46.9 million per year for the MRP, \$22.7 million per year for the
5 MMO program, and \$7.8 million per year for the PI program.¹⁰³

6 **Q Please describe the Company's current IRM.**

7 A The Commission approved DTE Gas's current IRM in Case No. U-21291. The
8 approved IRM allowed DTE to recover the predetermined incremental revenue
9 requirement for annual infrastructure capital expenditures in certain programs for
10 each year from 2025 through 2029. The current, approved IRM includes two
11 programs: the GRP and the PI program.¹⁰⁴ The GRP includes the legacy MRP and
12 MMO programs.

13 **Q What did the Commission say regarding the IRM in DTE's last rate case?**

14 A In the last rate case:

- 15 • The Commission did not approve inclusion of capital expenditures for
16 cathodic protection, as proposed by DTE, because the Company “did not
17 provide an adequate reason that the project could not remain in base rates.”

18 ¹⁰⁵

¹⁰² Case No. U-16999, Order, April 16, 2013, p. 22.

¹⁰³ Case No. U-16999, Order, April 16, 2013, pp. 24-25.

¹⁰⁴ Janness Direct, p. 18.

¹⁰⁵ Case No. U-21291, Order, November 7, 2024, p. 64.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

- 1 • The Commission encouraged DTE to “prudently consider the
2 appropriateness of NPAs and repairs versus replacements when planning
3 main replacements.”¹⁰⁶
- 4 • The Commission found that “this practice of overperformance and the
5 associated increase in construction costs is not reasonable and prudent. As
6 such, the company is cautioned that, in the future, capital expenditures
7 associated with overperformance beyond the levels authorized in the
8 surcharge will be closely scrutinized for reasonableness and prudence and
9 may be subject to disallowance in future cases.”¹⁰⁷

10 **Q What is the Company proposing to include in the IRM in this rate case?**

11 A DTE proposes to include four programs: GRP, PI program, Regulator Station
12 Replacement Program (RSRP), and Cathodic Protection (CP).

13 **Q Is DTE proposing changes to the IRM in this rate case?**

14 A Yes. DTE is proposing to add programs to the IRM and proposing new activities
15 under existing programs in the IRM. The RSRP and CP programs are new programs
16 that DTE proposes for inclusion in IRM in this rate case.

17 In addition, DTE is proposing changes to the GRP, which currently includes the
18 MRP and MMO program. DTE is proposing to add new legacy services¹⁰⁸ renewals
19 under the GRP as an extension of the MMO program, as well as capital costs

¹⁰⁶ *Id.* at p. 77.

¹⁰⁷ Case No. U-21291, Order, November 7, 2024, p. 77.

¹⁰⁸ Janness Direct, p. 32.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

associated with ultrasonic meter technology and by-pass devices for meters installed during GRP work.¹⁰⁹

Q What is the Company's budget forecast for the IRM proposals?

A DTE is asking for increased funding for the IRM, which will result in higher IRM surcharges. IRM is projected to be \$377.8 million in 2027, rising to \$455 million in 2031 (see Table 2), for a total of \$2.1 billion over the five-year period. The majority of IRM spending is for the GRP. The two new programs, Cathodic Protection and Regulator Station Replacement Program, add a total of \$275.5 million in targeted capital expenditures over 2027 through 2031, accounting for 13% of total IRM targeted capital expenditures.¹¹⁰

Table 2. Total IRM Proposed Capital Expenditures through 2031 (\$Millions)

Program	2027	2028	2029	2030	2031
Gas Renewal Program	341.7	355.5	364.5	372.5	381.5
Pipeline Integrity	6.0	6.0	0.4	6.0	6.0
Cathodic Protection	17.6	17.6	17.6	17.6	17.6
Regulator Station Replacement Program	12.5	25.5	50.0	50.0	50.0
Total IRM	377.8	404.1	432.5	446.1	455.1

Source: Direct Testimony of E. D. Janness, Table 1, p. EDJ-19.

¹⁰⁹ Janness Direct, p. 37.

¹¹⁰ Exhibit A-12 Schedule B6.

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

ii. Concerns with the IRM

Q Please summarize your concerns with the IRM.

A Budget and actual spending on IRM programs has increased substantially since the Commission first approved the IRM, and DTE's IRM expenditures have consistently exceeded budget. DTE is planning for increasingly large IRM programs, which it is likely to overspend based on its historical track record.

- There is limited evidence that IRM is mitigating risk in the most cost-effective manner. DTE targets achievement of a certain level of spending on the IRM, and tracks miles renewed, which are not directly related to risk mitigation. DTE does not justify risk mitigation and prioritization effectively.
- By fast-tracking review and cost-recovery of IRM investments, the IRM minimizes the risk to investors and provides a powerful, unmonetized incentive. However, DTE already has an incentive to make capital investments and does not need extra incentives.
- The criteria for what types of projects qualify for the IRM are unclear, and the utility has incentives to include routine projects in the IRM. The IRM includes minimal guardrails.
- DTE is seeking to expand the bounds of the IRM by adding new programs and new activities within existing programs. DTE is proposing two new programs and is adding activities under the GRP, but it does not provide

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 sufficient justification as to why it cannot meet its safety and reliability
2 requirements through normal distribution capital, rather than the IRM.

- 3 • DTE does not adequately consider NPAs to IRM expenditures.

4 **Q Do utilities have incentives to make capital investments without the special**
5 **treatment provided by the IRM?**

6 A Yes. Regulated utilities have an existing incentive to spend on capital projects
7 because they can earn a return for shareholders on capital expenditures. Even
8 without the reduced risk from IRM investments, utilities earn a return on rate base,
9 and therefore have an incentive to continue capital investments, as opposed to
10 operating expenses (which typically do not earn a return) in order to increase
11 earnings and profit to investors. The IRM enhances and magnifies an incentive that
12 the utility already has.

13 **Q What happens to expenditures on IRM programs that exceed the authorized**
14 **IRM spending amounts?**

15 A Any capital expenditures in excess of the expenditure targets used to calculate the
16 IRM surcharge are recovered in subsequent general rate cases.¹¹¹

17 **Q What are your concerns around rising IRM costs?**

18 A DTE's IRM budget has increased dramatically over the past nine years. As shown
19 in Figure 6, annual spending is increasing over time. The Commission approved

¹¹¹ Janness Direct, p. 16.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 the initial IRM with an annual budget of about \$77 million. Since the start of the
2 IRM, the annual budget for IRM programs has nearly tripled.¹¹²

3 The GRP is the largest component of the IRM. Projected target GRP capital
4 expenditures in 2027–2031 are 20 percent to 34 percent higher than the average
5 targeted expenditure in 2024–2026.¹¹³ Total IRM capital expenditures for 2027–
6 2031 are 26 percent to 52 percent higher than average 2024–2026 IRM target
7 capital expenditures. This is in part due to new programs and activities. Under the
8 GRP, new legacy service renewal activities are projected to cost \$89.8 million over
9 the years 2029–2031, replacing 21,900 legacy services.¹¹⁴ Ultrasonic meters and
10 by-pass devices are projected to cost \$55.4 million in capital expenditures from
11 2026 through 2031.¹¹⁵

¹¹² Exhibit A-12 Schedule B6.

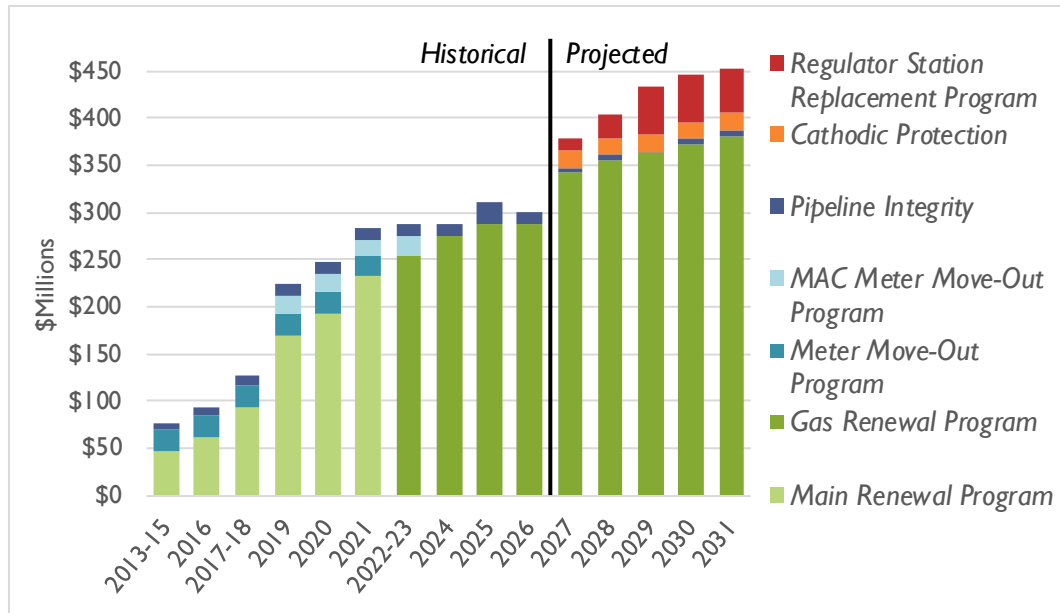
¹¹³ Exhibit A-12 Schedule B6.

¹¹⁴ Exhibit A-12 Schedule B6.5.

¹¹⁵ Exhibit A-12 Schedule B6.5.

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

Figure 6. Historical and projected target IRM capital expenditures



Source: Exhibit A-12 B6.

Q What action did the Commission take regarding main replacements in the IRM in the last case?

A In DTE Gas’s last rate case, the Company projected \$274 million per year in main replacement spending under the IRM. The Commission articulated an objective to appropriately balance IRM program priorities with rapidly growing IRM costs.¹¹⁶ The Commission encouraged DTE Gas “to prudently consider the appropriateness of NPAs and repairs versus replacements when planning main replacements.”¹¹⁷ The Commission also found it was “not persuaded that DTE Gas has done all it could to reduce MRP costs, as suggested by MNSC.”¹¹⁸ The Commission adopted the Attorney General’s proposed \$240 million limitation on the MRP, not as a cap

¹¹⁶ Case No. U-21291, Order, November 7, 2024, p. 76.

¹¹⁷ *Id.* at 76-77.

¹¹⁸ *Id.* at 77.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 to the program, but as a figure to use in calculating the surcharge, and stated it
2 would closely scrutinize future recovery requests that exceeded authorized amounts
3 for reasonableness and prudence as a way to address concerns about affordability,
4 lack of accountability, and rapid growth of the IRM.¹¹⁹

5 **Q What has DTE proposed regarding main replacements in this case?**

6 A DTE seeks to increase main replacement spending in the Gas Renewal Program
7 even further, to \$334 million in 2027 and escalating from there in the years
8 beyond.¹²⁰

9 DTE witness Janness claims that a variety of factors require the Company to
10 increase spending on the program. However, when asked in discovery for
11 documentation supporting these claimed cost drivers, DTE produced only a one-
12 page workpaper titled “2024 to 2025 GRP Variance Summary.”¹²¹ This workpaper
13 has hard-coded values for several categories (wage inflation, material inflation,
14 contractor rates, region mix variance, flow fill, and traffic control), as well as a
15 figure for an overall complexity increase.¹²² No sources or calculations were
16 provided for any of these values, nor does DTE provide any explanation for how
17 these variance estimates relate to or inform the GRP budget forecasts for 2025 and
18 beyond.

¹¹⁹ *Id.* at 77-78.

¹²⁰ Exhibit A-12, Schedule B5.3, line 2, columns g-k.

¹²¹ Ex MEC-19, Company Response to MECCUBDG 11.4a-f and attachment U-21973 MECCUBDG-11.4-01 2024 to 2025 GRP Variance Summary.

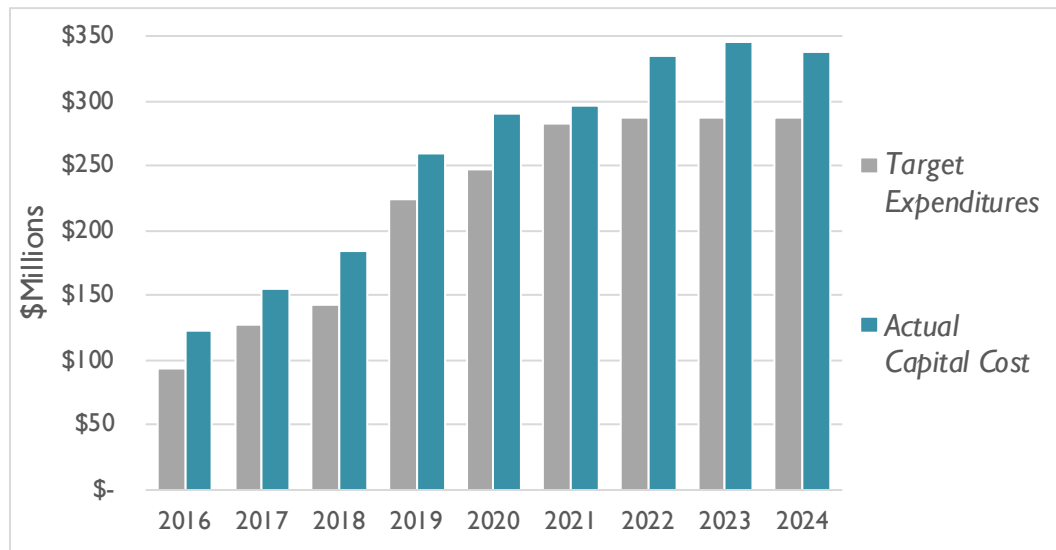
¹²² *Id.*

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q What are your concerns about overspending?**

2 **A At the same time as annual IRM budgets have been increasing, DTE’s actual IRM**
3 **expenditures have consistently exceeded budget. In every year since 2016, the**
4 **actual capital cost of the IRM has been higher than the planned cost (see Figure**
5 **7).¹²³ From 2022 to 2024, the annual average variance between the actual capital**
6 **cost and the targeted levels was over \$50 million (see Table 3).¹²⁴**

Figure 7. Actual capital cost of IRM compared to targeted levels, 2016–2024



Source: Exhibit A-12 B6.1.

Table 3. Actual capital cost of IRM compared to targeted levels 2016-2024 (\$ thousands)

Year	Planned	Actual	Variance
2016	\$93,018	\$122,020	\$29,002
2017	\$127,610	\$155,373	\$27,763
2018	\$143,215	\$183,347	\$40,132

¹²³ Exhibit A-12 Schedule B6.1.

¹²⁴ *Id.*

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

2019	\$223,820	\$258,774	\$34,954
2020	\$247,120	\$290,794	\$43,674
2021	\$282,720	\$295,888	\$13,168
2022	\$287,260	\$335,504	\$48,244
2023	\$287,260	\$345,474	\$58,214
2024	\$287,260	\$337,410	\$50,150

Source: Exhibit A-12 B6.1.

1 **Q Why are increasing costs and overspending a concern?**

2 A As I described above, regulated utilities already have an incentive to increase
3 capital spending. IRM investments are lower risk for the utility and shareholders,
4 and they are guaranteed a rate of return on IRM investments. This provides an
5 incentive for DTE to inflate its IRM budget targets. Furthermore, because DTE
6 recovers any budget overruns in subsequent rate cases, there is little incentive for it
7 to control costs.

8 **Q What targets have been set for the IRM?**

9 A Historically, DTE identified miles of mains and other metrics as targets for the
10 IRM. For the IRM programs proposed in this rate case, DTE states that the
11 Company will have “target capital expenditure and plan work to fit within that
12 budget. Milage will be an outcome rather than the target.”¹²⁵

¹²⁵ Company Response to AGDG-5.188c.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q What are your concerns with the targets for the IRM?**

2 A The cost per mile installed for main renewal has increased since 2022 and is
3 projected to remain higher than in historical years.¹²⁶ DTE is proposing to spend an
4 increasing amount on GRP activities. Targeting capital spending, rather than
5 outcomes achieved, does not encourage cost-efficient investment.

6 **Q How does DTE evaluate risk in its capital planning process?**

7 A DTE uses a risk model, the Probabilistic Risk Assessment (PRA), for prioritizing
8 risk.¹²⁷ DTE began using the PRA model in 2021.¹²⁸

9 **Q Does DTE prioritize risk cost-effectiveness when implementing IRM**
10 **programs?**

11 A No. DTE “does not select grids based on a lowest-cost or cost-per-risk unit basis”¹²⁹
12 and “does not select GRP projects based on a lowest-cost or cost-per-risk-unit
13 basis.”¹³⁰

14 **Q Has DTE conducted a cost-benefit analysis to determine the cost-effectiveness**
15 **of IRM programs?**

16 A No. DTE has not conducted a cost-benefit analysis for the GRP, the PI program,
17 the CP program, or the RSRP program.¹³¹ To the extent there are alternatives to

¹²⁶ Exhibit A-12 B6.5

¹²⁷ Janness Direct, pp. 38 to 39.

¹²⁸ *Id.* at p. 39.

¹²⁹ Company response to MECCUBDG-8.11.

¹³⁰ Company response to MECCUBDG-8.9.

¹³¹ Company responses to MECCUBDG-8.8a, MECCUBDG-8.8b, MECCUBDG-8.8c, MECCUBDG-8.8d.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 these programs, such as emissions monitoring and pipe repair, an assessment of the
2 cost-effectiveness of these programs relative to the alternatives is a necessary step
3 to understanding and minimizing costs.

4 **Q Why is it problematic to not consider risk cost-effectiveness for IRM**
5 **programs?**

6 A By not evaluating risk cost-effectiveness in selecting risk mitigation projects, i.e.,
7 risk reduction per dollar spent, DTE is not demonstrating prudent decision-making.
8 DTE states “The Probabilistic Risk Assessment (PRA) expresses risk in monetary
9 terms, and Main Renewal project selection follows a highest-risk-grid-first
10 prioritization. This approach reflects the mandate of the GRP to focus on reducing
11 system safety risk as quickly as possible, rather than optimizing for cost efficiency
12 at the individual project level.”¹³²

13 DTE disagrees that risk-reduced-per-dollar spent is relevant, because the PRA
14 model identifies high-complexity, high-risk projects for priority renewal that may
15 come with high costs. DTE states “Many higher-risk grids are also more complex
16 and costly to execute due to density, congestion, or municipal coordination
17 requirements. Excluding or deferring these projects based on cost would undermine
18 the program’s risk-reduction objectives.”¹³³

19 Without risk-per-dollar spent metrics, there is no way to know whether DTE is
20 spending ratepayer dollars most effectively to reduce system risk. If DTE could

¹³² Ex MEC-20, Company Response to MECCUBDG-8.9.

¹³³ *Id.*

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

1 reduce the same amount of risk on its system for a lower cost to ratepayers, it should
2 do so. Ensuring risk cost-effectiveness does not “undermine the program’s risk-
3 reduction objectives;” it merely ensures that DTE is achieving the most risk
4 reduction for the least cost.

5 **Q What do you recommend regarding risk prioritization?**

6 A The Commission should require DTE to calculate risk reduction per dollar spent,
7 and include this in the metrics used to prioritize IRM and other capital projects.

8 The Commission should require DTE to report on risk mitigation metrics.

9 **Q How does DTE determine what types of projects qualify for the IRM?**

10 A DTE has provided no clear set of specific parameters for projects to qualify for the
11 IRM.

12 **Q Why are vague criteria for qualifying projects for the IRM problematic?**

13 A DTE may be applying these parameters liberally to proposed investments that are
14 part and parcel of a gas utility’s business and do not reasonably warrant special
15 treatment. Qualifying projects for the IRM reduces the Company’s risk that the
16 project could be found imprudent in the future. Safety and reliability investments
17 are supposed to be the core duties of the utility and are required by law. Nothing is
18 stopping DTE from applying these parameters liberally to proposed investments.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Describe the proposed Regulator Station Replacement Program.**

2 A According to the Company, the RSRP¹³⁴ is intended to proactively mitigate
3 overpressure risks by replacing and upgrading distribution regulator stations.¹³⁵
4 DTE proposes capital spending of \$12.5 million for the RSRP in 2027 and ramping
5 up to \$50 million by 2029.¹³⁶ DTE projects completing six district regulator stations
6 in 2026, one in 2027, and three in 2028.¹³⁷

7 **Q What reasons does DTE give for including the RSRP in the IRM?**

8 A DTE justifies including the RSRP in the IRM by claiming that “the current pace of
9 replacement is insufficient to address the large number of aging and outdated
10 regulator asset stations within the distribution system”¹³⁸ and that DTE has been
11 experiencing an “increasing trend of overpressure events.”¹³⁹ DTE argues that
12 including this program in the IRM would allow it to “proactively replace these
13 stations at an accelerated pace before they become liabilities, rather than reacting
14 to failures that could disrupt service or compromise safety in significant
15 incidents.”¹⁴⁰

¹³⁴ “Distribution regulator stations include district regulators, secondary regulators, and control line operated service regulators. Distribution regulator stations reduce pressure supplied from a higher pressure distribution system to another with a lower pressure distribution system” Janness EDJ-64.

¹³⁵ Janness Direct, p. 63.

¹³⁶ *Id.* at 3.

¹³⁷ Company response to MECCUBDG-5.10c.

¹³⁸ Janness Direct, p. 68.

¹³⁹ *Id.*

¹⁴⁰ Janness Direct, p. 68.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q What has been DTE’s historical pace and spending on district regulator**
2 **station replacements and repair?**

3 A DTE has historically been replacing legacy regulators to address overpressure risk
4 through its system reliability work.¹⁴¹ When asked in discovery, DTE did not
5 provide historical capital expenditure on district regulator station replacements
6 included in system reliability routine capital and the GRP, because DTE “has not
7 tracked the number of district regulator stations replaced per year.”¹⁴² DTE states
8 that the “average number of total district regulators replaced through System
9 Reliability and GRP is approximately 75 stations per year over the past 7 years.”¹⁴³

10 **Q Please describe the Cathodic Protection program.**

11 A The CP program would include corrosion and cathodic protection. DTE states that
12 inclusion of the CP program in the IRM would move a forecasted \$17.6 million of
13 capital spend from routine capital to the IRM.¹⁴⁴

14 **Q Did the Commission approve DTE to include the Cathodic Protection program**
15 **in the IRM in the last rate case?**

16 A No. The Commission determined that the projected capital expenditures for
17 cathodic protection “should not be included in the IRM because the company did
18 not provide an adequate reason that the project could not remain in base rates.”¹⁴⁵

¹⁴¹ *Id.*

¹⁴² Company response to MECCUBDG-5.9a.

¹⁴³ Company response to MECCUBDG-5.12b.

¹⁴⁴ Janness Direct, p. 3.

¹⁴⁵ Case No. U-21291, Order, November 7, 2024, p. 64.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q Has the Commission disallowed any cathodic protection expenditures?**

2 A DTE states it “is not aware of a disallowance” of cathodic protection expenditures
3 in the last 10 years.¹⁴⁶

4 **Q Should the Commission approve the inclusion of the cathodic protection and**
5 **RSRP programs in the IRM?**

6 A No. DTE does not provide sufficient justification as to why it cannot meet its safety
7 and reliability requirements through normal distribution capital expenditures, rather
8 than the IRM. DTE should allocate sufficient resources to system improvements
9 regardless of the cost recovery methodology.

10 **Q Are there other activities that DTE proposes to include in the IRM?**

11 A Yes. DTE is proposing to include legacy service renewals as an extension of the
12 MMO program in the GRP, as well as capital costs associated with ultrasonic meter
13 technology and by-pass devices.¹⁴⁷ As I mentioned above, legacy service renewals
14 are projected to cost \$89.8 million in capital expenditures through 2031, and
15 ultrasonic meters and by-pass devices are projected to cost \$55.4 million through
16 2031.¹⁴⁸ I did not review these activities in detail. But, I note that DTE does not
17 justify why these need IRM treatment, rather than distribution capital normal
18 treatment.

¹⁴⁶ Company response to MECCUBDG-8.13.

¹⁴⁷ Janness Direct, pp. 2 and 37.

¹⁴⁸ Exhibit A-12 Schedule B6.5.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q** Beyond immediate affordability issues, are there other concerns with the
2 increases in rates caused by IRM investments?

3 A DTE is increasing the scale of investments in activities that have already in the past
4 been flowing through the IRM, as well as seeking to add new cost categories to
5 recover through the IRM without adequately demonstrating why these activities
6 necessitate recovery through the IRM.

7 **Q** What do you recommend?

8 A First, the Commission should not approve inclusion of two new programs in the
9 IRM, nor should the Commission approve inclusion of new activities or spending
10 increases in GRP.

11 Furthermore, there must be changes to the existing problematic framework of the
12 IRM:

- 13 • Given the high likelihood of cost recovery for IRM-approved programs,
14 there should be more stringent guidelines for IRM program eligibility.
- 15 • The Commission should implement spending caps on IRM. IRM spending
16 should be capped at \$300 million, roughly equivalent to 2024–2025 IRM
17 spending.
- 18 • DTE should have to justify overspending relative to its annual budget.
- 19 • The Commission should require DTE to target risk mitigation rather than
20 spending.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

- 1 • DTE should provide evidence it is prioritizing investments based on a risk-
2 per-dollar spent metric.
- 3 • The Commission should require DTE to pursue NPAs more actively,
4 including but not limited to identifying dead-end or redundant areas and
5 create NPA criteria for stakeholder and intervenor scrutiny.

6 **VI. DTE HAS NOT DEMONSTRATED THAT IT CONSIDERED**
7 **REASONABLE ALTERNATIVES TO ITS PROPOSED LARGE CAPITAL**
8 **PROJECTS**

9 **Q Describe DTE's Large Capital Projects.**

10 **A DTE provides project summaries for 25 most expensive capital projects in its rate**
11 **case, called the Highest Cost Top 25 Capital Projects. The Highest Cost Top 25**
12 **Capital Projects are broken into categories including Large Capital Projects,**
13 **Routine Distribution, IRM, Information Technology, and others. My testimony**
14 **focuses on four of the Large Capital Projects presented by Witness Fedele:**

- 15 • **Fort Street Main Replacement:** DTE proposes installing 12.9 miles of
16 new main, 43 valves, and 11 district regulators. It also proposes to replace
17 92 services and abandon 14.2 miles of main and 11 district regulators in
18 Detroit. According to DTE, this project is necessary to reduce the risk of
19 leaks from aging, mechanically coupled steel mains, reduce outage potential
20 by creating redundant supply, and provide high-pressure supply to enable

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

future projects.¹⁴⁹ DTE projects to spend \$32,423,000 in the 9 months ending 9/30/2026 and \$13,520,000 in the projected test year.¹⁵⁰

- **East Petoskey Pipeline Reinforcement:** DTE proposes to construct a new 13.5 mile, 8” diameter distribution pipeline with remote-controlled valves alongside the existing East Petoskey pipeline. DTE plans to retain the existing East Petoskey pipeline to create redundancy. The pipeline is scheduled to be inspected for the In-Line Inspection (ILI) Expansion program in 2028, however, according to DTE the ILI tool is at risk of becoming stuck in the line. DTE finds that it is necessary to construct a new pipeline to overcome inspection barriers with the existing pipeline, and because the existing pipeline has a high outage potential as a single-source pipeline.¹⁵¹ DTE projects to spend \$3,266,000 in the 9 months ending 9/30/2026 and \$32,168,000 in the projected test year.¹⁵²

- **Carlton Main Replacement:** DTE proposes to install 4.6 miles of main operating at 274 psig and 6 main valves, and to replace or modify 3 district regulators, abandoning 5.1 miles of 6” main operating at 125 psig along the Carlton Main. According to DTE, this project is necessary to reduce safety concerns associated with the aging, thin-walled steel pipe, and mitigate outage risk by creating redundancy to the Willow Gate Station and Sumpter

¹⁴⁹ Fedele Direct, p. 53.

¹⁵⁰ Exhibit A-12, Schedule B5, line 12.

¹⁵¹ Fedele Direct, p. 37.

¹⁵² Exhibit A-12, Schedule B5, line 12.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 Gate Station.¹⁵³ DTE projects to spend \$6,960,000 in the 9 months ending
2 9/30/2026 and \$7,000,000 in the projected test year.¹⁵⁴

3 • **Taggart Compressor Station Replacement:** DTE plans to completely
4 replace compression assets, dehydration assets, and auxiliary systems at the
5 existing Taggart Compressor Station. According to DTE, this project is
6 necessary due to aging infrastructure with obsolete replacement parts, and
7 an increasing random outage rate.¹⁵⁵ DTE projects to spend \$53,484,000 on
8 the Taggart project in the 9 months ending September 30, 2026 and
9 \$218,175,000 in the projected test year.¹⁵⁶

10 **Q Do you observe any patterns in DTE's investment decisions for Large Capital**
11 **Projects?**

12 A Yes, I observe that DTE frequently opts for solutions that provide system
13 redundancy and expand system capacity over potentially lower cost alternatives.
14 Such is the case with the Fort Street Main, East Petoskey, and Carlton Main
15 projects, three out of the four Large Capital pipeline replacement projects proposed
16 in this rate case.

17 • For the Fort Street Main project, DTE opted to replace the previously
18 existing 50 psig and 99 psig pipelines with 145 psig pipelines to provide
19 redundant, "looped" supply to downstream customers and to enable future

¹⁵³ Fedele Direct, p. 59.

¹⁵⁴ Exhibit A-12, Schedule B5, line 12.

¹⁵⁵ Fedele Direct, p. 73.

¹⁵⁶ Exhibit A-12, Schedule B5, line 14.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 GRP grid projects.¹⁵⁷ DTE considered one alternative solution, involving
2 replacing the Fort Street main at existing pressures (50 psig and 99 psig),
3 however DTE determined that this option “would not have increased
4 reliability by creating redundant supply to Downtown and Southwest
5 Detroit...”¹⁵⁸

- 6 • For the East Petoskey project, DTE decided to install an entirely new main
7 instead of seeking an alternative pipeline inspection method such as direct
8 assessment. DTE considered alternatives including derating the pipe (i.e.
9 reducing the maximum allowable operating pressure), increasing the
10 frequency of leak patrols and surveys, and performing ILI with liquid
11 natural gas backup. However, DTE determined that installing a new pipe
12 was the best solution since “[a]n alternate supply with a new interconnect
13 is the only solution that provides redundancy. Redundancy is necessary
14 because it is the only way to continue providing safe and reliable gas
15 services to customers in the event of an outage.”¹⁵⁹

- 16 • For the Carlton Main project, DTE decided to replace the existing 6” 125
17 psig pipeline with a 12” 274 psig pipeline. DTE considered two alternatives
18 including pipe derating and abandonment. However, DTE determined that
19 replacement with a 12” 274 psig pipeline provides “supply redundancy and
20 operational flexibility” and “capitalizes on the existing designs of the

¹⁵⁷ Exhibit A-12, Schedule B5.5, p. 4 of 41.

¹⁵⁸ Fedele Direct, p. 56.

¹⁵⁹ Fedele Direct, p. 38.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 Augusta pipeline and the regulation infrastructure at the Sumpter and
2 Augusta Gate Stations... [which were] designed, constructed, and tested to
3 operate at this higher 274 psig operating pressure...”¹⁶⁰

4 **Q How does DTE justify its proposed solutions?**

5 A DTE makes claims about the superior reliability benefits of its chosen solutions.
6 For the Fort Street Main, East Petoskey, and Carlton Main projects, DTE prioritizes
7 solutions that provide redundancy, since redundancy “reduces the risk of service
8 disruptions and outages caused by maintenance, third-party damage, and natural
9 disasters, thus ensuring safe and reliable natural gas service to customers.”¹⁶¹

10 **Q Do you believe that increasing capacity of certain segments of the system for**
11 **redundancy is appropriate at this time?**

12 A No, not without evidence proving the increased demand and a robust analysis
13 demonstrating that the selected solution is the most cost-effective way to reduce
14 risk on the system. Unless DTE can prove these things, it is not appropriate to
15 pursue solutions that increase system capacity. DTE’s approach to Large Capital
16 Projects relies on the outdated assumption that demand will continue to grow, when
17 in fact there is great uncertainty about future demand as discussed in Section III.

18 **Q Does DTE consider any alternative solutions for these Large Capital Projects?**

19 A Yes, DTE considers some alternative solutions. Witness Fedele describes the
20 potential solutions DTE considered for each project and provides a high-level

¹⁶⁰ *Id.* at p. 61.

¹⁶¹ *Id.* at p. 15.

DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973

1 explanation of why the solution was not pursued. However, that explanation was
2 lacking for several reasons: the number and type of alternatives considered vary by
3 project; alternatives do not consider non-pipeline or other demand-side solutions
4 (such as electrification and demand response); and DTE's approach for identifying
5 a preferred solution is not clear.

6 **Q Does DTE conduct quantitative analysis to support its decision about which**
7 **solution to pursue?**

8 A DTE conducts some quantitative analysis to assess different solutions, yet the
9 extent of DTE's analysis appears to be extremely limited. DTE conducts hydraulic
10 system modeling to assess the technical feasibility of potential solutions. However,
11 DTE does not appear to compare other aspects of potential solutions such as costs
12 and benefits and risk of stranded costs. Additionally, the inputs and assumptions
13 for DTE's hydraulic system modeling are not clear.

14 Furthermore, DTE did not provide any of its quantitative analysis when asked.
15 Witness Fedele discusses alternative solutions qualitatively but does not present
16 quantitative analysis comparing the advantages and disadvantages of each solution.
17 DTE objected to providing its hydraulic system modeling analysis, claiming that
18 the analysis is proprietary¹⁶² and stating that "the large and cumbersome amount of

¹⁶² Ex MEC-22, Company Response to MECCUBDG-8.25a-c, "DTE Gas objects for the reason that the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Gas, its ratepayers, and its customers competitive harm. DTE Gas further objects to the extent the request seeks information that contains Customer Account Information, disclosure of which is prohibited by the Company's Data Privacy Tariff."

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 data cannot easily be shared. The Company's hydraulic system models are available
2 for viewing at DTE offices."¹⁶³

3 **Q Do you have specific concerns about the East Petoskey project?**

4 A Yes. DTE has not provided sufficient evidence to justify why it is proposing to
5 install a new redundant pipe over other alternative options. When asked in
6 discovery, DTE would not or could not provide the capacity of the existing pipeline,
7 and would not provide the impact on reliability of the project, claiming that the
8 analysis was performed using proprietary modeling that could not be shared.¹⁶⁴ It
9 is not clear why the *results* of the modeling could not be shared. DTE also refused
10 for the same reason to provide any information to support its claim that reducing
11 the pipeline's Maximum Allowable Operating Pressure to 405 psig would not
12 provide enough pipeline capacity to serve the existing customers under peak
13 conditions and would not mitigate the outage potential.¹⁶⁵ DTE acknowledges that
14 it is possible to perform ILI on the pipeline during the summer when any problems
15 with getting an inspection tool stuck would be less severe,¹⁶⁶ however DTE did not
16 demonstrate that it has analyzed this option. The record therefore contains no
17 substantiation of DTE's claimed justifications for the project.

¹⁶³ *Id.*

¹⁶⁴ Ex MEC-21, Company Response to MECCUBDG-8.21a and 8.22a.

¹⁶⁵ Ex MEC-22, Company Response to MECCUBDG-8.25a-c, sub-part a.

¹⁶⁶ Ex MEC-23, Company Response to AGDG-3.107a.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q What are your concerns about the Fort Street Main project?**

2 A DTE refuses to disclose the impact on reliability associated with the Fort Street
3 Main project, claiming that the analysis was performed using proprietary modeling
4 that could not be shared.¹⁶⁷ Nor has DTE provided any evaluation of the alternative
5 it purportedly considered of replacing the mains at existing pressures nor any cost
6 estimate for that alternative.¹⁶⁸ I acknowledge that the Commission approved
7 capital expenditures for the Fort Street Main project in Case No. U-21291 and so I
8 raise these concerns primarily because they are consistent with a pattern that I will
9 continue to describe with respect to the other projects.

10 **Q What are your concerns about the Carlton project?**

11 A Similar to the other Large Capital Projects, DTE did not demonstrate sufficient
12 consideration and analysis of alternatives to justify its proposed solution. In
13 particular, DTE did not justify why pipe relining or a like-for-like replacement of
14 the Carlton main were inferior to DTE's proposed solution to replace the existing
15 main with a pipeline of twice the capacity.¹⁶⁹

16 **Q In your opinion, does DTE adequately justify the reason for selecting its
17 proposed solutions?**

18 A No. DTE does not provide sufficient evidence to support its proposed investments
19 for Large Capital Projects. DTE makes claims about the superior reliability benefits
20 of its chosen solutions, however it does not back up these claims with rigorous

¹⁶⁷ Ex MEC-24, Company Response to MECCUBDG-8.31.

¹⁶⁸ Ex MEC-25, Company Response to MECCUBDG-8.34a.

¹⁶⁹ Ex MEC-26, Company Response to MECCUBDG-8.37a, b.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 quantitative analysis of improvements in reliability or cost-effectiveness. DTE's
2 approach for identifying preferred solutions is not transparent and does not allow
3 the Commission or stakeholders an adequate opportunity to examine the
4 Company's proposed investments.

5 From the available information, it appears that DTE favors solutions that expand
6 its system without adequately justifying the need to do so. DTE does not appear to
7 consider the risks associated with overinvesting at a time when customer
8 consumption has been dropping and the future of gas demand is uncertain. Given
9 this uncertainty, DTE should be looking for places to cut back, not expand
10 investment in its system.

11 **Q What are your concerns about the Taggart Compressor Station Replacement**
12 **project?**

13 A. In total, DTE's Board of Directors has approved \$389.9 million on the Taggart
14 project.¹⁷⁰ In Case No. U-21291, DTE projected to spend \$22 million on the
15 Taggart project in 2026 and \$73 million in 2027 and estimated a total cost for the
16 project of \$100 million.¹⁷¹ In U-21291, DTE characterized the project as a
17 Compressor Replacement Project,¹⁷² where now the Company calls it a Compressor
18 Station Replacement Project. Witness Fedele states that DTE Gas determined
19 during project scope and engineering design that a full compressor station

¹⁷⁰ Company response to AGDG-3.127a, attachment "AGDG-3.127a DTE Gas Taggart Compression Station Replacement Project Resolution."

¹⁷¹ Fedele Direct, p. 89.

¹⁷² Fedele Direct, pp. 84-90.

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 replacement is the most prudent and cost-effective solution.¹⁷³ However, DTE has
2 not filed any evidence in this case to support that determination. DTE has no
3 engineering report evaluating alternatives for the project.¹⁷⁴ DTE has also
4 performed no cost-benefit analysis on the project,¹⁷⁵ and has not even estimated
5 costs for any alternatives to the project.¹⁷⁶ With this paucity of evidence, DTE has
6 not supported its claim that full station replacement for an additional \$289 million
7 over the projection in the last case is the most cost-effective solution.

8 **Q What are your major concerns with DTE's Large Capital Project approach?**

9 **A** My major concerns with DTE's Large Capital Projects are as follows:

- 10 • DTE's approach for assessing alternative solutions is not transparent.
- 11 • DTE does not support its proposed investments with robust quantitative
12 analysis, nor has DTE demonstrated that it conducts such analysis to
13 compare potential solutions, such as a cost-benefit analysis.
- 14 • DTE is expanding capacity and creating redundancy in places where it is
15 not strictly necessary (i.e. not driven by material customer demand).
- 16 • DTE is not considering demand-side alternatives such as demand response
17 or electrification that could potentially mitigate capacity concerns for less
18 money; nor does DTE consider relining pipes.

¹⁷³ Fedele Direct, p. 79.

¹⁷⁴ Ex MEC-27, Company Response to AADG-2.2bvi.

¹⁷⁵ Ex MEC-28, Company Response to AGDG-3.126.

¹⁷⁶ *Id.*

**DIRECT TESTIMONY OF ALICE NAPOLEON FOR MEC
CASE NO. U-21973**

1 **Q What are your recommendations?**

2 A The Commission should disallow inclusion in rate base of the projected bridge
3 period and test year capital expenditures for the East Petoskey, Carlton Main, and
4 Taggart Compressor projects until and unless DTE adequately demonstrates
5 consideration of alternatives and provides robust quantitative analysis comparing
6 the proposed solutions with a reasonable set of alternatives.

7 Also, the Commission should require DTE to consider NPAs wherever possible.

8 **Q Does this complete your direct testimony?**

9 A Yes, it does.



Alice Napoleon, Principal Associate

Synapse Energy Economics | 485 Massachusetts Avenue, Suite 3 | Cambridge, MA 02139 | 617-453-7041
anapoleon@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Principal Associate*, June 2021 – Present; *Senior Associate*, June 2013 – June 2021; *Associate*, July 2008 – June 2013; *Research Associate*, April 2005 – July 2008.

- Provides expert analysis, stakeholder support, research, expert witness services, and consulting services regarding energy efficiency program design and performance, funding and incentive mechanisms, cost-effectiveness screening, potential studies, and strategic planning.
- Develops and sponsors testimony on electric and natural gas energy efficiency plans, energy transition planning and policy, innovative programs, regulatory structures, and advanced metering infrastructure (AMI) proposals in states and provinces across the U.S. and Canada.
- Conducts distributional equity analysis and develops reports on disparate impacts of electric and natural gas infrastructure on economic, social, and health outcomes, as well as options for improving energy equity. Analyzes factors that affect participation in, and the effectiveness of, energy efficiency programs to inform program design and targeting efforts.
- Oversees and conducts interviews and research, including literature reviews and case studies.

Resource Insight, Inc., Arlington, MA. *Research Assistant*, 2003-2005.

Responsible for conducting research and analysis of electric, gas, steam, and water resource issues. Conducted discounted cash flow analysis for asset valuation. Developed market-price benchmarks for analysis of power-supply bids including energy, capacity, ancillary services, transmission, ISO services, losses, and adjustment for load shape. Prepared discovery responses, formal objections, comments, and testimony; collaboratively wrote and edited reports; created and formatted exhibits. Participated in drafting an Energy Plan for New York City. Edited solicitation for competitive power supply to serve aggregated municipal load.

University of Massachusetts, Amherst, MA. *Teaching Assistant*, 2001-2002.

Developed and taught lessons on applied math to a diverse group of incoming graduates; tutored students in microeconomic theory and cost benefit analysis; graded problem sets and memoranda.

International Council for Local Environmental Initiatives, Berkeley, CA. *Cities for Climate Protection Intern for the City of Northampton, MA*, 2001.

Compiled primary and secondary source data on energy consumption and solid waste generation by the municipal government, city residents, and businesses; applied emissions coefficients to calculate total GHG emissions; identified current and planned municipal policies that impact GHG emissions;

researched the predicted local effects of global warming; gathered public feedback to provide acceptable and proactive policy alternatives. Composed a GHG emissions inventory describing research findings; wrote and distributed a policy report and press releases; gave newspaper and radio interviews; addressed public officials and the public during a televised meeting.

University of Massachusetts, Amherst, MA. *Research Assistant*, 2000-2001.

Located federal data sources, identified changes, and updated a research database to evaluate the Habitat Conservation Program; proofread articles and white papers; composed a literature review on land use modelling. Collaboratively administered, tested, and proposed interface enhancements for a web-based data warehouse of regional habitat change research; formally presented the system to an independent research group.

Court Square Data Group, Inc., Springfield, MA. *Administration Manager*, 1998-2000; *Project Administrator*, 1996-1998.

As Administration Manager, analysed profitability and diversity of income sources; managed cash flow, expense, and income data; created budgets; devised and implemented procedures to increase administrative efficiency; implemented new accounting system with minimal disruption to workflow.

As Project Administrator, coordinated implementation of software features; identified opportunities for future development; monitored problem resolution; wrote and coordinated production of a user's manual and questionnaires; edited technical proposals and a business plan.

EDUCATION

University of Massachusetts, Amherst, MA
Master of Public Administration, 2002

Rutgers University, New Brunswick, NJ
Bachelor of Arts in Economics, 1995

Syracuse University, Syracuse, NY, 1994

PUBLICATIONS

Napoleon, A., S. Schadler. 2025. *New York Gas Utilities Digging Consumers Into a Deeper Hole Factsheet*. Synapse Energy Economics for Natural Resources Defense Council.

Napoleon, A., S. Koester, S. Schadler, C. Mattioda. 2024. *Natural Resources Defense Council Comments on Staff Straw Proposal to Modify 16 NYCRR Part 230*. Synapse Energy Economics for Natural Resources Defense Council.

Napoleon, A., T. Nguyen, S. Schadler, S. deLeon, K. Takahashi. 2024. *Comments of Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, Earthjustice, and Alliance for a Green*

Economy on Non-Pipes Alternative Framework Questions. Synapse Energy Economics for Natural Resources Defense Council.

Hopkins, A. S., A. Napoleon, S. Schadler, T. Gyalmo. 2024. *The High Cost of New Jersey Gas Utilities' Leak Prone Pipe Replacement Programs 2024*. Synapse Energy Economics for Natural Resources Defense Council.

Kallay, J., A. Napoleon, E. Ashley, K. Takahashi, T. Woolf. 2024. *Review of New Brunswick Power's 2024/25 to 2026/27 DSM Program Initiatives Update*. Synapse Energy Economics for the New Brunswick Energy and Utilities Board Staff.

Woolf, T., A. Napoleon, D. Goldberg, E. Carlson, C. Mattioda. 2023. *Distributed Equity Analysis for Energy Efficiency and Other Distributed Energy Resources*. Synapse Energy Economics for Lawrence Berkley National Lab and E4TheFuture.

Hopkins, A. S., A. Napoleon, K. Schultz. 2023. *The High Cost of New York Gas Utilities' Leak- Prone Pipe Replacement Programs*. Synapse Energy Economics for Natural Resources Defense Council.

Hopkins, A. S., S. Kwok, A. Napoleon, K. Schultz, K. Takahashi. Presentation: "Massachusetts Clean Heat Standard: Policy and Regulatory Analysis" presented with Conservation Law Foundation, February 2023.

Hopkins, A. S., A. Napoleon, J. Litynski, K. Takahashi, J. Frost, S. Kwok. 2022. *Climate Policy for Maryland's Gas Utilities: Financial Implications*. Synapse Energy Economics for Maryland Office of the People's Counsel.

Hopkins, A. S., S. Kwok, J. Litynski, A. Napoleon, K. Takahashi. 2022. Memo: Evaluation of Draft Consultant Reports in Massachusetts DPU Docket 20-80. Synapse Energy Economics for Conservation Law Foundation.

Frost, J. S. Kwok, K. Takahashi, A.S. Hopkins, A. Napoleon. 2021. *New York Heat Pump Trajectory Analysis*. Synapse Energy Economics for NRDC.

Hopkins, A. S., A. Napoleon, K. Takahashi. 2021. *A Framework for Long-Term Gas Utility Planning in Colorado*. Synapse Energy Economics for the Colorado Energy Office.

Hopkins, A. S., A. Napoleon, T. Woolf, K. Takahashi. 2021. *Long-Term Planning to Support the Transition of New York's Gas Utility Industry*. Synapse Energy Economics for Natural Resources Defense Council.

Kallay, J., A. Napoleon, K. Takahashi, E. Sinclair, T. Woolf. 2021. *Opportunities for Evergy Kansas to Address Energy Equity Within its Integrated Resource Plan and Other Planning Processes*. Synapse Energy Economics for Union of Concerned Scientists.

Takahashi, K., E. Sinclair, A. Napoleon, A. Hopkins, D. Goldberg. 2021. *Evaluation of EnergyWise Low-Income Energy Efficiency Program in Mississippi – Program Performance, Design, and Implications for Low-Income Efficiency Programs*. Synapse Energy Economics for Sierra Club and Gulf Coast Community Foundation.

Kallay, J., A. Napoleon, J. Hall, B. Havumaki, A. Hopkins, M. Whited, T. Woolf, J. Stevenson, R. Broderick, R. Jeffers, B. Garcia. 2021. *Regulatory Mechanisms to Enable Investments in Electric Utility Resilience*. Synapse Energy Economics for Sandia National Laboratories.

Kallay, J., A. Napoleon, B. Havumaki, J. Hall, C. Odom, A. Hopkins, M. Whited, T. Woolf, M. Chang, R. Broderick, R. Jeffers, B. Garcia. 2021. *Performance Metrics to Evaluate Utility Resilience Investments*. Synapse Energy Economics for Sandia National Laboratories.

Hopkins, A., S. Kwok, A. Napoleon, C. Roberto, K. Takahashi. 2021. *Scoping a Future of Gas Study*. Synapse Energy Economics for Conservation Law Foundation.

Kallay, J., A. Hopkins, A. Napoleon, B. Havumaki, J. Hall, M. Whited, M. Chang, R. Broderick, R. Jeffers, K. Jones, M. DeMenno. 2021. *The Resilience Planning Landscape for Communities and Electric Utilities*. Synapse Energy Economics for Sandia National Laboratories.

Napoleon, A., E. Camp, S. Letendre, E. Sinclair. 2021. *Synapse Comments on the Pennsylvania Public Utility Commission on the Utilization of Storage Resources as Electric Distribution Assets - Docket No. M-2020-3022877*. Synapse Energy for the National Resources Defense Council.

Hopkins, A. S., A. Napoleon, K. Takahashi. 2020. *Gas Regulation for a Decarbonized New York: Recommendations for Updating New York Gas Utility Regulation*. Synapse Energy Economics for Natural Resources Defense Council.

Takahashi, K., A. Napoleon. 2020. *Synapse Comments on EfficiencyOne Performance Alignment Study - M09096*. Questions and comments regarding the EfficiencyOne Performance Alignment Study filed on April 21, 2020. Synapse Energy Economics for the Nova Scotia Utility and Review Board.

Napoleon, A., J. Hall, J. Kallay, M. Chang, P. Eash-Gates, N. L. Seidman, C. James, D. Torre, D. Brutkoski, J. Migden-Ostrander, K. Colburn, K. Maddux, D. Harlow, M. Power. 2020. *Energy Infrastructure: Sources of Inequities and Policy Solutions for Improving Community Health and Wellbeing*. Synapse Energy Economics, Regulatory Assistance Project, and Community Action Partnership for the Robert Wood Johnson Foundation.

Napoleon, A., J. Kallay, K. Takahashi. 2020. *Utility Energy Efficiency and Building Electrification Portfolios Through 2025: A Brief on the New York Public Service Commission's Recent Order*. Synapse Energy Economics for the Natural Resources Defense Council.

Takahashi, K., A. Napoleon. 2019. *Synapse Comments on EfficiencyOne's 2019 Rate and Bill Impact Analysis and Model - M09471*. Comments regarding the revised 2019 Rate and Bill Impact Analysis filed by EfficiencyOne on November 1, 2019. Synapse Energy Economics for the Nova Scotia Utility and Review Board.

Napoleon, A., B. Havumaki, D. Bhandari, T. Woolf. 2019. *Review of New Brunswick Power's Application for Approval of an Advanced Metering Infrastructure Capital Project: In the Matter of the New Brunswick Power Corporation and Section 107 of the Electricity Act; Matter No. 452*. Synapse Energy Economics for the New Brunswick Energy and Utilities Board Staff.

Kallay, J., A. Hopkins, J. Frost, A. Napoleon, K. Takahashi, J. Slason, G. Freeman, D. Grover, B. Swanson. 2019. *Net Zero Energy Roadmap for the City of Burlington, Vermont*. Synapse Energy Economics and Resource Systems Group for Burlington Electric Department.

Napoleon, A., T. Woolf, K. Takahashi, J. Kallay, B. Havumaki. 2019. *Comments in the New York Public Service Commission Case 18-M-0084: In the Matter of a Comprehensive Energy Efficiency Initiative*. Comments related to NY Utilities report regarding energy efficiency budgets and targets, collaboration, heat pump technology, and low- and moderate-income customers and requests for approval. Prepared by Synapse Energy Economics on behalf of Natural Resources Defense Council.

Allison, A., A. Napoleon, J. Kallay. 2019. *Maine Low-Income Home Energy Burden Study*. Synapse Energy Economics for the Maine Office of the Public Advocate.

Napoleon, A., D. Goldberg, K. Takahashi, T. Woolf. 2019. *An Assessment of Prince Edward Island Energy Corporations' 2018 - 2021 Energy Efficiency and Conservation Plan*. Synapse Energy Economics for Carr, Stevenson and MacKay as Counsel to the Island Regulatory and Appeals Commission.

Takahashi, K., A. Napoleon. 2018. *Synapse Comments on EfficiencyOne's 2019 Rate and Bill Impact Analysis and Model - M09471*. Comments regarding the revised 2019 Rate and Bill Impact Analysis filed by EfficiencyOne on November 1, 2019. Synapse Energy Economics for the Nova Scotia Utility and Review Board.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation*. Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Hall, J., J. Kallay, A. Napoleon, K. Takahashi, M. Whited. 2018. *Locational and Temporal Values of Energy Efficiency and other DERs to Transmission and Distribution Systems*. Synapse Energy Economics.

Ackerman, F., S. Fields, A. Napoleon, D. Bhandari. 2018. *Can Clean Energy Replace California Oil Production: Petroleum cutbacks and the California economy*. Synapse Energy Economics for the 11th Hour Project.

White, D., K. Takahashi, A. Napoleon, T. Woolf. 2018. *Value of Energy Efficiency in New York: Assessment of the Range of Benefits of Energy Efficiency Programs*. Synapse Energy Economics for Natural Resources Defense Council.

Woolf, T., A. Hopkins, M. Whited, K. Takahashi, A. Napoleon. 2018. *Review of New Brunswick Power's 2018/2019 Rate Case Application*. In the Matter of the New Brunswick Power Corporation and Section 103(1) of the Electricity Act Matter No. 375. Prepared by Synapse Energy Economics for the New Brunswick Energy and Utilities Board Staff.

Fagan, B., A. Napoleon, S. Fields, P. Luckow. 2017. *Clean Energy for New York: Replacement Energy and Capacity Resources for the Indian Point Energy Center Under New York Clean Energy Standard (CES)*. Synapse Energy Economics for Riverkeeper and Natural Resources Defense Council.

Kallay, J., A. Napoleon, M. Chang. 2016. *Opportunities to Ramp Up Low-Income Energy Efficiency to Meet States and National Climate Policy Goals*. Synapse Energy Economics.

Woolf, T., A. Napoleon, P. Luckow, W. Ong, K. Takahashi. 2016. *Aiming Higher: Realizing the Full Potential of Cost-Effective Energy Efficiency in New York*. Synapse Energy Economics for Natural Resources Defense Council, E4TheFuture, CLEAResult, Lime Energy, Association for Energy Affordability, and Alliance for Clean Energy New York.

Napoleon, A., K. Takahashi, J. Kallay, T. Woolf. 2016. "Evaluation, Measurement, and Verification in Virginia." Memorandum prepared by Synapse Energy Economics for Clean Energy Solutions Inc., Virginia Energy Efficiency Council, and Virginia Department of Mines, Minerals and Energy.

Woolf, T., A. Napoleon, M. Whited. 2015-2016. *Comments and Reply Comments in the New York Public Service Commission Case 14-M-0101: Reforming the Energy Vision*. Comments related to Staff's (a) a benefit-costs analysis framework white paper, (b) ratemaking and utility business models white paper, and (c) Distributed System Implementation Plan guide. Prepared by Synapse Energy Economics on behalf of Natural Resources Defense Council and Pace Energy and Climate Center.

Kallay, J., K. Takahashi, A. Napoleon, T. Woolf. 2015. *Fair, Abundant, and Low-Cost: A Handbook for Using Energy Efficiency in Clean Power Plan Compliance*. Synapse Energy Economics for the Energy Foundation.

Woolf, T., K. Takahashi, E. Malone, A. Napoleon, J. Kallay. 2015. *Ontario Gas Demand-Side Management 2016-2020 Plan Review*. Synapse Energy Economics for the Ontario Energy Board.

Biewald, B., J. Daniel, J. Fisher, P. Luckow, A. Napoleon, N. R. Santen, K. Takahashi. 2015. *Air Emissions Displacement by Energy Efficiency and Renewable Energy*. Synapse Energy Economics.

Takahashi, K., A. Napoleon. 2015. "Pursue Behavioral Efficiency Programs." Ed. John Shenot. In *Implementing EPA's Clean Power Plan: A Menu of Options*. National Association of Clean Air Agencies.

Daniel, J. A. Napoleon, T. Comings, S. Fields. 2015. *Comments on Entergy Louisiana's 2015 Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Whited, M., T. Woolf, A. Napoleon. 2015. *Utility Performance Incentive Mechanisms: A Handbook for Regulators*. Synapse Energy Economics for the Western Interstate Energy Board.

Takahashi, K., T. Comings, A. Napoleon. 2014. *Maximizing Public Benefit through Energy Efficiency Investments*. Synapse Energy Economics for Sierra Club.

Keith, G., S. Jackson, A. Napoleon, T. Comings, J. Ramey. 2012. *The Hidden Costs of Electricity: Comparing the Hidden Costs of Power Generation Fuels*. Synapse Energy Economics for Civil Society Institute.

Keith, G., B. Biewald, K. Takahashi, A. Napoleon, N. Hughes, L. Mancinelli, E. Brandt. 2010. *Beyond Business as Usual: Investigating a Future without Coal and Nuclear Power in the US*. Synapse Energy Economics for Civil Society Institute.

Napoleon, A., W. Steinhurst, M. Chang, K. Takahashi, R. Fagan. 2010. *Assessing the Multiple Benefits of Clean Energy: A Resource for States*. US Environmental Protection Agency with research and editorial support from Stratus Consulting, Synapse Energy Economics, Summit Blue, Energy and Environmental Economics, Inc., Demand Research LLC, Abt Associates, Inc., and ICF International.

Napoleon, A., D. Schlissel. 2009. *Economic Impacts of Restricting Mountaintop/Valley Fill Coal Mining in Central Appalachia*. Synapse Energy Economics for Sierra Club, and Appalachian Center for the Economy and the Environment.

Napoleon, A., J. Fisher, W. Steinhurst, M. Wilson, F. Ackerman, M. Resnikoff. 2008. *The Real Costs of Cleaning Up Nuclear Waste: A Full Cost Accounting of Cleanup Options for the West Valley Nuclear Waste Site*. Synapse Energy Economics for Citizens' Environmental Coalition.

Napoleon, A., G. Keith, C. Komanoff, D. Gutman, P. Silva, D. Schlissel, A. Sommer, C. Chen, A. Roschelle, J. Levy, P. Kinney. 2007. *Quantifying and Controlling Fine Particulate Matter in New York City*. Synapse Energy Economics for Coalition Helping Organize a Kleaner Environment, Natural Resources Defense Council (NRDC), Reliant Energy.

Drunic, M., A. Napoleon, E. Hausman, R. Hornby. 2007. *Arkansas Electric Generation Fuel Diversity: Implementation of EPC Act 2005 Amendments to PURPA Section 111 (d)*. Synapse Energy Economics for Arkansas Public Service Commission Staff.

Hausman, E., R. Fagan, D. White, K. Takahashi, A. Napoleon. 2007. *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers*. Synapse Energy Economics for American Public Power Association.

Synapse Energy Economics. 2006. *Portfolio Management: Tools and Practices for Regulators*. Prepared for National Association of Regulatory Utility Commissioners.

Steinhurst, W., A. Napoleon, K. Takahashi. 2006. *Energy in the Northern Forest Region: A Situation Analysis*. Synapse Energy Economics for Northern Forest Center and The North Country Council.

Synapse Energy Economics. 2006. *Ensuring Delaware's Energy Future: A Response to Executive Order Number 82*. Synapse Energy Economics for Delaware Public Service Commission Staff by the Delaware Cabinet Committee on Energy and others.

Fagan, R., A. Napoleon, A. Rochelle, A. Sommer, W. Steinhurst, D. White, K. Takahashi. 2006. *Mohave Alternatives and Complements Study: Assessment of Carbon Sequestration Feasibility and Markets*. Sargent & Lundy and Synapse Energy Economics, Inc. for Southern California Edison.

TESTIMONY

Michigan Public Service Commission (Case No. U-21806): Direct Testimony of Alice Napoleon in the matter of the Application of Consumers Energy Company for authority to increase its rates for the

distribution of natural gas and for other relief. Synapse Energy Economics for Michigan Environmental Council and Sierra Club. April 23, 2025.

Michigan Public Service Commission (Case No. U-21291): Direct Testimony of Alice Napoleon 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. Synapse Energy Economics for Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club. May 7, 2024.

New York Public Service Commission (Case 23-G-0627): Direct Testimony of Alice Napoleon in the Matter of the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation. On behalf of Natural Resources Defense Council. March 1, 2024.

New York Public Service Commission (Case 23-G-0225 and Case 23-G-0226): Direct Testimony of Alice Napoleon regarding proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service and The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service. On behalf of Natural Resources Defense Council. September 1, 2023.

Nova Scotia Utility and Review Board (NSUARB M11003): Evidence of Alice Napoleon in the Matter of The Public Utilities Act, R.S.N.S 1989, c.380, as amended, and the application of Nova Scotia Power Inc. for Authorization to Overspend on Capital Work Order CI47124- Advanced Metering Infrastructure. On behalf of Counsel to Nova Scotia Utility and Review Board. June 22, 2023.

New York Public Utilities Commission (Case No. 22-E-0064 and 22-G-0065): Direct and Rebuttal Testimony of Alice Napoleon and Asa Hopkins regarding Con Edison's proposed gas-side investments as greenhouse gas mitigation strategies and gas extension allowance rule changes and the need for long-term planning for the gas system and adequacy of the company's non-pipe alternatives framework. On behalf of Natural Resources Defense Council, May 2022.

Nova Scotia Utility and Review Board (M10473): Evidence of Alice Napoleon and Kenji Takahashi regarding EfficiencyOne's 2023-2025 DSM Resource Plan, with a focus on the Settlement Plan. On behalf of Counsel to Nova Scotia Utility and Review Board, May 2022.

Pennsylvania Public Utility Commission (Docket No. M-2020-3020824): Revised Direct Testimony of Alice Napoleon and Kenji Takahashi regarding PPL Electric Utilities' proposed Act 129 Phase IV Energy Efficiency and Conservation. On behalf of the Natural Resources Defense Council. January 19, 2021.

Pennsylvania Public Utility Commission (Docket No. M-2020-3020830): Direct testimony of Alice Napoleon and Courtney Lane regarding PECO Energy Company's proposed Act 129 Phase IV Energy Efficiency and Conservation Plan. On behalf of the natural Resources Defense Council. January 14, 2021.

Nova Scotia Utility and Review Board (Matter No. M09519): Evidence of Alice Napoleon regarding Nova Scotia Power's Smart Grid Nova Scotia Project proposal. On behalf of Counsel to the Nova Scotia Utility and Review Board. February 19, 2020.

New York Public Service Commission (Cases 20-E-0380 and 20-G-0381): Direct testimony of Alice Napoleon and Kenji Takahashi regarding proposed earnings adjustment mechanisms in a proceeding on Rates, Charges, Rules, and Regulations related to Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service and National Grid for Gas Service. On behalf of the Natural Resources Defense Council. November 25, 2020.

California Public Utilities Commission (Application Nos. 19-11-003, 19-11-004, 19-11-005, 19-11-006): Prepared Testimony of Alice Napoleon addressing proposals of Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company related to the Energy Savings Assistance (ESA) Program and Budgets for Program Years 2021-2026. On behalf of The Utility Reform Network. September 4, 2020.

California Public Utilities Commission (Application Nos. 19-11-003, 19-11-004, 19-11-005, 19-11-006, 19-11-007): Comments of The Utility Reform Network on the Energy Division Staff Proposal and Utility Applications. On behalf of The Utility Reform Network. July 24, 2020.

Nova Scotia Utility and Review Board (Matter No. M09096): Evidence of Alice Napoleon regarding EfficiencyOne's 2020-2022 DSM Plan. On behalf of Counsel to the Nova Scotia Utility and Review Board. May 28, 2019.

New York Public Service Commission (Cases 19-E-0065 and 19-G-0066): Direct testimony of Tim Woolf and Alice Napoleon regarding energy efficiency targets and incentives in Con Edison rate case. On behalf of the Natural Resources Defense Council. May 24, 2019.

Nova Scotia Utility and Review Board (Matter No. M08604): Evidence of Alice Napoleon regarding the 2019 Demand Side Management Resource Plan. On behalf of Counsel to the Nova Scotia Utility and Review Board. June 13, 2018.

Nova Scotia Utility and Review Board (Matter No. M08349): Evidence of Alice Napoleon regarding Nova Scotia Power's Advanced Meter Infrastructure Proposal. On behalf of Counsel to the Nova Scotia Utility and Review Board. January 18, 2018.

Nova Scotia Utility and Review Board (Case No. M07767): Direct evidence in the matter of the Nova Scotia Power Advanced Meter Infrastructure Pilot. On behalf of Counsel to the Nova Scotia Utility and Review Board. February 16, 2017.

Public Service Commission of South Carolina (Docket No. 2016-223-E): Direct Testimony of Alice Napoleon regarding South Carolina Electric and Gas Energy Efficiency Efforts. On behalf of South Carolina Coastal Conservation League. September 1, 2016.

Nova Scotia Utility and Review Board (Case No. M06247): Direct evidence in the matter of an application by Efficiency Nova Scotia Corporation for approval of its electricity demand-side management plan for 2015. On behalf of Counsel to the Nova Scotia Utility and Review Board. July 14, 2014.

TESTIMONY ASSISTANCE

Public Service Commission of South Carolina (Docket No. 2017-2-E): Direct Testimony of Thomas Vitolo, PhD regarding Avoided Cost Calculations and the Costs and Benefits of Solar Net Energy Metering for South Carolina Electric & Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. March 22, 2017.

State of New Jersey Board of Public Utilities (Docket No. ER16060524): Direct testimony of Tim Woolf regarding the Petition of Rockland Electric Company for Approval of an Advanced Metering Program, and for Other Relief. On behalf of New Jersey Division of the Ratepayer Advocate. September 9, 2016.

Nova Scotia Utility and Review Board (Matter No. M06733): Direct testimony of Tim Woolf regarding EfficiencyOne's 2016-2018 demand-side management plan. On behalf of the Nova Scotia Utility and Review Board. June 2, 2015.

Missouri Public Service Commission (File No. EO-2015-0055): Rebuttal and surrebuttal of Tim Woolf on the topic of Ameren Missouri's 2016-2018 Energy Efficiency Plan. On behalf of Sierra Club. March 20, 2015 and April 27, 2015.

State of New Jersey Board of Public Utilities (Docket No. EO14080897): Direct testimony of Kenji Takahashi regarding the Petition of Public Service Electric & Gas Company to continue its Energy Efficiency Economic Extension Program on a Regulated Basis (EEE Extension II). On behalf of New Jersey Division of the Ratepayer Advocate. November 7, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): Direct testimony of Tim Woolf regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan. On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

State of New Jersey Board of Public Utilities (Docket No. GO12050363): Direct testimony of Maximilian Chang regarding South Jersey Gas Company's proposal to extend and modify its energy-efficiency programs. On behalf of New Jersey Division of the Ratepayer Advocate. November 9, 2012.

State of New Jersey Board of Public Utilities (Docket No. GO12070640): Direct testimony of Robert Fagan regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs. On behalf of the New Jersey Division of the Ratepayer Advocate. October 26, 2012.

State of New Jersey Board of Public Utilities (Docket No. GO11070399): Direct testimony of Robert Fagan regarding Elizabethtown Gas Company's Proposed Energy Efficiency Program. On behalf of New Jersey Division of the Ratepayer Advocate. December 16, 2011.

State of New Jersey Board of Public Utilities (Docket No. GR11070425): Direct testimony of Robert Fagan regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs. On behalf of the New Jersey Division of the Ratepayer Advocate. November 16, 2011.

State of New Jersey Board of Public Utilities (Docket No. GR10030225): Direct testimony of David Nichols regarding New Jersey Natural Gas Company's Proposed Energy Efficiency Program. On behalf of New Jersey Division of the Ratepayer Advocate. July 9, 2010.

Virginia State Corporation Commission (Case No. PUE-2009-00097): Direct testimony of William Steinhurst regarding Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq. On behalf of the Southern Environmental Law Center, Chesapeake Climate Action Network, Appalachian Voices, and the Virginia Chapter of The Sierra Club. March 23, 2010.

Delaware Public Service Commission (Docket No. 07-20): Jointly authored an expert report, with Robert Fagan, William Steinhurst, David White, and Kenji Takahashi, In the Matter of Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company Under 26 DEL. C. §1007 (c) & (d). On behalf of the Staff of Delaware Public Service Commission. April 2, 2009.

State of New Jersey Board of Public Utilities (BPU Docket EM05020106): Direct and surrebuttal testimony of Bruce Biewald, Robert Fagan, and David Schlissel regarding the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations. On behalf of New Jersey Division of the Ratepayer Advocate. November 14, 2005 and December 27, 2005.

Illinois Commerce Commission (Dockets 05-0160, 05-0161, 05-0162): Direct testimony of William Steinhurst regarding Ameren's proposed competitive procurement auction (CPA). On behalf of Illinois Citizens Utility Board. June 15, 2005 and August 10, 2005.

Illinois Commerce Commission (Docket 05-0159): Direct testimony of William Steinhurst regarding Commonwealth Edison's Proposal to implement a competitive procurement process. On behalf of Illinois Citizens Utility Board and Cook County State's Attorney's Office. June 8, 2005 and August 3, 2005.

Resume updated July 2025

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-5.19a

Respondent: H. J. Decker

Page: 1 of 1

Question: Refer to the GDP at page 83, Figure 73, which includes future emission reductions from “New Technologies / Carbon Offsets / Operational Improvements.”

a. Please describe in detail what “new technologies” DTE Gas believes can contribute to future emissions reductions.

Answer: DTE recognizes that emerging technologies—including, but not limited to, renewable natural gas (RNG), hydrogen, gas heat pumps, carbon capture, and geothermal systems—have the potential to contribute to future emissions reduction and continues to monitor their development.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-5.19b

Respondent: H. J. Decker

Page: 1 of 1

Question: Refer to the GDP at page 83, Figure 73, which includes future emission reductions from “New Technologies / Carbon Offsets / Operational Improvements.”

b. Has DTE quantified or otherwise estimated the potential emission reductions specifically from “new technologies”? If yes, please provide the associated analysis and results, in native or Excel-file format with formulas intact and units and assumptions clearly identified.

Answer: New technologies is not a specifically defined category, and therefore DTE Gas has not studied the total potential of all new technologies to reduce emissions. See also MECCUBDG-5.19a.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-3.13

Respondent: H. J. Decker

Page: 1 of 1

Question: Refer to Exhibit A-12 Schedule B5.6 on page 85 where it states, “In each of these scenarios, a safe and reliable natural gas distribution system is required to provide critical energy delivery during the coldest days of the year.” Please clarify whether the Electric scenario assumes continued use of and investment in the natural gas distribution system. If so, please quantify the cost of continued gas system use in the Electric scenario in Figure 75.

Answer: The analysis in Figure 75 shows the cost to an individual homeowner. Overall natural gas distribution system (nor the overall electric distribution system) capital spend is not considered in this analysis.

Attachment: None

MPSC Case No: U-21973

Requester: FLO

Question No.: FLODG-3.31g

Respondent: H. J. Decker

Page: 1 of 1

Question: Refer to Guidehouse's Residential Heat Pump Breakeven Analysis, included in this case as Exhibit A-29.

g. Please describe how DTE has accounted for significant improvements in heat pump efficiency, performance, and lower costs since the study was published in 2022.

Answer: The analysis used data available at that time and has not been updated to account for changes in performance, efficiency or cost.

Attachment: None.

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-5.16a

Respondent: H. J. Decker

Page: 1 of 1

Question: Refer to the GDP at page 86 where it states, “Given the previously discussed costs of electrification... and strong customer preference for natural gas, DTE Gas is not actively pursuing electrification opportunities to meet natural gas customer demand.”

a. Has DTE surveyed customers about their preferences for natural gas versus other alternatives like electrification? If so, please provide all survey materials and results.

Answer: DTE engaged external consultants to conduct customer surveys evaluating preferences for natural gas relative to alternative options, including electrification. The survey material is attached (*DTE 2025 Market Electrification Consideration Survey – Final*)

The results of the survey are included in witness J.L. Huffman’s testimony in U-21973 Exhibit A-25 Schedule O1_DTE Electrification Study - Final

Attachment: U-21973 MECCUBDG-5.16a - 01 DTE 2025 Market Electrification Consideration Survey – Final

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-5.16b

Respondent: H. J. Decker

Page: 1 of 1

Question: Refer to the GDP at page 86 where it states, “Given the previously discussed costs of electrification... and strong customer preference for natural gas, DTE Gas is not actively pursuing electrification opportunities to meet natural gas customer demand.”

b. Please provide DTE’s justification behind the claim that there is a “strong customer preference for natural gas.”

Answer: Please see witness J.L. Huffman’s testimony in U-21973 and Exhibit A-25 Schedule O1_DTE Electrification Study - Final

Attachment: None

Co-Respondent(s): J. L. Huffman

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-5.16c

Respondent: H. J. Decker

Page: 1 of 1

Question: Refer to the GDP at page 86 where it states, “Given the previously discussed costs of electrification... and strong customer preference for natural gas, DTE Gas is not actively pursuing electrification opportunities to meet natural gas customer demand.”

c. Please provide any other surveys, studies, and communications with customers that inform the claim that there is “strong customer preference for natural gas.”

Answer: Refer to the Company’s response to MECCUBDG-5.15a and 5.15b.

Attachment: None

Co-Respondent(s): Legal



DTE Energy
2025 Market Electrification Consideration Study – FINAL
August 20, 2025

Study recap: Online Panel (RepData provided); Non-Sponsored (blind)

Sample Quotas: Michigan (Zip Code Defined)

- Total Surveys – 700 - 1,000

INTRODUCTION (On-line Survey)

(Intro Screen) Thank you for your participation in our survey regarding general opinions about the area in which you live. This survey will take roughly 7 minutes to complete, and your responses will be kept confidential. Thank you again for your time.

Screeners:

S1. Please select the category that contains your age.

1. 17 or younger (Terminate)
2. 18 to 24
3. 25 to 34
4. 35 to 44
5. 45 to 54
6. 55 to 64
7. 65 or older
8. Refused (Terminate)

S2. Are you the person in your household who makes or shares in the financial decisions related to your energy bills? (Terminate if no)

S3. Are you the person in your household who makes or shares in the decisions concerning your home energy needs, such as electricity, natural gas, and propane? (Terminate if no)

S4. What is the zip code or postal code of your primary residence where you live six months or more a year? (Terminate if not on list)

S5. Do you own or rent your current home?

1. Own
2. Rent (Terminate)



S6. How would you classify your current home? Is it a(n) . . .

1. Apartment (Terminate)
2. Condominium
3. Duplex or townhome
4. Single family home
5. Mobile Home
6. Something else (Terminate)
7. Don't know/Not applicable/Refused (Terminate)

S7. Which of the following best describes your current employment status?

1. Part-time (under 40 hours a week)
2. Full-time
3. Unemployed (skip S8)
4. Retired (skip S8)
5. Prefer not to answer

S8. In what industry are you or anyone in your household currently employed full or part time? (Accept multiple responses; ~~rotate responses~~)

1. Aerospace
2. Agriculture
3. Business Services
4. Chemical
5. Computers/Information Technology
6. Construction
7. Consumer Products or Services
8. Defense
9. Education (Public sector)
10. Education (Private sector)
11. Energy & Utilities (Terminate)
12. Entertainment
13. Financial Services
14. Food
15. Government (City/local/county/state)
16. Government (Federal)
17. Health Care (Hospital/doctor office/nursing home, etc.)
18. Health Care (Insurance)
19. Hospitality
20. Insurance (non-healthcare)
21. Manufacturing
22. Mass Media
23. Raw Materials & Natural Resources
24. Real Estate
25. Retail
26. Telecommunications



- 27. Transport/Logistics
- 28. Travel & Leisure
- 29. Other
- 30. Don't know/Refused (Terminate)

A. HOME ENERGY USAGE/SATISFACTION/LOYALTY

Definitions:

For this survey, please read the following definitions of two types of household energy.

- **Natural Gas** – natural gas is normally supplied through a pipe connected to a main line on the street and can be used to fuel appliances like a central heating system, clothes dryer, stovetop or water heater.
- **Propane** - propane is normally supplied in smaller tanks for barbeque grills or can also be supplied in larger tanks for home heating, water heating, cooking and clothes drying.

Click "Next" below to continue.

1. Which energy type do you **primarily use** for your...? (Terminate if Propane is not answered for home heating or water heating)

- a) Home heating
- b) Water heater
- c) Stovetop cooking
- d) Oven
- e) Clothes drying
- f) Fireplace
- g) Back-up generator

(Program as a grid / one screen for all questions)

- 1. Electricity
- 2. Natural Gas (Terminate if answered to any)
- 3. Propane
- 4. Heating Oil
- 5. Geothermal
- 6. Other
- 7. Don't have
- 8. I don't know



2. How do you rate your **overall satisfaction** with (insert energy type) for your...? (Scale – 1 = Very Dissatisfied; 10 = Very Satisfied)
 - a) Home heating
 - b) Water heating
 - c) Stovetop cooking
 - d) Oven
 - e) Clothes drying
3. And if **any** of the following energy types were currently available for your home, which energy type would you **prefer** for...?
 - a) Home heating
 - b) Water heater
 - c) Stovetop cooking
 - d) Oven
 - e) Clothes drying
 1. Electricity
 2. Natural Gas
 3. Propane
 4. Heating Oil
 5. Geothermal
 6. Other (please specify)
 7. Do not use
 8. I don't know
4. (Ask if propane for home heating) Have you ever considered switching your current **home heating** energy source to electric?
 1. Yes (Open-end Question: Why have you not switched to electric?)
 2. No
5. If natural gas was available in your area and you **had** to choose between natural gas or electric for your household energy source (home heating, water heating and cooking), which would you choose?
 1. Electricity (Open-end Question: Why would you choose electricity?)
 2. Natural Gas (Open-end Question: Why would you choose natural gas?)
- 5B. [Ask if Q5 = Electricity] How likely would you be to switch to electric if your monthly energy bills doubled and there would be additional costs to switch your current appliances to electric?

[Use a scale 1-10 where 1=Very unlikely and 10=Very likely]



- 5C. [Ask if rating is => 7] If you were to switch your current appliances to electric, what would be your estimated costs for this transition? [That way we can define intent and perhaps a respondent defined budget/estimate to do so]
6. Which of the following reasons would influence your home energy decisions for your primary residence (for example, changing from one energy source to another...from propane to electricity or propane to natural gas)? (Check all that apply) [RANDOMIZE]
1. Friends/family/neighbors recommendations
 2. Information on social media
 3. Advertising from energy companies
 4. Advertising from HVAC companies
 5. Online education about home energy
 6. Financial incentives, such as rebates from an energy company
 7. If everyone else is making home energy changes, I should too
 8. I want the best value for my home (lowest monthly energy bill)
 9. HVAC Contractor/dealer recommendation
 10. Environmental / Climate Change
 11. Builder recommendation
 12. Safety
 13. Other (specify) _____
 14. Don't know/Unsure
7. Choose the one energy source that best represents your opinion on the following attributes: (Electric, Natural Gas, Propane, Heating Oil, Geothermal, Solar, Wind)
1. Is the **most affordable** energy source
 2. Is the **most reliable** energy source
 3. Is the **cleanest** energy source
 4. Is the energy source with the **least negative impact** on the environment
 5. Is the energy source with **most negative impact** on the environment

B. NATURAL GAS ENERGY PERCEPTION

8. Have you ever used Natural Gas in a previous home?
1. Yes
 2. No
 3. Don't know

For this section, please think about natural gas in general. Even if you do not have natural gas or have not used it previously, we still want your opinions.

9. Please rate your agreement with each of the following statements about natural gas. If you do not know, then select "NA" (Rotate Statements; Scale – 1 = Strongly Disagree; 10 = Strongly Agree) [RANDOMIZE]

Natural gas...



- a. Is a safe energy source
- b. Is an environmentally friendly energy source
- c. Is a clean (produces less carbon emissions) energy source
- d. Is a reliable energy source
- e. Is an affordable energy source
- f. Energy prices are stable over time
- g. Is an efficient energy source
- h. Is good for the economy
- i. Supports our nation's energy independence
- j. Provides abundant energy supply

Split Screen [RANDOMIZE]

- k. Is the best choice for cooking
- l. Provides more continuous hot water
- m. Provides the most comfortable home heating
- n. Costs less for water heating
- o. Costs less for home heating
- p. *Validation Question – Please select #7 for validation purposes (If other than #7 answered – Terminate. Programming note – Never have this question appear first in the randomization)*
- q. Is the best overall value for household energy
- r. Is the best energy for higher end luxury appliances
- s. Is energy that will help achieve carbon emission goals
- t. Provides the energy needed for energy companies to generate electricity
- u. Increases the value of your home

10. To the best of your knowledge, is natural gas an option for your home?

- 1. Yes
- 2. No
- 3. Unsure

Our last few questions are for demographic purposes only.

D1. Is your household's total annual income before taxes?

- 1. Less than \$50,000
- 2. \$50,000 but less than \$75,000
- 3. \$75,000 but less than \$100,000
- 4. \$100,000 but less than \$150,000
- 5. \$150,000 but less than \$250,000
- 6. \$250,000 or more
- 7. Prefer not to answer

D2. Please specify your ethnicity?



1. White
2. Black or African American
3. Hispanic or Latino
4. Asian or Pacific Islander
5. Native American or American Indian
6. Other
7. Prefer not to answer

D3. Finally, what is your gender?

1. Male
2. Female
3. Other (specify)_____
4. Prefer not to answer

Those are all of the questions that we have for you. Thank you for your time.

2025 Electrification Consideration Study Timeline

To be determined during kick-off call.

Questionnaire Development	
Questionnaire Additions and Revisions	
Questionnaire Finalization	
Programming and Testing	
Survey Programming	
Survey Testing	
Final Survey Sign-off	
Survey Fielding	
Survey Soft Launch	
Survey Full Launch	
Close Survey (Out of field)	
Tabulation and Reporting	
Final Tabulation	
Final Report	



MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-3.16f

Respondent: H. J. Decker

Page: 1 of 1

Question: Refer to Decker direct, Q&A15, Exhibit A-12 Schedule B5.6 and Case No. U-21291, Order, November 7, 2024, pp. 216-217:

f. Describe in detail any coordination or other efforts between DTE Electric and DTE Gas regarding the evaluation or impacts of electrification on the companies' respective distribution capital investment plans.

Answer: There are no coordinated efforts between DTE Gas and DTE Electric to evaluate the impacts of electrification.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-3.16g

Respondent: H. J. Decker

Page: 1 of 1

Question: Refer to Decker direct, Q&A15, Exhibit A-12 Schedule B5.6 and Case No. U-21291, Order, November 7, 2024, pp. 216-217:

g. Produce the presentation from the April 10, 2025 stakeholder meeting and any notes on that meeting taken by DTE.

Answer: See attached presentation from the April 10, 2025, meeting. DTE Gas does not have any notes taken at the meeting.

Attachment: U-21973 MECCUBDG-3.16g GDP Summary Presentation



DTE Gas Delivery Plan Summary

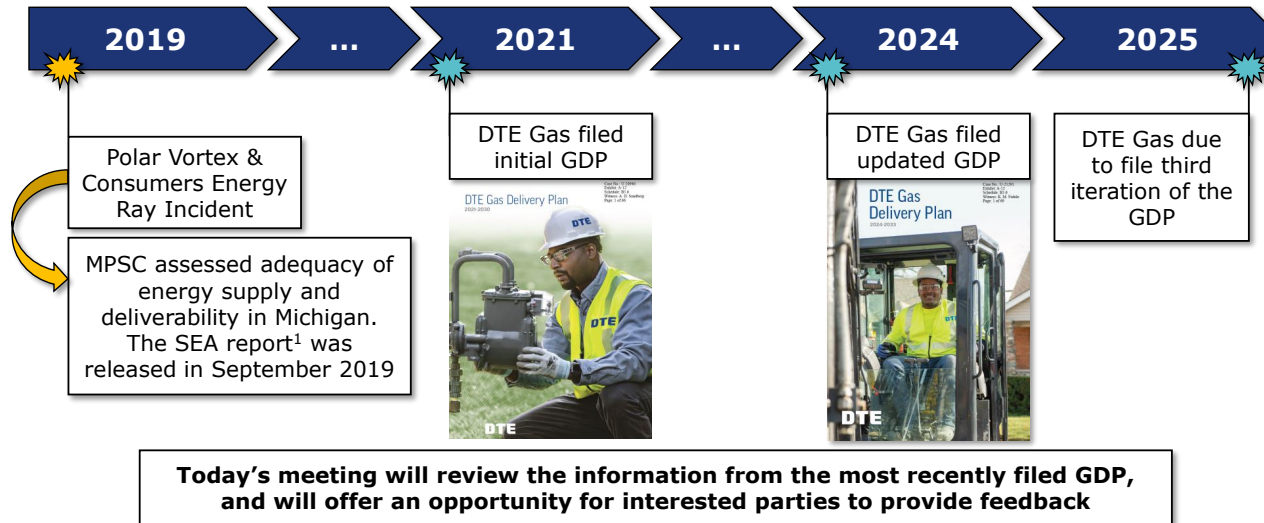
HJ Decker, Vice President – Gas Sales & Supply
Kelly Fedele, Director – Engineering

April 10, 2025

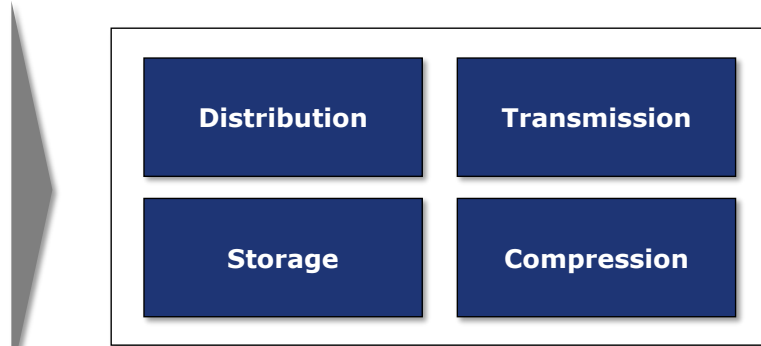
The purpose of today's meeting is to engage interested parties involved in the development of the next Gas Delivery Plan (GDP)

- In the last case the Commission directed DTE Gas to "meaningfully engage interested parties" in the next update of the GDP
- Today, we'll begin by review the genesis of the GDP and review what was in our most recently filed GDP
- At the end, we'll open it up for discussion to enable all attendees to provide suggestions and thoughts for DTE to consider as we develop our next GDP to be filed at the end of 2025

The MPSC released the State Energy Assessment (SEA) report in 2019; and as a result, DTE Gas agreed to file a GDP that specifically addressed safety & reliability



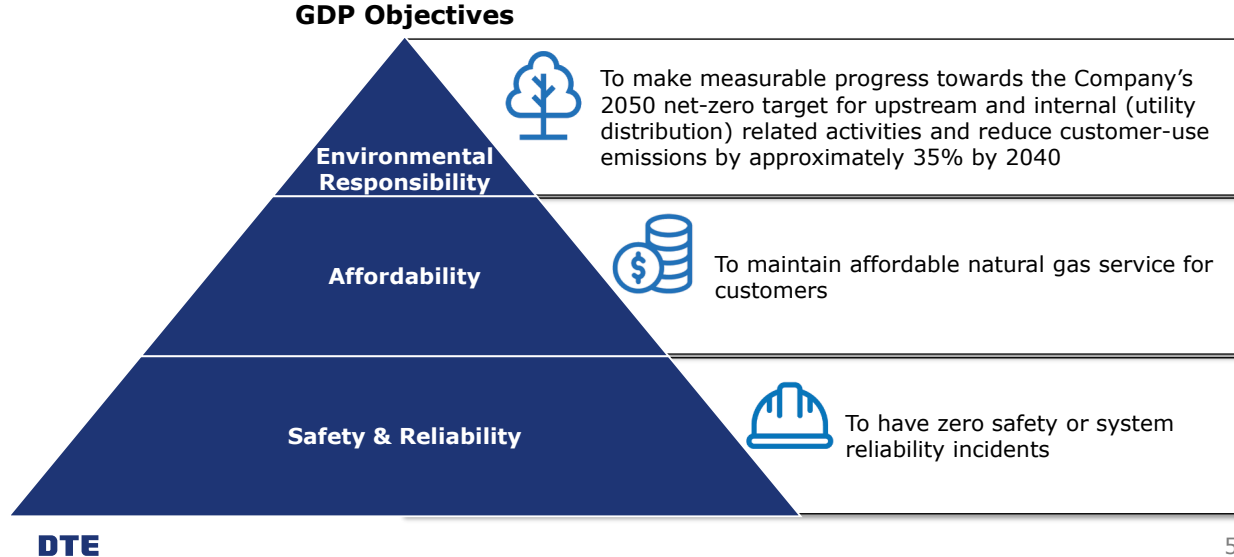
The GDP provides a summary of the DTE Gas long-term vision for the system and details the planned top priorities and associated countermeasures that address each asset category



DTE Gas intends to use the GDP as an effective communication and educational tool for the Commission and other stakeholders interested in the drivers behind the Company's capital investments

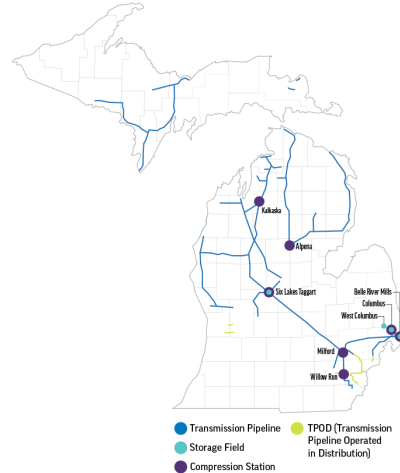
Vision and Objectives

DTE Gas's vision prioritizes safe and reliable natural gas service and maintains it in an affordable and environmentally responsible way for generations of Michiganders to come



System Overview

DTE Gas delivers natural gas through approximately 23,000 miles of pipeline distributed across the state of Michigan



- DTE Gas's system includes approximately 2,000 miles of transmission and 21,000 miles of distribution pipeline
- The Company owns and operates four underground storage fields, with a total of 165 active wells that can hold up to 139 Bcf of working gas
- DTE Gas has approximately 180,000 horsepower (HP) of compression distributed across seven compressor stations around the state

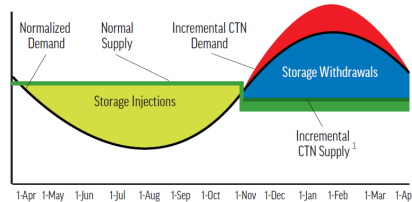
The main priority for DTE Gas is to maintain the safety and reliability of all the Company's assets

Demand and Supply

The focus of the DTE Gas demand and supply plan is to successfully execute three key strategies to maintain a safe and reliable natural gas service in an affordable and environmentally responsible way

1 Utilize storage assets to manage system demand during the winter heating season

Illustrative DTE Gas Storage Annual Cycle



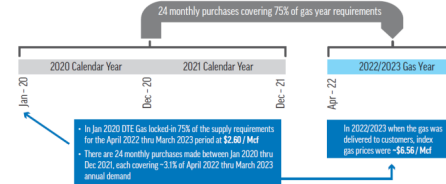
2 Ensure reliability of supply through a system of interconnects and transport agreements

DTE Gas Transportation Portfolio

Supply Basin Percentage of Total	Winter 22-23
Canadian	
Great Lakes Gas	8.2%
Viking	5.2%
Vector	4.4%
Alliance	12.5%
	30.3%
Mid-Continent	
ANR Southwest	16.0%
Panhandle Eastern	16.2%
	32.2%
Appalachian	
PEPL Falcon	3.7%
Shelbyville	15.0%
NEXUS - Kensington only	9.4%
NEXUS - Clarington/Teal	9.4%
	37.5%
Total All Pipelines	100%

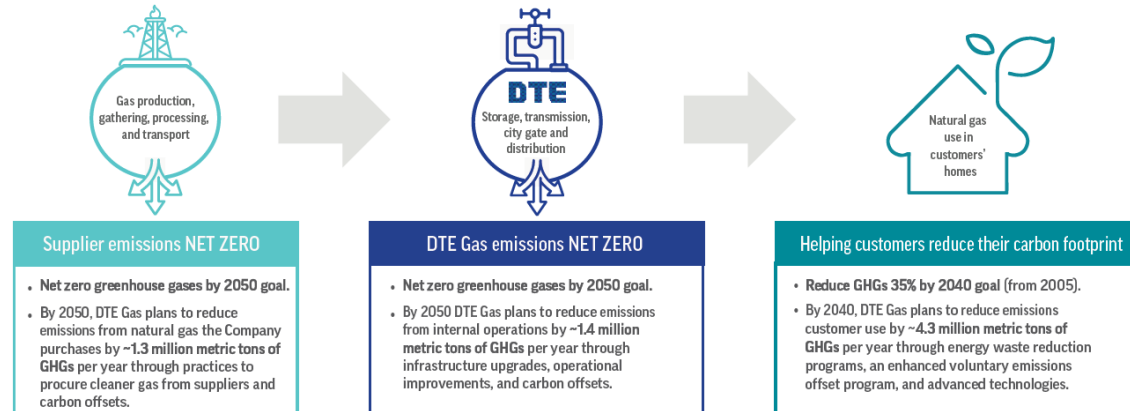
3 Execute a purchasing strategy to minimize price volatility associated with extreme weather event

DTE Gas GCR VCA² Program Example



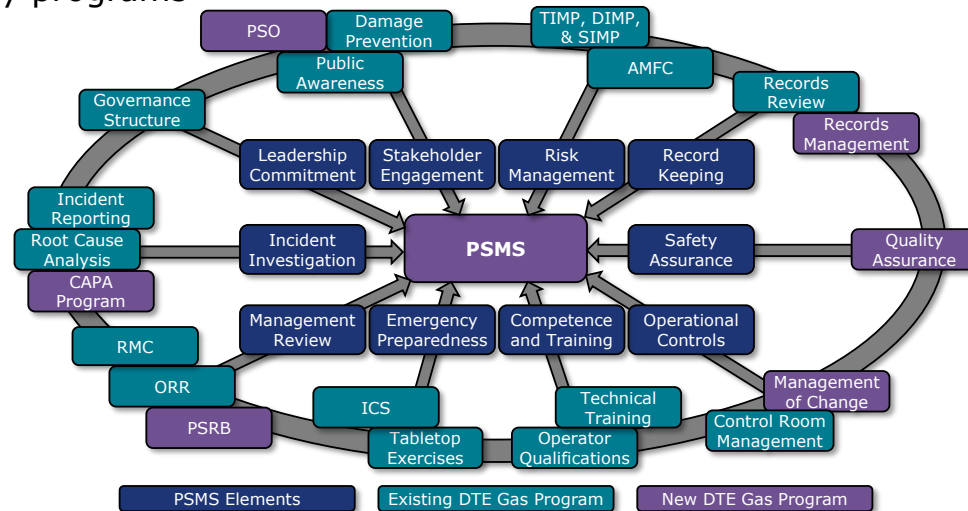
Demand and Supply

Although DTE Gas was not ordered to address environmental issues in the GDP, the Company included a discussion of the steps taken to reduce emissions



The plans includes the long-term goal to reduce internal and upstream emissions to net zero by 2050, and working to reduce downstream emissions by 35% by 2040

DTE Gas's commitment as a prudent utility operator is to identify and mitigate potential system risks and to continuously improve pipeline safety programs



Gas Safety

While the potential for incident is remote, DTE Gas recognizes the importance of reducing overall risk to its system by prioritizing a series of robust countermeasures

Risk Matrix Example

					HAZARD SEVERITY OUTCOME							
					FREQUENCIES							
					Almost Impossible	Rare	Possible	Likely	Very Likely	Highly Likely	Almost Certain	
Consequences (1 to 7)	Health & Safety	Customer Impact	Financial Loss and Regulatory Response	Environmental Impact	1A	1B	1C	1D	1E	1F	1G	
					2A	2B	2C	2D	2E	2F	2G	
					3A	3B	3C	3D	3E	3F	3G	
					4A	4B	4C	4D	4E	4F	4G	
					5A	5B	5C	5D	5E	5F	5G	
					6A	6B	6C	6D	6E	6F	6G	
					7A	7B	7C	7D	7E	7F	7G	

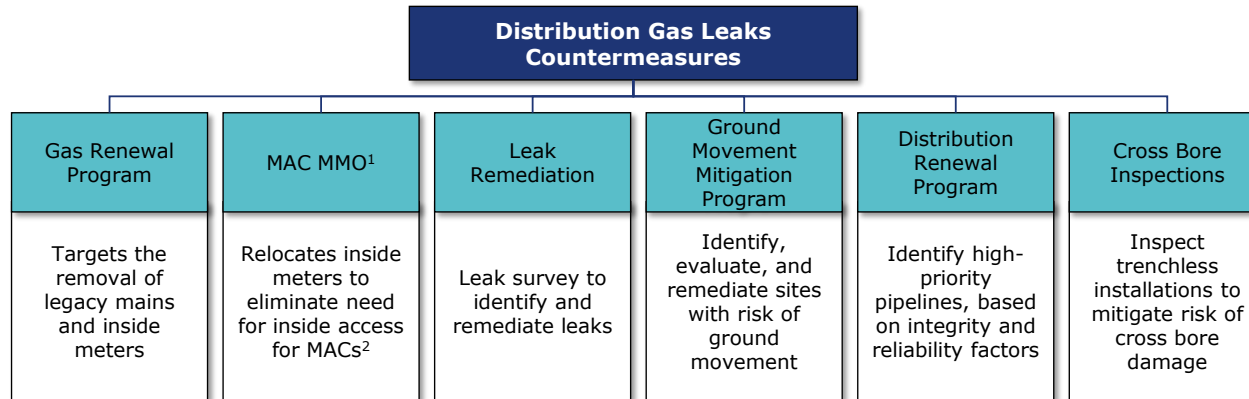
Top Industry Risks and Associated DTE Gas Countermeasures

Industry Risk	DTE Gas Countermeasures
Gas Supply & Deliverability	Belle River Dehydration Unit Redundancy
	Installation of Additional System Interconnects
	Transmission Renewal Program: Van Born Project
	Implementation of a Distribution System Planning Team
	Implementation of a Probabilistic Risk Assessment Model
Transmission Pipeline Failure	Compressor Renewal Program
	Transmission Renewal Program
	Records Management Program
	Transmission Maximum Allowable Operating Pressure (MAOP) Records Remediation
	Class 1 and Class 2 Facility Integration into GIS and the Probabilistic Risk Model
Distribution Gas Leaks	ILI Expansion Program
	Gas Renewal Program
	Meter Assembly Check - Meter Move Out (MAC MMO) Program
	Leak Remediation
	Ground Movement Mitigation Program
	Distribution Renewal Program
	Distribution MAOP Records Remediation
System Overpressure	Cross Bore Inspections
	Risk-Based Overpressure Protection Program
Storage Well Unintended Gas Release	Legacy Regulator Remediation/Replacement
	Well Renewal Program
Cyber/Physical Security	Well Pad Expansion Program
	DTE Gas Site Security Program
Excavation Damage	Damage Prevention Field Team

DTE

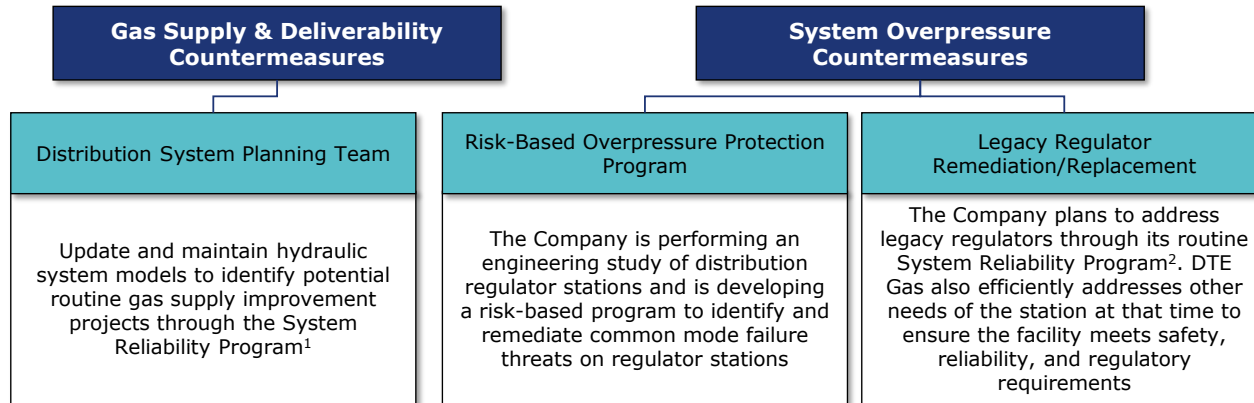
DTE Gas is planning to invest over \$4.5 billion on PSMS risk mitigation projects in its GDP to ensure the safety and reliability of its system

DTE Gas has six countermeasures to address the key distribution system industry risk of distribution gas leaks



Distribution

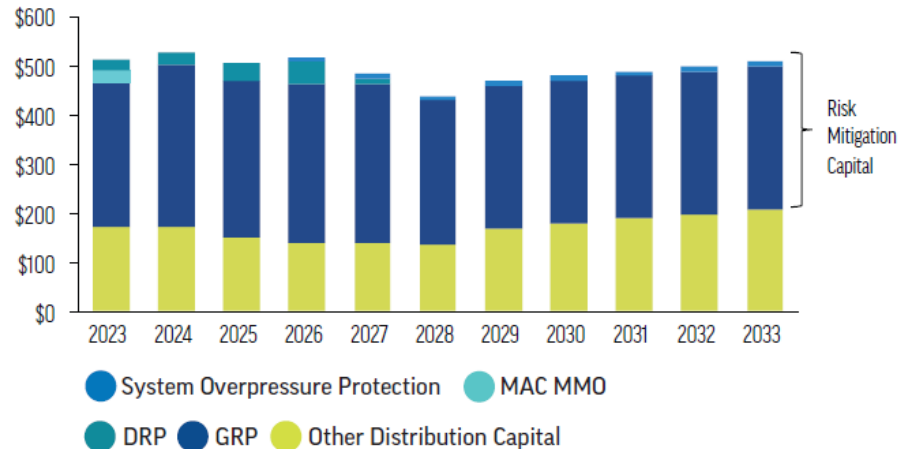
DTE Gas also has countermeasures for the two other distribution system industry risks of gas supply & deliverability and system overpressure



Distribution

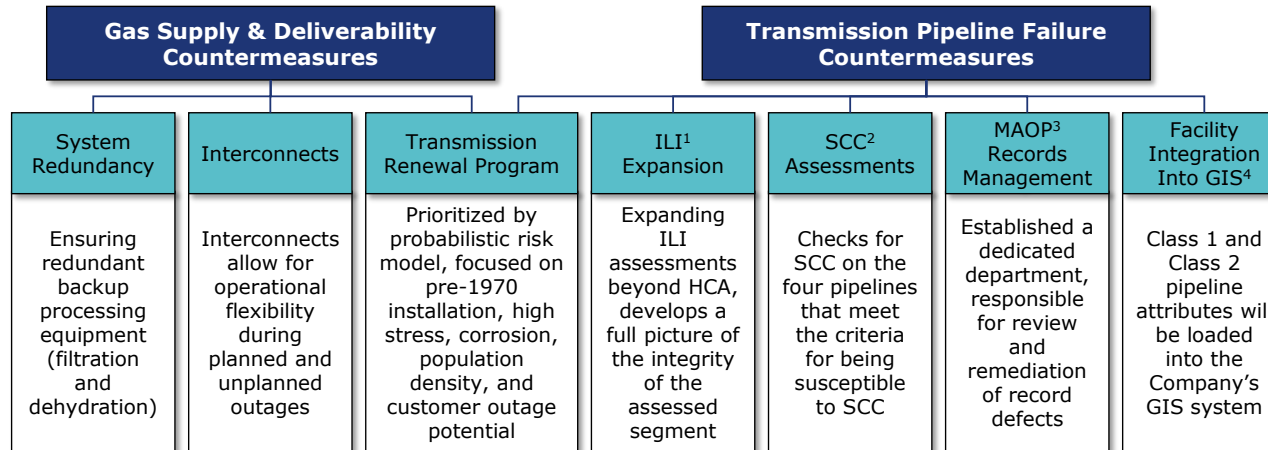
DTE Gas is planning for the annual capital investment in the distribution system to remain between \$435 - \$525M per year, with 66% of this capital dedicated to risk mitigation activities

Distribution 10-year Capital Plan



Transmission

DTE Gas has seven key countermeasures that address both transmission system industry risks of gas supply & deliverability and transmission pipeline failure



Transmission

DTE Gas plans to make significant capital investments in the transmission system over the next 10 years as it continues to implement the Transmission Renewal Program

Top 10 TRP Pipelines

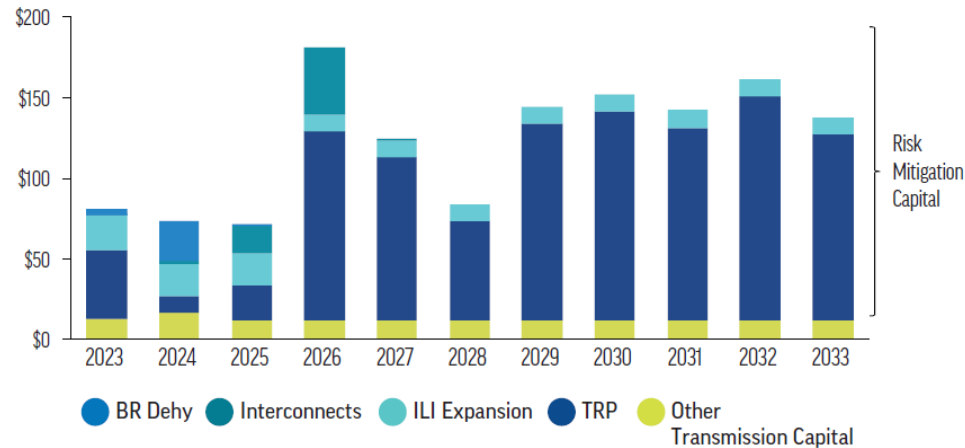
Rank	Pipeline / System	Risk Type	Customer Outage Potential	Mitigation
1	Milford - Belle River (E)	Integrity	-	Additional ILI and Defect Remediation, and Patrolling
2	Milford Loop (L)	Integrity	-	Additional ILI and Defect Remediation, and Patrolling
3	Austin - Detroit A	Integrity	-	Segment Replacement
4	Van Born 30"	Integrity	-	Segment Replacement
5	Evergreen	Integrity	-	Segment Replacement
6	Austin - Detroit B	Integrity	-	Segment Replacement
7	Belle River - Detroit	Outage and Integrity	70,000	Additional ILI and Defect Remediation, Patrolling, and Looping and Alternate Supply through Consumers Energy Interconnect or Distribution System Upgrades
8	Columbus (30)	Integrity	-	Segment Replacement
9	Austin - Detroit C	Integrity	-	Segment Replacement
10	Van Born 36"	Outage	160,000	Additional ILI and Defect Remediation, Patrolling, Regulation, and RCVs

- DTE Gas developed the TRP following a risk-based approach to support integrity and reliability of its system
- The TRP is a countermeasure that addresses both Gas Supply and Deliverability and Transmission Pipeline Failure risks
- The Company utilized its risk model to prioritize pipelines that need upgrading or replacement based on the following factors: Pre-1970 installation, high stress in steel, Corrosion growth rates, population density, customer outage potential, and comprehensive ILI data

Over the next 10 years, roughly 90% of DTE Gas planned transmission capital expenditures will be focused on PSMS countermeasures

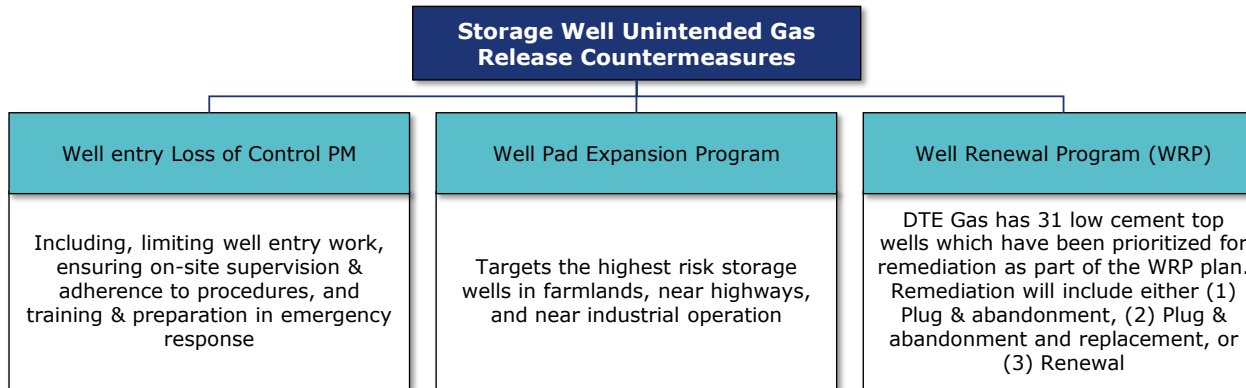
Transmission

Transmission 10-year Capital Plan



Storage

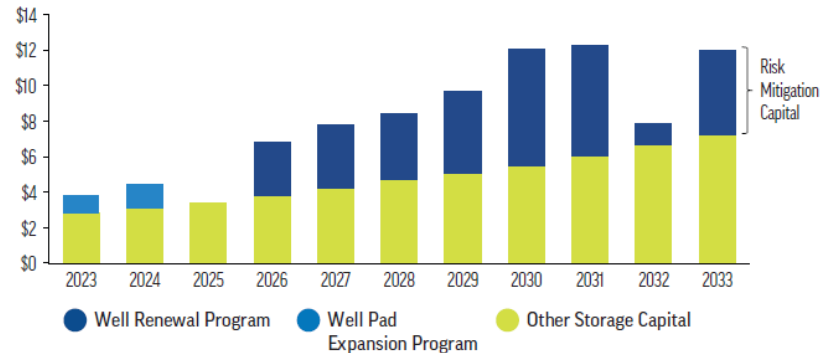
The top industry risk for storage assets is a storage well unintended gas release, and DTE Gas has three countermeasures planned to mitigate this risk



Storage

DTE Gas is planning to approximately allocate \$36M over the next 10 years to implement these countermeasures and mitigate the industry risk of a storage well unintended gas release

Storage 10-year Capital Plan



By 2033, DTE Gas plans to have completed all the well pad expansions and addressed 20 of its 31 low cement top wells through the Well Renewal Program

Compression

The main industry risk impacting compression is Gas Supply & Deliverability, which is planned to be mitigated through the development of a Compression Renewal Program

Compression Replacement Program (CRP)

Targeted Units for CRP

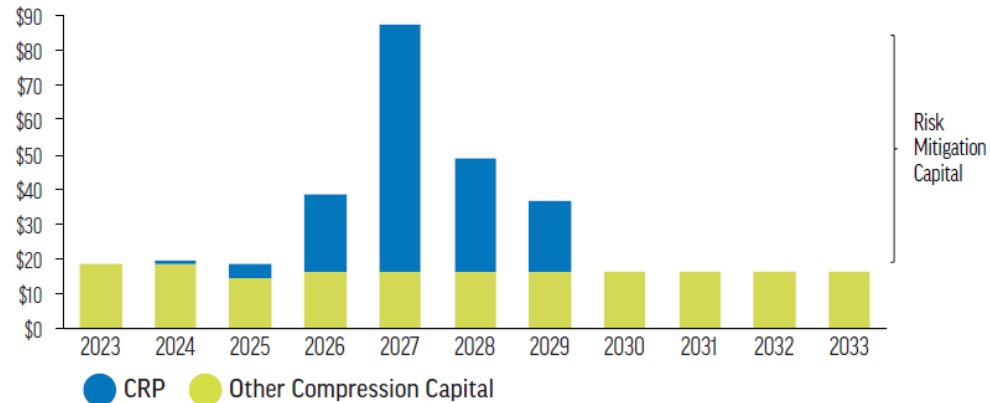
Compressor Station	Compression Equipment	# of Units	Total HP	Year Installed
Taggart	Taggart Plant 1 (Ingersoll Rand)	11	20,000	1955
	Taggart Plant 2 (Ingersoll Rand)	10	20,000	1959
Belle River	BRM Plant 1 (GMVCs)	3	5,000	1964
	BRM Plant 2 (Z-330s)	2	17,000	1972
	BRM Plant 3 Unit 6 (Mars-100)	1	15,000	2007
	Unit 7 (Centaur-50)	1	6,130	2016
	Unit 8 (Taurus-70)	1	10,915	2016
Columbus	Columbus (Delavals)	2	4,000	1972
Alpena	Alpena (White Superior)	1	2,000	1975
Milford	Milford Plant 1 (Delavals)	4	16,000	1979
	Milford Plant 2 & 3 (Taurus-70)	3	32,745	2018
Kalkaska	Kalkaska (GMVHs)	3	8,100	1992
Willow Run	Willow Run Plant 1 (CAT/Ariel)	1	4,735	2009
	(Taurus-60)	1	7,700	2018
	Willow Run Plant 2 (Cat/Ariel)	3	10,000	2018
Reed City	Retired	Retired	Retired	1997
	TOTAL	47	179,325	

- This program plans to target aging compression assets and prioritize replacement based on age, utilization, spare parts availability, and reliability
- This will ensure DTE Gas has reliable horsepower capacity to meet current and future customer demands
- When completed, the Company plans to have replaced 82,000 HP or approximately 46% of the total fleet HP

Compression

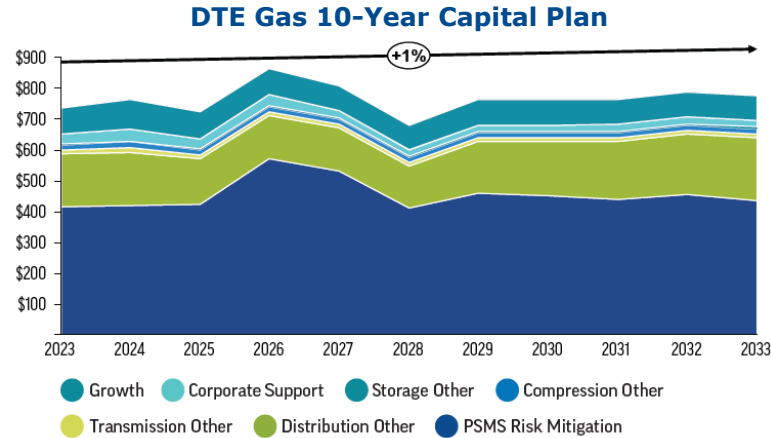
DTE Gas's compression system planned capital investments over the next 10 years remain focused on its critical routine capital programs, with plans to ramp up the Compression Replacement Program

Compression 10-Year Capital Plan



Financial Summary

DTE Gas's plan outlines investments totaling approximately \$7.7 billion over the 10-year period (2024-2033)



Approximately 60% of DTE Gas's planned investments are dedicated to the PSMS countermeasures. The remaining 40% of the plan is largely comprised of routine, system expansion, and corporate support capital; investment that is critical to the sustained operation of the system

DTE Gas was ordered to provide an updated GDP by the end of 2025 that includes consideration of the energy transition



The GDP is grounded in the Company's commitment to prioritize safe and reliable natural gas service in an affordable and environmentally responsible manner



This plan communicates both the Company's near-term and long-term capital investments guided largely by countermeasures designed to mitigate the top industry risks. Going forward, DTE Gas plan to update this document on a regular basis to reflect changing opportunities and challenges in the system, industry, and communities

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-3.22b

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to Huffman direct, Q&A 104:

b. Has DTE changed any CAP model inputs, methods, or assumptions since or in response to the Commission Order dated November 7, 2024 in Case No. U-21291? If yes, describe all such changes in detail.

Answer: Yes.

In response to the Commission Order in Case No. U-21291, the following changes were made to the CAP Model:

- a. Capital Structure update consistent with Commission Order in Case No. U-21291
- b. Monthly Customer Charge update consistent with Commission Order in Case No. U-21291
- c. Monthly IRM Surcharge update consistent with Commission Order in Case No. U-21291
- d. Distribution Charge update consistent with Commission Order in Case No. U-21291
- e. Depreciation Rate update consistent with Commission Order in Case U-21291 and Depreciation Case No. U-21384
- f. Property Tax Millage Rate update consistent with Case No. U-21291

Additionally, generic pricing and meter costs were updated on August 1, 2025.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-5.17ai-iii

Respondent: H. J. Decker

Page: 1 of 1

Question: Refer to page 85 of the GDP where it states, “NPAs are alternative investments that allow a utility to eliminate or delay the implementation of a traditional pipeline project.” Does DTE consider NPAs when assessing solutions for a traditional pipeline project?

a. If so, please provide the following information:

- i. Describe in detail what type of NPAs the Company considers (for example, electrification, demand response, etc.).
- ii. Describe in detail what type of traditional pipeline projects the Company considers NPAs for.
- iii. For how many traditional pipeline projects has the Company considered NPAs to-date?

Answer: i. Yes, DTE Gas considers NPAs when assessing project solutions. DTE Gas does not specify types of NPAs it considers. DTE Gas considers solutions that can be proven to meet the project’s objectives as it relates to safety and affordability. A specific example was provided on page 86 of the Gas Delivery Plan; Exhibit A-12 Sch B5.6, of Remote-Control Valves combined with additional interconnects on the Van Born project that avoided 22 miles of new pipeline. At this time, DTE Gas does not consider geographically targeted electrification of residential gas use to be a proven solution.

ii. There is no set criteria for the type of projects that explore alternative solutions. DTE Gas relies on the expertise of its engineers to identify cost effective alternatives when available.

iii. DTE Gas does not track the number of projects where alternative investment options were considered.

Attachment: None

Co-Respondent(s): K. M. Fedele

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-7.1ai

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to the response to MECCUBDG-3.21, confidential attachment “NDA U-21973 MECCUBDG-3.21 Capm136 08_01_25_Final”, “Mcf Tables” tab.
a. Refer to the “Mcf Tables” tab where it states, “UPDATED 8/27/2010.”
i. Please clarify what values and assumptions on this tab were updated on 8/27/2010.

Answer: Mcf table updated to reflect 15-year weather normalization on 8/27/2010.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-7.1aii

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to the response to MECCUBDG-3.21, confidential attachment “NDA U-21973 MECCUBDG-3.21 Capm136 08_01_25_Final”, “Mcf Tables” tab.
a. Refer to the “Mcf Tables” tab where it states, “UPDATED 8/27/2010.”
ii. Has DTE updated any values or assumptions on this tab since 8/27/2010? If so, please describe in detail these updates. If not, please explain why not.

Answer: DTE Gas has not made any updates to the Mcf Tables since August 27, 2010. Following a reasonable and diligent review of available records, the Company did not locate any documentation reflecting later revisions or providing an explanation for the absence of further updates. Accordingly, DTE is not in possession of additional information regarding the rationale for the lack of updates to this tab after 2010.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-7.1bi

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to the response to MECCUBDG-3.21, confidential attachment “NDA U-21973 MECCUBDG-3.21 Capm136 08_01_25_Final”, “Mcf Tables” tab.
b. Refer to the “Mcf Tables” tab where it states, “Annual Normal Heating Degree Days 1995-2009” and “3) Normals based on 1961-1990.”
i. Please describe in detail how DTE calculated Annual Normal Heating Degree Days.

Answer: Annual normal HDDs reflect the 15-year regional averages for years 1995-2009. For additional information please refer to the information provided in response to MECCUBDG-7.1aii

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-7.1bii

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to the response to MECCUBDG-3.21, confidential attachment “NDA U-21973 MECCUBDG-3.21 Capm136 08_01_25_Final”, “Mcf Tables” tab.
b. Refer to the “Mcf Tables” tab where it states, “Annual Normal Heating Degree Days 1995-2009” and “3) Normals based on 1961-1990.”
ii. Please clarify which historical years were used to calculate Annual Normal Heating Degree Days on this tab.

Answer: Please refer to the information provided in response to MECCUBDG-7.1aii and MECCUBDG-7.1bi.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-3.23d

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to DTE Gas Company's current Rate Book, section C8 (Customer Attachment Program).

d. Please provide the assumptions and methods used to calculate the Service Line Limit for each geographic location and category of customers, such that the Service Line Limit equals the "point at which the cost of the customer's service requirements are greater than the allowance based on the Cost of Service Model." (C8.5).

Answer: Since DTE Gas maintains a consistent service line limit of 400 feet for all customers, as outlined in section C8.5, the Company does not perform such analysis.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-3.23f

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to DTE Gas Company's current Rate Book, section C8 (Customer Attachment Program).

f. Please provide the Company's most recent analysis of the difference between the estimated incremental revenues and incremental costs associated with Customer Attachments and the actual incremental revenues and incremental costs associated with those attachments. Produce the data, assumptions, and any workpapers (in electronic form with formulas intact) used to complete this analysis.

Answer: The Company does not perform such analysis.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.49

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to DTE Gas' response to MECCUMDG-3.23c. Please provide the service line limit for each of the last 20 years.

Answer: The service line limit has remained 400 feet since the CAP model was implemented and has not been revised.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-3.28a

Respondent: J. L. Huffman

Page: 1 of 1

Question: Does the Company track whether new customers consume gas in the amounts assumed in the calculations used to determine customer contributions to the cost of new connections?
a. If yes, please provide any summary or average data in the Company's possession regarding the gas consumed by new customers, as well as the corresponding assumptions used when assessing those customer connections.

Answer: No. The Company does not perform such analysis.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-3.28b

Respondent: J. L. Huffman

Page: 1 of 1

Question: Does the Company track whether new customers consume gas in the amounts assumed in the calculations used to determine customer contributions to the cost of new connections?
b. If not, why not?

Answer: The Company does not perform such an analysis. The June 5, 1995 Commission Order Approving Settlement Agreement in Case No. U-10745 stated that “Under the proposed Rule the customer contribution is not subject to reconciliation or refund.”

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.53a

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to Exhibit A-12, Schedule B5.5, page 11 of 41 where it states, "DTE Gas has received several inquiries from homeowners in the Greater Grand Rapids area."

a. Please describe in detail DTE's process for identifying the number of new attachments/customers to include in the scope of the Austin community expansion project, differentiating between DTE's process for identifying committed customers and non-committed customers.

Answer: DTE Gas identifies new attachments by first defining the project scope based on the proposed gas main installation. All premises within the feasible service area of the proposed main are identified as potential customers, representing the maximum number of customers the project could serve. DTE Gas then conducts door-to-door outreach to assess customer interest. Premises that sign a gas application committing to natural gas service are classified as committed customers. Premises that are feasible to serve but have not committed at the time of outreach are classified as non-committed customers and are included only in the total potential customer count, not as committed attachments.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-3.31a

Respondent: J. L. Huffman

Page: 1 of 1

Question: Refer to Huffman direct, Q&A 108:

a. Produce the source documents, including breakdowns and any workpapers in electronic format, for the year-to-date targeted attachments and actual attachments for AEP projects started in 2024.

Answer: See the attached file U-21973 MECCUBDG-3.31a AEP Projects YTD Attachments 2020-2025

Attachment: U-21973 MECCUBDG-3.31a AEP Projects YTD Attachments 2020-2025

Year	Project Name	Total Potential	Targeted - YTD (Aug 31, 2025)	Actual - YTD (Aug 31, 2025)
2020	Lakeshore - Charlevoix	108	92	80
2020	Lake Skegemog	324	275	229
2020	US 31/ Rothbury-Montague	247	210	133
2020	Apple Lane	44	37	38
2020	River Rd	111	94	88
2020	Springbrook	204	173	130
2020	Myers Lake - Peterson Farms	322	274	367
2020	Lamb/Fewins Rd - Interlochen	185	157	136
2020	3 & 4 Mile	75	64	49
2020	Cram/Palaestrum	49	42	33
2021	Lake Manuka	124	99	89
2021	170th Hersey	81	65	71
2021	Ferry Road	320	256	180
2021	Mission	50	40	23
2021	M-76	60	48	40
2021	Barnhart Rd	217	174	147
2021	W Jones Lake	117	94	96
2021	VanTyle	197	158	110
2021	Perry & 24th	209	167	215
2021	Stephan/Steckert Bridge	228	182	138
2021	15 Mile/Indian Lakes	197	158	172
2021	Holton Duck Lake	373	298	271
2021	Center Road - Kingsley	90	72	65
2021	Higgins Lake	452	362	265
2021	Partridge Rd - Barnhart Addition	49	39	46
2022	S Higgins Lake	217	163	119
2022	Tiffany Ave	94	71	94
2022	SpringwaterBeach	112	84	63
2022	Intermediate Lake	91	68	52
2022	Fishermans Paradise	103	77	46
2022	Arthur St	307	230	341
2022	11 Mile	48	36	40
2022	Pine Lake	99	74	68
2022	Brown Lake	53	40	47
2022	Blue Lake	432	324	306
2022	Kilackey	159	119	124
2022	Phelps	50	38	34
2022	Fonger St	59	44	52
2022	Cedar Valley	109	82	105
2022	Krueter	207	155	168
2022	State Rd	95	71	49
2022	Alanson	67	50	56
2022	W County Line	348	261	235
2022	Eveline Orchards	31	23	18
2023	Stonington	245	176	172
2023	16 Mile	96	72	128
2023	17 Mile	160	112	126

2023	17 Mile - Woodlawn - Olin	103	77	76
2023	18 Mile - Gowen	96	67	51
2023	Kalamazoo	119	85	106
2023	Peach Ridge	493	369	353
2023	Pine Lake	72	53	67
2023	Heintzelman Ave - Repriced	155	106	108
2023	Redmond Rd - 2023 Pricing	61	37	41
2023	Pioneer Rd - Repriced	207	137	90
2023	M 72	316	219	142
2023	N Higgins Lake	104	72	42
2023	Chestnut Ave	75	57	54
2023	Stone Rd	162	121	92
2023	Atkins Rd	34	25	27
2023	Gaunt Rd	85	52	55
2023	Hoxie Rd - Repriced	221	166	110
2023	Mayfield	181	136	128
2023	Norton Rd	103	77	58
2023	Lake George	208	135	161
2024	Ashton	212	127	107
2024	Negaunee/Miramichi Lakes	219	142	92
2024	E 32nd	59	38	28
2024	Mesick-Buckley	1063	691	725
2024	Mesick-Buckley Additions	74	47	53
2024	Vining Rd	98	59	54
2024	Hart Rd	134	80	87
2024	Morgan Mills	176	106	93
2024	Satterlee Rd	60	36	30
2024	Adams	95	45	133
2024	Podunk	55	36	32
2024	Stage Ave	32	17	31
2024	Mead Rd	64	35	25
2024	M-55	56	31	31
2024	S Grayling Rd	151	79	94
2024	Iris Rd	113	73	60
2024	Cranberry Lake	115	69	69
2024	Washington Rd	105	48	83
2024	Bosset Rd	164	107	103
2024	W 1 Mile	113	68	55
2024	Holton - Whitehall	47	31	27
2024	Crystal Lake	69	41	42
2024	Ridge Lane	52	33	36
2024	Hobbs Highway	218	131	134
2024	Green Lake	289	154	98
2024	Click Rd	27	10	20
2024	Solon St	39	16	22
2024	Bush Rd	38	18	40
2025	US 2	266	53	60
2025	12th Rd	101	18	20
2025	Johnson Rd	73	19	33

2025	Stacey Woods	39	11	9
2025	River Meadow	56	9	9
2025	Grant Ave	85	2	5
2025	S Mt. Hope Rd	86	22	23
2025	E Bard Rd	56	14	9
2025	Ironton	276	22	22
2025	Richardson Rd	88	4	4

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-9.4

Respondent: J. L. Huffman

Page: 1 of 4

Question: Please refer to DTE’s responses to MECCUBDG-3.31, attachment “U-21973 MECCUBDG-3.31a AEP Projects YTD Attachments 2020-2025”. For each project listed, please provide the number of customers who connected to the project within 1 year of project completion, within 2 years, and within 3 years, in table format.

Answer: For the projects listed in Attachment “U-21973 MECCUBDG-3.31a AEP Projects YTD Attachments 2020-2025,” the accompanying table presents the number of customers who connected within one, two, and three years of project completion for projects completed between 2020 and 2023. For projects completed in 2024 and 2025, initial sign-up data is used due to the limited time since project activation to observe billed customer activity. Consistent with the definition provided in Huffman Direct Testimony, “sign-ups” represent a bound, written customer contract reflecting a customer’s formal commitment to participate in a project.

Project Year	Project Name	Year 1	Year 2	Year 3
2020	Lakeshore - Charlevoix	57	7	10
2020	Lake Skegemog	180	16	24
2020	US 31/ Rothbury-Montague	88	9	19
2020	Apple Lane	26	3	4
2020	River Rd	66	6	11
2020	Springbrook	87	13	20
2020	Myers Lake - Peterson Farms	284	14	48
2020	Lamb/Fewins Rd - Interlochen	115	7	11
2020	3 & 4 Mile	29	8	3
2020	Cram/Palaestrum	27	2	2
2021	Lake Manuka	71	16	1
2021	170th Hersey	59	10	0
2021	Ferry Road	116	37	16
2021	Mission	17	4	0

2021	M-76	36	2	0
2021	Barnhart Rd	110	20	4
2021	W Jones Lake	68	8	2
2021	VanTyle	84	15	5
2021	Perry & 24th	186	15	6
2021	Stephan/Steckert Bridge	108	22	5
2021	15 Mile/Indian Lakes	143	23	4
2021	Holton Duck Lake	202	52	9
2021	Center Road - Kingsley	44	15	4
2021	Higgins Lake	178	62	10
2021	Partridge Rd - Barnhart Addition	40	4	1
2022	S Higgins Lake	105	7	7
2022	Tiffany Ave	80	1	4
2022	SpringwaterBeach	54	7	2
2022	Intermediate Lake	47	1	1
2022	Fishermans Paradise	43	1	2
2022	Arthur St	272	9	12
2022	11 Mile	36	1	3
2022	Pine Lake	64	2	2
2022	Brown Lake	42	0	3
2022	Blue Lake	266	10	16
2022	Kilackey	103	5	5
2022	Phelps	32	2	0
2022	Fonger St	48	1	1
2022	Cedar Valley	94	4	4
2022	Krueter	142	14	12
2022	State Rd	42	4	3
2022	Alanson	47	6	3
2022	W County Line	210	7	18
2022	Eveline Orchards	16	2	0
2023	Stonington	165	6	
2023	16 Mile	126	2	
2023	17 Mile	115	4	
2023	17 Mile - Woodlawn - Olin	69	3	
2023	18 Mile - Gowen	48	3	
2023	Kalamazoo	97	1	
2023	Peach Ridge	335	5	

2023	Pine Lake	64	3
2023	Heintzelman Ave - Repriced	95	8
2023	Redmond Rd - 2023 Pricing	37	2
2023	Pioneer Rd - Repriced	86	4
2023	M 72	117	2
2023	N Higgins Lake	41	1
2023	Chestnut Ave	52	1
2023	Stone Rd	86	4
2023	Atkins Rd	17	1
2023	Gaunt Rd	49	1
2023	Hoxie Rd - Repriced	99	3
2023	Mayfield	119	5
2023	Norton Rd	54	4
2023	Lake George	153	5
2024	Ashton	107	
2024	Negaunee/Miramichi Lakes	92	
2024	E 32nd	28	
2024	Mesick-Buckley	725	
2024	Mesick-Buckley Additions	53	
2024	Vining Rd	54	
2024	Hart Rd	87	
2024	Morgan Mills	93	
2024	Satterlee Rd	30	
2024	Adams	133	
2024	Podunk	32	
2024	Stage Ave	31	
2024	Mead Rd	25	
2024	M-55	31	
2024	S Grayling Rd	94	
2024	Iris Rd	60	
2024	Cranberry Lake	69	
2024	Washington Rd	83	
2024	Bosset Rd	103	
2024	W 1 Mile	55	
2024	Holton - Whitehall	27	
2024	Crystal Lake	42	
2024	Ridge Lane	36	

2024	Hobbs Highway	134
2024	Green Lake	98
2024	Click Rd	20
2024	Solon St	22
2024	Bush Rd	40
2025	US 2	220
2025	12th Rd	86
2025	Johnson Rd	65
2025	Stacey Woods	27
2025	River Meadow	36
2025	Grant Ave	67
2025	S Mt. Hope Rd	74
2025	E Bard Rd	31
2025	Ironton	190
2025	Richardson Rd	74

Attachment: None.

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-11.4a

Respondent: E. D. Janness

Page: 1 of 1

Question: Refer to Witness Janness's testimony, pages 33-37 and, for sub-parts a and b, refer also to Q&A 66-68.

a. Has the company undertaken any quantitative analysis or evaluation to attribute or estimate the cost impact of the described complex work? If yes, produce it. If no, describe in detail how the complexity described is used to estimate cost increases?

Answer: See attached. Also refer to Exhibit A-12, Schedule B6.4 Infrastructure Challenges Associated with Complexity.

The Company's approach begins by applying the 2024 average cost per mile to the miles completed in 2025 to establish a reasonable baseline for comparison. The variance between this baseline and actual 2025 costs is then explained based on known cost drivers.

Attachment: U-21973 MECCUBDG-11.4-01 2024 to 2025 GRP Variance Summary

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-11.4b

Respondent: E. D. Janness

Page: 1 of 1

Question: Refer to Witness Janness's testimony, pages 33-37 and, for sub-parts a and b, refer also to Q&A 66-68.

b. Has the company undertaken any quantitative analysis or evaluation to attribute or estimate the cost impact of the described complex areas? If yes, produce it. If no, describe in detail how the complexity described is used to estimate cost increases?

Answer: See response to MECCUBDG-11.4a.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-11.4c

Respondent: E. D. Janness

Page: 1 of 1

Question: Refer to Witness Janness's testimony, pages 33-37 and, for sub-parts a and b, refer also to Q&A 66-68.

c. Has the company undertaken any quantitative analysis or evaluation to attribute or estimate the cost impact of the described contracts driver? If yes, produce it. If no, describe in detail how the contract developments described are used to estimate cost increases?

Answer: See response to MECCUBDG-11.4a.

The Company has not undertaken a standalone quantitative analysis that isolates and attributes a specific dollar value solely to the "contracts driver" described. Instead, contract-related cost impacts are embedded within the Gas Renewal Program's (GRP's) overall cost estimation based on actual contract terms and conditions of executed construction and restoration contracts, including unit pricing and rate structures, scope definitions and contractual responsibilities, and performance standards, controls, and risk allocation provisions. Contractor pricing incorporated into GRP estimates reflects competitive procurement outcomes, including negotiations and evaluation of vendor submissions. Contracts are evaluated at the program level, not as a discrete line item driver.

Attachment: Note:

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-11.4d

Respondent: E. D. Janness

Page: 1 of 1

Question: Refer to Witness Janness's testimony, pages 33-37 and, for sub-parts a and b, refer also to Q&A 66-68.

d. Produce any source documents for the statements made in the contract bullet, including but not limited to any updates since DTE filed this testimony.

Answer: See response to MECCUBDG-11.4a.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-11.4e

Respondent: E. D. Janness

Page: 1 of 1

Question: Refer to Witness Janness's testimony, pages 33-37 and, for sub-parts a and b, refer also to Q&A 66-68.

e. Has the company undertaken any quantitative analysis or evaluation to attribute or estimate the cost impact of the described inflation driver? If yes, produce it. If no, describe in detail how the inflation developments described are used to estimate cost increases?

Answer: See response to MECCUBDG-11.4a.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-11.4f

Respondent: E. D. Janness

Page: 1 of 1

Question: Refer to Witness Janness's testimony, pages 33-37 and, for sub-parts a and b, refer also to Q&A 66-68.

f. Produce any source documents for the statements made in the inflation bullet, including but not limited to any updates since DTE filed this testimony.

Answer: See response to MECCUBDG-11.4a.

Attachment: None

2024 to 2025 Variance Analysis

Year	Miles	Actuals	CPU
2024	236.62	\$ 299,594,382	\$ 1,266,166
2025	190.56	\$ 286,969,159	\$ 1,505,938
2025 Projected based on 2024 CPU			\$ 241,278,693
Wage Inflation	Average 3% increase year over year		\$ 1,167,894
Material Inflation	Average 3.3% increase of material prices		\$ 830,171
Contractor Rates	An average 3.2% increase of esclators and new contracts for construction contractors		\$ 2,652,387
Region Mix Variance	The scope of work in 2025 increased miles in higher cpu areas, such as Downtown Detroit, versus 2024 due to utility congestion, having to open cut more pavement, and because of commercial services		\$ 5,607,908
Flow Fill	The need for flow fill increased due to the varying requirements of municipalities and the increase in work that results in abandonment of larger diameter pipe.		\$ 1,919,156
Traffic Control	Traffic control is a municipal requirement and increasingly needed when performing work in densly populated/congested areas or on major thoroughfares.		\$ 816,862
Complexity	Overall complexity increased by \$20.46M and here are examples are are highest cost per mile projects in 2025: Milwaukee Junction 2 (\$5.4M per mile) - Large diameter pipe install, nearly half was 12" pipe - Majority open cut roadways in order to align with existing utility and navigate other utility congestion, increasing time/cost to install and requiring joint to joint restoration - Hydro excavation needed due to heavy utility congestion - Large directional bore effort for M-10 freeway crossing which was 12" pipe, 70ft deep, and approximately 1000ft long - 2 railroad crossing and 7 steam line crossings each requiring steel pipe and pickling - Many large commercial / industrial customers requiring large diameter services and large meter sets - Large diameter cast iron abandonment requiring specialty fittings, stopping techniques, and larger excavations Southwest Detroit 3B (\$2.5M per mile) - Large diameter 8" pipe installed down middle of Fort St - Removal of trolley tracks found frequently - Majority open cut roadways in order to align with existing utility and navigate other utility congestion, increasing time/cost to install and requiring joint to joint restoration - Hydro excavation needed due to heavy utility congestion - Large diameter cast iron abandonment requiring specialty fittings, stopping techniques, and larger excavations - Jack & Bore across lodge freeway with possibly the largest exacavation required in the ebankment of freeway requiring specialty earth retention (see photos right) - Many large commercial / industrial customers requiring large diameter services and large meter sets - Rail road crossing near I-75		\$ 20,456,333
		Midtown Muni (\$3.4M per mile) - Majority open cut roadways in order to align with existing utility and navigate other utility congestion, increasing time/cost to install and requiring joint to joint restoration - Hydro excavation needed due to heavy utility congestion - Many large commercial / industrial customers requiring large diameter services and large meter sets - 2 steam lines requiring steel pipe and pickling - Pressure department support for odorant testing	
GRP MMO	Cost of Supplemental MMO beginning to roll into the overall GRP program		\$ 12,239,755
Sub-total			\$ 45,690,466
2025 Actuals			\$ 286,969,159

1. 2025 Actuals, Units, and CPUs are based on preliminary data that will be finalized with the submission of the March 31st IRM filing

Southwest Detroit Freeway Crossing



MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.9

Respondent: E. D. Janness

Page: 1 of 1

Question: Does DTE consider the risk reduced per dollar spent on Main Renewal actions? If so, in what way does DTE consider the risk reduced per dollar spent? If not, why not?

Answer: DTE Gas does not select GRP projects based on a lowest-cost or cost-per-risk-unit basis because the Gas Renewal Program is a safety-driven program intended to systematically reduce risk across the system. Many higher-risk grids are also more complex and costly to execute due to density, congestion, or municipal coordination requirements. Excluding or deferring these projects based on cost would undermine the program's risk-reduction objectives.

The Probabilistic Risk Assessment (PRA) expresses risk in monetary terms, and Main Renewal project selection follows a highest risk grid first prioritization. This approach reflects the mandate of the Gas Renewal Program to focus on reducing system safety risk as quickly as possible, rather than optimizing for cost efficiency at the individual project level.

In general, cost-benefit analysis is used to determine whether a mitigation should be undertaken at all. In this case, both DTE Gas and the Commission have already determined that these assets must be renewed for safety reasons. As a result, cost is considered at the portfolio level to manage the overall capital budget, project complexity, and resource availability, rather than as a project-by-project determinant of whether risk mitigation will occur. This approach is consistent with the factors described in Q/A 65 of my direct testimony.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.21a

Respondent: K. M. Fedele

Page: 1 of 1

Question: Refer to the Direct Testimony of witness K. M. Fedele at page KMF-36 where it states, “The East Petoskey Pipeline Reinforcement project involves construction of a new 13.5-mile 8” diameter distribution pipeline...”

a. Please provide the capacity of the existing Petoskey pipeline and the capacity of the proposed 13.5-mile 8” diameter pipeline. Please specify the units in the response.

Answer: Pipeline capacities are not a single number. Pipeline capacity is a function of both where the load is located along the pipeline and what delivery pressure is required to be maintained at each load point in addition to the diameter, wall thickness, material type, and MAOP of the pipeline.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.22a

Respondent: K. M. Fedele

Page: 1 of 1

Question: Refer to the Direct Testimony of witness K. M. Fedele at page KMF-36 where it states, "The East Petoskey Pipeline Reinforcement project involves construction of a new 13.5-mile 8" diameter distribution pipeline..."

a.Has DTE calculated the impact on reliability associated with the proposed Petoskey pipeline, relative to the existing Petoskey pipeline? If so, please provide all analysis and supporting workpapers in Excel-file format with formulas intact and units, inputs, and assumptions clearly identified. If not, please explain why not.

Answer: DTE Gas objects for the reason that the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Gas, its ratepayers, and its customers competitive harm. DTE Gas further objects to the extent the request seeks information that contains Customer Account Information, disclosure of which is prohibited by the Company's Data Privacy Tariff.

Without waiving said objection and subject thereto, this analysis was performed using hydraulic system modeling. As described on pages 36-38 of my direct testimony, the East Petoskey Pipeline Reinforcement project will provide redundant supply which will mitigate the 19,000 customer outage potential on the existing 8" Petoskey pipeline. This analysis was not completed in Excel but instead was performed using hydraulic system modeling which requires a Synergi Gas software license to view. This analysis was completed by modelling the pipelines with either the existing or new pipeline disabled and reviewing the pressures across the pipelines to determine if acceptable levels are maintained. Hydraulic models used to determine the reliability impact of the East Petoskey project include all of the distribution assets and loads in the Cadillac-Petoskey-Traverse City region and due to the large and cumbersome amount of data cannot easily be shared. The Company's hydraulic system models are available for viewing at DTE offices.

Attachment: None

Co-Respondent(s): Legal

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.25a

Respondent: K. M. Fedele

Page: 1 of 1

Question: In the Direct Testimony of witness K. M. Fedele, refer to Q&A 80 beginning on page KMF-38.

a. Please provide the Company's analysis showing that it "would not provide enough pipeline capacity to serve the existing customers under peak conditions and would not mitigate the outage potential of the pipeline" if DTE were to reduce the pipeline's Maximum Allowable Operating Pressure to 405 psig. Please provide all analysis and workpapers in native or Excel-file format with formulas intact and units, inputs, and assumptions clearly identified.

Answer: DTE Gas objects for the reason that the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Gas, its ratepayers, and its customers competitive harm. DTE Gas further objects to the extent the request seeks information that contains Customer Account Information, disclosure of which is prohibited by the Company's Data Privacy Tariff.

Without waiving said objection and subject thereto, this analysis was not completed in Excel but instead was performed using hydraulic system modeling which requires a Synergi Gas software license to view. The modeling results showed that this option was not feasible if the MAOP is reduced to 405 psig. Hydraulic models used to determine this include all of the distribution assets and loads in the Cadillac-Petoskey-Traverse City region and due to the large and cumbersome amount of data cannot easily be shared. The Company's hydraulic system models are available for viewing at DTE offices.

Attachment: None

Co-Respondent(s): Legal

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.25b

Respondent: K. M. Fedele

Page: 1 of 1

Question: In the Direct Testimony of witness K. M. Fedele, refer to Q&A 80 beginning on page KMF-38.

b.What is the peak demand for the area served by the Petosky Pipeline?
Please indicate units in the response, and the period on which the peak demand is based.

Answer: The total modelled hourly peak demand for the area served by the existing 8" Petoskey Pipeline is approximately 1,240 mscfh and is based on loads modelled for a -12F day in the Petoskey station area.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.25c

Respondent: K. M. Fedele

Page: 1 of 1

Question: In the Direct Testimony of witness K. M. Fedele, refer to Q&A 80 beginning on page KMF-38.

c.If DTE were to reduce the pipeline's Maximum Allowable Operating Pressure to 405 psig, what portion of the area's peak demand would not be met? Please indicate units in the response.

Answer: The Company would not review an alternative that would not meet the area's peak demand.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-3.107a

Respondent: K. M. Fedele

Page: 1 of 1

Question: Refer to page 37 of Ms. Fedele's direct testimony on the East Petoskey Pipeline project. Please:

a. Confirm that ILI on the pipeline could be done in the summer months when any problems with an inspection tool getting stuck would be less severe.

Answer: ILI can be performed during the summer months when loss of heat is not an issue, but the potential for customer outages still exists during the summer that would require relighting up to 19,000 customers. These outages, regardless of when they occur, would be expensive, would take resources away from other critical work, and would be unacceptable to our customers who rely on our service

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.31

Respondent: K. M. Fedele

Page: 1 of 1

Question: Has DTE calculated the impact on reliability associated with the Fort Street Main project, relative to the existing system? If so, please provide all analysis and supporting workpapers in Excel-file format with formulas intact and units, inputs, and assumptions clearly identified. If not, please explain why not.

Answer: DTE Gas objects for the reason that the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Gas, its ratepayers, and its customers competitive harm. DTE Gas further objects to the extent the request seeks information that contains Customer Account Information, disclosure of which is prohibited by the Company's Data Privacy Tariff.

Without waiving said objection and subject thereto, this analysis was not completed in Excel but instead was performed using hydraulic system modeling which requires a Synergi Gas software license to view. Hydraulic models used to determine this include all of the distribution assets and loads in the SEMI region and due to the large and cumbersome amount of data cannot easily be shared. The Company's hydraulic system models are available for viewing at DTE offices. As described on page 55 of my direct testimony, the Fort Street Main Replacement project will provide redundant supply to the Downtown Detroit and Southwest Detroit areas that will mitigate the 15,000 customer outage in this area.

Attachment: None

Co-Respondent(s): Legal

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.34a

Respondent: K. M. Fedele

Page: 1 of 1

Question: In the Direct Testimony of witness K. M. Fedele, refer to page KMF-56 where it states, “DTE Gas analyzed replacing the existing 50 psig and 99 psig mechanically coupled Fort Street mains at existing pressures, but this option would have required larger pipe at additional cost.”

a. Please provide all materials from the Company’s analysis of “replacing the existing 50 psig and 99 psig mechanically coupled Fort Street mains at existing pressures.” Please provide the associated analysis and results, including costs, in native or Excel-file format with formulas intact and units, inputs, and assumptions clearly identified.

Answer: DTE Gas objects for the reason that the information requested consists of confidential, proprietary, research and development of trade secrets, or commercial information, the disclosure of which would cause DTE Gas, its ratepayers, and its customers competitive harm. DTE Gas further objects to the extent the request seeks information that contains Customer Account Information, disclosure of which is prohibited by the Company’s Data Privacy Tariff. Without waiving said objections and subject thereto, this analysis was performed using hydraulic system modeling and no detailed cost estimating was prepared for this alternative. This analysis was completed by modelling the pipelines when operating at existing pressures and when operating at higher pressure and comparing pressure drops across the pipeline to determine if acceptable levels are maintained. This analysis is repeated at the higher operating pressure with various sizes of new steel pipeline to determine the smallest size that could be used for each section while meeting the requirements of the project and maintaining acceptable pressure levels. These analyses are not completed in Excel and require a Synergi Gas software license to view. Hydraulic models used to size the Fort St project include all of the distribution assets and loads in the entire SEMI region and due to the large and cumbersome amount of data cannot easily be shared. The Company’s hydraulic system models are available for viewing at DTE offices.

Attachment: None

Co-Respondent(s): Legal

MPSC Case No: U-21973**Requester:** MECCUB**Question No.:** MECCUBDG-8.37a**Respondent:** K. M. Fedele**Page:** 1 of 1

Question: Refer to the Direct Testimony of witness K. M. Fedele starting on page KMF-58 where it states, "The Carlton Main Replacement Project involves installing approximately 4.6 miles of new 12" steel pipe at a system operating pressure of 274 psig, abandoning approximately 5.1 miles of 6" 125 psig steel, installing approximately six main line valves, and replacing or modifying three district regulator stations."

a. Did DTE consider replacing the Carlton Main with a 125 psig pipeline instead of upgrading to a 274 psig pipeline? If so, please explain why DTE determined to install a 274 psig pipeline. If not, please explain why not.

Answer: DTE Gas did consider replacing the Carlton Main with a 125-psig pipeline instead of upgrading it to a 274 psig pipeline. As described on pages 59-60 of my direct testimony, installing the replacement at 274 psig will improve safety, simplify operations of the high-pressure system by integrating multiple pressure systems. It also provides redundancy to the 274 psig system from Willow Gate Station to Sumpter Gate Station. The 274 psig supply redundancy allows operational flexibility for maintenance, integrity assessments, and emergency response work.

Attachment: None

MPSC Case No: U-21973

Requester: MECCUB

Question No.: MECCUBDG-8.37b

Respondent: K. M. Fedele

Page: 1 of 1

Question: Refer to the Direct Testimony of witness K. M. Fedele starting on page KMF-58 where it states, “The Carlton Main Replacement Project involves installing approximately 4.6 miles of new 12” steel pipe at a system operating pressure of 274 psig, abandoning approximately 5.1 miles of 6” 125 psig steel, installing approximately six main line valves, and replacing or modifying three district regulator stations.”

b. Did DTE conduct a cost-benefit analysis comparing the cost of installing a 125 psig pipeline and associated valves and regulators with the cost of installing a 274 psig pipeline and associated valves and regulators? If so, please provide all calculations and workpapers in Excel-file format with formulas intact and units, inputs, and assumptions clearly identified. If not, please explain why not.

Answer: No. Replacing the 125-psig system with another 125 psig system would not mitigate the risk of a failure of the station or pipeline that could result in service interruptions to customers fed by the Carlton Main. Referring to pages 61-62 of my direct testimony describes that utilizing the existing 274 psig system capitalizes on the existing infrastructure as well as reduces unique pressure systems that DTE operates by interconnecting multiple single source systems into an integrated 274 psig system with multiple redundant supplies.

Attachment: None

MPSC Case No: U-21973

Requester: Ann Arbor

Question No.: AADG-2.2bvi

Respondent: K. M. Fedele

Page: 1 of 1

Question: For the following requests, please refer to the Taggart Compressor Main Replacement project summary in Exhibit A-12, Schedule B5.5, p. 3, and the Direct Testimony of K. M. Fedele, p. 72-84.

b. Please provide information on alternatives considered for this project by providing responses to the following:

vi. Please provide the engineering report that assessed the various alternatives to address the reliability concerns for the Taggart Compressor Station including the cost, NPV, and revenue requirement for each alternative.

Answer: Please refer to pages 80-82 of my direct testimony where the various alternatives were reviewed. Since the alternatives were evaluated qualitatively and a high level during the conceptual stage of this project, detailed cost estimates were not developed for the alternatives considered. There was not a revenue requirement calculated for this rate case.

Attachment: None

MPSC Case No: U-21973

Requester: AG

Question No.: AGDG-3.126

Respondent: K. M. Fedele

Page: 1 of 1

Question: Refer to lines 16-25 on page 80 of Ms. Fedele's direct testimony on the Taggart Compressor Station Replacement project and customer benefits. Please provide a copy of the cost/benefit analysis with the net present value calculations in Excel showing that the project is economically justified.

Answer: Lines 16-25 on Page 80 of Witness Fedele's testimony refers to the Company's inability to stock critical spare parts due to obsolescence. This was an alternative to an entire station replacement that was reviewed during design. There was no cost/benefit analysis performed because, without critical spare parts, there is no alternative option to consider.

Attachment: None

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21973

Proof of Service

On the date below, an electronic copy of **Public Direct Testimony and Exhibits of Alice Napoleon on behalf of Michigan Environmental Council (MEC-1 through MEC-28)** was served on the following:

Name/Party	E-mail Address
ALJ Christopher S. Saunders	saundersc4@michigan.gov
DTE Gas Company Carlton D. Watson Andrea E. Hayden Breanne K. Reitzel John A. Janiszewski	mpscfilings_account@dteenergy.com carlton.watson@dteenergy.com andrea.hayden@dteenergy.com breanne.reitzel@dteenergy.com john.janiszewski@dteenergy.com
Michigan Public Service Commission Staff Anna B. Stirling Adam M. Cozort Heather M.S. Durian Michael Orris Lori Mayabb	stirlinga1@michigan.gov cozorta1@michigan.gov durianh@michigan.gov orrism@michigan.gov mayabbl@michigan.gov
Michigan Attorney General Joel B. King Lucas Wollenzien	ag-enra-spec-lit@michigan.gov KingJ38@michigan.gov wollenzienl@michigan.gov
Detroit Thermal, LLC Arthur J. LeVasseur Troy C. Otto	levasseur@fischerfranklin.com otto@fischerfranklin.com
Retail Energy Supply Association Jennifer U. Heston	jheston@potomacclaw.com

Energy Michigan, Inc, Billerud Americas Corporation Laura A. Chappelle Timothy J. Lundgren Justin K. Ooms Lydia M. Lubbers Pamela Fox	lachappelle@varnumlaw.com tjlundgren@varnumlaw.com jkooms@varnumlaw.com lmubbers@varnumlaw.com plfox@varnumlaw.com
City of Ann Arbor Valerie Jackson	vjackson@a2gov.org
Urban Core Collective, Soulardarity, We Want Green, Too, Frontline Organizations Amanda Urban Mark N. Templeton Alexandria C. Miskho Emma Young	aclc_mpsc@lawclinic.uchicago.edu aurbanlaw@gmail.com templeton@uchicago.edu amiskho@uchicago.edu eyoung28@uchicago.edu
Association of Businesses Advocating Tariff Equity Michael J. Pattwell Stephen A. Campbell Benjamin Holwerda Lauren Degnan James Dauphinais	mpattwell@clarkhill.com scampbell@clarkhill.com bholwerda@clarkhill.com ldegan@clarkhill.com jdauphinais@consultbai.com
Utility Workers Union of America, Local 223 Richard Mack, Jr. Jacob S. Porcarelli	richardmack@millercohen.com jporcarelli@millercohen.com
Michigan Environmental Council and Citizens Utility Board of Michigan Christopher M. Bzdok Holly L. Hillyer Sean C. Clark Natasha Fowles Sue Fruchey Julielyn Gibbons Rick Bunch Sophie Schadler Alice Napoleon Matt Bandyk	chris@tropospherelegal.com holly@tropospherelegal.com sean@tropospherelegal.com natasha@tropospherelegal.com sue@tropospherelegal.com jgibbons@5lakesenergy.com rbunch@5lakesenergy.com sschadler@synapse-energy.com anapoleon@synapse-energy.com mbandyk@5lakesenergy.com

[signature page below]

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

Troposphere Legal
Counsel for MEC

Date: March 13, 2026

By: _____



Digitally signed by
Natasha Fowles
Date: 2026.03.13
18:07:41 -04'00'

Natasha Fowles, Legal Assistant
420 E. Front St.
Traverse City, MI 49686
Phone: 231-709-4000
Email: natasha@tropospherelegal.com