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December 12, 2025

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

RE: In the matter of the Application of **DTE GAS COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority
MPSC Case No. U-21973

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter is DTE Gas Company's revised Direct Testimony of Witness Theresa M. Uzenski. Also attached is the Proof of Service.

Very truly yours,

Carlton D. Watson

CDW/erb
Attachments
cc: Service List

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21973

QUALIFICATIONS
AND
REVISED DIRECT TESTIMONY
OF
THERESA M. UZENSKI

DTE GAS COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF THERESA M. UZENSKI

Line
No.

1 **Q1. What is your name, business address and by whom are you employed?**

2 A1. My name is Theresa M. Uzenski. I am employed by DTE Energy Corporate
3 Services, LLC (LLC), a subsidiary of DTE Energy Company. My business address
4 is One Energy Plaza, Detroit, MI 48226.

5

6 **Q2. On whose behalf are you testifying?**

7 A2. I am testifying on behalf of DTE Gas Company (DTE Gas, or Company).

8

9 **Q3. What is your educational background?**

10 A3. I have a Bachelor of Science in Accounting from the University of Detroit and a
11 Master of Business Administration with a concentration in Finance from Wayne
12 State University.

13

14 **Q4. What is your work experience and what position do you currently hold at DTE**
15 **Energy?**

16 A4. I have worked for DTE Energy or one of its affiliated regulated utilities for over
17 thirty-six years in various accounting, finance, and management positions. I am
18 currently the Manager of Regulatory Accounting for DTE Gas Company and DTE
19 Electric Company.

20

21 **Q5. What are your current duties and responsibilities?**

22 A5. As Manager of Regulatory Accounting, I am responsible for the development and
23 management of regulatory accounting policies and practices, as well as supporting
24 regulatory filings. My department analyzes the accounting implications of new
25 legislation and Michigan Public Service Commission (Commission or MPSC)

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1 orders and provides expert testimony on accounting issues and financial projections
2 in various proceedings before the MPSC. We research and establish accounting
3 policies and assist the accounting operations departments with implementation. My
4 department also supports other Company expert witnesses in various proceedings
5 before the MPSC by preparing financial exhibits and other financial analyses.

6

7 **Q6. Do you hold any certifications or are you a member of any professional**
8 **organization?**

9 A6. I am a Certified Management Accountant, a member of the Institute of Management
10 Accountants, and a member of the Corporate Accounting Committee of the
11 American Gas Association and the Accounting, Reporting and Automation
12 Committee of the Edison Electric Institute.

13

14 **Q7. To what extent have you participated in prior rate cases and other regulatory**
15 **proceedings?**

16 A7. I have sponsored testimony in the following cases:

17 U-11222 Michigan Consolidated Gas Company (MichCon) Depreciation

18 U-13898 MichCon UETM

19 U-14702 Detroit Edison 2006 PSCR Plan

20 U-15160 Detroit Edison Enhanced Security Cost Recovery

21 U-15244 Detroit Edison Choice Incentive Mechanism Reconciliation

22 U-15259 Detroit Edison Pension Equalization Mechanism

23 U-15417-R Detroit Edison Pension Equalization Mechanism

24 U-15806-EO Detroit Edison Energy Optimization

25 U-15768 Detroit Edison UETM

<u>Line No.</u>		
1	U-15890	MichCon Energy Optimization
2	U-16009	Complaint Case against Detroit Edison
3	U-16246-R	Detroit Edison 2009 RETM Reconciliation
4	U-16246-R	Detroit Edison 2010 RETM Reconciliation
5	U-16356	Detroit Edison 2009 REP Reconciliation
6	U-16472	Detroit Edison 2010 Rate Case
7	U-16574	Detroit Edison 2010 UETM Reconciliation
8	U-16582	Detroit Edison 2014 REP Plan
9	U-16769	MichCon Depreciation
10	U-16952	Detroit Edison 2014 CIM Reconciliation
11	U-16956	Detroit Edison 2014 RETM Reconciliation
12	U-16964	Detroit Edison 2014 UETM Reconciliation
13	U-17302	DTE Electric Company 2017 REP Plan Update
14	U-17437	DTE Electric Company Transitional Cost Recovery Mechanism
15	U-17767	DTE Electric Company 2014 Rate Case
16	U-17999	DTE Gas Company 2015 Rate Case
17	U-18014	DTE Electric Company 2018 Rate Case
18	U-18122	DTE Electric Company Customer 360 Program Accounting
19	U-18255	DTE Electric Company 2017 Rate Case
20	U-18419	DTE Electric Company Certificates of Necessity
21	U-18999	DTE Gas Company 2018 Rate Case
22	U-20106	DTE Gas Company Tax Cut & Jobs Act – Credit A
23	U-20105	DTE Electric Company Tax Cut & Jobs Act – Credit A
24	U-20162	DTE Electric Company 2018 Rate Case
25	U-20298	DTE Gas Company Tax Cut & Jobs Act – Credit C

Line
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1	U-20561	DTE Electric Company 2019 Rate Case
2	U-20642	DTE Gas Company 2019 Rate Case
3	U-20940	DTE Gas Company 2021 Rate Case
4	U-21015	DTE Electric Company 2021 Securitization
5	U-20836	DTE Electric Company 2022 Rate Case
6	U-21193	DTE Electric Company 2022 Integrated Resource Plan
7	U-21297	DTE Electric Company 2023 Rate Case
8	U-21291	DTE Gas Company 2024 Rate Case
9	U-21534	DTE Electric Company 2024 Rate Case
10	U-21860	DTE Electric Company 2025 Rate Case

Line
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1 **Purpose of Testimony**

2 **Q8. What is the purpose of your testimony?**

3 A8. The purpose of my testimony is to support DTE Gas's financial statements for the
4 historical test year ended December 31, 2024, the interim forecast period and a
5 twelve-month projected test year ending September 30, 2027, including a 13-month
6 average balance sheet. The financial statements have certain adjustments necessary
7 for presenting the financial information in the appropriate format for ratemaking
8 purposes. My testimony supports the development of the projected test year for
9 adjusted Gas operating income based on forecasted changes from the normalized
10 historical Gas operating income, and the inflation rate used to develop projected
11 Operations and Maintenance (O&M) costs.

12

13 I support the Corporate Staff Group (CSG) expenses for the historical and forecast
14 periods and explain the function of this group and the method for allocating costs
15 to DTE Gas and the other DTE subsidiaries. I support that the costs recovered from
16 other mechanisms are excluded from the financial statements in this case (Energy
17 Waste Reduction, Infrastructure Recovery Mechanism, Gas Cost Recovery
18 Mechanism, Revenue Decoupling Mechanism and Voluntary Renewables
19 Program, now known as the Natural Gas Balance Program).

20

21 I explain the accounting for the Infrastructure Recovery Mechanism (IRM). I also
22 request recovery of deferred residential income assistance (RIA) and low-income
23 assistance (LIA) expenses over a five-year period and a continuation of deferral
24 treatment. I am also requesting continuation of the shared asset expense deferral
25 mechanism, continuation of the incentive compensation tracker, and the continued

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1 deferral of Other Post-Employment Benefits (OPEB) and Pension costs. Finally, I
2 am requesting deferral accounting for leak detection and repair costs above the
3 amount approved for current recovery in the instant case.

4

5 **Q9. Are you sponsoring any exhibits with your testimony?**

6 A9. Yes, I am supporting the following exhibits for the historical test period:

7

8	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
9	A-2	B2	Historical Utility Plant
10	A-2	B3	Historical Depreciation Reserve
11	A-2	B4	Historical Working Capital
12	A-2	B4.1	Historical 13-Month Average Adjusted Balance Sheet
13	A-2	B4.2	Historical Year-End Adjusted Balance Sheet
14	A-3	C1	Historical Adjusted Net Operating Income
15	A-3	C1.1	Adjustments to Historical Net Operating Income
16	A-3	C3	Historical Operating Revenue
17	A-3	C4	Historical Cost of Gas Sold
18	A-3	C5	Historical Operation and Maintenance Expenses
19	A-3	C6	Historical Depreciation and Amortization Expenses
20	A-3	C11	Historical Allowance for Funds Used During Construction
21	A-3	C14	Historical Advertising Adjustment
22	A-3	C15	Historical Corporate Memberships Adjustment
23	A-3	C16	Historical Top 5 Executive Incentive Plan Adjustment
24	A-3	C17	Historical Employee Incentive Plan Adjustment
25	A-3	C18	Historical Weather Normalization Adjustment

Line
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1

2

I am supporting the following exhibits for the projected test year:

3

ExhibitScheduleDescription

4

A-12

B2

Projected Utility Plant

5

A-12

B3

Projected Depreciation Reserve

6

A-12

B4

Projected Working Capital

7

A-12

B4.1

Projected Average Balance Sheet with Classifications

8

A-12

B4.2

Historical and Projected 13-Month Average Balance Sheet

9

A-12

B4.3

13-Month Average Common Equity Reconciliation

10

A-13

C1

Projected Net Operating Income

11

A-13

C1.1

Projected Net Operating Income Adjustments

12

A-13

C3

Projected Sales and Other Operating Revenue

13

A-13

C3.1

Projected Distribution Revenue by Rate Schedule

14

A-13

C3.4

Projected Other Operating Revenue - Grantor Trust Income

15

A-13

C5

Projected Operation and Maintenance Expenses Summary

16

A-13

C5.2.2

TCARP Deferral

17

A-13

C5.2.3

TCARP Demand Charges Deferral

18

A-13

C5.6

Projected O&M Expenses - Administrative and General

19

A-13

C6

Projected Depreciation and Amortization Expenses

20

A-13

C11

Projected Allowance for Funds Used During Construction

21

A-13

C12

Projected Inflation Factors

22

A-13

C14

Projected Amortization of Loss on Reacquired Debt

23

24 **Q10. Were these exhibits prepared by you or under your direction?**

25 A10. Yes, they were.

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1

2 **Q11. How were your exhibits prepared?**

3 A11. My team uses an Excel model to create historical and projected balance sheets and
4 income statements, and the supporting exhibits. We also have models to capture
5 historical and projected O&M and capital expenditures. The O&M and capital
6 models feed into the financial statement model. Our models start with historical
7 financial information from the MPSC Annual Report on Form P-522. I calculate
8 most of the rate case normalizations and adjustments to the historical balance sheet
9 and income statement, but other Company witnesses calculate the adjustments to
10 the O&M and capital expenditures for the business unit costs that they support. In
11 addition, Company Witnesses Vangilder and Wisniewski support certain
12 adjustments to interest and taxes. I support the O&M for the Corporate Staff Group
13 (CSG).

14

15 After the normalizations and adjustments are made to the historical period, I use
16 the adjusted amounts to develop the financial statements for the projected period.
17 Again, the witnesses supporting their business unit costs provide the known and
18 measurable adjustments to O&M expense and the details for the capital
19 expenditures. Sales are provided by Company Witness Chapel, and Company
20 Witness Huffman supports various Midstream and certain other revenues. Income
21 and property taxes are calculated by Witness Wisniewski. The data provided by
22 these witnesses is captured in my models to create the consolidated financial
23 statements for the projected period. My projected financial statement data is then
24 used by Witness Vangilder to calculate the revenue deficiency.

25

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1

Historical Test Year

2

Q12. What information are you providing with respect to the Historical Test Year ended December 31, 2024?

3

4

A12. For the historical test year ended December 2024, I am providing the balance sheet and net operating income (NOI) information with certain adjustments that are necessary to present the financial information in the appropriate ratemaking format. The adjusted historical financial statements are the starting point in creating the financial statements for the projected test period.

5

6

7

8

9

10 **Historical Balance Sheet**

11 **Q13. What historical test year balance sheet information are you providing?**

12

A13. Exhibit A-2, Schedules B4.1 and B4.2, contain the historical test year balance sheet information. Schedule B4.1 is a 13-month average balance sheet for the periods December 2023 through December 2024. Schedule B4.2 contains similar information but as of December 31, 2024. The balances in column (b), together with certain eliminations and reclassifications in columns (c) through (p) reflect the balance sheet for rate case purposes. The 13-month average adjusted balance sheet line items from Exhibit A-2, Schedule B4.1 column (q) are carried to Exhibit A-2, Schedule B4, Historical Working Capital. The December 2024 year-end adjusted balance sheet in column (q) of Exhibit A-2, Schedule B4.2 is used as the starting point for developing DTE Gas's projected balance sheet.

13

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23 **Q14. What adjustments are you making to the consolidated historical period**
24 **financial statements?**

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1 A14. Consistent with the treatment in past cases, I am reclassifying or eliminating certain
2 items. Non-utility property, Intercompany Notes Receivable/Payable, Customer
3 Attachment Notes Receivable, and the non-utility portion of Intercompany
4 Accounts Receivable balances as of December 31, 2024 are eliminated. I also
5 removed balances that are being recovered or refunded via other mechanisms or
6 surcharges including Energy Waste Reduction (EWR), Gas Voluntary Renewables
7 Program (Natural Gas Balance Program), Gas Cost Recovery (GCR), and Revenue
8 Decoupling Mechanism (RDM). The adjustments are shown on the balance sheets
9 on Exhibit A-2, Schedules B4.1 and B4.2, columns (c) through (p). Since I used
10 the adjusted historical period to build the forecast, I did not have to make these
11 same adjustments to the projected period. I will discuss each adjustment below.

12

13 **Q15. What is the adjustment for Taxes?**

14 A15. Column (c) nets the Accumulated Deferred Income Tax Asset on line 59 with the
15 Accumulated Deferred Income Tax Liability on line 95.

16

17 **Q16. Can you explain the adjustment for benefit plans?**

18 A16. ASC 715 requires the recognition of the unfunded liabilities for defined benefit
19 pension and other post-retirement plans with a charge to other comprehensive
20 income within equity. DTE Gas recorded a regulatory asset in place of the charge
21 to other comprehensive income because the costs are included in rates consistent
22 with when the expense is recognized in the income statement. Since the liability
23 and offsetting regulatory asset result in no change to revenue requirements, Exhibit
24 A-2, Schedules B4.1 and B4.2, column (d) eliminates the 2024 balance sheet

Line
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1 impacts related to ASC 715. This treatment is consistent with DTE Gas's
2 presentation in prior cases starting with Case No. U-15985.

3

4 **Q17. What is the adjustment for asset retirement obligations?**

5 A17. The accounting for asset retirement obligations (ARO) results in timing differences
6 in the recognition of legal asset retirement costs for accounting purposes, compared
7 to the recognition of amounts the Company is currently recovering in rates. ARO
8 accounting requires an up-front accrual for future legal removal costs as a liability.
9 Utility accounting recognizes the removal obligation in accumulated depreciation
10 and accrues it through depreciation expense over the life of the asset. The timing
11 differences are deferred under ASC 980, Regulated Operations. The ARO liability
12 is offset by a corresponding net plant Asset Retirement Cost and a regulatory asset,
13 resulting in no impact on the revenue requirements in this case. To ensure that there
14 is no impact on revenue requirements from ARO accounting in the forecast years,
15 I have removed all 2024 regulated balance sheet impacts on Exhibit A-2, Schedules
16 B4.1 and B4.2, column (e).

17

18 **Q18. What is the adjustment to eliminate Operating Leases?**

19 A18. The Financial Accounting Standards Board issued Accounting Standards
20 Codification (ASC) 842 which required operating leases to be recognized on the
21 balance sheet effective for DTE in 2019. GAAP financial statements now include
22 operating lease right-of-use assets and liabilities. The Uniform System of Accounts
23 does not include balance sheet accounts for operating leases. Since the FERC ruled
24 that the new lease accounting standard cannot impact ratemaking, and operating

Line
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1 lease expense must continue to be based on actual amounts paid and be recorded as
2 rent expense, I eliminated the operating lease right-of-use accounts in column (f).

3

4 **Q19. Why has the Company's historical balance sheet been adjusted to exclude the**
5 **MGP Environmental Liability Reserve?**

6 A19. As required under generally accepted accounting principles, DTE Gas has recorded
7 a reserve for the expected liability of future Manufactured Gas Plant (MGP)
8 environmental obligations with an offsetting deferral to the MGP Regulatory Asset
9 account. The adjustment in column (g) to exclude the MGP reserve is appropriate
10 for ratemaking purposes to demonstrate that only the allowable portion of the MGP
11 Regulatory Asset is included in working capital that the Company is entitled to earn
12 a return on, pursuant to Commission Order in Case Nos. U-13898/U-13899 dated
13 April 28, 2005.

14

15 **Q20. What is the adjustment for Energy Waste Reduction?**

16 A20. The MPSC has established separate proceedings to address the EWR program. I
17 removed the regulatory asset and liability along with the related Accumulated
18 Deferred Federal Income Tax (ADFIT) and short-term debt in column (h). I also
19 removed the program plant and the associated debt and equity consistent with the
20 capital structure authorized by the Commission for the program.

21

22 **Q21. Why are the GCR Over/Under Collection and Other Regulatory Liabilities**
23 **removed from the Company's historical balance sheet for rate case purposes?**

24 A21. The MPSC has established separate proceedings to address the recovery of the GCR
25 Over/Under Collection and RDM. For each regulatory asset and liability amount

Line
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1 excluded, I removed the related Accumulated Deferred Federal Income Tax with
2 the remaining capital removed from short-term debt in columns (j) and (l), as these
3 items are considered temporary working capital requirements.

4

5 **Q22. What is the adjustment for the Voluntary Renewables Program in column (i)?**

6 A22. On October 29, 2020, the commission approved the company's Voluntary
7 Renewables pilot program in Case No. U-20839. The program, offered to both
8 residential and commercial customers, allows them to pay a surcharge to offset a
9 portion of their emissions profile. Per the order, the program is to be accounted for
10 separately and not recovered in base rates.

11

12 **Q23. What is the adjustment for the Customer Attachment Program in column (k)?**

13 A23. The Customer Attachment receivable accrues interest income at the Company's
14 authorized pre-tax weighted rate of long-term debt and equity. Since the Company
15 is compensated outside of base rates for carrying this receivable, I have removed it
16 from working capital.

17

18 **Q24. What is included in the working capital adjustments in column (o)?**

19 A24. On Exhibit A-2, Schedule B4.1 the 13-month average balances of certain accounts
20 have been normalized as follows:

- 21 • Customer accounts receivable has been normalized for estimated weather
22 impacts.
- 23 • Intercompany receivables that do not support core utility services are eliminated
24 from working capital.

Line
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- 1 ○ A portion of the receivable from DTE Electric Company that relates to
2 cash settlements pending for billing system collections from DTE Gas
3 customers remains in working capital.
- 4 ○ Intercompany accounts payable have all been deemed to support core
5 utility services and are not eliminated. These services would otherwise
6 have been provided by an outside party.
- 7 • Deferred Lost Gas accounting impact is eliminated from the unbilled revenue
8 balance, together with its impact on Short-Term Debt, because this accounting
9 treatment adopted by the Company is not recognized by the Commission.

10

11 Since the year-end balances on Exhibit A-2, Schedule B4.2 are used as the starting
12 point for the projected balance sheet, certain accounts that fluctuate throughout the
13 year and will not be specifically forecasted in the projected period are adjusted to
14 the 13-month average. These items include the following: cash, receivables
15 (customer, other and intercompany), uncollectible reserve, unbilled revenues,
16 material and supplies inventories, and payables (external and intercompany).

17

18 **Q25. What is included in Other Reclases and Eliminations?**

19 A25. Column (p) removes deferred taxes related to equity interest of non-affiliates.

20

21 Historical Income Statement

22 **Q26. What information are you supporting on Exhibit A-3, Schedule C1, Historical**
23 **Adjusted Net Operating Income?**

24 A26. On Exhibit A-3, Schedule C1, DTE Gas's Historical Adjusted Net Operating
25 Income for the historical test year ended December 31, 2024, was determined by

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1 starting with the financial information reported on the Company's MPSC Annual
2 Report Form P-522, page 114. Then I adjusted the reported financial information
3 for certain exclusions and inclusions to get to a rate case filing level. Column (c)
4 of the exhibit shows the various components of the \$368.2 million Net Operating
5 Income (line 18) as reported in the Company's 2024 Annual Report to the MPSC
6 on Form P-522. The adjustments necessary for ratemaking purposes include
7 adjustments and normalizations in column (d). The net result of these adjustments
8 is an adjusted Net Operating Income of \$429.4 million as shown on line 23, column
9 (e).

10

11 **Q27. What are the specific adjustments and normalizations that have been made to**
12 **Net Operating Income for the historical test year?**

13 A27. Exhibit A-3, Schedule C1.1 provides a detailed reconciliation of Net Operating
14 Income (NOI) for the historical test year. Line 2 of the exhibit shows the various
15 components of the \$368.2 million NOI reported in the Company's 2024 Annual
16 Report to the MPSC on Form P-522.

17

18 **Q28. What items are included in the Adjustments of Recorded Net Income for the**
19 **historical test year?**

20 A28. The Adjustments are shown on Exhibit A-3, Schedule C1.1, lines 4 through 46 and
21 represent income effects of items that are a) disallowed or adjusted, b) reclassified
22 within utility operating earnings, c) reclassified to or from other income and
23 deductions, or d) eliminated because they are covered under separate proceedings.
24 The result of the adjustments and reclassifications is an increase of \$61.2 million
25 in Net Operating Income.

Line
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1

2 **Q29. What impact do the adjustments have on the various components within NOI?**

3 A29. The NOI impact of the adjustments is reflected on Exhibit A-3, Schedule C1.1 on
4 the following lines:

- 5 • Gas in Kind (line 4) of \$27.7 million, originally reflected as credit within Cost
6 of Gas sold on line 2, is reclassified to Other Revenue.
- 7 • Lost Gas Expense (line 5) of \$0.3 million is reclassified out of Cost of Gas Sold
8 into the Company Use and Lost Gas Expense component.
- 9 • Company Use Expense (line 6) of \$15.9 million is reclassified out of O&M into
10 the Company Use and Lost Gas Expense component.
- 11 • Blue Lake Income (line 7) increases NOI by \$0.9 million; and is comprised of
12 \$1.2 million of Other Revenue offset by \$0.3 million of income taxes. The
13 Equity Earnings were originally recorded to Non-Utility Income, net of tax.
- 14 • Customer Deposit Interest (line 8) decreases income by \$0.5 million for interest
15 paid to customers. The related taxes are already reflected in utility income
16 taxes. Customer deposits are included on the balance sheet as a liability,
17 reducing net working capital.
- 18 • Vector Interest Revenue (line 9) increases Other Revenue and NOI by \$2.9
19 million. The adjustment is displayed on a pretax basis since this is merely a
20 reclassification from interest revenue to operating revenue and income taxes are
21 already reflected in recorded utility income taxes.
- 22 • Grantor Trust Investment Earnings (line 10) increases NOI by \$1.9 million and
23 is comprised of a \$2.6 million increase to Other Revenue less \$0.7 million for
24 income tax benefit that was previously reflected in non-utility income taxes.

Line
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- 1 • Title Transfer Fees (line 11) reduces NOI by \$0.7 million; and is comprised of
- 2 a \$0.9 million reduction in revenue from Third Party Transportation & Storage,
- 3 and a \$0.2 million corresponding Income Tax reclassification to non-utility
- 4 income pursuant to the Commission order in Case No. U-11210.
- 5 • Non-Utility Depreciation (line 12) removes \$61,000 of depreciation expense
- 6 and increases NOI by \$45,000.
- 7 • Taxes related to interest from the Customer Attachment Program (line 13) are
- 8 removed because the interest is not included in customer rates, but the taxes are
- 9 recorded in utility income taxes. This increases NOI by \$436,000.
- 10 • Cost of Gas (line 14) removes \$500.9 million of GCR Cost of Gas and the
- 11 related revenues because they are included in a separate reconciliation
- 12 proceeding.
- 13 • Lost Gas Deferral (line 15) eliminates \$3.1 million of deferred expense
- 14 reflected in Distribution Revenues in 2024 because it relates to an accounting
- 15 treatment adopted by the Company that is not recognized by the Commission.
- 16 This results in an after-tax increase to NOI of \$2.5 million.
- 17 • Revenue Decoupling Mechanism (RDM) (line 16) removes amounts related to
- 18 the RDM as there is a separate reconciliation for this mechanism. The most
- 19 recent RDM was in effect between January 2024 and November 2024 per the
- 20 Order in Case No. U-20940 and resulted in a \$10.5 million liability which was
- 21 refunded to customers in July 2025.
- 22 • Other (line 17) removes miscellaneous surcharges and credits, decreasing NOI
- 23 by \$1,000.
- 24 • Energy Waste Reduction (EWR) (line 18) removes amounts related to EWR
- 25 because there is a separate recovery mechanism for this program. The \$61.5

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- 1 million reduction in revenue plus the removal of the related expense items
2 results in an after-tax reduction to NOI of \$7.6 million.
- 3 • Voluntary Renewable Program (line 19) removes amounts related to the Gas
4 Voluntary Renewables Program approved in Case No. U-20839 which will be
5 accounted for separately and not included in base rates. This results in an after-
6 tax increase to NOI of \$0.7 million.
 - 7 • Excluded Advertising Expenses and Corporate Memberships (lines 20 and 21)
8 removes \$0.7 million in expenses which are not recoverable for ratemaking
9 purposes, and results in an after-tax increase in NOI of \$0.5 million. Exhibit
10 A-3, Schedule C14 identifies the actual advertising expenses by categories as
11 prescribed by the standard filing requirements. The purpose of this exhibit is
12 to quantify the advertising expenses that are not recoverable per the
13 Commission's rate case filing requirements. Allowable advertising expenses
14 for ratemaking include public safety, conservation, and billing practices.
15 Exhibit A-3, Schedule C15 identifies allowable operating expenses for
16 corporate memberships, and quantifies expenses unrelated to utility operations
17 that are not recoverable per the Commission's rate case filing requirements.
 - 18 • Executive Incentive Plan (line 22) removes incentive compensation expense of
19 \$3.7 million for the top five officers of DTE, increasing NOI by \$2.8 million as
20 shown on Exhibit A-3, Schedule C16 and as directed by Company Witness Fix.
 - 21 • Regional Relations (line 23) removes \$11,000 of expense related to lobbying
22 and political advocacy activities that was incurred in the historical test year,
23 increasing NOI by \$8,000. (Note that this type of expense related to federal and
24 state activities was recorded to an account excluded from net operating income.
25 Thus, elimination of those costs is not required.)

Line
No.

1

2 **Q30. What items are included in the Normalizations to Recorded Net Income for**
3 **the historical test year?**

4 A30. Normalizations are shown on Exhibit A-3, Schedule C1.1, lines 28 through 38.
5 These adjustments increase NOI by \$48.2 million.

6 • Removal of miscellaneous taxes (line 28) supported by Witness Wisniewski
7 increases NOI by \$6,000.

8 • Employee Incentive Plan Normalization Adjustment (line 29) – increases O&M
9 expense by \$1.0 million. It decreases NOI by \$0.8 million.

10 • Inclusion of the impact from warmer than normal weather (line 30) increases
11 revenue by \$75.1 million and NOI by \$55.4 million.

12 • Removal of one-time Lost Gas adjustment (line 31) increases Lost Gas expense
13 by \$8.2 million and decreases NOI by \$6.1 million.

14 • Normalize Customer Service (line 32) – increases O&M expense by \$1.1
15 million is supported by Witness Sparks. It decreases NOI by \$0.8 million.

16 • Adjusting injuries and damages to a five-year average (line 33) decreases O&M
17 expense by \$607,000 and increases NOI by \$448,000. The calculation is shown
18 on page 2 of Exhibit A-13, Schedule C5.6.

19 • VSIP Cost to Achieve (line 34) – removal of one-time payment from voluntary
20 separations program in 2024 reduces O&M expense by \$8.2 million and
21 increases NOI by \$6.0 million.

22 • Lag Hiring (line 35) – normalizes 2024 for hiring delays increasing O&M
23 expense by \$1.8 million and decreasing NOI by \$1.4 million.

24 • Shared Asset Deferral Mechanism – reset base (line 36) increases O&M
25 expense by \$5.4 million and decreases NOI by \$4.0 million. This normalization

Line
No.

1 adjustment represents 2024 shared asset expenses above the approved base
2 amount established by the Commissions' Order in Case No. U-21291.

3 • Benefit adjustments (line 37) supported by Witness Cooper increase expense
4 by \$960,000 and decrease NOI by \$708,000.

5

6 **Q31. How did you determine the Incentive Plan adjustments for the historical test**
7 **year on line 29?**

8 A31. Line 29, Employee Incentive Plan Adjustment, is supported by Exhibit A-3,
9 Schedule C17 and increases 2024 incentives expense by \$1.0 million. This is made
10 up of three items related to the short-term incentive plan and one related to the long-
11 term plan. (Incentive plans are discussed in more detail by Witness Fix.)

12

13 The short-term incentive plan design allows for a payout within a range of zero to
14 200% of the target, depending on actual results achieved. Incentives related to
15 operating metrics within the short-term plan are covered by a mechanism that
16 allows for a deferral of incentives paid above or below a base amount, capped at
17 100% of the overall target. Short-term incentive expense related to operating
18 metrics in 2024 was \$1.6 million above the amount in base rates. Since the amount
19 above the base was deferred, it must be added back to reflect expense equal to the
20 amount accrued for payout. In addition, the amount accrued for payout under the
21 short-term plan was \$0.4 million below the 100% target, so the total adjustment to
22 reflect short-term incentives at 100% is an increase of \$2.0 million. The third item
23 removes \$0.2 million of prior period adjustments. Since deferrals, payments below
24 the target, and prior period adjustments may not recur, I have increased the
25 historical amounts by \$2.2 million to a baseline expense level.

Line
No.

1

2

The last adjustment relates to long-term incentives. Long-term incentives in 2024 include a \$1.2 million increase in expense for the 2022 through 2024 performance shares based on performance relative to 100% of the target. Since an incentives payout above the target may not recur, I have reduced the historical expense by \$1.2 million. The net impact of the adjustments to the short-term and long-term incentive expense is an increase to O&M of \$1.0 million as shown on Exhibit A-3 Schedule C17, column (d), line 5. The after-tax impact is a reduction to NOI of \$0.8 million.

3

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11 **Q32. How did you determine the Weather normalization adjustment for the**
12 **historical test year?**

13

A32. The Weather normalization for distribution revenue (line 30) reflects warmer than normal temperatures in 2024, requiring a \$75.1 million margin increase and an after-tax increase to NOI of \$55.4 million to normalize earnings. See the calculation on Exhibit A-3, Schedule C18 for the volume and revenue impact of weather by customer class (Residential, Commercial, and Transportation). As shown on line 4, column (b), sales decreased by 20.5 Bcf from the warmer than normal weather in the historical test year. The computation was estimated based on 15-year rolling heating degree day (HDD) weather normalization as supported by Witness Chapel. The volume impacts are then multiplied by an average distribution rate for the customer class in column (c), resulting in a total margin impact of \$75.1 million on line 4, column (d) and \$55.4 million on a net of tax basis as shown on line 7.

14

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Line
No.

1 **Q33. What operating income items did you include in adjusted historical net**
2 **operating income?**

3 A33. Operating income adjustments are shown on Exhibit A-3, Schedule C1.1, lines 41
4 through 44. These adjustments increase NOI by \$1.3 million.

5 • Allowance for Funds Used During Construction (AFUDC) (line 41) adds \$2.7
6 million of debt and equity AFUDC to net operating income. The adjustment
7 is displayed on a pretax basis since income taxes are already reflected in
8 recorded utility income taxes.

9 • Amortization of Loss on Reacquired Debt (line 42) increases other expense
10 and reduces NOI by \$1.4 million because the loss on reacquired debt is not
11 included in the cost of long-term debt for ratemaking purposes. The
12 adjustment is displayed on a pretax basis since this is merely a reclassification
13 from interest expense to operating expense and income taxes are already
14 reflected in recorded utility income taxes. This amortization is a result of DTE
15 Gas's efforts to reduce interest costs by redeeming and refinancing long-term
16 debt securities in advance of their scheduled maturities. The cost related to
17 each of these early redemptions is amortized over the life of the new issue.

18 • Income Tax Effect of Interest (line 43), supported by Witness Vangilder
19 decreases NOI by \$0.1 million to align the actual interest expense tax
20 deduction with the allowable ratemaking interest expense tax deduction
21 associated with the capital structure debt components.

22

23

24

Line
No.

1 **Q34. What information is displayed in Exhibit A-3, Schedule C3, Historical Sales**
2 **Revenue?**

3 A34. Exhibit A-3, Schedule C3 provides the amount as reported on MPSC Annual Report
4 Form P-522 for residential, commercial, industrial, wholesale, transportation,
5 refund provisions and miscellaneous revenues, underlying total revenue reported
6 on Exhibit A-3, Schedule C1.1, column (c), line 2.

7

8 **Q35. What is the purpose of Exhibit A-3, Schedule C4, Historical Cost of Gas Sold?**

9 A35. Exhibit A-3, Schedule C4 provides the cost of gas sold accounts as reported on the
10 MPSC Annual Report Form P-522 for the 12-month period ended December 31,
11 2024, and carried to Exhibit A-3, Schedule C1.1, column (d), line 2.

12

13 **Q36. What information is displayed in Exhibit A-3, Schedule C5, Historical**
14 **Operation and Maintenance Expenses?**

15 A36. Exhibit A-3, Schedule C5 provides the operations and maintenance and expense
16 accounts as reported on the MPSC Annual Report Form P-522, adjusted to exclude
17 cost of gas and uncollectible expense, for the 12-month period ended December 31,
18 2024, and carried to Exhibit A-3, Schedule C1.1, column (f), line 2.

19

20 **Q37. What information is displayed in Exhibit A-3, Schedule C6, Historical**
21 **Depreciation and Amortization Expenses?**

22 A37. Exhibit A-3, Schedule C6 provides the depreciation and amortization expense
23 accounts as reported on the MPSC Annual Report Form P-522 for the 12-month
24 period ended December 31, 2024, and carried to Exhibit A-3, Schedule C1.1,
25 column (h), line 2.

Line
No.

1

2 **Q38. What information is displayed in Exhibit A-3, Schedule C11, Historical**
3 **Allowance for Funds Used During Construction (AFUDC)?**

4 A38. Exhibit A-3, Schedule C11 provides the AFUDC accounts as reported on the MPSC
5 Annual Report Form P-522 for the 12-month period ended December 31, 2024, and
6 carried to Exhibit A-3, Schedule C1.1, column (m), line 41.

7

8 **Forecast Period**

9 **Q39. How was the financial forecast for the projected test year, the twelve months**
10 **ending September 30, 2027, prepared?**

11 A39. Projected DTE Gas financial statements for the twelve-month period ending
12 September 30, 2027 were based on projected changes from the adjusted normalized
13 amounts for the year ended December 31, 2024. The financial forecast for the
14 projected test year incorporates assumptions supported by the various DTE Gas
15 witnesses including myself. Monthly data was used to derive 13-month average
16 balance sheet calculations.

17

18 **Balance Sheet Forecast**

19 **Q40. How was the 13-month average balance sheet developed in support of DTE**
20 **Gas's Rate Base for the projected test year ending September 30, 2027?**

21 A40. I started with the December 31, 2024, adjusted balance for each component carried
22 from Exhibit A-2, Schedule B4.2. Certain line items were projected if warranted
23 by key assumptions in the case, while other line items were held constant at the
24 adjusted historical balance as of December 31, 2024. Exhibit A-12, Schedule B4.2,
25 provides a comparison of the 13-month average balance sheet for historical test

Line
No.

1 year December 31, 2024, and the projected test year September 30, 2027. The
2 balance sheet line items in column (b) represent the Adjusted Historical Test Year
3 balances carried from Section A, Exhibit A-2, Schedule B4.1.

4

5 **Q41. What are the major components making up the Assets in Exhibit A-12,**
6 **Schedule B4.2, page 1?**

7 A41. Exhibit A-12, Schedule B4.2 page 1, is comprised of the following major
8 components:

- 9 1) Property, Plant and Equipment
10 2) Other Property and Investments
11 3) Current and Accrued Assets
12 4) Deferred Debits

13

14 Property, Plant and Equipment (Net Utility Plant)

15 **Q42. How did you develop the Net Utility Plant balance for the projected test year?**

16 A42. Net Utility Plant on line 7 of Exhibit A-12, Schedule B4.2, page 1 of 2, increases
17 over the historical test year due to capital additions in excess of depreciation
18 expense levels. The projected change in Plant in Service is driven by construction
19 added to plant in service less retirements from January 1, 2025 through September
20 30, 2027. Additions to plant in service are \$645.6 million in 2025, \$667.2 million
21 in 2026 and \$601.2 million in 2027, offset by retirements of \$63.1 million in 2025,
22 \$73.8 million in 2026 and \$58.4 million in 2027. Retirements were assumed based
23 on either a historical five-year average (Distribution, Transmission, and Storage
24 Plant) or scheduled retirements (Intangible and General Plant).

25

Line
No.

1 Construction Work in Progress (CWIP) reflects capital expenditures of \$2,043.0
2 million for the period January 2025 through September 2027, less \$153.1 million
3 of removal costs classified to accumulated depreciation. Capital expenditures are
4 supported and explained by Company Witnesses Fedele, Jackson, Janness,
5 Huffman, and Bolda and include approximately \$843 million of routine
6 investments, \$688 million of IRM related projects, \$447 million of special projects,
7 and \$65 million of information technology. Special projects include the South
8 Grand Rapids Distribution Line, Van Born project, the Fort Street main
9 replacement project, Carlton Main Replacement, East Petoskey Reinforcement
10 Project, Oakland Resilience Project, Taggart Compressor Station, and the Belle
11 River Dehydration Unit project. CWIP generally assumes all projects are
12 completed and unitized within the same calendar year as when the costs are incurred
13 except for the following multi-year projects: Carlton Main Replacement, East
14 Petoskey Reinforcement Project, Oakland Resilience Project, Belle River
15 Dehydration Unit, Taggart Compressor Replacement, South Grand Rapids
16 Distribution Line and the Northern Operations Resource Center (NORC) expansion
17 and renovation project.

18

19 Projected Accumulated Depreciation has been developed based on estimated plant
20 depreciation expense of \$431.4 million for the interim period January 2025 through
21 September 2026 and \$267.6 million for the test year ending September 2027,
22 including approximately \$12.3 million of annualized Transportation and Mobile
23 Power Equipment depreciation which is charged to O&M and capital clearing
24 accounts. The calculation of depreciation expense is described later in my
25 testimony. Accumulated Depreciation is also adjusted for retirements from January

Line
No.

1 1, 2025, through September 30, 2027, consistent with those assumed in Plant in
2 Service, plus net removal costs of \$153.1 million based on a historical average.

3

4 **Q43. Will all the forecasted capital expenditures be unitized to plant in service by**
5 **the end of the projected test period?**

6 A43. No. The NORC project is expected to remain under construction past September
7 2027. Thus, there is no depreciation expense projected for this project, and the
8 AFUDC credit on the income statement offsets the impact of reflecting the project
9 in rate base. In other words, there is no current revenue requirement for this project.

10

11 Other Property and Investments

12 **Q44. What is included in Other Property and Investments?**

13 A44. Other Property and Investments are reflected on lines 12-17 of Exhibit A-12,
14 Schedule B4.2. These are comprised of Blue Lake and the Grantors Trust. During
15 the projected test year, it is assumed that Blue Lake subsidiary will pay a dividend
16 equal to its Equity Earnings at the end of each quarter while the Grantors Trust
17 Investment is assumed to grow based on a five-year average of historical income.

18

19 Current and Accrued Assets

20 **Q45. What is included within the Current and Accrued Assets section of the balance**
21 **sheet?**

22 A45. Current and Accrued Assets are listed on lines 20-35 of Exhibit A-12, Schedule
23 B4.2. This category consists primarily of Customer Accounts Receivable, Other
24 Accounts Receivable, Uncollectible Reserve, Inventories (Gas in Storage and

Line
No.

1 Materials & Supplies), Prepayments, Gas Customer Choice (GCC) Deferred Asset,
2 Unbilled Revenue, and various other current assets.

3

4 **Q46. How did you calculate the projected balances for Customer Accounts**
5 **Receivable?**

6 A46. Since Customer Accounts Receivable balance fluctuates throughout the year, the
7 projected period was based on the weather normalized 13-month historical average
8 as of December 31, 2024.

9

10 **Q47. What other forecast assumptions were made within the Current Assets**
11 **section?**

12 A47. Other items within this category that fluctuate throughout the year and are not
13 specifically forecasted were held constant at the adjusted 13-month average
14 historical December 31, 2024 balance. These items include Cash, Other Accounts
15 Receivable, Uncollectible Reserve, Intercompany Accounts Receivable, Materials
16 and Supplies, and Unbilled Revenue.

17

18 Other items within this category are specifically forecasted starting with the adjusted
19 year-end balance at December 31, 2024. Gas in Underground Storage and the GCC
20 Deferred Asset reflect inventory activity based on a Source and Disposition
21 provided by our Gas Planning Department. Prepayments were projected based on
22 projected property tax payments, offset by property tax accruals, supported by
23 Witness Wisniewski. Other current assets were held constant at the adjusted 13-
24 month average historical December 31, 2024 balance.

25

Line
No.

1 Deferred Debits

2 **Q48. What is included in Deferred Debits?**

3 A48. Exhibit A-12, Schedule B4.2 lists Deferred Debits on page 1 (lines 38-61). The
4 major accounts within this category relate to Unamortized Debt Expenses and
5 Unamortized Loss on Reacquired Debt, Vector Pipeline Lease, Prepaid Pensions
6 and Prepaid OPEB, various Regulatory Assets, and Tax Related Deferred Debits.
7 The Other Deferred Debits balance was held constant at the adjusted 13-month
8 average historical December 31, 2024 balance.

9
10 **Q49. How did you develop the balances for Unamortized Debt Expenses and**
11 **Unamortized Loss on Reacquired Debt?**

12 A49. Unamortized Debt Expenses and Unamortized Loss on Reacquired Debt are
13 included in Deferred Debits on lines 38-39 of Exhibit A-12, Schedule B4.2, page
14 1. Unamortized Debt Expense is reduced by annual straight-line amortization of
15 about \$1.3 million and increased by 0.7% of projected long-term debt issuances.
16 Unamortized Loss on Reacquired Debt is reduced by annual straight-line
17 amortization of \$1.4 million.

18
19 **Q50. What is the Vector Pipeline Lease?**

20 A50. The Vector Pipeline lease is a capital lease agreement between DTE Gas and Vector
21 Pipeline that began in 2000. The lease was renewed for an additional fifteen-year
22 term, effective December 1, 2025. The Vector Pipeline Lease shown on line 40 is
23 credited for the annual lease payments with an offsetting debit for the interest
24 portion of the payment. The net reduction in the Vector Lease balance represents
25 the principal portion of the lease payments.

Line
No.

1

2 **Q51. What is the Prepaid Pension?**

3 A51. The balance included in the Prepaid Pensions Deferred Debit account on line 41
4 represents prepaid pension costs related to DTE Gas's union and non-union plans.
5 Prepaid Pension represents the cumulative difference between accrued pension
6 costs and cash contributions to the pension trusts. The prepaid balance decreases
7 in 2025 through 2027 with positive expense. While there is no planned funding of
8 the DTE Gas Non-Union pension plan through the end of the projected test period,
9 the Company plans on transferring \$25 million of assets to the DTE Electric
10 pension plan in 2025 and in 2026, which decreases the Prepaid Pensions Deferred
11 Debit.

12

13 **Q52. Why does DTE Gas plan to transfer \$25 million per year to the DTE Electric**
14 **pension plan?**

15 A52. As of December 31, 2024, the DTE Gas Non-Union pension plan had assets in
16 excess of its projected benefit obligation (PBO) of about \$139 million, whereas the
17 DTE Electric pension plan had assets that were about \$247 million less than its
18 PBO. Since the DTE Gas Non-Union pension plan is a component of the overall
19 DTE Energy Retirement plan, as is the DTE Electric pension plan, the Company
20 can transfer the excess assets in the DTE Gas Non-Union plan to DTE Electric
21 without any income tax or ERISA consequences. This transfer will be
22 accomplished through payments by DTE Electric of \$25 million in 2025 and in
23 2026 to DTE Gas in consideration for the transfer of DTE Gas trust assets of \$50
24 million within the DTE Energy Retirement plan trusts.

25

Line
No.

1 **Q53. Will this transfer have any impact on DTE Gas's revenue requirement?**

2 A53. Yes. DTE Gas's revenue requirement will be lower due to the prepaid pension
3 asset included in the Company's working capital component of rate base being
4 lower than it would have been in the absence of the transfers. While DTE Gas's
5 pension costs will increase due to a reduction in the Expected Return on assets as a
6 result of lower DTE Gas pension trust assets, this will not change the Company's
7 revenue requirement because of the deferral of pension costs to a regulatory
8 liability.

9

10 **Q54. What components are used to derive the projected balance for Prepaid OPEB?**

11 A54. Prepaid OPEB on line 42 represents the cumulative difference between accrued
12 costs and cash contributions. No funding contributions are projected. The prepaid
13 balance increases by negative expense in 2025, 2026 and 2027.

14

15 **Q55. What is included in the Environmental Regulatory Asset?**

16 A55. The Commission has established a cost deferral and rate recovery mechanism for
17 investigation and remediation costs related to environmental cleanup at the
18 Company's former MGP sites. The related regulatory asset as shown on line 46
19 reflects the unamortized balance of allowable MGP costs (net of insurance or other
20 recoveries) which are tracked by vintage year layers and amortized over ten years
21 beginning the year after payments are made, pursuant to the Commission Order in
22 Case No. U-13898. Payments of \$0.4 million are supported for recovery by
23 Company Witness Dziekan.

24

Line
No.

1 **Q56. What is included in the Pension Regulatory Asset?**

2 A56. The Pension Regulatory Asset was established pursuant to the Commission's order
3 in Case No. U-13898 that authorized the accrual of a regulatory asset for the non-
4 capitalized portion of the positive pension cost. Pension expense was negative in
5 2024 and is forecasted to be positive in 2025, 2026 and 2027. The net result of these
6 fluctuations is the Pension Regulatory Asset on line 47 for the total amount of \$1.2
7 million.

8

9 **Q57. What is the regulatory asset for Deferred TCARP expense?**

10 A57. TCARP is a capital project supported by Witness Fedele to provide a backup supply
11 of gas to mitigate outage risks. DTE Gas was authorized to record a regulatory
12 asset for expenses associated with TCARP operations per the July 27, 2021 Order
13 in Case No. U-21102. In Case No. U-21291 DTE Gas was approved to begin
14 amortization of the deferred expense of \$17.071 million beginning in November
15 2024. Upon reconciling the TCARP expenses that were requested in U-21291,
16 DTE Gas deferred an additional \$1.546 million of expense to the TCARP
17 regulatory asset as shown on Exhibit A-13, Schedule C5.2.2. The remaining layer
18 of the regulatory asset will be amortized to O&M over three years, starting in
19 October 2026. Witness Kehoe reflects the amortization expense and on-going
20 O&M expense on his Exhibit A-13, Schedule C5.2.

21

22 **Q58. What is the regulatory asset for Deferred TCARP Demand Charge expense?**

23 A58. TCARP demand charge is discussed by Witness Kehoe as an expense that we pay
24 to DT Midstream for capacity on their pipelines to mitigate potential integrity and
25 outage risks for approximately 91,000 customers. DTE Gas is authorized to record

Line
No.

1 a regulatory asset for expenses associated with TCARP demand charges per the
2 Order in Case No. U-21917. Line 49 reflects the total expected deferral of
3 approximately \$1.0 million through September 2026, less the related amortization
4 over three years.

5

6 **Q59. What is the regulatory asset for Demand Response (DR) costs?**

7 A59. As discussed by Witness Farrell, the Company conducted a pilot to determine the
8 effectiveness of a gas demand response program within the Company's service
9 territory. In Case No. U-20642, the Commission approved the use of account 182.3,
10 Other Regulatory Assets, to defer the actual DR O&M expenses for recovery in a
11 future case. As sponsored by Witness Farrell on Exhibit A-26, Schedule P1, the
12 Company deferred approximately \$2.6 million of demand response costs over the
13 three-year pilot period. Line 50 of Exhibit A-12, Schedule B4.2 reflects the actual
14 deferrals and amortization of the deferred cost over three years starting in
15 November 2024, as approved in Case No. U-21291. The projected test period
16 amortization expense of \$0.9 million is reflected on Witness Huffman's Exhibit A-
17 13, Schedule C5.5, line 5, column (I).

18

19 **Q60. What is the regulatory asset for EWR Uncollectibles?**

20 A60. In Case No. U-21291 the Commission approved a deferral mechanism for the
21 uncollectible expense associated with EWR revenues to be reviewed in the next
22 rate case. Exhibit A-12, Schedule B4.2, line 51 reflects the \$0.2 million of costs
23 deferred to the regulatory asset through August 2025.

24

25

Line
No.

1 **Q61. What is the regulatory asset for Low-Income Stability Plan Pilot?**

2 A61. In Case No. U-20929, the Commission authorized DTE Gas to defer costs
3 associated with its low-income customer assistance pilot (the Payment Stability
4 Plan or “PSP”). The PSP pilot creates a fixed maximum bill for participating
5 customers based on their income, rather than providing a fixed credit amount on a
6 variable bill like those provided by the residential income assistance or the low-
7 income assistance programs. The balance consists of supplemental payments,
8 arrears forgiveness, benefit awards, and certain O&M implementation costs
9 associated with the pilot. The balance reflected on line 53 of Exhibit A-12, Schedule
10 B4.2 reflects \$1.0 million of deferred expenses through June 2024 net of the related
11 amortization over two years. The amortization expense is a reduction to
12 distribution revenue on Exhibit A-13, Schedule C3.1, line 8.

13

14 **Q62. What is the regulatory asset for Deferred Shared Asset Expense?**

15 A62. In Case No. U-20940, the Commission approved a deferral mechanism for shared
16 asset charges from DTE Electric for DTE Gas’s proportionate use of DTE Electric’s
17 assets above or below a base amount of \$48.9 million. The balance sheet reflects
18 the actual deferral from 2022 through year end 2024 and the projected deferrals
19 from January 2025 through September 2026, net of the related amortization over
20 five years. I explain the activity underlying this account in my discussion of A&G
21 expenses.

22

23

24

25

Line
No.

1 **Q63. Do you recommend that the shared asset deferral mechanism be continued?**

2 A63. Yes. I also propose that the base be reset to \$52.2 million, or to the amount
3 ultimately approved as a revenue credit in DTE Electric's current rate case, No. U-
4 21860, if different from DTE Electric's initial filing in that case.

5

6 **Q64. What is the impact if not all the shared asset projects are approved or**
7 **implemented at DTE Electric?**

8 A64. If actual charges from DTE Electric are lower than projected due either to projects
9 being disallowed in a DTE Electric rate case, or costs varying from current
10 assumptions, then the DTE Gas will record a refund obligation in account 254,
11 Other Regulatory Liabilities, for any difference between actual Shared Asset
12 charges included in account 931, Rents, and the base approved in this case.
13 Account 182.3, Other Regulatory Assets, would be used to defer expense incurred
14 above the base.

15

16 **Q65. What is the regulatory asset for Deferred Incentive Compensation Expense?**

17 A65. In Case No. U-21291, the Commission approved recovery of \$3.5 million for
18 incentive compensation related to operating metrics. The approved base amount
19 assumed the Company achieved 55% of its targeted metrics. The Commission's
20 Order also provided for deferral treatment above or below the base amount, up to a
21 maximum 100% target level, to be refunded or recovered in DTE Gas's next rate
22 case. I explain the activity underlying this account in my discussion of A&G
23 expenses.

24

Line
No.

1 **Q66. Do you recommend that the incentive compensation deferral mechanism be**
2 **continued?**

3 A66. Yes, I request the deferral be continued and that the base amount be reset equal to
4 the amount of incentive compensation approved for recovery in base rates in this
5 case.

6
7 **Q67. What modifications to the incentive compensation mechanism are you**
8 **proposing?**

9 A67. The deferral should cover the total actual payout, including amounts above 100%
10 of the target. As described in more detail by Witness Fix, the incentive program
11 allows for a range of payouts from zero to 200% of target. The incentive plan is
12 designed to motivate employees to achieve results beyond the target, further
13 improving organizational performance and benefiting customers. Since the
14 Company must provide a refund to customers if results fall below the baseline, it is
15 reasonable to include the cost of achieving exceptional results.

16
17 **Q68. What are the regulatory assets for Low-Income Assistance and Residential**
18 **Income Assistance?**

19 A68. In Case No. U-20940, the Commission authorized DTE Gas to defer Low-Income
20 Assistance (LIA) credits and Residential Income Assistance (RIA) credits issued
21 above or below a base amount. I am requesting that the deferral mechanism be
22 continued. Lines 56 and 57 reflect that the Company issued more LIA and RIA
23 credits to customers through August 2025 than were reflected in the base. The
24 Company is requesting recovery of these regulatory assets over five years. The

Line
No.

1 amortization expense is a reduction to distribution revenue on Exhibit A-13,
2 Schedule C3.1, line 7.

3

4 **Q69. What is in the Miscellaneous Deferred Debit-Tax Related account?**

5 A69. The Miscellaneous Deferred Debit-Tax Related account is an offset to the deferred
6 tax liabilities related to state and local tax rate changes, such as the enactment of
7 the Michigan Corporate Income Tax, and is supported by Witness Wisniewski.
8 This item is netted with deferred tax liabilities for purposes of the capital structure
9 and cost of capital calculation sponsored by Witness Vangilder.

10

11 **Q70. What are the major components making up the Stockholders' Equity and**
12 **Liabilities in Exhibit A-12, Schedule B4.2, page 2?**

13 A70. Exhibit A-12, Schedule B4.2 page 2, is comprised of the following major
14 components:

- 15 1) Current and Accrued Liabilities
- 16 2) Deferred Credits and Reserves
- 17 3) Capitalization (Common Equity and Long-Term Debt)

18

19 Current and Accrued Liabilities

20 **Q71. What is included within the Current and Accrued Liabilities section of the**
21 **balance sheet?**

22 A71. Current and Accrued Liabilities are listed on lines 72-85 of Exhibit A-12, Schedule
23 B4.2 page 2. This category consists primarily of Short-Term Debt, Accounts
24 Payable, Intercompany Accounts Payable, Interest Payable, Inventory
25 Equalization, and various other current liabilities. Accounts Payable, Intercompany

Line
No.

1 Accounts Payable, Customer Deposits, Other Taxes Payable, Non-MGP
2 Environmental Reserve and other current liabilities were held constant at the 13-
3 month average historical December 31, 2024 adjusted year-end balance. Other
4 items that were specifically forecasted include Short-Term Debt, Income Taxes
5 Payable, Interest Payable, and Inventory Equalization.

6

7 **Q72. How was the Short-Term Debt balance calculated?**

8 A72. Short-term debt is used to finance DTE Gas's working capital requirements not
9 funded through permanent capital. Thus, to the extent long-term financing does
10 not cover monthly working capital requirements, short-term debt was calculated as
11 the amount needed to fund the Company's operations on a month-to-month basis.

12

13 **Q73. How was Income Taxes Payable calculated?**

14 A73. Income Taxes Payable on line 79 is supported by Witness Wisniewski. The balance
15 reflects monthly accruals and quarterly payments for federal, state and municipal
16 income taxes. The 13-month average is driven by the monthly calculations of
17 current income tax expense that utilize test-period data and assumptions.

18

19 **Q74. How was Interest Payable calculated?**

20 A74. Interest Payable on line 80 was projected based on accruals and payments of interest
21 on commercial paper and long-term debt. Commercial paper interest is assumed to
22 be paid the month following the accrual. Interest on long-term debt is paid semi-
23 annually.

24

25

Line
No.

1 **Q75. What is Inventory Equalization?**

2 A75. Inventory equalization represents the difference between the current year gas
3 purchase rate and the average prior year-end LIFO inventory gas rate applied to
4 volumes withdrawn from storage in the early part of the calendar year. While
5 inventory balances are reduced by only the low LIFO cost, the equalization reserve
6 reflects the difference between the current period cost and the LIFO cost as a
7 temporary liability. For example, a liability was accrued during the first quarter of
8 2025, reaching \$94.3 million in March. As gas is injected in the summer months
9 to replace the gas withdrawn earlier in the year, the equalization reserve is reduced
10 by the same methodology until the gas storage balance reaches the prior year-end
11 level. The equalization account balance reaches zero by year-end but does have an
12 impact on the 13-month average balance sheet as shown on Exhibit A-12, Schedule
13 B4.2, line 81.

14

15 Deferred Credits and Reserves

16 **Q76. What is included in Deferred Credits?**

17 A76. Exhibit A-12, Schedule B4.2, page 2 lists Deferred Credits (lines 87-109). The
18 major accounts within this category include Provision for Injuries and Damages,
19 Accumulated Deferred Income Taxes, the Tax Reform Regulatory Liability, and
20 various regulatory liabilities.

21

22 **Q77. What is included in Accumulated Deferred Income Taxes?**

23 A77. This balance includes both federal and state deferred income tax and is supported
24 by Witness Wisniewski.

25

Line
No.

1 **Q78. What is the Tax Reform Regulatory Liability?**

2 A78. The Tax Reform Regulatory liability on line 93 represents the excess deferred
3 income taxes from the 2017 Tax Cuts and Jobs act which lowered the federal
4 corporate income tax rate from 35% to 21%. The reduction in deferred taxes was
5 recorded to a regulatory liability. Witness Wisniewski supports the regulatory
6 liability and the Company's refund schedule.

7

8 **Q79. What is the Negative Pension Liability?**

9 A79. The Negative Pension Regulatory Liability was established pursuant to the
10 Commission's order in Case No. U-13898 that authorized the accrual of a
11 regulatory liability for the non-capitalized portion of the negative pension cost.
12 Once the balance became positive, the net expense after capitalization and transfers
13 was deferred to a regulatory asset account on line 47 pursuant to the Commission's
14 Order in Case Nos. U-20642 and U-20940. Pension expense was negative in 2024
15 and is forecasted to be positive in 2025, 2026 and 2027. The net result of these
16 fluctuations is the Pension Regulatory Asset on line 47. The Pension Regulatory
17 Liability will reach zero by November 2026.

18

19 **Q80. What is the regulatory liability – TCJA?**

20 A80. Line 102 represents the excess deferred taxes that were remeasured related to the
21 reduction of the federal corporate income tax rate change resulting from the 2017
22 Tax Cuts and Jobs Act (TCJA) and is supported by Witness Wisniewski.

23

24

25

Line
No.

1 **Q81. What is the regulatory liability for Other Postemployment Benefits (OPEB)?**

2 A81. The OPEB liability was established pursuant to the Commission's Order in Case
3 No. U-17999. Consistent with the treatment of pension expense, negative OPEB
4 expense, less amounts capitalized and transferred, are offset by a regulatory
5 liability.
6

7 **Q82. What are the regulatory liabilities for Pension and OPEB capitalized?**

8 A82. DTE Gas has historically capitalized pension and OPEB expense related to
9 capitalized labor. Effective in 2018, the non-service cost components of these
10 benefits could no longer be charged to capital under GAAP. Instead, the non-
11 service costs that would have been capitalized under the traditional accounting
12 treatment (but expensed under GAAP) are recorded to a regulatory liability (or asset
13 if positive) instead of plant as shown on lines 104 and 105. The regulatory asset or
14 liability is depreciated using the prior year's composite depreciation rate for plant
15 in service, with the expense recorded to a unique account within Depreciation and
16 Amortization expense. This treatment was approved in Case No. U-18999.
17

18 **Q83. What is the regulatory liability for Residential Income Assistance?**

19 A83. In Case No. U-20940, the Commission authorized DTE Gas to defer Residential
20 Income Assistance credits above or below a base amount. The balance sheet
21 reflects the regulatory liability balance from 2024 for credits issued below the base
22 amount. The projected period reflects a regulatory asset, as previously discussed.
23
24

Line
No.

1 **Q84. What other forecast assumptions were made within the Deferred Credits**
2 **section?**

3 A84. All other deferred credits were assumed to be held constant at the 13-month average
4 historical December 31, 2024 balance because the historical fluctuation in these
5 accounts has not been material.

6

7 Capitalization

8 **Q85. How were the projected capitalization amounts determined in this case?**

9 A85. Capitalization is comprised of Common Equity and Long-Term Debt as shown on
10 lines 66 through 68 of Exhibit A-12, Schedule B4.2, page 2. Long-Term Debt
11 includes bonds net of unamortized discounts. Key long-term debt drivers include
12 new capital requirements, scheduled retirements, refinancing, level of equity, and
13 the amount of short-term debt. Long-Term Debt includes bond issuances of \$451
14 million from January 2025 through September 2026, and \$150 million in the
15 projected test year October 2026 through September 2027, as discussed by
16 Company Witness Lepczyk. There is \$70 million of bonds maturing in the interim
17 period and \$40 million maturing in the projected test period.

18

19 **Q86. How did you develop the 13-month average Common Equity balance?**

20 A86. Common equity will increase to finance the growing asset base and to meet targeted
21 capitalization percentages. Exhibit A-12, Schedule B4.3 reconciles DTE Gas's
22 monthly common equity starting from year-end December 31, 2024 by adding net
23 income in column (c) and subtracting dividend payments in column (d). DTE Gas
24 has assumed common dividend payments of \$398.8 million in the interim period
25 from January 2025 through September 2026, and \$252.0 million in the projected

Line
No.

1 period from October 2026 through September 2027. I then solved for the equity
2 infusions/rate relief in column (e) to arrive at the ending monthly balance in column
3 (f) needed to support the targeted capital structure of 50.75% equity discussed by
4 Witness Lepczyk.

5

6 **Q87. Do the equity balances include amounts to support the infrastructure**
7 **program?**

8 A87. Generally, no. Costs related to the infrastructure program after December 31, 2026
9 are proposed to be recovered through a separate infrastructure recovery mechanism
10 (IRM), as will be discussed later in my testimony. The infrastructure program rate
11 base and capitalization are not included in the projected financial statements used
12 to determine the revenue deficiency for base rates.

13

14 Net Operating Income Forecast

15 **Q88. How was net operating income on Exhibit A-13, Schedules C1 and C1.1**
16 **developed for the projected twelve-month period ending September 30, 2027?**

17 A88. DTE Gas's projected net operating income for the twelve months ending September
18 30, 2027 was developed on Exhibit A-13, Schedules C1 and C1.1, based on
19 forecasted changes from the year ended December 31, 2024 normalized amounts.
20 As shown on Schedule C1, line 22 in column (e), projected net operating income
21 for the test year ending September 30, 2027, is \$320.8 million, which is a \$108.6
22 million decrease from the 2024 adjusted historical test year. The decrease in
23 income is due to higher operating costs, partially offset by slightly increased
24 revenues, and higher AFUDC. The increase in costs results from growth in plant,
25 increased O&M, and higher depreciation. Operating revenues reflect increased

Line
No.

1 midstream offset by decreased distribution revenues, the discontinuation of the
2 IRM surcharge, and lower other operating revenues. Each of these projections is
3 sourced from separate exhibits sponsored by various witnesses in this case.

4

5 **Q89. What items are you sponsoring with respect to development of the Net**
6 **Operating Income for the projected twelve-month period ending September**
7 **30, 2027?**

8 A89. I am sponsoring the development of DTE Gas's projected test year Operating
9 Revenue, Operation & Maintenance Expense, Depreciation and Amortization, and
10 AFUDC. I am also providing the projected inflation rates used for developing
11 O&M and capital.

12

13 Operating Revenue

14 **Q90. How were DTE Gas's revenues developed for the projected twelve-month**
15 **period ending September 30, 2027?**

16 A90. Projected revenues were developed in Exhibit A-13, Schedule C3, which details the
17 major categories of revenue and sponsoring witnesses.

- 18 • Gas Sales revenue – I am the sponsoring witness for these revenues
- 19 • End-User Transportation – sponsored by Witness Huffman
- 20 • Exelon – I am the sponsoring witness for these revenues
- 21 • Off-System Transportation and Storage – sponsored by Witness Huffman
- 22 • Other Operating Revenue – Witness Huffman is sponsoring Appliance Service
- 23 Programs, Gas Choice Supplier Revenue, Other Gas Revenue, and Blue Lake
- 24 Investment Income. Gas in Kind Revenue from third parties and end-user
- 25 transportation customers is based on volumes sponsored by Witness Huffman

Line
No.

1 multiplied by the cost of gas rate; and is shown on Company Witness Bence's
2 Exhibit A-15, Schedule E8, line 3, column (e). I am sponsoring the remaining
3 items.

4

5 **Q91. What is the projected change in revenues from the historical normalized**
6 **period to the projected test year?**

7 A91. Exhibit A-13, Schedule C3, column (b) displays revenue for the historical test year
8 totaling \$1,341.9 million including the reclassifications and adjustments previously
9 discussed. Total operating revenue is expected to increase by \$3.2 million to
10 \$1,345.0 million, as shown on line 8, column (d). The projected changes in revenue
11 shown in column (c) include:

- 12 • \$72.1 million increase in Gas Sales revenue
- 13 • \$5.3 million increase in End-User Transportation
- 14 • \$2.5 million increase in easement revenue from Exelon
- 15 • \$80.6 million decrease from the discontinuation of the current IRM
- 16 surcharge
- 17 • \$11.6 million increase in off-system revenue, comprised of a \$3.7 million
- 18 decrease in transportation and exchange revenue and a \$15.4 million
- 19 increase in storage service revenue
- 20 • \$7.7 million decrease in other operating revenue

21

22 **Q92. How did you develop Gas Sales revenues for the projected twelve-month**
23 **period ending September 30, 2027?**

24 A92. Gas Sales revenues of \$919.5 million were developed in Exhibit A-13, Schedule
25 C3.1. These revenues were derived from the forecasted sales volumes and

Line
No.

1 customer counts provided by Witness Chapel, multiplied by existing tariff rates and
2 service charges authorized in Case No. U-21291 Gas Sales revenue includes
3 \$668.0 million of distribution revenue which includes amortization for the LIA /
4 RIA program and the PSP program, \$279.5 million of service charges and \$28.0
5 million in reductions for the Residential Income Assistance (RIA) and Low-Income
6 Assistance (LIA) programs.

7

8 **Q93. What assumptions were used related to the Residential Income Assistance**
9 **(RIA) credit?**

10 A93. The RIA provides a credit of \$14.50 per month in current rates for eligible low-
11 income customers within the DTE Gas service territory. The projected annual
12 credit within service charge revenue for Residential Rate A is \$12.2 million, based
13 on an enrollment of 70,000 low-income customers as sponsored by Witness Sparks.

14

15 **Q94. What assumptions were used related to the Low-Income Assistance (LIA)**
16 **credit?**

17 A94. Customers enrolled in the LIA program currently receive a \$40.00 credit per month.
18 The projected annual LIA credit within service charge revenue for Residential Rate
19 A is \$15.8 million, based on an enrollment of 33,000 eligible customers as
20 sponsored by Witness Sparks.

21

22 **Q95. What accounting treatment are you proposing for the RIA and LIA**
23 **programs?**

24 A95. In Case Nos. U-20940 and U-21291, the Commission authorized the Company to
25 record a regulatory asset or liability for the difference between actual RIA and LIA

Line
No.

1 credits issued and the amount in base rates. The Company is expecting a \$0.8
2 million regulatory asset balance through August 2025 for RIA and \$5.5 million
3 regulatory asset balance for LIA. I am proposing that the deferrals continue and
4 that the cumulative amount be amortized over five years into base rates.

5

6 **Q96. What assumptions were used related to the Payment Stability Plan Pilot (PSP)**
7 **credit?**

8 A96. As further described by Witness Sparks, the PSP pilot program was intended to
9 help low-income customers with financial assistance. The pilot established a flat
10 bill payment based on the customer's gross income, and the Company absorbed the
11 difference between the fixed bill amount and the actual usage. Those amounts were
12 deferred to the regulatory asset, and the balance is being amortized over two years.

13

14 **Q97. How did you develop the Exelon revenue for the projected twelve-month**
15 **period ending September 30, 2027?**

16 A97. Pursuant to a contract between DTE Gas and Exelon, Exelon makes a fixed annual
17 payment for an initial 5 Bcf block of easement capacity, and an additional payment
18 for 5.5 Bcf of supplemental easement capacity. The projected period total fixed
19 annual easement capacity payment is \$14.8 million, as shown on Exhibit A-13,
20 Schedule C3, column (d), line 3. The increase from the historical period is based
21 on the payment expected under the terms of the contract.

22

23

24

Line
No.

1 **Q98. What components of Other Operating Revenue are you sponsoring on Exhibit**
2 **A-13, Schedule C3 for the projected period ending September 30, 2027?**

3 A98. I am sponsoring the following other operating revenue components included on
4 Exhibit A-13, Schedule C3:

- 5 1. Late Payment/NSF Charges
- 6 2. Miscellaneous Service Revenue
- 7 3. Rent from Gas Property & Inter-department Rent
- 8 4. Vector Lease Interest
- 9 5. Grantor Trust

10 Projected Late Payment Revenue/NSF charges, miscellaneous service and rent
11 revenues are forecasted at the 2024 historical level.

12

13 **Q99. How did you forecast Vector Lease interest revenue?**

14 A99. As previously mentioned, the Vector Pipeline lease was a capital lease agreement
15 between DTE Gas and Vector Pipeline that is like a mortgage loan. It was renewed
16 for a 15-year term effective December 1, 2025, with an annual lease payment of
17 \$3.5 million. Interest revenue in the projected test year is assumed at \$2.7 million.

18

19 **Q100. What is the impact to customer rates from the Vector lease?**

20 A100. The projected required return on the Vector lease balance within working capital is
21 \$2.5 million (assuming an ROE of 10.25%). This is offset by the interest revenue
22 of \$2.7 million, resulting in a net reduction to the revenue requirement, which
23 lowers customer rates.

24

25

Line
No.

1 **Q101. How did you forecast the Grantor Trust investment income?**

2 A101. The Grantor Trust Investment Fund realized a gain of \$2.6 million in 2024 but any
3 gains or losses in the projected period are dependent on the future performance of
4 the fund. A five-year historical average was used to develop the estimate of \$1.2
5 million of income shown on line 20, supported by Exhibit A-13, Schedule C3.4.

6

7 Company Use and Lost and Unaccounted for Gas

8 **Q102. What is the projected change in Company Use and Lost Gas from the**
9 **historical period to the projected test year?**

10 A102. Line 7 of Exhibit A-13, Schedule C1, column (d) reflects an increase in Company
11 Use and Lost Gas of \$3.4 million and is supported by Witness Bence.

12

13 Operation and Maintenance Expense

14 **Q103. What is the projected change in O&M expense from the historical period to**
15 **the projected test year?**

16 A103. Line 8 of Exhibit A-13, Schedule C1, column (d), shows a projected increase in
17 O&M expense of \$110.7 million due primarily to inflation, higher Transmission
18 and Distribution expenses, and increased Administrative and General (A&G)
19 expense, partially offset by lower Customer Service expense.

20

21 **Q104. How was DTE Gas's O&M Expense developed for the projected twelve-month**
22 **period ending September 30, 2027?**

23 A104. Exhibit A-13, Schedule C5 provides a reconciliation of O&M starting with the
24 published amount on page 325 of the 2024 MPSC Form P-522, incorporating
25 reclassifications and adjustments, and arriving at the historical test year amount of

Line
No.

1 \$433.1 million in column (f). Forecast adjustments include the effects of general
2 inflation in columns (g) through (i), assumed to be 3.0% in 2025, 2.9% in 2026,
3 and 2.2% in 2027. I support the projection adjustments for Administrative and
4 General expense. Witnesses Kehoe, Sparks, Huffman, Cooper, and Fix support the
5 other major categories of O&M expense. Each line is supported with a schedule as
6 indicated in column (b). These adjustments result in a projected base O&M
7 expense of \$543.8 million for the twelve months ending September 30, 2027,
8 shown on line 8, column (l).

9

10 **Q105. What is the basis for the general inflation rate assumption used in this case?**

11 A105. As shown on Exhibit A-13, Schedule C12, I have calculated a composite inflation
12 rate based on a labor factor and a non-labor factor. The inflation rate of 3% for
13 internal labor is supported by Witness Fix. I used the same rate for contract labor
14 since a portion of our contract workforce are members of the same unions as the
15 DTE union employees. The inflation factor for non-labor costs is based on a
16 consumer price index (CPI)-Urban published by S&P Global Market Intelligence
17 in July 2025. I used the labor and non-labor rates to calculate a composite rate of
18 inflation for 2025, 2026, and 2027 as shown on line 15. The inflation rate for 2027
19 is prorated for nine months.

20

21 Administrative and General

22 **Q106. What were the actual O&M expenses incurred in the Administrative and**
23 **General Expense category in the 2024 historical test year?**

24 A106. Historical 2024 O&M expense for Administrative and General (A&G) expense,
25 excluding benefits, was \$119.6 million, as shown in detail on Exhibit A-13,

Line
No.

1 Schedule C5.6, page 1, column (c), line 23. Columns (d) and (e) are the Section A
2 adjustments previously discussed, resulting in adjusted historical A&G expense of
3 \$114.8 million shown in column (f). Many of the A&G costs are charged to DTE
4 Gas by the Corporate Staff Group.

5

6 **Q107. What is the Corporate Staff Group (CSG)?**

7 A107. The CSG is a shared services LLC organization, “DTE Energy Corporate Services
8 LLC” (LLC), which includes corporate staff functions. This business model
9 provides efficiency, cost savings and enhanced governance and internal controls.
10 Each organization within the CSG provides enterprise-wide services.

11

12 **Q108. What organizations are included in the CSG?**

13 A108. The organizations within the CSG provide a variety of Administrative and General
14 (A&G) type services to the Company. These include:

- 15 • Audit Services
- 16 • Accounting and Planning
- 17 • Tax
- 18 • Finance and Treasury
- 19 • Corporate and Governmental Affairs
- 20 • Communications
- 21 • Corporate Offices
- 22 • Supply Chain
- 23 • Corporate Fleet and Facilities
- 24 • Human Resources
- 25 • Information Technology

Line
No.

- 1 • Legal
- 2 • Regulatory Affairs
- 3 • Environmental Management and Safety
- 4 • Program Management Organization (PMO)

5

6 **Q109. Does the LLC provide other services in addition to corporate staff functions?**

7 A109. Yes. Customer Service also resides at the LLC and operates under a shared service
8 model, but their span of support is only to the regulated DTE Electric and DTE Gas
9 distribution operations versus the enterprise-wide orientation of the CSG.
10 Customer Service O&M expenses are sponsored by Witness Sparks.

11

12 **Q110. What types of O&M expense do you support for the CSG organizations?**

13 A110. I support the CSG expense projections except for benefits on Exhibit A-13,
14 Schedule C5.6. (See Witnesses Cooper and Fix for a discussion of DTE Gas benefit
15 expenses.)

16

17 **Q111. What expenses are included in account 920 on line 3?**

18 A111. Account 920 reflects internal labor costs that are allocated to DTE Electric for the
19 CSG organization.

20

21 **Q112. What is the incentive deferral amortization on line 4?**

22 A112. Line 4 reflects amortization expense for 2024 historical actuals related to the
23 incentive deferral mechanism as approved in Case No. U-21291.

24

25

Line
No.

1 **Q113. What type of expenses are included in account 921 on line 5?**

2 A113. The largest cost items in line 5, Office Supplies and Expenses, are for software
3 maintenance and telecommunications. Witness Bolda provides more detail on the
4 O&M expenses for the IT organization. This account also includes bank fees,
5 assessments, and utilities expenses.

6

7 **Q114. What is the negative expense in account 922 on line 6?**

8 A114. Line 6 reflects the transfer of A&G costs to capital as an overhead. The amount of
9 A&G transferred is based on the percentage of total direct labor charged to capital.

10

11 **Q115. What is included in account 923 on line 7?**

12 A115. The account for Outside Services primarily includes contract labor for IT. It also
13 includes security services, janitorial services, external audit fees and consulting
14 services.

15

16 **Q116. What expenses are included in lines 8 through 15 and 18 through 21?**

17 A116. These lines are for property insurance, injuries and damages, advertising,
18 environmental remediation, rents, maintenance of general plant, and other
19 miscellaneous expenses.

20

21 **Q117. What is the Shared Asset Charge on lines 16 and 17?**

22 A117. The Shared Asset charge on line 16 represents an intercompany billing from DTE
23 Electric for the cost of assets such as buildings and information systems, which are
24 owned by DTE Electric and jointly used by the companies. The charge is
25 comprised of the return on the assets and the related depreciation incurred by DTE

Line
No.

1 Electric. DTE Gas reflects the charge from DTE Electric for Shared Assets in rent
2 expense. Line 17 reflects the amortization from previously deferred layers
3 approved in case U-21921 and the projected amortization requested in the current
4 case.

5

6 **Q118. How is the Shared Asset cost allocated from DTE Electric to affiliates?**

7 A118. The CSG capital costs incurred by DTE Electric must be paid for by the companies
8 that utilize those assets, including DTE Gas, based on each company's
9 proportionate share. This ensures that DTE Electric customers are not subsidizing
10 costs for DTE Gas. The shared asset charge from DTE Electric is based on cost
11 drivers for each group of assets. DTE Gas occupies space in some of the buildings
12 owned by DTE Electric (e.g., the headquarters complex). In addition, the Corporate
13 Services Group and Customer Service organization that provide services to DTE
14 Gas do not own any of the assets or infrastructure needed to function; the assets are
15 owned by DTE Electric. Buildings are allocated based on the location of employees
16 and the cost drivers associated with the functions performed by those employees.
17 Similarly, computer systems are allocated based on user headcount and their related
18 cost drivers. For example, Customer Service building and computer costs are
19 allocated based on the number of utility customers.

20

21 **Q119. How are expenditures underlying the shared asset charge reviewed for**
22 **reasonableness and prudence?**

23 A119. As discussed above, the capital investments are owned by DTE Electric; therefore,
24 the total capital investment, including return on capital and depreciation, along with
25 reasonableness and prudence of the project, is reviewed in a DTE Electric rate case.

Line
No.

1 Upon approval of the investment in a DTE Electric rate case, the DTE Electric
2 revenue requirement is reduced by the amount it receives from affiliates, including
3 DTE Gas, for use of the assets, which is also approved by the Commission. Costs
4 in the Electric case that are not justified in total, or for either the Electric or Gas
5 companies, would be disallowed in the Electric rate case along with the related
6 revenue credit.

7

8 **Q120. Can you explain the rate case adjustments and normalizations reflected in**
9 **columns (d) and (e), respectively on Exhibit A-13, Schedule C5.6?**

10 A120. Column (d) shows rate case adjustments starting on line 3 reflecting a reduction of
11 \$3.7 million to remove the incentive compensation for DTE Gas's top five
12 executive officers. The remaining eliminations in column (d) reflect \$0.2 million
13 of corporate memberships, \$0.2 million of advertising expenses, \$19,000 related to
14 Gas Voluntary Renewable Program, and \$11,000 related to advocacy costs.

15

16 Column (e) shows normalization adjustments starting on line 3 reflecting a
17 reduction of \$5.3 million. The \$5.3 million is comprised of a \$8.2 million reduction
18 to 2024 historical actuals related to VSIP costs to achieve, and employee incentive
19 plan adjustments of \$0.6 million, which were partially offset by an increase related
20 to lag hiring of \$1.8 million and elimination of the incentive compensation deferral
21 of \$1.6 million. Line 9 reflects the adjustment of injuries and damages to a 5-year
22 average. Line 16 removes the shared asset expense deferral.

23

24 The net between columns (d) and (e) is a total \$4.7 million reduction to 2024
25 historical actuals.

Line
No.

1

2 **Q121. What projected adjustments did you make to O&M as reflected in columns (g)**
3 **through (j)?**

4 A121. Columns (g) through (i) reflect the inflation rate applied to the adjusted historical
5 test period expenses (column f) for the period January 2025 through September
6 2027, except for line items with specific forecasts.

7

8 Column (j) represents other adjustments to the projected period expenses. Line 3
9 reflects a decrease of \$0.6 million related to the Voluntary Separation Plan, which
10 is supported by Witness Shpargel. Line 4 reflects \$2.8 million related to the
11 Incentive Deferral Mechanism further described below. Line 14 reflects a
12 reduction of \$1.0 million related to the MGP amortization. Line 16 reflects an
13 increase of \$2.6 million related to the increase of the Shared Asset Charge further
14 described below. Line 17 reflects an increase of \$3.2 million for the amortization
15 expense related to the Shared Asset Charge further described below. Line 18
16 reflects a reduction of \$0.2 million driven by a lower return on the Customer 360
17 asset partially offset by higher intercompany rent.

18

19 **Q122. How did you calculate the \$2.8 million adjustment to the amortization of**
20 **deferred incentives on line 4?**

21 A122. Line 4 is supported on page 5 of Exhibit A-13, Schedule C5.6. The Commission
22 approved a recovery mechanism for incentive compensation related to operating
23 metrics that provided for deferral treatment above or below the base amount to be
24 recovered or refunded. Schedule C5.6, page 5, calculates the amortization expense
25 related to the 2022, 2023 and 2024 layers. The layer for 2022 on line 4 of page 5

Line
No.

1 reflects the regulatory deferral approved in Case No. U-21291. Lines 5 and 6 reflect
2 the amount deferred above the approved base amount for 2023 and 2024
3 respectively. The regulatory asset results in an annual amortization expense in the
4 projected period of \$3.0 million as shown on line 7, col (i). The \$2.8 million
5 projection adjustment on line 4 of Exhibit A-13, Schedule C5.6 page 1, is simply
6 the difference between the projected period and the historical period.

7

8 **Q123. What is the basis for the \$2.6 million increase in rent expense on line 16?**

9 A123. Please refer to Exhibit A-13, Schedule C5.6 page 4. The increase is mostly
10 attributable to the Shared Asset charge. DTE Gas is projecting its Shared Asset
11 charge from DTE Electric for the projected test period at \$52.2 million, based on
12 the amount of revenue projected in DTE Electric's rate case, No. U-21860. The
13 historical 2024 charge was \$49.6 million, resulting in an increase of \$2.6 million.

14

15 **Q124. Why did you use the \$52.2 million projected revenue in DTE Electric's rate
16 case for the projected test period shared asset charge?**

17 A124. As discussed above, the assets are owned by DTE Electric and reviewed for
18 reasonableness and prudence in DTE Electric rate cases. This would align the
19 revenue received by DTE Electric and the cost incurred by DTE Gas for use of the
20 assets.

21

22 **Q125. How did you determine the \$3.2 million increase in amortization of deferred
23 Shared Asset expenses on line 17?**

24 A125. Please see Exhibit A-13, Schedule C5.6, page 3. Columns (b) through (c) calculate
25 the difference between the actual charge from DTE Electric and the approved base.

Line
No.

1 The base per the Order in Case No. U-20940 was \$43.6 million, effective through
2 November 19, 2024. Comparing actual expense to the base results in a net deferred
3 asset of \$6.2 million and \$5.7 million in 2022 and 2023, respectively. The related
4 amortization for 2022 is \$1.2 million and 2023 is \$1.1 million per year for five
5 years. Column d shows the actual expense for January through September 2024
6 compared to the base (prorated for 9 months in column d) resulting in an additional
7 projected deferral of \$4.0 million. The related amortization is \$0.8 million per year.
8 Amortization of the 2022 through September 2024 layers was approved in Case
9 No. U-21291.

10

11 The annual base was updated to \$48.9 million in Case No. U-21291, effective
12 November 20, 2024. Column (e) shows actual expense from October through
13 December 2024 compared to the base amount (which is prorated in November)
14 resulting in a deferral amount of \$1.4 million. The related amortization is \$0.3
15 million. Column (f) shows the Shared Asset charge based on the Company's latest
16 forecast for 2025. Column (g) reflects the amount projected for revenue by DTE
17 Electric in case U-21860. When comparing the projected actuals to the approved
18 base amount of \$48.9 million, the result is a reduction to the regulatory asset of
19 \$1.9 million in 2025 and an increase to the regulatory asset of \$2.4 million in 2026.
20 The related amortization for 2025 is a credit of \$0.4 million and expense of \$0.5
21 million related to 2026. Columns (h) through (j) show the forecasted Shared Asset
22 charge for the projected period as equal to the amount projected for revenue by
23 DTE Electric and assumes the base will be reset to match.

24

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1 **Q126. What costs are included in IT O&M?**

2 A126. IT costs are included in A&G expense on Exhibit A-13, Schedule C5.6. IT O&M
3 consists of expenses related to DTE Gas and shared asset project work along with
4 on-going and base operating expense not tied to specific projects. Non-project costs
5 include software maintenance, software licenses, cloud computing fees, software
6 as a service, hardware and software defect remediation, business support services,
7 and IT administration.

8

9 **Q127. What O&M expense level is projected for Administrative and General**
10 **Expense in the twelve months ending September 2027 projected test year?**

11 A127. Projected 2027 O&M for Administrative and General Expense is \$126.0 million,
12 as shown on Exhibit A-13, Schedule C5, column (I).

13

14 **Q128. How are the CSG cost allocations to DTE Energy companies accomplished?**

15 A128. CSG costs are first incurred and accumulated at the LLC in cost pools. The pools
16 are distributed and billed to DTE Gas and other DTE entities using an appropriate
17 cost driver. A cost driver is the unit of work/output that is used to determine a
18 formula for billing the products or services to the DTE entities.

19

20 **Q129. How does this cost driver allocation process work?**

21 A129. Cost drivers represent units of work that best reflect the content of the work
22 performed. For example, the Company's payroll department within the CSG
23 processes paychecks. Given the transactional nature of this work, the volumetric
24 cost driver of "paychecks processed" provides the best indication of work
25 performed by this group for a specific legal entity. This department provides

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1 services for DTE Gas and other DTE entities; therefore, payroll processing costs
2 are billed based on the volume of paychecks processed for DTE Gas during the
3 year. Other examples within the CSG include invoices paid, number of system
4 application users, and application support hours. Cost drivers are evaluated and
5 established based on resource consumption. These cost driver standards and levels
6 of support are periodically reviewed and updated to reflect actual experience.

7

8 **Q130. Has this cost driver allocation methodology been reviewed by the Commission**
9 **in prior rate cases?**

10 A130. Yes. This methodology is the same cost allocation methodology supported by DTE
11 Gas in prior rate cases and historically approved by the Commission going back to
12 Case No. U-13898. This methodology has also been consistently approved in DTE
13 Electric's general rate cases going back to Case No. U-13808.

14

15 **Q131. How has the Company billed costs for which no direct cost driver was**
16 **discernable?**

17 A131. While most costs have been billed to DTE Gas and its affiliated companies based
18 on the direct cost drivers I have described, a limited number of administrative
19 activities are shared across the enterprise that do not possess cost driver attributes
20 (a unit of work directly attributed to a legal entity), or that are incurred on behalf of
21 the parent, DTE Energy, that indirectly benefits DTE Gas. It is in these cases that
22 the Company uses the commonly accepted cost allocation methodology
23 traditionally referred to as the Massachusetts Formula (Mass Formula). The Mass
24 Formula, which utilizes a three-factor formula of gross margin, net plant and labor
25 costs, is designed to measure relative size and complexity as a means of assessing

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1 the degree of support services attributable to each individual company, within the
2 context of the broader enterprise.

3

4 **Q132. Has the Commission approved the use of the Mass Formula in allocating**
5 **common costs in prior cases?**

6 A132. Yes. Consistent with the cost driver methodology, the use of the Mass Formula for
7 the allocation of CSG common costs has been reviewed and historically approved
8 by the Commission in DTE Gas's general rate cases as well as in DTE Electric's
9 general rate cases. Examples of CSG costs that utilize the Mass Formula include
10 certain Corporate Communication, Strategic Planning, Investor Relations and
11 Corporate Secretary activities.

12

13 **Q133. Are you supporting any other O&M costs or projection adjustments?**

14 A133. No. However, as described by Witness Kehoe, DTE Gas is projected to incur an
15 additional \$9.0 million in distribution O&M expenses related to advanced leak
16 detection and repair, but the amount could be higher if a pending Notice of
17 Proposed Rule Making (NPRM) is approved. I am proposing that the Commission
18 allow DTE Gas to continue the LDAR deferral mechanism for amounts incurred
19 above the expenses approved in the current case, and I am requesting the use of
20 account 182.3, Other Regulatory Assets, to record the deferral.

21

22

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1 Pension and Other Post-Employment Benefits Deferral

2 **Q134. Can you explain the adjustments you made to Witness Cooper's and Witness**
3 **Fix's forecasts?**

4 A134. Yes, Witness Cooper has forecasted retiree health care costs including DTE Gas's
5 OPEB and Witness Fix has forecasted DTE Gas's pension costs. I am proposing
6 the existing deferral treatment of OPEB expense be continued; and have reflected
7 the impact on Witness Cooper's Exhibit A-13, Schedule C5.11, line 18. If OPEB
8 expense becomes positive in the future, then the expense will be charged against
9 the regulatory liability. Witness Fix's Exhibit A-13, Schedule C5.10, line 17
10 reflects the continued deferral of pension expense. The Commission's Order in
11 Case Nos. U-20642 and U-20940 approved the deferral of positive pension expense
12 in addition to the prior practice of deferring negative expense, and I propose that
13 this deferral of pension expense also be continued.

14

15 **Q135. How does the capitalization of Pension and OPEB costs impact Witness Fix's**
16 **and Witness Cooper's forecasted expense?**

17 A135. Exhibit A-13, Schedules C5.10, sponsored by Witness Fix, and C5.11, sponsored
18 by Witness Cooper, detail the components of Pension and OPEB costs. Each
19 schedule has a reconciliation of total cost to expense. As previously discussed, the
20 Commission approved regulatory asset or liability treatment for the capital portion
21 of non-service cost components of Pension and OPEB expense because GAAP no
22 longer allows it. The service cost component continues to be capitalized directly
23 to CWIP/Plant. The amounts recorded to the balance sheet for all components are
24 based on the related labor capitalized. Basically, the amount previously shown as
25 capitalized to plant has been bifurcated into two lines. This treatment, originally

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1 approved in Case No. U-18999, results in recognizing the same expense and rate base
2 that would have occurred under the historical accounting and rate-making method.

3

4 Uncollectible Expense

5 **Q136. What is DTE Gas’s uncollectible expense for the projected test year?**

6 A136. Witness Sparks supports the forecast of \$23.5 million for uncollectible expense on
7 Exhibit A-13, Schedule C5.7.

8

9 Depreciation and Amortization Expense

10 **Q137. How was DTE Gas’s twelve months ending September 2027 projected test year**
11 **Depreciation and Amortization expense developed?**

12 A137. To develop depreciation expense, composite depreciation rates are applied to
13 average plant in service estimated for Distribution, Transmission, Storage, and
14 General plant. Projected depreciation expense is calculated using the rates
15 approved by the Commission within the depreciation case (Case No. U-21384).
16 Average plant in service balances were derived based on estimated additions,
17 largely driven by the capital expenditure forecast provided by Witnesses Fedele,
18 Jackson, Janness, Bolda and Huffman, together with estimated retirements of
19 Storage, Transmission and Distribution plant based on historical averages and
20 scheduled retirements of Intangible and General plant assets. Intangible plant is
21 amortized over its expected service life.

22

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1 **Q138. What is the projected change in Depreciation and Amortization expense from**
2 **the historical period to the projected test year?**

3 A138. Line 10 of Exhibit A-13, Schedule C1, column (d) shows a projected increase in
4 Depreciation and Amortization expense of \$32.9 million. This is further supported
5 on Exhibit A-13, Schedule C6, which displays the adjusted historical and projected
6 year totals on page 1, line 5. Schedule C6, page 2 provides details on how
7 depreciation expense is derived from the various types of plant.

8

9 **Q139. What is the reason for the increase in Depreciation and Amortization expense**
10 **between 2024 and the twelve-month period ending September 2027?**

11 A139. The \$32.9 million increase is due to growth in plant in service balances offset by
12 utilizing the depreciation rates approved in Case No. U-21384. The increase in
13 expense reflects:

- 14 • \$17 million related to main replacements
- 15 • \$22 million from routine distribution and smaller projects
- 16 • \$7 million related to investments in storage and transmission plant
- 17 • \$14 million from new computer hardware and other general plant

18 The increases are partially offset by a \$16 million decrease from lower depreciation
19 rates (primarily in distribution plant), a \$5 million reduction related to retirements,
20 \$5 million of lower software amortization, and \$1 million in higher amortization of
21 regulatory liabilities.

22

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Line
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1 Taxes

2 **Q140. What is the projected change in Property Taxes?**

3 A140. Line 11 of Exhibit A-13, Schedule C1, column (d) shows a projected increase in
4 Property Taxes of \$30.8 million. Witness Wisniewski explains the changes and
5 supports the amount on Exhibit A-13, Schedule C7.

6

7 **Q141. What is the projected change in Other General Taxes?**

8 A141. Line 12 of Exhibit A-13, Schedule C1, column (d) shows a projected increase in
9 Other General Taxes of \$1.5 million due primarily to inflation on payroll taxes and
10 an increase in the MPSC assessment fee. Witness Wisniewski supports the amount
11 on Exhibit A-13, Schedule C7.

12

13 **Q142. What is the projected change in State and Local Income Taxes?**

14 A142. Column (d) on line 13 of Exhibit A-13, Schedule C1, reflects the projected changes
15 in State and Local Taxes, with a total decrease of \$15.7 million. Witness
16 Wisniewski explains the changes and supports the amount on Exhibit A-13,
17 Schedules C9 and C10.

18

19 **Q143. What is the projected change in Federal Income Tax expense from the historic
20 normalized amount to the projected year?**

21 A143. Column (d) on line 14 of Exhibit A-13, Schedule C1, reflects the projected decrease
22 in Federal income tax expense of \$42.7 million. Witness Wisniewski explains the
23 changes and supports the amount on Exhibit A-13, Schedule C8.

24

Line
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1 Other Income

2 **Q144. Why is other income increasing?**

3 A144. Other income primarily reflects AFUDC and Amortization of Losses on
4 Reacquired Securities. AFUDC is projected to increase \$10.3 million from the
5 historical test year as seen on line 19 of Exhibit A-13, Schedule C1, column (d),
6 due to large longer-term capital projects, primarily the Taggart Compressor Station
7 replacement project. The equity and debt components of AFUDC are displayed on
8 Exhibit A-13, Schedule C11, lines 1 and 2. The rate used to compute AFUDC is
9 based on DTE Gas's overall rate of return of 5.80% approved by the Commission
10 in Case No. U-21291.

11

12 **Q145. How does AFUDC impact the Company's revenue requirement and**
13 **deficiency?**

14 A145. AFUDC represents the financing costs incurred while projects are under
15 construction. Such costs are added to the asset being constructed with a
16 corresponding credit to the income statement. AFUDC is applied to projects greater
17 than \$50,000 and lasting more than six months. The accrual of AFUDC ceases
18 once the asset is complete and placed in service. Including the credit to income
19 from AFUDC offsets the impact of including CWIP in rate base and therefore
20 projects that do not go into service during the projected test period have no impact
21 on the Company's revenue requirement and deficiency.

22

23 **Q146. What impact should a disallowance of projects that do not go into service**
24 **during the projected test period, on which AFUDC is accrued, have on the**
25 **Company's requested rate relief?**

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1 A146. Such disallowances should not have any impact. To ensure that is the result, either
2 the proposed disallowances for projects not going into service should be excluded
3 from any reductions to rate base approved by the Commission, or a corresponding
4 adjustment (reduction) in pre-tax AFUDC should be added to offset the removal of
5 the projects from approved rate base.

6

7 **Accounting for the Infrastructure Recovery Mechanism**

8 **Q147. How does the Infrastructure Recovery Mechanism (IRM) impact the**
9 **projected financials?**

10 A147. An overview of the mechanism is provided by Company Witness Shpargel. The
11 Commission order in Case No. U-18999 required the IRM surcharges be terminated
12 effective when new base rates superseding the IRM are implemented. Case No. U-
13 21291 allowed for the IRM to be structured consistent with U-18999. All related
14 net plant forecasted through December 2026 is reflected in base rates in this case.
15 The IRM capital expenditures and plant balances, the related costs and revenues,
16 and the related debt and equity are excluded from my projected financial statements
17 for the periods after December 2026 because the Company is proposing to recover
18 those costs in a new IRM surcharge. This exclusion ensures that the revenue
19 requirement for the IRM is separate and distinct from the revenue requirement for
20 base rates. The IRM-related net plant forecasted for 2027 through 2031 is included
21 in the proposed new IRM and supported by Company Witness Janness.

22

23 **Q148. How should the 2024 through 2026 IRM spend be reviewed?**

24 A148. Since the IRM capital spend through 2026 is included in projected test year in this
25 general rate case, it should be reviewed as part of the Staff audit in the instant case.

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2 **Q149. How does DTE Gas intend to record activity under the IRM?**

3 A149. Consistent with past practice, DTE Gas proposes to record revenue on an accrual
4 basis consistent with its accounting policies for other customer revenues. The
5 capital expenditures will be recorded to unique accounting codes to isolate the
6 costs.

7

8 **Q150. Is DTE Gas proposing to reduce its future recovery by the amount of plant
9 that is being retired in this program?**

10 A150. No. When plant is retired, the original recorded cost of the plant is both credited to
11 the plant in service accounts and charged to accumulated depreciation reserve; thus,
12 there is no change in the net plant balance related to the retirement. With no change
13 in net plant, there is no adjustment to the largest portion of the return-on-investment
14 portion of the revenue requirement calculation. As depreciation rates are
15 periodically adjusted in subsequent depreciation cases, the impact of any abnormal
16 retirements will be incorporated.

17

18 **Accounting Request**

19 **Q151. What accounting treatment are you requesting for certain debt issuance costs?**

20 A151. As described by Witness Lepczyk, the Company is in the process of securing
21 financing of up to \$1.7 billion from the United States Department of Energy under
22 the Energy Dominance Financing Program (EDF). Normally, issuance costs
23 associated with debt financing are recorded to FERC account 181, Unamortized
24 Debt Expense, and amortized over the life of the debt. Issuance costs include, but
25 are not limited to, commitment fees, due diligence and legal expenses.

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The Company is requesting recovery of the issuance costs via a regulatory asset if the Company does not reach financial close on this loan. I am requesting the use of account 182.3, Other Regulatory Assets, to defer the costs for inclusion in a future rate case. (If the loan closes, the expenses will be recorded to FERC account 181 and amortized per standard accounting practices.)

3

4

5

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7

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Summary

9

Q152. Would you please summarize what Commission approvals the Company is requesting?

10

11

A152. In addition to the forecasted costs and revenues included herein, the Company is requesting:

12

13

- Continued deferral accounting for LIA and RIA credits above or below the base amount authorized.

14

15

- A continuation of the Shared Asset deferral mechanism for amounts charged by DTE Electric above or below the amount included in base rates.

16

17

- A continuation of the Incentive Compensation tracker for amounts above or below the amount authorized.

18

19

- Continued deferral for OPEB and Pension expense.

20

- A continuation of the LDAR deferral approved in case U-21291 for any increase in leak detection and repair costs above the amount approved in this case, and the use of account 182.3 for actual costs incurred.

21

22

23

- The accounting for the IRM to continue as authorized in Case No. U-21291.

24

- Use of account 182.3 for issuance costs related to the EDF program, if the financing does not close.

25

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3 **Q153. Does this complete your direct testimony?**

4 A153. Yes, it does.

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

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on December 12, 2025, she served a copy of DTE Gas Company’s revised Direct Testimony of Witness Theresa M. Uzenski in the above captioned matter, via electronic mail upon the persons listed on the attached service list.

ESTELLA R. BRANSON

MPSC CASE NO. U-21973

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