STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21291

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)

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of
Attorney General Dana Nessel

May 7, 2024

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I. Introduction

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Sebastian Coppola. I am an independent business consultant. My office is at 5928 Southgate Rd., Rochester, Michigan 48306.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. I have testified in several regulatory proceedings before the Michigan Public Service Commission ("MPSC" or "Commission") and other regulatory jurisdictions. I have prepared and/or filed testimony in rate case proceedings, revenue decoupling reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power Supply Cost Recovery (PSCR) cases. As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, I have been intricately involved in regulatory proceedings related to gas cost recovery cases, gas purchase strategies, rate case filings and power plant cost analysis. I have also supported other witnesses in testimony before the MPSC in various rate settings and other regulatory proceedings.

Q. PLEASE LIST SOME OF THE MORE RECENT CASES YOU HAVE PARTICIPATED IN BEFORE THE MPSC AND OTHER REGULATORY AGENCIES.

A. Here is a partial list of the most recent regulatory cases in which I have participated in the last two years:

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2022-2023 GCR reconciliation in case No. U-21065.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2022-2023 GCR reconciliation case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in the Indian Michigan Power Company's 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate Case U-21297 on several issues, including

operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.

Appendix A elaborates further on my qualifications in the regulated energy field.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Michigan Attorney General (AG) to perform an independent analysis of DTE Gas Company's ("Company" or "DTE Gas") Rate Case filing in Case No. U-21291. This testimony presents a report of that analysis with related recommendations.

Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?

A. I am addressing the following major topics in this case:

1. The level of gas sales, End-User Transportation, and Midstream revenues
2. The net margin from the Home Protection Plan (HPP)
3. Operations and maintenance expenses
4. Incentive compensation and deferred expense
5. Rate base and capital expenditures
6. The Main Replacement Program and IRM
7. The Company's proposal to include Cathodic Protection expenditures in the IRM
8. The proposal for the Company to recover premiums paid to purchase gas supply labeled as Responsibly Sourced Gas (RSG)
9. Cost of Capital and Working Capital
10. Depreciation and Property Tax Expense
11. Customer Monthly Charges

The absence of a discussion of other matters in my testimony should not be taken as an indication that I agree with those aspects of DTE Gas's rate case filing. The narrow focus of my testimony is, instead, a consequence of focusing on select issues within the available resources.

Q. IS YOUR TESTIMONY ON THESE TOPICS ACCOMPANIED BY EXHIBITS?

A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under my direct supervision:

1. Exhibit AG-1 DTE Energy Investor Presentation Information
2. Exhibit AG-2 CONF CPI Forecast Publication
3. Exhibit AG-3 Main Renewals Units
4. Exhibit AG-4 Actual Capex Distribution Program Costs 2021-2023

5. Exhibit AG-5 Public Improvements information
6. Exhibit AG-6 System Reliability Units and Costs 2020-2025
7. Exhibit AG-7 Meters and Modules Purchases 2018-2025
8. Exhibit AG-8 LDAR O&M and Capex Current
9. Exhibit AG-9 Fort Street Mai Replacement Timeline
10. Exhibit AG-10 Van Born Project Costs
11. Exhibit AG-11 PRA Risk Ranked Projects
12. Exhibit AG-12 MRP Cost Overruns 2016-2023
13. Exhibit AG-13 Cathodic Protection reasons for IRM
14. Exhibit AG-14 Transmission Projects
15. Exhibit AG-15 ILI Projects
16. Exhibit AG-16 TARP Project Higher Costs
17. Exhibit AG-17 Gas Storage and Compression Projects
18. Exhibit AG-18 Transportation Vehicles and Equipment Purchases
19. Exhibit AG-19 IT Project Cap Savings-Gas Scheduler Optimizer
20. Exhibit AG-20 Capital Expenditures, Depreciation, Property Taxes Disallowance
21. Exhibit AG-21 Working Capital
22. Exhibit AG-22 Overall Cost of Capital
23. Exhibit AG-23 Cost of Common Equity Capital
24. Exhibit AG-24 Cost of Common Equity Capital-DCF
25. Exhibit AG-25 Cost of Common Equity-CAPM
26. Exhibit AG-26 Cost of Common Equity-Risk Premium
27. Exhibit AG-27 Peer Group Analysis-Capital Structure
28. Exhibit AG-28 Market to Book Ratios
29. Exhibit AG-29 Gas ROE Decisions by Regulatory Commissions
30. Exhibit AG-30 DTE Gas Calculation of CFO Pre-WC to Debt Ratio
31. Exhibit AG-31 Value Line Analysis of Stock Market Volatility
32. Exhibit AG-32 Gas Sales Analyses
33. Exhibit AG-33 Gas Sales External Adjustments and Customer Usage Trends
34. Exhibit AG-34 Gas Sales Revenue Adjustments
35. Exhibit AG-35 End-User Transportation Power Generation Volumes

36. Exhibit AG-36 Midstream Revenue 2018-2023
37. Exhibit AG-37 Midstream Revenue Adjustments
38. Exhibit AG-38 Appliance Program Revenue and Margin 2018-2023
39. Exhibit AG-39 Other O&M Expense Adjustments Summary
40. Exhibit AG-40 Company Use Gas and LAUF Gas
41. Exhibit AG-41 Cost of Gas Update
42. Exhibit AG-42 Uncollectible Accounts Expense Calculation
43. Exhibit AG-43 Inflation Adjustment
44. Exhibit AG-44 2023 O&M Reduction
45. Exhibit AG-45 2023 O&M Cost Savings
46. Exhibit AG-46 DTE Voluntary Separation Package
47. Exhibit AG-47 Health Care Cost Adjustment
48. Exhibit AG-48 Rents Adjustment
49. Exhibit AG-49 Incentive Compensation Measures Achieved
50. Exhibit AG-50 O&M Expense-MAOP Records Review
51. Exhibit AG-51 OPEB Credit Balance
52. Exhibit AG-52 Fees for EFT, ACH, etc.
53. Exhibit AG-53 Corporate Jet Travel
54. Exhibit AG-54 Deferred Incentive Compensation Accrual
55. Exhibit AG-55 Revenue Deficiency Calculation

II. SUMMARY CONCLUSIONS & RECOMMENDATIONS

Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND ADJUSTMENTS TO THE COMPANY'S REVENUE DEFICIENCY CALCULATION BEFORE YOU ADDRESS EACH TOPIC IN DETAIL.

A. The Company filed for a base rate increase of $265.5 million. This rate increase represents an increase in base rates of 27% and an overall increase in rates of 9.3%, with a 9% increase to residential customers. As a result of the rate case adjustments I propose in my testimony, the average residential customer would see an increase of approximately 6.5% in their total bill.

It is noteworthy to point out that during the five-year period from 2015 to 2019, the Company earned a return on common equity on a regulatory basis generally at or above the authorized ROE rate. In 2022, DTE Gas had an earned ROE of 11.7% and had a revenue sufficiency (excess) of $35.7 million.[1]

Based on my analysis, I have identified several cost disallowances to the Company's proposed cost levels and capital projects, which I recommend that the Commission approve. As a result of these adjustments, I have determined that the Company has a revenue deficiency of $112.2 million. This result should not be surprising given the fact that the Company reported a revenue sufficiency in 2022 and earned a return on equity above the authorized level.

Based on my analysis of the Company's case, I have reached the following summary conclusions and recommendations:

1. I propose adjustments to increase gas sales, end-user transportation service, and other revenues, which reduce the Company's filed revenue deficiency by $19.6 million.
2. I propose a lower level of Operations and Maintenance expenses of $97.2 million for the test year.

[1] Exhibit A-1, Schedule A1 and A2, page 1.

3. I propose a reduction in capital expenditures of $172.3 million and a reduction in rate base of $124.5 million, which reduce the revenue deficiency by $9.8 million.

4. I propose a reduction in depreciation expense of $3.4 million and property taxes of $5.0 million pertaining to the proposed reductions in capital expenditures.

5. I recommend an authorized rate of return on equity of 9.85%, in comparison to the Company's proposed ROE rate of 10.25%, and a permanent capital structure with 50% common equity and 50% long-term debt, which results in a reduction in the revenue deficiency of $21.1 million.

6. I recommend that the Commission reject the recovery of RSG premiums.

7. I recommend that the Commission approve the amortization of the deferred OPEB credit balance.

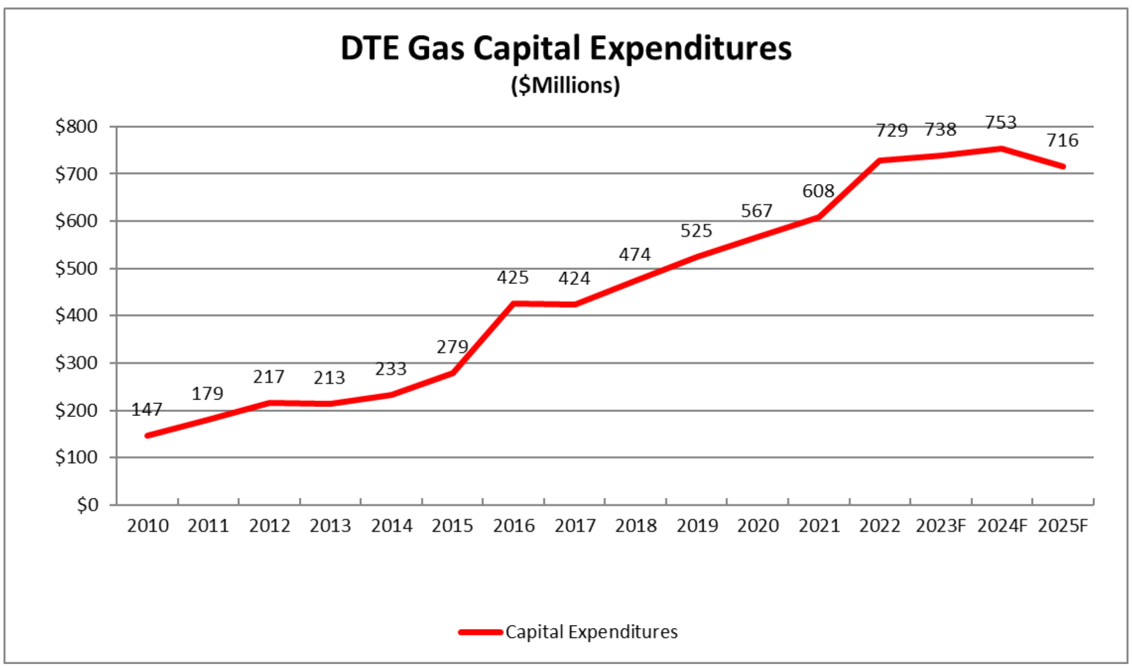
8. I recommend that the Commission reject the Company's proposed increase in the Monthly Customer Service Charges for Rate Schedules A, 2A, and GS-1 and preferably keep those monthly charges at the same current levels, or in the alternative increase Rate A and 2A by no more than $1 per month.

The remainder of my testimony provides further details and support for these summary conclusions and recommendations.

III. LARGE INCREASE IN RATE BASE AND CAPITAL EXPENDITURES

Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LEVEL OF CAPITAL EXPENDITURES PROPOSED BY THE COMPANY AND THE RESULTING INCREASE IN RATE BASE.

A. In this general rate case, DTE Gas proposes capital expenditures of $730.6 million for 2023, $559 million for the 9 months ending September 2024, and an additional $465 million for the 12 months ending September 2025. In addition, the Company proposes to spend $354 million in 2025 on the IRM program with similar amounts in the subsequent four years. The total proposed capital expenditures over this 36-month period are nearly $2.1 billion.[2] These expenditures follow capital expenditures of $1.9 billion made during the prior three years from 2020 to 2022.[3] The following chart in Table 1 shows the dramatic increase in capital expenditures over recent years, in comparison to more moderate amounts in prior years.



[2] Exhibit A-12, Schedule B5.
[3] DTE Gas response to DR U-21291-AGDG-5.125.

Until 2012, the Company was able to keep capital expenditures below $200 million annually. By 2016, annual capital expenditure had doubled and eight years later has nearly doubled again, to $753 million.

The capital expenditures have fueled an alarming increase in rate base. As shown below in Table 2, rate base has been growing at high-single digit to double digit rates in recent years and the Company is proposing to increase rate base again in this rate case by 22%, to $6.9 billion. The proposed level of rate base in this rate case is more than double the amount of rate base the Company had 9 years ago.

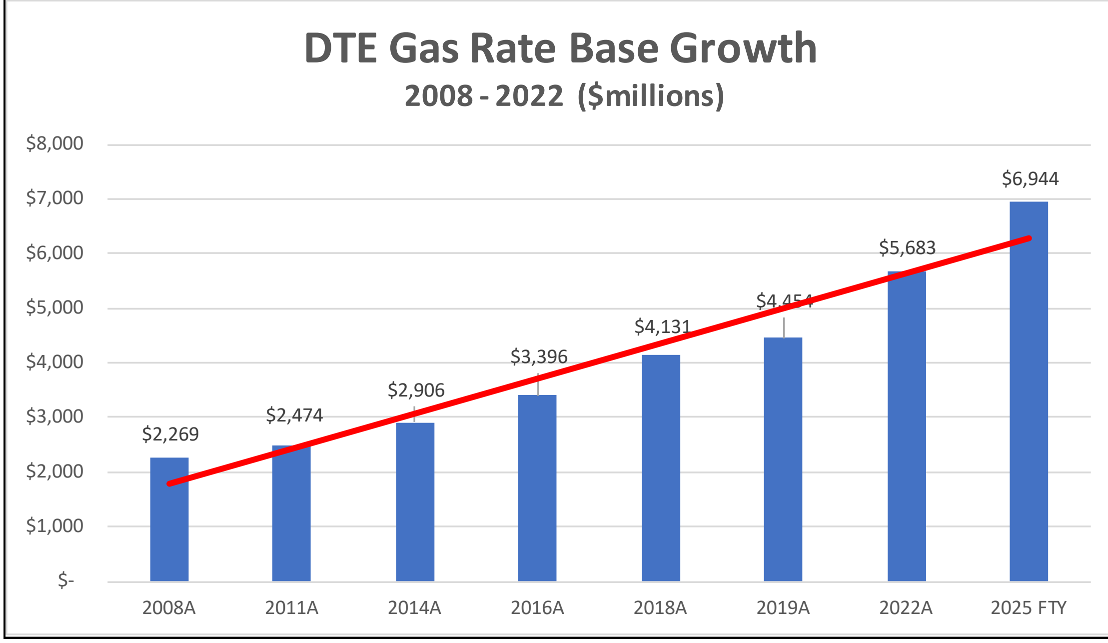
Table 2
DTE Gas Rate Base Growth
2008 to Projected 2022 Test Year

Rate Base Year	2008A	2011A	2014A	2016A	2018A	2019A	2022A	2025 FTY
Docket No.	U-15985	U-16999	U-17999	U-18999	U-20642	U-20940	U-21291	U-21291
Rate Base [1] (Millions)	$ 2,269	$ 2,474	$ 2,906	$ 3,396	$ 4,131	$ 4,454	$ 5,683	$ 6,944
Year over Year Change		9%	17%	17%	22%	8%	28%	22%
Cumulative Change over 2008 Rate Base		9%	28%	50%	82%	96%	150%	206%

[1] Historical actual rate base in each docket, except 2025 FTY is proposed amount.

This significant increase in rate base is illustrated by the following chart, included in Table 3, which shows the accelerated trend of increases in recent years. The current trend has significant negative implications for customer bills, as discussed later in my testimony.

Table 3



Q. WHAT DO YOU BELIEVE IS DRIVING THIS DRAMATIC INCREASE IN CAPITAL EXPENDITURES AND RATE BASE AT LEAST IN THE LAST 10 YEARS?

A. I believe there are two main drivers. First, replacement of aging infrastructure and new capital spending to address market growth have required an increase in capital expenditures, which have accelerated investment to some degree. The Company continues to propose ever-increasing capital expenditures to replace cast iron mains, service lines and related facilities. Some of this work is necessary and must be done. However, the Company has intensified the pace of replacement of pipelines and other facilities without sufficient engineering analysis to support the increase in capital expenditures.

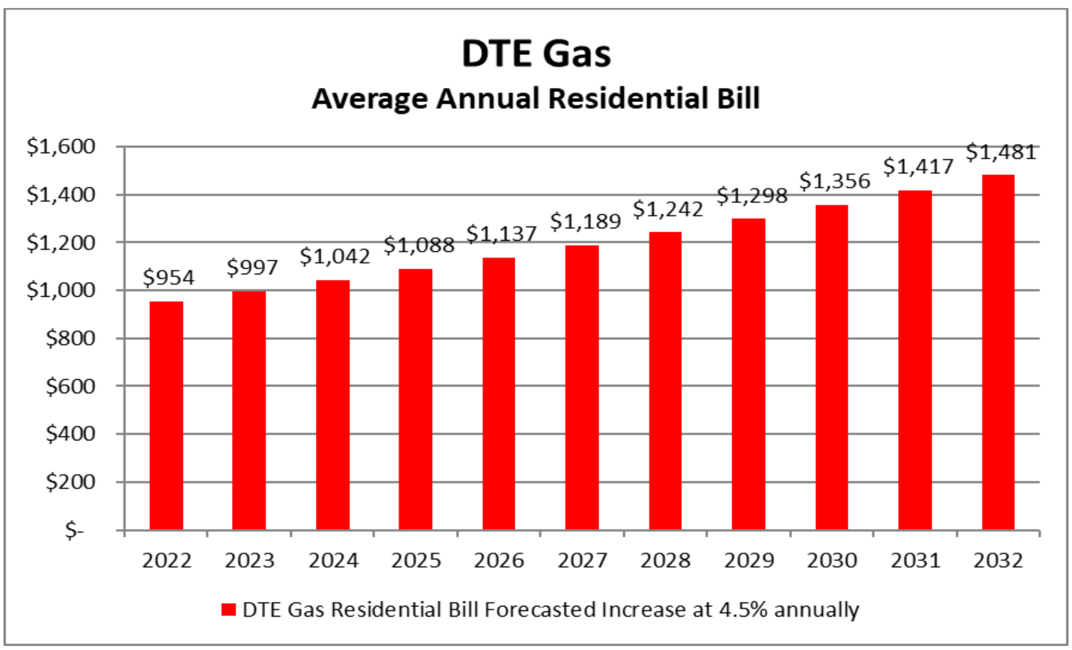
The Company also seems to be experiencing moderate customer growth in its market area. However, moderate customer growth has existed in prior years. Prior to 2012, DTE Gas was able to manage replacement of aging infrastructure and also invest in new facilities to meet market growth within a more reasonable increase in rate base. Therefore, customer growth and replacement of aging infrastructure by themselves do not fully explain the significant increase in capital expenditures and rate base since 2011.

Second and perhaps a bigger driver, the replacement of aging gas infrastructure has given the Company an opportunity to accelerate rate base growth in order to increase earnings growth. For utility companies, earnings growth is directly related to rate base growth. As shown in the tables above, large increases in capital expenditures result in double digit increases in rate base, which in turn fuels earnings growth, dividend growth, and stock price appreciation for shareholders.

The Company's parent company, DTE Energy, has been quite clear and aggressive in communicating to investors and securities analysts its goal of increasing operating earnings at the gas utility at an average annual rate of 7%. Exhibit AG-1 includes pertinent pages from an April 2024 Investor Presentation, which show this drive to increase earnings through increased capital spending at the utility. For a utility such as DTE Gas with limited sales and revenue growth, the increase in earnings comes almost entirely from the increase in capital expenditures and rate base. The presentation is devoid of any discussion about sales or revenue growth to propel earnings growth at the utility. Recent investor presentations reaffirm the same goals, showing how shareholders have been well rewarded.

Q. HAVE YOU DETERMINED WHAT THE IMPACT ON RESIDENTIAL CUSTOMER BILLS COULD BE OVER THE COMING YEARS IF THE COMMISSION APPROVES THE PROPOSED RATE INCREASE AND THAT RATE OF INCREASE CONTINUES INTO FUTURE YEARS?

A. Yes. The Company has proposed to increase residential rates in this rate case by 9%. If we assume that the Company continues its current pace of capital expenditures with bi-annual rate cases and rate increases, the average residential total annual gas bill in 10 years will increase by nearly 50%, from $954 in 2022 to $1,481 in 2032.[4] Table 4 below shows the potential increase in the average residential gas bill if the current trend in rate base growth continues and gas commodity costs remain the same.



[4] Current average gas bill (2022) of $954 = Total Rate A revenue of $1,190,770,000 divided by 1,248,500 Rate A/A2 residential customers per Exhibit A-16, Schedule F2, page 1 and Exhibit A-16, Schedule F3, page 1. Current bill escalated at 4.5% per year through 2032 (9% increase from 2022 to 2024 divided by 2).

Such an escalation in annual customer bills would pose a significant burden on all residential customers, and especially those with fixed and low income. In addition, this dramatic potential increase in residential bills does not take into consideration potential increases in gas commodity costs and further escalations in capital expenditures. Should gas commodity costs increase significantly in the coming years, customers may run into even greater bill affordability problems.

The compounding effect of large additions to rate base will continue to increase customer rates to unaffordable levels for many customers, particularly those in fixed and lower income brackets. Simply put, this trend is not sustainable for customers. To avoid bill affordability problems, the Company needs to moderate and be more selective in its capital spending in the coming years.

IV. Review of Capital Expenditures

Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE CAPITAL EXPENDITURES COULD BE REDUCED?

A. Yes. I analyzed the Company's forecasted capital expenditures by major department or area, and I identified reasonable expenditure levels that the Commission should adopt. In projecting adjusted capital expenditures for 2024 and the projected test year, where applicable, I applied an inflation factor to the historical cost base to reflect inflationary cost pressure that the Company may face in those years. The inflation factors are 2.6%

for 2024 and 2.2% for 2025. These rates reflect the increase in the forecasted Consumer Price Index for the 2024-2025 periods published on March 1, 2024.[5]

A. Distribution Plant

As shown in Exhibit A-12, Schedule B5.1, the Company forecasted capital expenditures for routine distribution facilities of $234.0 million for 2023, $186.1 million for the 9 months ending September 2024, and $230.3 million for the 12 months ending September 2025. After reviewing the testimony of Company witness Emil Abona, related exhibits, and responses to discovery, I have identified capital expenditure reductions applicable to several areas.

1. Main Renewals

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR MAIN RENEWALS.

A. As shown on page 2, line 3 of Exhibit A-12, Schedule B5.1, the Company had average capital expenditures of $5.8 million for main renewals during the 5 years from 2018 to 2022 and forecasted capital expenditures of $5.8 million for 2023, $7.0 million for the 9 months ending September 2024, and $5.3 million for the 12 months ending September 2025. On page 8 of his direct testimony, Mr. Abona briefly discusses the forecasted cumulative spending in this area over the 3-year period ending in 2025 in comparison to

[5] Exhibit AG-2 CONF includes the publication with the forecasted CPI for 2024 and 2025.

the 5-year historical period ended in 2022 and noted the unplanned or emergent nature of the capital expenditures.

In discovery, the Attorney General asked the Company to provide the historical and forecasted number of feet of main renewals. In the response, the Company identified the historical feet of main renewals from 2018 to 2023 and stated that it does not forecast the units to be renewed. The response also stated that the capital expenditures for future periods were forecasted based on the historical average.[6] The discovery response shows that historical feet of main replaced has been rather consistent in the past 3-years, ranging from 13,455 to 17,980 feet and averaging approximately 15,000 feet annually. The three-year average of main renewed is only slightly higher that the 14,200 feet renewed on average over the past five years.

Q. WHAT IS YOUR ASSESSMENT OF MAIN RENEWAL PROGRAM?

A. Based on the more recent 3-year average, I determined that the Company incurred capital spending for main renewals of $7,313,000 on average annually over the 2021 to 2023 period. This amount was calculated based on actual expenditures provided by the Company in response to discovery request STDG-1.1.[7] After adjusting for inflation, I determined that the forecasted capital expenditures for main renewals for 2024 should be $7,503,000 and $5,627,000 for the 9 months ending September 2024.[8] The Company forecasted capital expenditures of $7,019,000 for the 9 months ending September 2024.

[6] Exhibit AG-3 includes DR AGDG-5.127.
[7] Exhibit AG-4 includes DR STDG-1.1 with related attachment.
[8] $7,313,000 x 1.026 = $7,503,000 x 9/12 = $5,627,000.

This amount is excessive and overstated by $1,392,000. For the projected test year ending September 2025, I find the Company forecasted capital expenditures to be in line with historical spending levels and I do not propose any adjustments.

Therefore, I recommend that the Commission remove the $1,392,000 from the Company's forecasted capital expenditures for the 9 months ending September 2024 included in rate base.

2. Public Improvements

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR PUBLIC IMPROVEMENTS.

A. On page 2, line 4 of Exhibit A-12, Schedule B5.1, the Company shows average capital expenditures of $22.1 million for public improvements during the 5 years from 2018 to 2022 and forecasted capital expenditures of $32.2 million for 2023, $19.9 million for the 9 months ending September 2024, and $19.5 million for the 12 months ending September 2025. Beginning on page 8 of his direct testimony, Mr. Abona discusses the forecasted cumulative spending in this area over the 3-year period ending in 2025 in comparison to the 5-year historical period ended in 2022 and noted that the capital expenditures in this area are dependent on projects undertaken by government agencies in the public right-of-way (ROW) often requiring relocation or changes to the gas lines located in the ROW. In his testimony, Mr. Abona discusses the East Jefferson and the Connor/I-94 projects as two major projects included in this category of capital expenditures.

In discovery, the Attorney General asked the Company to provide the historical and forecasted number of units, miles, or quantity of work performed in this expenditure category and the related spending for both the historical and forecasted periods. In response, the Company provided the list of projects and related dollars spent for the historical three years of 2021 to 2023 and stated that it did not have a list of future projects past 2023, other than a few identified major projects.[9]

Based on the information provided by the Company in DR STDG-1.1 for 2021 through 2023, I determined that the three-year average routine capital spending in this area was $16,247,000. I arrived at this amount by removing four major projects from the historical periods (2021-2023), including the East Jefferson and the Connor/I-94 project costs.[10] After adjusting for inflation, I calculated forecasted capital expenditures of $12,502,000 for the 9 months ending September 2024 and $16,944,000 for the projected test year.[11]

I took a similar approach to determine the cost for routine of routine capital expenditures forecasted by the Company for this spending category. Page 1 of Exhibit A-12, Schedule B5.11, shows forecasted amounts for 2024 and 2025. For 2024, the Company identifies certain projects included in the total forecasted amount of $24,869,000. To determine the routine level of capital expenditures in this spending category, I removed two large projects identified by the Company in the exhibit schedule. Those projects are the Conner/I-94 and the Springfield/I-94, which total to $8,373,000 for 2024 and $6,280,000

[9] Exhibit AG-5 includes DR AGDG-5.128.
[10] Exhibit AG-4 DR STDG-1.1 attachment under Public Improvements. Removed projects on sub-lines 4.1 to 4.4.
[11] 9 months 2024: $16,247,000 x 1.026 = $16,669,000 x 9/12 = $12,502,000. PTY: $16,669,000 x 1.022 = $17,036,000 x 9/12 + 16,690,000 x 3/12 = $16,944,000.

for the 9 months ending September 2024. By removing this amount from the Company's total forecasted amount of $19,942,000, I determined routine capital expenditures for public improvements in the Company's forecast for the 9 months ending September 2024 to be $13,662,000. For 2025, the Company forecasted $19,459,000 in capital expenditures, but did not identify any projects supporting that amount.

In comparing my calculations of the forecasted capital expenditures for the 9 months ending September 2024 of $12,502,000 to the Company's adjusted forecasted amount of $13,372,000, I find that the Company's forecast is overstated by $1,160,000. For the projected test year, the Company's forecasted amount of $19,518,000 is excessive in comparison to my forecast of $16,944,000 discussed above by $2,574,000. The Company did not provide any justification for the higher capital expenditures.

I recommend that the Commission remove $1,160,000 for the 9 months ending September 2024 and $2,574,000 from the capital expenditures forecasted by the Company for public improvements.

3. System Reliability

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR SYSTEM RELIABILITY PROJECTS.

A. On page 2, line 8 of Exhibit A-12, Schedule B5.1, the Company shows average capital expenditures of $26.4 million for system reliability projects during the 5 years from 2018 to 2022 and forecasted capital expenditures of $35.9 million for 2023, $34.9 million for the 9 months ending September 2024, and $31.0 million for the 12 months ending September 2025. Beginning on page 19 of his direct testimony, Mr. Abona discusses the forecasted cumulative spending in this area over the 3-year period ending in 2025 in comparison to the 5-year historical period ended in 2022 and describes the type of work performed.

In his testimony, Mr. Abona also discusses various cost pressure that affected the unit cost historically and for the projected periods. In Table 6 on page 22 of his testimony, he shows the unit costs and the number of units completed during 2020 to 2022 and forecasted for 2023 to 2025. The table shows the number of units increasing significantly in 2024 and 2025 from historical level. However, Mr. Abona's testimony does not explain or support the increase in forecasted units.

In discovery, the Attorney General asked the Company to provide an updated Table 6 with 2023 actual data. The updated table provided in response to discovery shows that in 2023 the Company actually installed only 87 units instead of the forecasted 97 units planned and at a higher unit cost.[12] From the actual units completed between 2021 and 2023, I calculated an average of 86 units completed annually. In comparison, the 118 units forecasted by the Company for 2024 is an increase of 37% over the three-year average. For 2025, the 103 units forecast is an increase of 20% over the three-year average.

As stated above, the Company has not provided any justification to support the higher number of forecasted units or projects. Furthermore, in response to discovery, the

[12] Exhibit AG-6 includes DR AGDG-5.134 with attachment.

Company stated that several of the listed projects are in the planning or early design phase, indicating that the projects have not yet been sufficiently developed through the engineering phase to be certain for completion within the 2025 projected test year.[13]

Based on the information provided by the Company, I calculated the reduction in forecasted capital expenditures in this spending category using the 86 units completed on average annually over the most recent three years versus the number of units forecasted by the Company. For 2024, the difference in the number of units is 32 (118 – 86). By multiplying the 32 units by the Company's forecasted unit cost of $292,458, I calculated lower capital expenditures of $9,359,000 for 2024 and $7,019,000 for the 9 months ending September 2024. Similarly, for 2025, the 17 fewer units (103 – 86) multiplied by the Company's forecasted unit cost of $332,039 results in lower capital expenditures of $5,645,000. For the 12 months ending September 2025, the applicable adjustment is a reduction of $6,573,000.[14]

I recommend that the Commission remove the $7,019,000 from the Company's forecasted capital expenditures for the 9 months ending September 2024 and $6,573,000 for the 12 months ending September 2025.

4. Communications & Control - Meters

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR COMMUNICATIONS & CONTROL - METERS.

[13] Id. includes DR AGDG-5.149a and b.
[14] $9,359,000 x 3/12 + $5,645,000 x 9/12 = $6,573,000.

A. As shown on page 2, line 10 of Exhibit A-12, Schedule B5.1, the Company had average capital expenditures of $14.8 million for communication and control meters during the 5 years from 2018 to 2022 and forecasted capital expenditures of $21.8 million for 2023, $18.3 million for the 9 months ending September 2024, and $16.5 million for the projected test year. Beginning on page 27 of his direct testimony, Mr. Abona discusses the drivers for the forecasted capital expenditures for meters and related equipment, describing supply chain issues, price increases, and volume changes.

In discovery, the Attorney General asked the Company to provide specific information of quantity and related costs by meter type, modules, and related equipment for each year 2018 to 2023 and forecasted for 2024 and 2025. The granular information provided by the Company shows that although average meter prices increased from 2018 to 2022 peaking at $220 in 2022, in 2023 the average price decreased to $167. In contrast, the Company forecasted average meter prices of $215 for 2024 and $190 for 2025.[15] The forecasted prices represent increases of 29% and 14%, respectively, over the 2023 actual price of $167.

For modules, average prices reached a peak of $57 in 2023 and the Company forecasted further increases to $68 in 2024 and $71 in 2025.[16] The forecasted prices represent increases of 19% and 25%, respectively, over the 2023 actual price of $57.

[15] Exhibit AG-7 includes DR AGDG-5.137b with attachment.
[16] Id.

Although in his direct testimony, Mr. Abona provides general statements and reasons for the price increases, there is no quantifiable evidence that historical price increases will continue into the future and particularly at the rate of increases identified above. By applying the forecasted rate of inflation for 2024 and 2025 to the actual price paid per meter in 2023 of $167, I calculated a forecasted price per meter of $171 for 2024 and $175 for 2025.[17] Using these prices and the number of units forecasted by the Company of 38,627 for 2024 and 50,058 for 2025, I calculated forecasted capital expenditures of $6,605,000 and $8,760,000, respectively for each year. These amounts are $1,719,000 lower than the $8,324,000 for 2024 and $763,000 lower from the $9,523,000 for 2025 shown in the attachment to DR AGDG-5.137b.[18]

For the module purchases, I applied the inflation factors for 2024 and 2025 to the actual price of $57 for 2023 to arrive at the forecasted prices of $58 and $59 for each year.[19] By applying these prices to the number of units forecasted by the Company of 88,454 for 2024 and 67,714 for 2025, I arrived at forecasted capital expenditures of $5,130,000 and $3,995,000 for each respective year. These amounts are lower by $898,000 from the $6,028,000 forecasted by the Company for 2024 and $816,000 from the $4,811,000 forecasted by the Company for 2025. The Company's forecasted costs are shown in the attachment in DR AGDG-5.137 (Exh. AG-7).

[17] $167 x 1.026 =$171 x 1.022 = $175.
[18] Exhibit AG-7.
[19] $57 x 1.026 = $58 x 1.022 = $59.

The total lower forecasted amounts for meters and modules, combined, for 2024 and 2025 are $2,617,000 and $1,579,000, respectively. Based on the reasonable price forecasts I calculated for 2024 and 2025, I recommend that the Commission remove capital expenditures of $1,963,000 for the 9 months ending September 2024 and $1,406,000 for the 12 months ending September 2025.[20]

Q. ARE THERE ARE ADJUSTMENTS THAT YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR COMMUNICATIONS AND CONTROL METERS?

A. Yes. The detailed meter and module forecasted costs provided by the Company in response to DR AGDG-5.137b are significantly lower than the forecasted capital expenditures shown on line 10 of page 2 of Exhibit A-12, Schedule B5.11. Schedule B5.11 shows forecasted capital expenditures of $18,273,000 for 9 months ending September 2024 and $16,466,000 for the projected test year. In comparison, the attachment to DR AGDG-5.137b, when prorated for the 9 months ending September 2024 and 12 months ending September 2025 shows $10,764,000 ($14,352,000 x 9/12) and $14,338,000, respectively.[21] The difference is $7,509,000 for the 9 months ending September 2024 and $2,128,000 for the 12 months ending September 2025. These amounts are unsupported and there is no explanation in Mr. Abona's testimony describing any other spending

[20] $2,617,000 x 9/12 = $1,963,000 and $2,617,000 x 3/12 + $1,579,000 x 9/12 = $1,406,000.
[21] $14,352,000 x 3/12 + $14,334,000 x 9/12 = $14,338,000.

category other the meters and module purchases. Furthermore, the Company did not provide any schedules or data supporting data the remaining forecasted amounts.

Due to the lack of supporting evidence, I propose that the Commission remove the forecasted capital expenditures differences of $7,509,000 for the 9 months ending September 2024 and $2,128,000 for the 12 months ending September 2025.

5. Leak Detection & Repair

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE LEAK DETECTION AND REPAIR PROJECT.

A. On page 2, line 16 of Exhibit A-12, Schedule B5.1, the Company shows forecasted capital expenditures of approximately $15.0 million for leak detection and repairs (LDAR) for the projected test year. Mr. Abona discusses this expanded program beginning on page 36 of his direct testimony. According to Mr. Abona, the incremental expenditures stem from a pending rule to be issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA). As described by Mr. Abona, the rule would require the Company to perform more intensive gas leak detection procedures and require more timely repairs of leaking pipes and facilities along with other preventive measures. In Table 9 on page 37 of his direct testimony, Mr. Abona identifies the capital expenditures that total to $15.0 million. These projected capital expenditures are incremental to the Company's current leak detection and repair program.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S SPENDING PLANS FOR THE LDAR PROJECT?

A. The forecasted expenditures are premature and not likely to occur in the amounts forecasted in the projected test year. Furthermore, the Company has not presented a detailed plan of how it plans to implement the new rule requirements and over what timeframe, the equipment needed over that timeframe, and how the new requirements dovetail into the Company's current practices and procedures in detecting and repairing gas leaks. The only information Mr. Abona has provided is contained in Table 9.

Based on information provided in discovery responses, the Company had nearly $4.0 million of capital expenditures in 2023 related to leak detection and repairs, and an additional $19.5 million was spent on O&M expenses for leak detection and repairs during the year. None of those expenditures are shown in Exhibit A-12, Schedule B5.1, or addressed by Mr. Abona or other Company witnesses. The discovery responses also show that the Company has forecasted $27.4 million of capital expenditures for leak detection and repairs for 2024 in addition to the $15 million shown in Schedule B5.1. In his direct testimony, Company witness Scotty Kehoe proposes an additional $10.3 million in O&M expense for LDAR related to the new PHMSA rule. Therefore, in total for all those activities, the Company is proposing to spend in excess of $53 million on leak detection and repairs for the projected test year.[22] It is not clear why, in less than one year, the total

[22] Exhibit AG-8 includes DRs AGDG-2.30a, 2.30c, 5.142a, 5.143a-h.

spending would more than double or whether the Company would have the capability to accomplish that level of increased activity and related spending.

According to the Company, the final rule is not expected to be issued before September 2024 and the rule would go into effect six months thereafter, which would place the initial effective date in March 2025 at the earliest. It is also common for such rules to have a provision to achieve compliance over several years. Therefore, the rush for the Company to spend an additional $15 million in capital expenditures and $10.3 million in O&M expense to comply with the new proposed rule requirements is unwarranted. Until the Company is able to present a comprehensive plan of how and when it will expand the current leak detection and repair program to be compliant with the final PHMSA LDAR rule, it is premature to approve the significant increase in spending proposed by the Company both for capital and O&M expenditures.

Therefore, I recommend that the Commission reject the $14,970,000 of capital expenditures and the $10,276,000 of O&M expense forecasted by the Company for the projected test year.

6. Fort Street Main Replacement

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE FORT STREET MAIN REPLACEMENT PROJECT.

A. On line 6 of Exhibit A-12, Schedule B5.2, the Company shows capital expenditures of $13.2 million for the Fort Street Main Replacement project for 2022 and forecasted capital expenditures of $19.9 million for 2023, $15.9 million for the 9 months ending September 2024, and $32.8 million for the 12 months ending September 2025. Beginning on page 32 of her direct testimony, Company witness Kelly Fedele discusses this multi-phase project spanning over multiple years. The Company's capital forecast for 2023 through 2025 anticipates completion of Phases 5, 6, 7, and 7A and coordination with municipal and state projects for reconstruction and modification to Jefferson Street and the I-375 Reconstruction project.

In discovery, the Attorney General asked the Company to provide the timing of the I-375 Reconstruction and other applicable municipal projects that will drive the timing of the Fort Street project. In response, the Company stated that Phase 5 was completed in 2023 and Phase 7 around the Michigan Central Train Station would be completed by April 2024. With regard to the I-375 Reconstruction project, no timing was provided and the Company is waiting for more information from the Michigan Department of Transportation (MDOT).[23]

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S SPENDING PLANS FOR THE FORT STREET MAIN REPLACEMENT PROJECT?

A. Although the capital spending forecasted for 2024 appears likely to occur, the capital spending for the projected test year is dependent on the timing of the I-375 Reconstruction project and MDOT has not yet defined a specific timeline. It is premature to approve capital spending on the Fort Street Main Replacement for the projected test year until there

[23] Exhibit AG-9 includes DR AGDG-5.106b.

is more clarity and specific plans from MDOT for the Company to act on. It would be imprudent for the Company to proceed with construction activities without a firm timeline and an approved project plan from MDOT and the City of Detroit.

As the Company discovered with the East Jefferson main replacement project, costs can increase significantly if government agencies decide to postpone their project plans. With the East Jefferson project, the Company proceeded with the main replacement project anticipating that the City of Detroit would concurrently undertake the Jefferson Road Reconstruction project and certain costs would be avoided by joint construction in the street ROW. However, when the City of Detroit cancelled the project, the Company had to incur an additional $7.0 million to complete the main replacement project on its own.[24]

Therefore, the $32,753,000 forecasted by the Company for the projected test year for the Fort Street Main Replacement project are not likely to be spent and I recommend that Commission remove that amount for the Company's forecasted capital expenditures in this rate case.

7. Van Born Project

Q. PLEASE EXPLAIN YOUR DISALLOWANCE OF CAPITAL EXPENDITURES FOR THE VAN BORN PROJECT.

A. On line 5 of Exhibit A-12, Schedule B5.2, the Company shows capital expenditures of $10.9 million for the Van Born project for 2022 and forecasted capital expenditures of

[24] Id. includes DR AGDG-5.129.

$35.2 million for 2023, $2.9 million for the 9 months ending September 2024, and $1.3 million for the 12 months ending September 2025. Beginning on page 47 of her direct testimony, Ms. Fedele discusses the purpose of the project, which is to prevent a potential service outage if a pipeline failure were to occur along the length of the line. The Company proposed a different and larger project in the two prior rate cases, and I filed testimony on behalf of the Attorney General questioning the Company's plans and the level of proposed capital expenditures. As explained by Ms. Fedele in her direct testimony in this rate case, the Company revised its plans and project designs to achieve the same objective at a much lower cost. The decision to change course on the project was made in May 2022.[25]

However, from 2020 to May 2022, the Company incurred $8.7 million in capital costs related to the project. On page 57 of her direct testimony, Ms. Fedele states that the Company wrote-off to expense $1.9 million of the project costs incurred related to the previous project. In response to discovery request AGDG-5.117b, the Company identified the components of the $1.9 million, which were rounded up to $2.0 million, but did not identify what the remaining $6.7 million were specifically spent on and why they should remain in rate base. Most of the remaining costs have been categorized as contracted services, labor, and overheads.[26] With the project changing significantly from its initial scope and the Company filing an expensive Act 9 application, which it subsequently withdrew after the project scope changed, the $1.9 million write-off seems considerably insufficient.

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[25] Exhibit AG-10 includes DRs AGDG-5.115a-c and 5.117a.
[26] Id. includes DR AGDG-5.117b.

In fact, it is likely that subsequent to its decision to change the scope of the project in May 2022, the Company incurred additional design and engineering costs, which the Company also seeks to recover in this rate case. Given the lack of transparency for the remaining $6.7 million of project costs incurred prior to May 2022, I recommend that the Commission remove this amount from rate base in this rate case.

8. Gas Main Replacement Program (MRP/GRP) and IRM

As shown in Exhibit A-12, Schedule B5.3, the Company spent $347.7 million in 2022 under the Infrastructure Recovery Mechanism (IRM) and forecasted $359.5 million for 2023, $271.5 million for the first 9 months of 2024, and $89.6 million for the partial 12-month period ending September 2025. The Company also proposes to continue the IRM for the five calendar years 2025 to 2029, with spending levels exceeding $300 million annually. Included in the IRM are the Main Replacement Program (MRP), the Meter Move-Out (MMO) program, the MMO MAC Initiative program, the Pipeline Integrity program, and in this rate case, the Company proposes to also include the Cathodic Protection program.

Mr. Eric Janness's direct testimony discusses each of these programs and the IRM proposed expenditures from 2022 to 2029. In his testimony and related exhibits, Mr. Janness proposes to incorporate the MMO MAC Initiative program with the other MMO program, which seems reasonable. With this change, the Company now refers to the MMO program and the MRP as the Gas Renewal Program or GRP.

Q. WHAT IS YOUR ASSESSMENT OF THE LEVEL OF SPENDING PROPOSED BY THE COMPANY IN THE MRP, GRP, AND THE IRM?

A. The Company has continued to escalate the size of the program in each prior rate case and other cases specific to the MRP. Although not fully evident in Exhibit A-12, Schedule B6, the Company proposed the MRP for the first time in August 2010 in Case No. U-16407. At that time, the Company proposed to replace 30 miles of targeted mains for an annual capital spending of $17.4 million. Shortly thereafter, in 2012, in case No. U-16999, the Company proposed, and the Commission approved, an escalation of the program for replacement of 66 miles of main at an annual spending level of $46.9 million. Case No. U-16999 also established the IRM as a mechanism for the Company to more quickly recover the cost of capital additions for the MRP and other programs.

In 2014, in Case No. U-17701, the Company proposed to again increase the annual spending level to $78.3 million by 2017 and to replace 103 miles of main annually. In December 2015, the Company filed a rate case in Case No, U-17999 and requested a further increase in the capital expenditures for the MRP to $93.8 million for 2017 with plans to replace 123 miles of main. Subsequent to that rate case, the Company scaled down the number of miles of main to be replaced but maintained the same proposed spending level.

In rate Case No. U-18999, filed in November 2017, the Company once more requested a further escalation of the program capital expenditures to $169.7 million for 2019 and increases to $193.0 million for 2020. In the subsequent two rate cases, spending levels again increased, reaching $340 million in 2022 for all the component programs within the IRM. This trend of ever escalating spending on programs within the IRM continues in this case with proposed spending of $359 million in 2023 and comparable amounts annually at least through 2027.

In other words, what began as a modest program of $17.4 million to replace cast iron mains and other unprotected and deteriorating gas mains has now mushroomed into a monstrous program of more than $350 million annually.

Q. WHAT REASONS DOES THE COMPANY OFFER FOR THE FURTHER ESCALATION OF PROGRAM COSTS IN THIS RATE CASE?

A. In his testimony, Mr. Janness points to more complex projects, higher permit and restoration costs, and higher contractor costs. It appears the new probabilistic risk model is either selecting or aggregating more complex projects. Why this is occurring is not entirely clear and may be a shortcoming of the model. However, the evidence provided by the Company does not show that complex projects are a significant portion of the total number of projects completed each year. In discovery, the Attorney General asked the Company to provide the list of projects from which the projects targeted for 2024 and 2025 were selected. In response the Company provided a list of about 470 projects. On that list, the number of identified complex projects is less than 20 and two were completed in

2019 through 2023 and five are scheduled for 2024.[27] No information was provided about projects scheduled for 2025.

With regard to cost increases, higher permit costs, restoration costs, and contractor costs are a function of activity and the increased demand for services placed on those organizations by the Company and other utilities. More projects require more resources to review and issue permits. More damage to streets and sidewalks inconvenience customers and the public and there is more demand by municipalities for a wider restoration span around the project damage area. More projects also increase the cost of materials from pipe to valves and trench filling materials. Demand for contractor services has also been increasing as other utilities regionally and around the country have expanded their main replacement programs and have increased construction activity. With higher demand for resources and materials, prices for contractor installation services increase and so does the cost of completing construction projects.

This dramatic increase in demand for contractor services with limited availability of resources has resulted in significant annual cost escalations. Unless the demand for materials, contractor services, and other services ebbs with more rational limitations on the pace of main replacement and construction activity by gas utilities, the cost escalation problem will not improve and in fact may get worse.

[27] Exhibit AG-11 includes DR AGDG-6.167a with attachment.

Q. HAS THE COMPANY PROVIDED ANY HARD EVIDENCE OR ANALYSIS TO SUPPORT THE CONTINUED ESCALATION OF THE MRP IN THIS RATE CASE OR PRIOR RATE CASES?

A. No. There has been no evidence presented by the Company that deterioration of the legacy mains is increasing to require an increase in spending. Although reducing risk and increasing safety are laudable goals, there must be more quantitative and qualitative analysis performed to show that the rate of deterioration of the gas mains and services is accelerating to justify increasing annual capital expenditures by more than 10-fold between 2010 and 2025. Without this quantitative evidence, the current pace of main replacement and the escalating capital expenditures have become totally subjective.

The list of MRP/GRP projects provided the Company discussed above were risk scored using the Probabilistic Risk Assessment (PRA) model. The 470 projects on the list have risk scores ranging from 0.961 to zero. Most of the projects have a risk score of less than 0.005 and many are at zero or close to zero.[28] In other words, there is no compelling evidence that keeping the current pace of main replacement, or even accelerating it, is necessary.

Q. HAS THE COMPANY SHOWN FINANCIAL DISCIPLINE IN REFRAINING FROM OVER-SPENDING ON THE MRP AND STAYING WITHIN THE ESTABLISHED COST PLAN?

[28] Id.

A. No. In response to discovery, the Company provided an updated Exhibit A-12, Schedule B6.1, to include actual expenditures through 2023. The updated schedule shows that the Company overspent the plan by nearly $60 million in 2023, or 21%. More alarming is the fact that the Company overspent in each year since 2016 mostly by double digit percentage as high as 33%. Exhibit AG-12 includes the attachment to the discovery response with the percentages of over-spending added.

Q. WHAT LEVEL OF CAPITAL EXPENDITURES FOR THE MRP AND OTHER COMPONENTS OF THE IRM SHOULD THE COMMISSION APPROVE IN THIS RATE CASE?

A. The increasing cost trend of the IRM discussed above is not sustainable from a customer affordability viewpoint and must be reversed. The Commission should set a maximum spending level or a cap for the IRM and the related component programs to avoid the current runaway cost. Most homeowners must live within their own cost budgets and do not have unlimited resources to be able to afford ever increasing household costs. They make hard choices every day as to where to spend their money within the available resources. Similarly, the Company needs to set an annual budget and replace and install the number of miles of main, MMO projects, and pipeline integrity projects that can be completed within a set budget cap, unless justified by unexpected and critical safety situations. The current practice of unlimited and increasing capital spending on the IRM programs needs to restrained.

In response to discovery request AGDG-6.179, the Company provided a schedule that shows the capital spending on each of the programs included within the IRM from 2018 to 2029 with related quantity of work units. Based on the actual spending of $240 million in 2021, the Company retired 214 miles of legacy mains and replaced them with 252 miles of new main under the MRP. During 2021, the Company also replaced 25,967 services as part of the MRP.[29]

Therefore, I recommend that the Commission approve a maximum capital spending level of $240 million for the MRP within the IRM instead of the $274 million proposed by the Company for 2025. I chose 2021 as the benchmark year because it was the last year when spending on the MRP was still below $250 million and the Company was able to retire more than 200 miles of legacy mains. For 2024 through 2029, the Company's forecast is to retire 206 miles of legacy mains, albeit at a higher cost per mile.

In total, for the MMO programs, the Company spent $48.2 million in 2021 and forecasted to spend approximately $47.5 million in 2025. I recommend that the Commission approve inclusion of $48 million in capital expenditures in the IRM for 2025 for the combined MMO programs. For Pipeline Integrity, the Company spent $11.7 million in 2021 and forecasted to increase spending on this program to $23 million in the IRM for 2025.

According to Mr. Janness, the Company plans to accelerate spending in this area to meet its goal of completing 97% of the total HCA assessments by 2025.[30] The assessments

[29] AG-12 includes DR AGDG-6.179 with attachment.
[30] Eric Janness direct testimony at page 32.

should be stretched over a longer period. No compelling reason has been provided by the Company that the 97% goal must be achieved in 2025. The Company's capital expenditures forecast for Pipeline Integrity from 2025 to 2029 total to $72.1 million, which average to $14.4 million annually over the five-year period. Therefore, I recommend that capital expenditures for this program under the IRM for 2025 be set at no higher than $15 million.

In total, I recommend that the Commission approve a spending level of $303 million for the IRM for 2025 and allow the Company to increase that amount by an inflation factor of 2.5% annually beginning in 2026 and in subsequent years.

Although the lower spending level that I propose may somewhat reduce the number of miles that the Company planned to retire and install in 2025 and subsequent years, the inflation adjusted spending cap beginning in 2026 should give the Company more room to absorb cost increases. The lower capital spending level will also give the Company added incentive to reduce the cost per mile of main installed and reduce pressure on scarce resources. As stated earlier, the competition for limited resources has contributed to the higher cost of pipe replacement under the Company MRP program during recent high inflationary periods. A more moderate pace of pipe replacement will help take the pressure off the competition for those resources.

It is also noteworthy to point out that through the risk-based approach to pipe replacement that the Company has employed over the past 12 years, most of the high-risk mains and services should already have been replaced. The Company has not provided any compelling evidence that the planned increase in spending is tied to any increased safety risks. Therefore, if the completion of the MRP program is extended a few more years past the current 2035 target date, it is a reasonable trade-off to balance against customer affordability from uncontrolled capital spending on the program.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO INCLUDE CATHODIC PROTECTION CAPITAL EXPENDITURES IN THE IRM?

A. No. The Company has not provided any compelling reasons why cathodic protection costs need to be included in the IRM. Mr. Janness discusses this program beginning on page 47 of his direct testimony. The reasons to include the cathodic protection program within the IRM mentioned by Mr. Janness, such as assurance that the expenditures would be reasonable and prudent and that sufficient expenditures will be dedicated to cathodic protection, apply whether the capital expenditures are in base rates or in the IRM. The Company should make prudent spending decisions irrespective of how cost recovery occurs and should allocate sufficient resources to the program irrespective of the cost recovery methodology. As to formalizing a holistic and programmatic approach to cathodic protection, the Attorney General asked the Company to explain what such a program would look like and why it could not be done also with cost recovery in base rates. In response, the Company states that it had not determined yet that cathodic protection cannot continue to be included in bases rates, but seems to prefer the automatic cost recovery through the IRM.[31]

[31] Exhibit AG-13 includes DR AGDG-6.172b.

The Company has not made a convincing case that capital expenditures for cathodic protection should be included in the IRM. Therefore, I recommend that the Commission reject the Company's proposal and instead add $7,400,000 of cathodic protection costs to the $2,200,000 already included the projected test year for a total amount of $9,600,000.

Q. ARE YOU PROPOSING ANY DISALLOWANCES OR ADJUSTMENTS TO THE MRP OR THE MMO FORECASTED CAPITAL EXPENDITURES FOR 2024?

A. No. Cognizant of the fact that capital programs for 2024 have already being scheduled and are being implemented and the fact that a Commission order in this rate case would not be issued until later in the year, it would not be productive to propose adjustments to the two capital expenditure programs for 2024.

B. Transmission Plant

Transmission plant additions consist of both routine projects and large capital projects. Below, I will discuss adjustments to both routine transmission projects and large capital projects.

1. Routine Transmission Plant

As shown on page 2, line 19 of Exhibit A-12, Schedule B5.1, the Company spent an average annual amount of $11.6 million on routine transmission plant additions during the five years from 2018 to 2022 and forecasted capital expenditures of $12.7 million for 2023, $14.2 million for the 9 months ending September 2024, and $12.7 million for the projected test year. Page 6 of Exhibit A-12, Schedule B5.11, shows a list of some of the capital projects included in the forecasted amounts for 2023-2025.

In discovery, the Attorney General asked the Company to identify the current phase of development for four large projects forecasted for 2025. The projects with related 2025 capital expenditures are: the MLV7 Replacement ($2,800,000), the Au Gres Tributary Pipe Replacement ($2,350,000), the Willow Gate Station ($2,000,000), and the MLV 5C Line Replacement ($1,928,000). The total forecasted cost for the four projects is $9,078,000 for 2025 and $6,809,000 for the projected test year.[32]

The Company evaded answering the question about the current phase of development and instead stated that engineering and construction phases would occur sometime in 2024 and 2025.[33] The evasive answer indicates that the four projects are currently in the initial conceptual or planning phase with no stated start and completion date for project engineering. These projects are still in the early phase of development with no assured timeline and thus premature to include in rate base in this rate case. Therefore, I recommend that the Commission disallow $6,809,000 of capital expenditures for the projected test year.

2. Pipeline Integrity – ILI Projects

Line 19 of Exhibit A-12, Schedule B5.3, shows the Company's forecasted spending on Pipeline Integrity of $27.7 million for 2023, $16.0 million for the 9 months ending

[32] $9,078,000 x 9/12 = $6,809,000.
[33] Exhibit AG-14 includes DR AGDG-5.150b.

September 2024, and $6.3 million for the three-month stub period in the projects test year plus $23.1 million in the IRM for 2025.

In discovery, the Attorney General asked the Company to provide the current phase of development for four large ILI projects shown on pages 27, 29, 36, and 44 of Exhibit A-12, Schedule B5.5. In response, the Company reported that three of the four projects are currently in the conceptual design phase. Those projects are the Muskegon-Ludington 10 Scott Tie-in, the Belle River Field Headers 12 &16, and the Belle River Field Header 24.[34] The forecasted amount for the three projects for the 9 months ending September 2024 is $3,588,000 and $8,576,000 for the 12 months ending September 2025.[35]

These projects are still in the early phase of development with no assured timeline and thus premature to include in rate base in this rate case. Therefore, I recommend that the Commission disallow $3,588,000 of capital expenditures for the 9 months ending September 2024 and $8,576,000 for the projected test year.

3. Large Transmission Projects Not Approved

On page 27 of her direct testimony, Ms. Fedele identifies three projects that have not yet received formal corporate approval to proceed with project development. Those projects are the Austin-Detroit A&B Lines replacement, the Belle River/Detroit Interconnect & Loop, and the Taggart Compressor Replacement. In addition, those projects have not yet completed the engineering design phase and will not be placed in service until well past

[34] Exhibit AG-15 includes DR AGDG-6.180.
[35] Sourced from individual project documents on pages 29, 36, and 44 of Exhibit A-12, Schedule B5.5.

the end of the projected test year. Nevertheless, the Company included capital expenditures for those projects in rate base in this rate case. The Company stated that it recorded an Allowance for Funds Under Construction (AFUDC) credit that offsets the revenue requirement from including the project costs in rate base.

According to the amounts shown on lines 9, 11, and 12 of Exhibit A-12, Schedule B5.2, the total forecasted capital expenditures for the three projects are $1.3 million for 2023, $4.7 million for the 9 months ending September 2024, and $27.1 million for the projected test year.

Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES INCLUDED IN THIS RATE CASE FOR THE THREE PROJECTS?

A. It is premature to include any amount of capital expenditures for the three projects in rate base. As Ms. Fedele stated in her testimony, the projects have not yet been formally approved. Therefore, it is still uncertain whether the projects will proceed as anticipated by the Company. Furthermore, the Belle River/Detroit Loop and the Taggart Compressor Replacement projects have not yet been designed and according to the timeline in the project description document in Exhibit A-12, Schedule B5.5, pages 13 and 35, the design will not be completed until late in 2025, past the end of the projected test year in this rate case.

These projects have not yet been approved and are still in the early phase of development with no assured timeline and thus premature to include in rate base in this rate case, irrespective of the fact that an AFUDC cost offset has been recorded to operating income.

Therefore, I recommend that the Commission remove the capital expenditures of $1.3 million for 2023, $4.7 million for the 9 months ending September 2024, and $27.1 million for the projected test year. Later in my testimony, I discuss the necessary adjustment to the AFUDC recorded by the Company for the three projects.

4. Oakland Resilience Interconnect (CMS Line 2700)

Line 10 of Exhibit A-12, Schedule B5.3, shows the Company's forecasted spending for the Oakland Resilience Interconnect project of $100,000 for 2023, $1.1 million for the 9 months ending September 2024, and $4.7 million for the projected test year. The project development timeline in the project description document on page 16 of Exhibit A-12, Schedule B5.5, shows that engineering design work on the project has not yet been completed. The project appears to be still in the conceptual design phase. Furthermore, the project will not be in service until after the end of the projected test year for this rate case. It is also premature to include this project in rate base in this rate case.

Therefore, I recommend that the Commission disallow the forecasted capital expenditures of $100,000 for 2023, $1.1 million for the 9 months ending September 2024, and $4.7 million for the projected test year.

5. Traverse City Alpena Reinforcement

Line 4 of Exhibit A-12, Schedule B5.3, shows actual capital expenditures for the Traverse City Alpena Reinforcement (TCARP) project of $40.7 million for 2022 and $3.4 million forecasted for 2023. Ms. Fedele discusses this project beginning on page 91 of her direct testimony and on page 93 states that the cost of the project increased from the initial estimate of $100.8 million to a final cost of $114.8 million. On page 95, she attributes the higher cost of the project to three factors: (1) $3.0 million due to the one-year delay by DT Midstream Michigan Lateral Company (DTMLC) in receiving its Act 9 certificate to build a portion of the project, (2) $9.8 million due to higher construction costs than previously estimated, and (3) $1.2 million to add pressure regulators not previously anticipated.

In discovery, the Attorney General asked the Company to explain why the one-year delay would cause an additional $3.0 million in higher internal labor costs, higher contractor and material costs, and higher corporate overhead costs, and to provide the amount related to each item. In response, the Company repeated the reason for the project delay but failed to explain why the delay would cause internal labor to increase by $1,800,000, overhead costs to increase by $1,100,000, and contractor and material costs to increase by $50,000 each.[36] The response provides no justification for the higher costs. Although the delay seems plausible due to the Act 9 proceedings, no work took place during that time and no new employees were hired to justify the additional $1.8 million of internal labor costs while the Company waited for DTMLC to obtain the Act 9 certificate. The overhead costs of $1.1 million follow the labor cost and at 61% seem excessive. The additional contractor and material costs are relatively small at $50,000 each but also befuddling given than the project was on hold during the one-year period.

The Company has failed to adequately justify the additional $3.0 million in project costs, mostly arising from internal labor and overheads. Therefore, I recommend that the

[36] Exhibit AG-16 includes DR AGDG-5.124a.

commission remove the $3.0 million from rate base in this case and instruct the Company to also remove the amount permanently from future rate cases.

Q. ARE THERE OTHER COST DISALLOWANCES THAT YOU PROPOSE FOR THE TCARP PROJECT?

A. Yes. In my involvement as an expert witness on behalf of the Attorney General in Case No. U-21525, which pertains to establishing revised transportation rates for the converted Michigan wet header pipeline and related interconnections owned by DTMLC and supporting the TCARP project, I discovered that DTE Gas incurred additional costs to build temporary facilities to correct a problem with excessive moisture in the gas stream transported by DTMLC to the DTE Gas pipeline system. In response to DR U-21525-AGDG-2.7 and 2.8, DTE Gas admitted that it should have billed the incremental costs to DTMLC and instead included them in rate base, which it seeks to recover in this rate case.[37]

In response to further discovery on this matter in this rate case, the Company identified the total incremental costs to be $323,000, consisting of $155,000 to build the Saginaw Bay interconnect loop and $168,000 for the West Branch interconnect loop.[38] These costs should have been paid by DTMLC due to problems they should have addressed and prevented. Customers of DTE Gas should not pay for those costs. Therefore, I recommend that the Commission remove the $323,000 from rate base in this case and instruct the Company to remove the amount permanently from future rate cases.

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[37] Id. includes DR U-21525-AGDG-2.7 and 2.8.
[38] Id. includes DR AGDG-5.123.

C. Gas Storage Plant

As shown on page 2, line 22 of Exhibit A-12, Schedule B5.1, the Company spent an average annual amount of $4.3 million on routine storage plant additions during the five years from 2018 to 2022 and forecasted capital expenditures of $3.4 million for 2023, $3.6 million for the 9 months ending September 2024, and $4.1 million for the projected test year. Also, on line 24 of the exhibit schedule, the Company shows capital expenditures for storage compression of $16.6 million for the 2018-2022 period and forecasted amounts of $18.7 million for 2023, $16.2 million for the 9 months ending September 2024, and $10.9 million for the projected test year. Mr. Abona discusses the storage plant additions beginning on page 42 of his direct testimony.

In discovery, the Attorney General asked the Company to provide the number of projects or work units underlying the historical and forecasted periods for the gas storage and storage compression programs. In response, the Company provided the work units for each program from 2018 to 2025.[39] The forecasted number of work units for 2024 and 2025 are generally lower for those years than the previous three years from 2021 to 2023. For gas storage, the Company forecasted 44 work units for 2024 and 37 for 2025. In comparison, the Company completed 63 work units on average annually during 2021-2023. For the storage compression program, the Company forecasted 78 units for 2024 and 60 units for 2025. On average over the 2021-2023 period, the Company completed 110 units.

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[39] Exhibit AG-17 includes DR AGDG-5.145a.

To establish the reasonableness of the Company's forecasted capital expenditures for the forecasted periods for the gas storage routine program, I calculated the historical average cost per work unit for the 2021-2023 period at $54,642.[40] After applying the inflation factor, I calculated a unit cost of $58,980 for 2024, which when multiplied by the 44 units forecasted by the Company resulted in a forecasted cost of $2,467,000 for the year, or $1,850,000 for the 9 months ending September 2024.[41] In comparison, the Company forecasted capital expenditures of $3,108,000 for the 9-month period. The Company's forecast is overstated by $1,258,000.

For the projected test year, I increased the 2024 unit cost by the inflation factor for 2025 to determine a unit cost of $57,296. By multiplying this amount by the 37 units forecasted by the Company, I calculated forecasted capital expenditures of $2,120,000 for 2025 and $2,207,000 for the 12 months ending September 2025.[42] In comparison, the Company forecasted capital expenditures of $4,067,000 for the 12-month period. The Company's forecast is overstated by $1,860,000.

For the storage compression program, I followed a similar process. The average cost per unit for the three years 2021-2023 was $132,812.[43] After applying the inflation factor, I calculated a unit cost of $136,265 for 2024, which when multiplied by the 78 units

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[40] Actual capital expenditures for 2021-2023 from line 23 of the attachment to DR STDG-1.1 (Exh. AG-4) of $10,382,000 divided by the number of units each year of 190 from DR AGDG-5.145a (Exh. AG-17) result to a cost of $54,642 per unit.

[41] $54,642 x 1.026 = $56,063 x 44 = $2,467,000 x 9/12 = $1,850,000.

[42] $56,063 x 1.022 = $57,296 x 37 = $2,120,000. PTY: $2,120,000 x 9/12 + $2,467,000 x 3/12 = $2,207,000.

[43] Actual capital expenditures for 2021-2023 from line 25 of the attachment to DR STDG-1.1 (Exh. AG-4) divided by the number of units each year from DR AGDG-5.145a (Exh. AG-17): $43,695,000 / 329 units = $132,812 per unit.

forecasted by the Company resulted in a forecasted cost of $10,629,000 for the year, or $7,972,000 for the 9 months ending September 2024.[44] In comparison, the Company forecasted capital expenditures of $16,220,000 for the 9-month period. The Company's forecast is overstated by $8,248,000.

For the projected test year, I increased the 2024 unit cost by the inflation factor for 2025 to determine a unit cost of $139,263. By multiplying this amount by the 60 units forecasted by the Company, I calculated forecasted capital expenditures of $8,356,000 for 2025 and $8,924,000 for the 12 months ending September 2025.[45] In comparison, the Company forecasted capital expenditures of $10,883,000 for the 12-month period. The Company's forecast is overstated by $1,959,000.

In total, for the gas storage and compression programs, the Company's forecasted capital expenditures are overstated by $9,506,000 for the 9 months ending September 2024 and $3,819,000 for the 12 months ending September 2025. The Company's forecasted capital expenditures in this spending category are not reasonable and the Company has not adequately justified the higher forecasted costs in comparison to recent historical unit cost plus forecasted inflation. Therefore, I recommend that the Commission remove the excess capital expenditures of $9,506,000 for the 9 months ending September 2024 and the $3,819,000 for the 12 months ending September 2025.

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[44] $132,812 x 1.026 = $136,265 x 78 = $10,629,000 x 9/12 = $7,972,000.
[45] $56,063 x 1.022 = $57,296 x 37 = $2,120,000. PTY: $2,120,000 x 9/12 + $2,467,000 x 3/12 = $2,207,000.

D. Transportation Vehicles & Equipment

On page 2, line 27 of Exhibit A-12, Schedule B5.1, the Company shows capital expenditures for transportation vehicles and equipment of $10.4 million from 2018 to 2022 and forecasted capital spending of $12.9 million for 2023, $10.0 million for the 9 months ending September 2024, and $20.3 million for the projected test year. On pages 49 and 50 of his direct testimony, Mr. Abona discusses the challenges that the Company has experienced in obtaining new vehicles in recent years due to limited availability of certain models. Mr. Abona also discusses generally the higher prices paid for vehicles and equipment purchases but does not identify any specific amounts or percentages for either the historical or forecasted years.

In discovery, the Attorney General asked the Company to provide the number of vehicles and equipment purchases by vehicle class from 2018 to 2023 and forecasted for 2024 to 2025 with related purchase costs. The information provided by the Company shows forecasted 2024 vehicle and equipment purchase costs with a cost per vehicle of $136,783 and 2025 forecasted purchases with a cost per vehicle of $126,145. In contrast, the Company spent $79,010 per vehicle in 2023 and for the three year 2021-2023 the average purchase cost per vehicle was $80,439.[46] The forecasted cost per vehicle in 2024 is 70% above the three-year average cost and the 2025 forecasted unit cost is 57% over the same average cost. Clearly, the forecasted cost per vehicle for 2024 and 2025 is significantly inflated and overstated.

[46] Exhibit AG-18 includes DR AGDG-5.147a with attachment and unit costs added.

Using the historical three-year average cost per vehicle of $80,439 and after adjusting it for the 2024 inflation factor to $82,530, I determined that for the 47 vehicles and equipment that the Company plans to purchase in 2024 the forecasted cost is $3,879,000 and $2,909,000 for the 9 months ending September 2024.[47] In comparison, the Company forecasted capital expenditures for the 9-month period of $10,006,000. The Company's forecast is overstated by $7,097,000.

Similarly, by escalating the 2024 unit cost by the inflation factor, the 2025 unit cost is $84,346. After multiplying this amount by the 125 vehicles the Company plans to purchase, I determined the total forecasted cost for 2025 at $10,543,000. For the 12 months ending September 2025, the forecasted cost is $8,877,000.[48] In comparison, the Company forecasted capital expenditures of $20,255,000. The Company's forecast is overstated by $11,378,000.

The Company did not provide any evidence to justify the large unit cost increase of 57% to 70% over recent historical levels. The Company's forecast is not reasonable and is not adequately supported. Therefore, I recommend that the Commission remove the excess capital expenditures of $7,097,000 for the 9 months ending September 2024 and $11,378,000 for the projected test year.

[47] $82,530 x 47 = $3,879,000 x 9/12 = $2,909,000.
[48] $82,530 x 1.022 x 125 = $10,543,000. PTY: $10,543,000 x 9/12 + $3,879,000 x 3/12 = $8,877,000.

E. Gas Information Technology

Q. PLEASE DISCUSS WHAT ADJUSTMENT YOU PROPOSE TO FORECASTED CAPITAL EXPENDITURES FOR INFORMATION TECHNOLOGY.

A. In my review of the information technology (IT) projects presented by the Company in this rate case, I discovered that the Company did not include a reduction in capital expenditures pertaining to the recent implementation of the Gas Scheduling Optimizer system. In response to discovery, the Company admitted that capital savings of $450,000 were not included as a reduction to the IT capital expenditures forecasted by the Company for the projected test year in this rate case.[49] Therefore, I recommend that this amount be removed from the projected test year capital expenditures.

F. Capital Expenditures Adjustments - Summary

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING THE TOTAL AMOUNT OF ADJUSTMENTS TO THE COMPANY'S CAPITAL EXPENDITURES AND RATE BASE?

A. The chart below summarizes my proposed reductions in capital expenditures in those areas where the level of capital expenditures presented by the Company is excessive, unnecessary, or unsupported.

[49] AG-19 includes DR AGDG-5.151c.

Summary of AG Disallowed Capital Expenditures	
	Amount (millions)
Distribution Plant	
Main Renewals	1.4
Public Improvements	3.7
System Reliability	13.6
Communications & Controls - Meters	13.0
Leak Detection and Repair	15.0
Fort Street Main Replacement	32.8
Van Born project	6.7
Transmission Plant	
Routine Transmission Projects	6.8
ILI Projects	12.2
Austin-Detroit A&B Lines	21.0
Belle River Detroit Loop	8.1
Taggart Compression Replacement	4.0
Oakland Resilience Interconnect	5.9
TCARP-DTML Interconnect/Dehydration	3.3
Cathodic Protection	(7.4)
Gas Storage & Compression	13.3
Transportation Vehicles	18.4
Other	0.5
Total	**$ 172.3**

Based on my analysis and information presented in my testimony above, the Commission should reduce the Company's proposed capital expenditures by $172.3 million and average rate base by $124.5 million, including a $10.1 million reduction in working capital. Exhibit AG-20 provides additional details and calculations of these amounts.

V. Working Capital

Q. ON EXHIBIT A-12, SCHEDULE B4, THE COMPANY PROPOSES A WORKING CAPITAL AMOUNT OF $872.9 MILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY'S FORECASTED AMOUNT?

A. No. I propose an adjustment to reduce the Company's forecasted working capital amount by $10,083,000. This adjustment pertains to the deferred Regulatory Asset-Incentive Tracker balance of $13.3 million calculated by the Company and shown on line 37 of Exhibit A-12, Schedule B4. In Case No. U-20940, the Commission approved only 20% of the Company's proposed incentive compensation related to operating performance measures and directed the Company to establish a two-way cost tracking mechanism for actual incentive compensation earned in the projected test year. The pertinent section of the December 9, 2021 Order states:

> Therefore, the Commission is persuaded that DTE Gas should not recover as if it will achieve all operating measures at the 100% target level. Instead, the Commission adopts the proposal from the Attorney General to allow recovery of 20% of the incentive compensation for meeting operating metrics. In addition, the Commission authorizes DTE Gas to implement a two-way tracker mechanism, which will require refunds to customers if the 20% target level is not achieved or will allow the company to recover additional funds if it exceeds the 20% target level, up to a maximum of 100% target level. DTE shall record the over-or underrecovery, compared to the 20% base, in a regulatory asset or liability to be included in the company's next general rate case.

To arrive at the $13.3 million balance, the Company added $6,378,000 of expense to the $1,057,000 incentive compensation expense approved by the Commission in Case U-20940. The information provided in response to discovery shows that the $6,378,000 included in the deferred regulatory asset is a new calculated amount by the Company that does not conform to the amount requested by the Company in Case No. U-20940 for achieving 100% target level performance in 2022 for operating performance measures.[50] The amount forecasted by the Company in Case U-20940 was $5,286,000, consisting of the sum of $1,277,000 for the AIP and $4,009,000 for the REP, assuming the Company achieved all measures at 100% of target. This information is shown on page 53 of Mr. Cooper's direct testimony in that rate case and should be the base on which the actual performance percentage should be applied, as I discuss below in my testimony. The $6,378,000 used by the Company is incorrect and should not be adopted by the Commission.

The $13.3 million working capital balance in the deferred compensation regulatory asset also included accruals that the Company has added for 2023, and 9 months of 2024. Page 5 of Exhibit A-13, Schedule C5.6 shows the build-up of the deferred incentive compensation balance proposed by the Company. The accruals for 2023 and 2024 are premature because the Company has not provided any evidence that it has achieved 100% of the operating target measures. The direct testimony of Ms. Uzenski, who sponsors the deferred compensation regulatory asset, is devoid of any details supporting those amounts and the underlying performance goals achieved for 2023 and 2024. It is premature and unnecessary to include those amounts in the deferred regulatory asset in this rate case. The Company seeks to recover only the amortization of the incremental amount of incentive

[50] Exhibit AG-54 includes DR AGDG-7.201a.

compensation earned in 2022 in this rate case and the regulatory asset deferred amount should only reflect those incremental costs.

Q. HAVE YOU DETERMINED WHAT THE APPROPRIATE REGULATORY ASSET BALANCE AND AMORTIZATION EXPENSE SHOULD BE FOR THE DEFERRED INCENTIVE COMPENSATION AMOUNT?

A. Yes. In Exhibit AG-21, I applied the percentage of actual performance achieved for the operational performance measures in each of the two incentive plans in 2022 to the amount of incentive payout at 100% of target that Mr. Cooper had forecasted on page 53 of his direct testimony in Case No. U-20940. The result is $4,643,000 owed to the Company for 2022, which was the projected test year in Case No. U-20940. This amount is $3,586,000 higher than the $1,057,000 that the Commission approved for inclusion in rates in Case No. U-20940. The $3,586,000 is the only and proper amount that has been earned and supported and should be included in the regulatory asset and amortized over five years at an annual amount of $717,000.

Therefore, as shown in Exhibit AG-21, the regulatory asset deferred balance that should be included in working capital is $3,227,000. The Company's working capital balance of $13,310,000 is overstated by $10,083,000. I recommend that the Commission remove the $10,083,000 from the Company's forecasted working balance amount for the projected test year.

Q. YOU STATED ABOVE THAT THE DEFERRED INCENTIVE COMPENSATION BALANCE SHOULD BE AMORTIZED OVER FIVE YEARS. WHY DO YOU BELIEVE FIVE YEARS IS A REASONABLE AMORTIZATION PERIOD?

A. In her direct testimony, Ms. Uzenski proposes a three-year amortization period but does not explain or support why that short amortization period is reasonable or appropriate. In discovery, the Attorney General asked the Company to justify the three-year amortization. In response, the Company focuses on wanting to achieve a timely recovery of the deferred balance and reduce future amortization amounts if the deferred balance grows in future years.[51] Although the Company may prefer a faster recovery of the deferred expense, customers are absorbing significant cost increases in other areas of this rate case and future rate cases to come, and would certainly appreciate a more gradual amortization period of at least five years as I have proposed.

With regard to the deferred balance growing over time, it is not certain yet what level of performance the Company will achieve for the operating performance measures in coming years. Therefore, it is premature to speculate as to how much or how fast the deferred balance may grow. Nevertheless, if it were to grow significantly, a longer amortization period instead of a shorter period would be preferrable to smooth out the amount of expense that would be included in rates in future rate cases.

Furthermore, it is unknown how soon the Company will file its next rate case. With the current case, the Company waited three years to file a new rate case since the prior case.

[51] DR AGDG-7.189b.

If the Company delays filing another rate case past three years and the deferred balance is amortized over three years, the Company would continue to recover the amortization expense past the three-year period while it is no longer incurring the expense. Therefore, it is preferrable to amortize deferred balances over a longer time period to prevent cost over-recovery from occuring. By amortizing the deferred balance over five years, the Company does not forfeit recovery and any changes in the deferred balance and amortization amount would be properly adjusted and re-established if and when the Company files its next rate case.

For the reasons provided above, I recommend that the Commission approve an amortization period of five years with an amortization expense of $717,000 in this rate case.

Q. ON PAGE 35 OF HER TESTIMONY, MS. UZENSKI RECOMMENDS CERTAIN MODIFICATIONS TO THE INCENTIVE COMPENSATION TRACKER MECHANISM. DO YOU AGREE?

A. No. On page 35 of her direct testimony, Ms. Uzenski proposes three modifications. The first modification pertains to setting a new base amount of approved compensation to use for future deferral. This proposal is appropriate and should be adopted if the Commission decides to continue the mechanism. The second proposal is to include also incentive compensation related to financial measures. This proposal should be rejected. The Commission has made it clear repeatedly that inclusion in rates of incentive compensation related to financial measures is inappropriate and no convincing evidence has been provided in this rate case that the Commission should change its prior decisions.

The third proposal is to include compensation payout above 100% of target. This proposal also should be rejected. As I have stated in my testimony below in the Incentive Compensation section, several of the operating performance measures have a very low threshold to achieve payout under the plan and it is relatively easy for the Company to exceed the 100% target level without achieving superior performance. The deferral mechanism should not bypass what the Commission has previously accepted as reasonable recovery of incentive compensation capped at 100% of target.

In summary, the Commission should reject the second and third proposed modifications to the mechanism.

VI. Cost of Capital and Capital Structure

A. CAPITAL STRUCTURE

Q. **WHAT IS THE CAPITAL STRUCTURE YOU RECOMMEND FOR USE IN THE OVERALL RATE OF RETURN CALCULATION?**

A. I recommend that the capital structure shown on page 1 of Exhibit AG-22 be used in this case. Lines 1 and 3 show the projected long-term debt and common equity (the permanent capital of the Company) for the test period ending September 2025. The permanent capital balances in this exhibit reflect two changes. First, I reduced the level of common equity to $2.749 billion, which is an $82 million reduction from the Company's case. Second, I have included this $82 million amount as additional long-term debt. The result is the allocation of the total permanent capital of $5.5 billion to 50% long-term debt and 50% common equity.

Q. WHY DID YOU INCREASE LONG TERM DEBT AND REDUCE COMMON EQUITY TO ACHIEVE A 50%/50% CAPITAL STRUCTURE?

A. The Company has proposed a permanent capital structure with a common equity component of 51.5%. While this percentage is lower than the 2022 historical test year percent of 52.60%, there are other factors to consider, which are discussed below.

First, the common equity ratio of the peer group is approximately 46%. Exhibit AG-25 shows this information. It is worth pointing out that this lower average common equity level supports these companies' utility operations as well as non-utility operations, which tend to be somewhat riskier. The riskier non-utility operations require a higher common equity cushion to maintain similar credit ratings. Therefore, if we adjusted for the higher equity capital required by the non-utility businesses, the equity capital for the utility portion of the peer group's capital structure would be lower than 46%.

Second, in Case U-18999, the Commission directed the Company to develop a plan to move to a 50%/50% balanced capital structure, which I discuss in more detail below.

Third, DTE Gas is a captive subsidiary of DTE Energy. DTE Energy, which is a publicly traded company, had a permanent capital common equity ratio of 36.1% and 63.9% long-term debt at the end of 2023 and 36.5% equity to 63.5% debt at the end of 2022. DTE Energy can make the common equity ratio of DTE Gas whatever it wants. The same executive management that runs DTE Energy controls the Company's major decisions. Management can direct at any time how much in capital it wants to inject into the Company from the parent company and call it "equity capital" even though in reality it is debt. As a result, DTE Energy management has artificially set the common equity ratio of DTE Gas at nearly 52.6%, when the parent company only has a common equity ratio of approximately 36.5%. Such freedom to inject phantom equity capital in the capital structure would not exist if DTE Gas itself was a publicly traded company.

Q. **YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP USED TO ASSESS THE COST OF COMMON EQUITY IS AROUND 46%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE COMMON EQUITY RATIO FOR THE COMPANY IN THIS CASE.**

A. As shown in Exhibit AG-25, the average common equity ratio of the peer company group for 2023 was 45.7%. The cost of equity capital for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure. Thus, it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible in order to have consistency with the cost of equity capital derived from those peer group companies. The Company's proposed common equity capital ratio of 51.5% creates a disconnect that is not acceptable. Additionally, it is more costly to customers.

Q. DO YOU AGREE WITH MR. LEPCZYK'S ANALYSIS ON THE NEED FOR A 51.5% COMMON EQUITY RATIO?

A. No. On pages 11 through 17 of his direct testimony, Mr. Lepczyk makes several claims in an attempt to support his recommendation that a 51.5% common equity ratio should be approved by the Commission in this rate case. His key points are summarized below.

1. Peer equity ratios are higher
2. The capital structure is balanced if short-term debt is included
3. The Company's use of short-term debt is higher versus other Michigan utilities
4. The Company is significantly smaller compared to other Michigan utilities
5. The Company needs to maintain access to the capital markets for its large capital expenditures program.

In my testimony below, I respond to each of Mr. Lepczyk's claims.

Q. WHAT IS YOUR OPINION OF MR. LEPCZYK'S CLAIM THAT THE PEER GROUP EQUITY RATIO IS HIGHER THAN THE COMPANY'S PROPOSED 51.5% RATIO?

A. In Exhibit A-17, Schedule G-3, Mr. Lepczyk calculated a 53.8% equity ratio from a group of purported peer utilities. There are several flaws with the 53.8% ratio presented by Mr. Lepczyk. First, the exhibit states that the information presented is as of year-end 2022. After reviewing the data presented in the exhibit, I discovered that some of the information is more than a year old as of September 2022, with other underlying data as of December 2022. The equity ratios were calculated on those dates at a single point in time for each of the companies. In addition to the time inconsistency, the calculation of the equity ratios for the companies is not based on common equity and long-term debt balances over multiple periods during the most recent year. The convention when calculating a regulatory capital structure is to use a 13-month average. At minimum, Mr. Lepczyk should have used an average equity ratio over a 12-month period or over four quarters to develop an appropriate comparison to the Company's proposed equity ratio.

Second, and even more critical, the equity ratio of 53.8% does not represent the average equity ratio approved by the state commissions regulating those companies. Although the Company attempts to portray the equity ratios of the companies in Exhibit A-17, Schedule G3, as representative of the equity ratios approved in each company's rates, they are far from that. The equity ratios were calculated by the Company using equity capital balances reported by the companies in their public financial reports as of either September 2022 or December 2022 and as published by S&P Global Market Intelligence, with no further adjustments by the Company.

Third, the utility companies included in this peer group are captive subsidiaries and, as stated above, management can set the capital structure of those companies to any desired level for financial reporting and are not necessarily reflective of the permanent capital structure approved in rates.

Fourth, the peer group of companies included in Exhibit A-17, Schedule G3, includes only a select group of utilities and is not the same list of companies used by the Company's cost of equity witness in determining the cost of equity. This selective list of purported peer companies is disconnected from the capital structure and equity ratio of the peer companies used to calculate the cost of equity capital.

In summary, the common equity ratios presented by Mr. Lepczyk in Exhibit A-17, Schedule G3, are significantly flawed and the Commission should not rely on that information in setting an appropriate and balanced capital structure in this rate case.

Q. DO YOU AGREE WITH MR. LEPCZYK THAT THE COMPANY'S USE OF HIGHER AMOUNTS OF SHORT-TERM DEBT REQUIRES A HIGHER COMMON EQUITY RATIO?

A. No. In Table 4 on page 16 of his direct testimony, Mr. Lepczyk shows that the DTE Gas short-term debt is higher on a percentage basis than the short-term debt of DTE Electric and of Consumers Energy on December 31, 2022. However, there are a few problems with this comparison. First, short-term has a seasonal pattern and balances vary throughout the year. Electric utilities tend to have higher sales during the summer and late fall. The higher revenues during those periods diminish the need for short-term debt once the billed revenues are collected. In contrast, gas utilities need to finance gas inventories going into the winter months and therefore their short-term debt peaks late in the calendar year before revenue billed in December, January, and February is collected and short-term debt is paid down.

Second, the issuance of long-term debt and the timing of those issuances affect the amount of short-term debt at any point in time, as cash raised from long-term financing pays down short-term debt used to temporarily finance capital programs. The table below shows the different seasonal pattern of short-term debt balances between the electric and gas utility with the peak balance highlighted in yellow.

Short-term Debt ($ Millions)*

Quarter End	DTE Electric	DTE Gas	Consumers
Dec. 2022	$ 568	$ 242	$ 95
Mar. 2023	-	-	-
Jun. 2023	222	-	6
Sep. 2023	679	190	327
Dec. 2023	385	77*	93

Source: SEC reports on 10K and 10Q for each company.
*In October 2023, DTE Gas issued long-term debt of $295 million reducing short-term debt.

Mr. Lepczyk's claim that the Company's level of short-term should be a factor in setting the percent of common equity in the permanent capital structure is flawed and should be disregarded by the Commission.

Q. MR. LEPCZYK STATES THAT THE SMALLER SIZE OF DTE GAS COMPARED TO OTHER MICHIGAN UTILITIES JUSTIFIES A HIGHER COMMON EQUITY RATIO. DO YOU AGREE?

A. No. Certainly, compared to Consumers Energy (a combination gas and electric company) and DTE Electric, DTE Gas is a smaller company. As is generally the case, most electric utility companies are far larger than natural gas distributors. Therefore, the comparison of DTE Gas to electric utilities or combination gas and electric companies is inappropriate and not relevant in setting the equity ratio for the Company's capital structure. I will also point out that DTE Gas is far larger than the other two gas utilities in Michigan: Michigan Gas Utilities Corporation and SEMCO Energy Gas Company. Additionally, as can be easily observed from Exhibit A-17, Schedule G3, DTE Gas is the fifth largest gas utility of the 14 companies shown in the exhibit based on total capitalization. Accordingly, DTE

Gas is one of the largest natural gas distribution companies in the United States today. Therefore, the smaller size claim is another red herring.

Q. MR. LEPCZYK STATES THAT HIS PROPOSED EQUITY RATIO OF 51.5% WOULD FACILITATE ACCESS TO THE CAPITAL MARKETS TO FINANCE THE COMPANY'S CAPITAL EXPENDITURE PROGRAMS. DO YOU AGREE?

A. No. Mr. Lepczyk presents no evidence that a 51.5% equity ratio is necessary to access the capital markets or that a balanced capital structure with 50% equity and 50% long-term debt would inhibit access to the capital markets. To the contrary, as discussed later in my testimony, other utilities are able to easily access the capital markets with lower equity ratios and lower approved return on equity rates.

On page 13 of his testimony, Mr. Lepczyk alleges that a move to a 50/50 capital structure may be seen as an adverse change in the regulatory environment. However, he offers no analysis or other evidence to support that claim. The Commission has signaled its desire for a balanced 50/50 permanent capital structure for Michigan utilities for several years and in a March 2024 order in Case No. U-21389, the Commission approved a common equity ratio of 50.02% for Consumers Energy. Moreover, in the latest Moody's report on the Company dated July 25, 2023, the rating agency stated that "a rating upgrade could be possible if DTE Gas's financial metrics remain at current levels, such as the cash flow to debt ratio continuing to be in excess of 19%." Therefore, the concern by Mr. Lepczyk that rating agencies and investors would somehow interpret a balanced structure as "an adverse change in the regulatory environment" is not credible.

Q. PLEASE DISCUSS THE COMMISSION'S DIRECTIVE TO DTE GAS IN ITS ORDER OF SEPTEMBER 13, 2018 IN CASE No. U-18999 RELATING TO THE CAPITAL STRUCTURE.

A. In paragraph J on page 127 of the September 13, 2018 rate order, the Commission directed that "DTE Gas shall, in its next rate case, articulate its strategy to return to a balanced capital structure and the steps it will take to reach the goal."

Q. DID THE COMPANY ADDRESS THIS ISSUE IN TESTIMONY AND EXHIBITS IN THE SUBSEQUENT RATE CASE IN CASE U-20642?

A. No. This was a troubling omission by the Company with significant implications, particularly given the fact that both the Commission and the ALJ in U-18999 discussed this issue at length. In the discussion of this issue on pages 43 and 44 of the U-18999 rate order, the Commission stated:

> The Commission agrees with the ALJ and adopts the PFD's recommendation that the Commission should encourage DTE Gas to move to a more balanced 50/50 capital structure. As the Commission has stated, "[a] common equity ratio that is unnecessarily equity-heavy burdens ratepayers because equity capital is more expensive than debt capital and carries with it the additional expense of a tax burden that is not present with debt capital." The Commission directs DTE Gas to, in its next rate case, present its strategy for returning to a balanced capital structure and a detailed outline of the steps it plans to take to accomplish this goal. Id., p. 46. If the company is unable to do so, a more complete analysis should be included to explain why such a result is reasonable and prudent. For example, a pro-forma debt capacity analysis using rating agency methodology ratio benchmarks could be included to bolster DTE Gas' arguments.

Case No. U-20642 was concluded with a settlement agreement and the Commission did not have an opportunity to adjudicate this matter further in that rate case.

Q. WAS THE ISSUE OF DTE GAS MOVING TOWARD A BALANCED CAPITAL STRUCTURE ADDRESSED IN THE SETTLEMENT AGREEMENT FOR CASE U-20642?

A. Yes. In paragraph 12 of the Settlement Agreement, DTE Gas agreed to file a plan in the next rate case (Case No. U-20940) that would move the Company toward a more balanced capital structure.

Q. WHAT EQUITY RATIO DID THE COMPANY PROPOSE IN CASE NO. U-20940 AND WHAT RATIO DID THE COMMISSION APPROVE WITH FURTHER INSTRUCTIONS TO THE COMPANY?

A. While the Company proposed only a slight decline in common equity ratio from 52% to 51.9%, the Commission approved a 51% common equity ratio and stated the following on page 77 of the December 9, 2021 of the rate order.

> The Commission agrees with the ALJ and the Staff's proposed 51/49 equity ratio should be adopted. As stated by Staff, DTE Gas "can operate at any capital structure it chooses", and as noted by Mr. Coppola, DTE can infuse as much equity capital into DTE Gas as it sees fit. 5 TR 1682, 1856. However, the capital structure must fairly balance the interests of the company and its customers. The Commission finds that a capital structure of 51% equity and 49% debt is a reasonable transition to a more balanced capital structure.

Q. HAS THE COMPANY COMPLIED WITH THE COMMISSION REPEATED DIRECTIVES TO PRESENT A BALANCED CAPITAL STRUCTURE?

A. No. Despite the Commission's directives in Case U-18999 and subsequent orders to move to a balanced capital structure, the Company has not presented a plan to do so and is making arguments in this case for a higher common equity ratio of 51.5%, rather than the 51% approved in the last rate case. The Company continues to flaunt the Commission's repeated directives. It is now clear that, left to its own discretion, the Company will not propose a balance capital structure unless the Commission orders it.

Q. DID YOU CALCULATE THE IMPACT ON THE MOODY'S CASH FLOW TO DEBT COVERAGE RATIO BASED ON A 50% EQUITY RATIO IN THE COMPANY'S CAPITAL STRUCTURE AND AN AUTHORIZED ROE OF 9.85%

A. Yes. In Exhibit AG-30, I calculated the Company's key cash flow to debt ratio for 2022 adjusted for the ROE of 9.85% that I advocate for in this case and a 50% common equity ratio on a pro forma basis, as discussed below.

For my calculation of the 2022 pro-forma cash flow to debt ratio, I start with Moody's actual calculated ratio of 22.1% on line 1. On line 2, I adjust the debt level to a 50%/50% capital structure versus the 52.6% common equity level shown in Exhibit A-4, Schedule D1, page 1. This change results in the addition of $117 million in additional debt in determining the Company's ratio results. Also, on line 2 I adjusted the Company's earnings downward by $13 million due to the reduction in common equity and increase in debt. On line 3, I adjusted the cash flow downward to reflect my recommended 9.85% ROE versus the 11.5% ROE actually achieved by the Company in 2022. The overall pro-forma results are shown on line 4 with a cash flow to debt ratio of 19.3%. This ratio is well above the 16% sustained ratio threshold that could trigger a credit rating downgrade, as stated by

Moody's in its July 25, 2023 report.[52] I did not present any ratio results for S&P since the ratio calculations are similar and the S&P downgrade threshold is lower at 11%.

By starting with actual Moody's 2022 results, items such as leases and short-term debt are already reflected in the cash flow and debt elements to calculate the cash flow to debt coverage ratio. This analysis shows that the 9.85% ROE and 50% common equity ratio metrics positions the Company's cash flow ratios well above the threshold ratio where it could face a downgrade of its debt. Furthermore, the 19.3% I calculated is slightly above the current ratio that Moody's stated could trigger an upgrade of the Company's debt. Accordingly, Mr. Lepczyk's concerns that a 50% equity ratio would trigger a ratings downgrade are unfounded.

Q. DID YOU CALCULATE THE DIFFERENCE IN REVENUE REQUIREMENT OF INCREASING THE COMMON EQUITY RATIO FROM 50% TO 51.5%?

A. Yes. If the Commission were to adopt a 51.5% common equity level in this case, the annual revenue requirement would be higher by approximately $7.8 million. This reflects the Company's shift of approximately $81 million from long term debt to common equity capital and the difference between the Company's pretax cost of common equity of 14% versus the pretax cost of long-term debt of approximately 4%.

Q. DID YOU MAKE ANY OTHER ADJUSTMENTS TO OTHER ITEMS INCLUDED IN THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

[52] Moody's indicates this to be "16% on a sustained basis".

A. No.

B. COST OF CAPITAL

Q. **WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL DO YOU RECOMMEND IN THIS CASE?**

A. I recommend an overall after-tax return on capital of 5.82%, which includes a return on common equity of 9.85%, as shown in Exhibit AG-22.

Q. WHAT COST RATE DID YOU UTILIZE FOR LONG TERM DEBT?

A. I used the 4.44% rate determined by Company witness Lepczyk.

Q. WHAT COST RATE DID YOU UTILIZE FOR SHORT TERM DEBT AND THE OTHER COMPONENTS OF THE CAPITAL STRUCTURE?

A. For Short-Term Debt and Deferred Taxes, I utilized the cost rates recommended by Company witness Lepczyk.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-22.

A. To develop the overall cost of capital on line 12, column (f), I have first developed the percentage weighting of each capital component in column (d) by dividing the individual capital balances in column (b) by the total of all capital components in that column. Next, I have multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the values in column (f). The total of the individual values in column (f) is the total cost of capital of 5.82%.

Regarding the pretax weighted cost of capital on line 12, column (h), I have multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income and other taxes paid by the Company for calculation of the pretax weighted cost of capital of 7.20% in column (h).

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN DETERMINING THE COST OF COMMON EQUITY FOR THE COMPANY?

A. A utility company is entitled to a fair return that will allow it to attract capital and be sufficient to assure investors of its financial soundness. In its opinion in Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia (the "Bluefield Case") 262 U.S. 679 (1923), the United States Supreme Court stated that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that being made at the same time…on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties….

The principals of the Bluefield Case were re-affirmed by the U.S. Supreme Court in 1944 in the case FPC v Hope Natural Gas Company, 320 U.S. 591.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON EQUITY IN EXHIBIT AG-23.

A. Determining the cost of common equity for an enterprise or an industry group is an inexact science, since investors can only estimate what the future cash flows from any enterprise may be over time. Because of this uncertainty, most financial experts will not rely solely on any one particular method. To determine the cost of common equity, I have utilized three distinct methods. They are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and the Utility Risk Premium approach. These methodologies have previously been accepted by the Commission and have been generally accepted by regulatory commissions in other jurisdictions in the United States. Also, I have considered the circumstances in the Capital Markets in 2023 and early 2024 and any potential changes in the risk profile of DTE Gas and the economy in the state of the Michigan. While Exhibit AG-23 shows a weighted average cost of common equity of 9.81% using the three methods, I recommend an authorized rate of return on equity of 9.85% for the reasons explained later in this section of my testimony. In connection with these methods for determining the cost of common equity, I have considered the cost of common equity for a proxy group of peer companies.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROXY GROUP OF PEER COMPANIES?

A. To develop my peer group, I started with the nine gas utility companies followed by the Value Line Investment Survey in its "Natural Gas Utility Industry" section. I removed two companies from consideration for the following reasons. The companies that I removed are (1) UGI Corporation due to its foreign investments and propane investments, which is 50% of its business; and (2) Southwest Gas Holdings, which has announced that it will either sell or spin-off its large infrastructure unit — Centuri. Also, I have added Black Hills Corporation (Black Hills), which is classified by Value Line as an electric utility but which derives approximately 50% of its earnings from natural gas distribution.

The result is the group of eight companies shown in Exhibit AG-24, all of which have growing earnings and dividends.

Q. HOW DOES YOUR PEER GROUP OF EIGHT COMPANIES COMPARE TO THE COMPANY'S PEER GROUP?

A. The Company's peer group presented by witness Dr. Bente Villadsen consists of a group of 17 companies. These companies include nine water utility companies, seven of the eight gas utility companies that comprise my peer group, and Southwest Gas Holdings, which I did not include for the reason discussed above. Witness Villadsen presents these companies (1) as a gas group; (2) as a water group; and (3) as a combined group.

Q. DO YOU BELIEVE THAT THE COMPANY'S PROPOSED PEER GROUP IS APPROPRIATE?

A. No. The inclusion of the nine water companies is not necessary and should be rejected. Four of the nine water companies selected by witness Villadsen are small entities with annual revenues of approximately $200 million or less and with one as low as $53 million in revenue. In comparison, DTE Gas reported more than $1.7 billion in revenue for the year 2023.[53] Smaller companies have unique characteristics, such as low stock trading volume and illiquidity in the financial markets, which increase their cost of doing business and their cost of capital. As such, they are not appropriate comparable companies to include in a peer group for calculation of the cost of common equity in this case.

Moreover, the Company has included these water utility companies in its rate cases in recent years and in the Company's most recent fully contested rate case, the Commission stated that the inclusion of water utilities and the use of ATWACC and the Hamada approach were all inappropriate. The Commission stated:

> Accordingly, the Commission agrees with the ALJ that water utilities are not appropriately included in a proxy group for determining an appropriate ROE for a gas utility. In addition, the Commission acknowledges the Staff's and Attorney General's concern that the application of an ATWACC or Hamada adjustment may excessively inflate ROE's, stock prices, and market-to-book ratios for utilities.[54]

In addition, the common stocks of three of the nine water companies have been trading at Price to Earnings (P/E) ratios of between 25 to 37 times trailing earnings in late April 2024 and also at high market to book equity ratios well above the gas utilities in the peer group. In comparison, the common stocks of the gas utilities peer group have been trading at an average P/E ratio of 17 times trailing earnings during April 2024.

Some of the water companies are likely acquisition targets due to their smaller size and the continuing consolidation taking place in the water industry.

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[53] DTE Energy 2023 Form 10-K, page 35.
[54] Commission order dated December 9, 2021 in Case U-20940, page 91.

Q. ARE WATER COMPANIES COMPARABLE TO GAS UTILITIES?

A. No. There are significant structural differences between gas utilities and water companies. Gas companies are subject to volatility in natural gas prices, state mandated energy conservation programs, and the risk of gas explosions among other unique factors affecting the gas industry. On the other hand, water utilities do not face the same water supply price volatility, and with the exception of arid areas on the west coast, do not have state-mandated water conservation programs or similar risks as gas utilities. Because of the factors enumerated above, I find the inclusion of water companies in a gas utility peer group inappropriate, unwise, and unnecessary. The gas peer group I have proposed is adequate and appropriate.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE COMPANY'S PROPOSED WATER COMPANY PEER GROUP AND THE COMBINED PEER GROUP WITH WATER UTILITIES?

A. The Commission should reject the Company's peer groups which include water utilities and Southwest Gas Holdings due to its pending divestiture of its pipeline construction business. Instead, the Commission should adopt my proposed peer group as a better comparable group of companies for DTE Gas.

Discounted Cash Flow (DCF) Approach

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") APPROACH.

A. The DCF approach is based on the proposition that the price of any security reflects the present value of all future cash flows (dividend flows) from the security discounted at a single discount rate, which in the case of common stocks, is the required return of equity. Expressed mathematically, the resulting equation can be reconfigured to solve for the required rate of return and this equation is:

$$R = D/P + g$$

where "R" = the Required Equity Return
"D/P" = the Dividend Yield on the Security
and "g" = the expected growth rate in dividends

Generally, the "D" or dividend is known, and the "P" or stock price is also known as the stock trades each day. Also, recent growth in the dividends and earnings is known or estimates of growth furnished by stock analysts can be relied upon with some degree of certainty. With this information, one can solve for "R" which is the required rate of return.

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-24. The stock price information in column (c) on this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from February 15, 2024 March 31, 2024. The annual dividend in column (d) is the projected average annual dividend level for the 2024-2025 period as projected by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on Value Line projections of earnings per share through the year 2028 and Yahoo Finance analysts' projected growth over the next five years. The resulting calculation of the DCF Method indicates an average required return on common equity of 9.51% for the proxy group.

This result is lower than the Company's "simple" DCF study result for the gas group of 11.1%, but comparable to the Company's "multi-stage" DCF result of 9.02% calculated by witness Villadsen and shown in Figure 14 on page 43 of her testimony. It is important to keep in mind that the Company's results were determined using witness Villadsen's ATWACC process which, as discussed later, should be rejected.

Q. **PLEASE EXPLAIN WHY WITNESS VILLADSEN'S DCF COST OF EQUITY FOR THE GAS SAMPLE IS SO MUCH HIGHER.**

A. The key differences between my 9.5% DCF cost of capital and witness Villadsen's DCF estimate for the gas group at 11.1% are (a) the growth rates utilized, which bring the outcome to 10.3%; and (b) the ATWACC process, which increases the result further to 11.1%. The growth rates she uses average to 6.6%, which was determined in the later part of 2023 and are stale at this point. My DCF average growth rate of 5.4% was developed in April 2024, is more recent, and is 120 basis points lower than the Company' growth rate. Also, the inclusion of Southwest Gas Holdings with a higher growth rate contributes to the higher outcome in the Company's calculations. Witness Villadsen's pre ATWACC DCF cost of capital for her gas group is 10.3%.[55] As mentioned above, the application of the ATWACC calculations inflate the DCF ROE rate to 11.1%.

[55] Exhibit A-14, Schedule D5.7 Panel A, column 3.

Q. PLEASE DESCRIBE THE ATWACC PROCESS AND WHY ITS APPLICATION BY THE COMPANY IN THIS CASE IS FLAWED.

A. Witness Villadsen's 11.1% Simple DCF for the gas group can be explained as follows. First, in Exhibit A-14, Schedule D5.7, she computes and shows the basic DCF result of 10.3% for her peer group of gas companies.

Second, starting with the 10.3% result noted in the preceding paragraph, witness Villadsen derives a 7.8% after-tax cost of capital for the gas peer group based on the market value of each of the companies in the peer group. The 7.8% result is shown in column 10 of the Schedule D5.7, Panel A. It is important to recognize that this outcome is a function of an average common equity ratio of 63% as noted in column 4 of Schedule D5.7.

Third, on Schedule D5.8, witness Villadsen redistributes the average after tax cost of 7.8% back to the debt and common equity components based on a 51.5% common equity ratio (not the 63% common equity ratio previously used), which results in her ROE determination of 11.1%.

The key driver in this complex process of calculations is the ratio by which the stock market equity exceeds book value equity. This process of determining the After-Tax Weighted Average Cost of Capital is simply a mathematical process to drive an upward adjustment of the final ROE rate using stock market premiums over book equity values.

The resulting effect of this ATWACC approach is that higher market to book ratios in the utility industry (due to lower interest rates and other factors), if embraced by regulatory commissions, would lead to higher ROEs awarded in rate cases and a form of future bonus earnings for achieving higher stock prices for utility investors.

Also, the Commission should recognize the inherent circularity of the ATWACC process. For example, if the ATWACC approach was to become universally embraced by regulatory commissions, the ROEs awarded in regulatory proceedings would increase. The inflated ROEs would result in higher utility earnings, stock prices, and higher market to book ratios for utility common stocks. The subsequent calculated ROEs in new rate cases under the ATWACC method would then produce even higher awarded ROEs because the ATWACC would use the higher stock market equity capitalization.

Most likely, because of this cost inflating circularity and the complexity of the methodology, the ATWACC method has not been embraced in the utility industry. In fact, the Company could not cite any state regulatory commissions in the U.S. that have adopted this methodology for purposes of setting an authorized ROE in a utility rate case. According to testimony by a colleague of witness Villadsen in case No. U-18999, the instances where this methodology has been used involve (1) property taxation disputes in Colorado; (2) a valuation dispute before the FERC; and (3) revenue adequacy hearings for railroads, as well as a revenue adequacy hearing involving Alabama Power related to its special rate RSE. Therefore, the Commission should disregard the ATWACC approach in calculating the DCF cost of common equity.

Q. PLEASE ASSESS THE RESULTS OF THE DCF ANALYSIS YOU PERFORMED.

A. The DCF analysis relies upon financial market information for the dividend yield portion of the equation. However, it also relies upon judgments of growth prospects of security analysts that may or may not be consistent with the beliefs of investors. I will point out that the forecasted growth rates for the proxy group include some very high growth rates, which in some cases are as high as 7.60%.

These high growth rates appear to be the result of a temporary rebound in earnings from a low point in recent years. While these earnings may materialize in the short term, such high rates are not sustainable long-term growth rates for gas utilities given that customer and revenue growth continue to be barely in low single digits. As such, the results of the DCF analysis in some cases reflect a return on equity rate that is somewhat higher than what investors currently expect in the long term. Nevertheless, I place a fairly high degree of reliability in the DCF results when considered in conjunction with the results of other approaches to determining the cost of common equity.

<u>Capital Asset Pricing Model Approach</u>

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL APPROACH TO DETERMINING THE COST OF COMMON EQUITY CAPITAL.

A. The Capital Asset Pricing Model (CAPM) is based on the proposition that the expected return on a common equity security is a function of risk as measured by the "Beta" of that security. In equation form, CAPM is as follows:

$k_e = R_f + (B \times R_p)$ *where*

k_e = *The market cost of common equity for a specific security*

R_f = the "risk free" rate of return

R_p = the overall return of the market less the risk-free rate (over several years)

B = the systematic risk of a particular common equity security vs. the market

Q. PLEASE EXPLAIN THE BETA OR "*B*" COMPONENT OF THE EQUATION.

A. This measure of risk reflects the extent to which the price of a particular security varies in relationship to the movement of the overall market. Some securities vary less in price over time than the overall market. In these cases, the Beta will be less than 1.00. Securities that vary over time more than the overall market will have a Beta that is greater than 1.00.

Q. PLEASE EXPLAIN EXHIBIT AG-25 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-25 shows the results of the CAPM method based upon (1) a projected 30-year U.S. Treasury bond rate; (2) Beta information available from Value Line; and (3) Historical Market Risk Premium (R_p) information of 7.17% based on the Ibbotson Classic Yearbook through 2022.

As shown in Exhibit AG-25, I have added the peer group risk premium of 6.32% to the 4.1% risk-free rate to arrive at the 10.42% ROE rate under the CAPM method.

The 6.32% group risk premium is the risk premium for the total stock market of 7.17% shown in column (d) multiplied by the average beta of 0.88 from column (c). These factors are explained further in Exhibit AG-25.

Q. PLEASE ASSESS THE CAPM APPROACH.

A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios of stocks. As such, it can be useful. However, the key issue with CAPM is that is assumes that the entire risk of a stock can be measured by the "Beta" component and as such the only risk an investor faces is created by fluctuations in the overall market. In actuality, investors take into consideration company-specific factors in assessing the risk of each particular security. As such, I give the CAPM approach less weight than the DCF approach in determining the cost of common equity.

Q. PLEASE COMMENT ON WITNESS VILLADSEN'S GAS GROUP CAPM COMMON EQUITY COST RATES RANGING FROM 9.4% TO 9.9%.

A. In Figure 13 on page 39 of her direct testimony, witness Villadsen presents 4 different CAPM cost of equity estimates and 4 different ECAPM estimates for her gas sample companies. The Commission should not rely upon any of these CAPM or ECAPM results. All of the estimates have been determined utilizing the Hamada Adjustment process with non-standard betas. This method provides faulty and inflated results.

In Figure 11 on page 37 of her testimony, witness Villadsen shows the market risk premium (MRP) data she uses for her two scenarios. In Scenario 1, she uses the same 7.17% MRP that I use, which is the long-term 1926-2022 result based on the classic Ibbotson study. Scenario 2 reflects a lower 5.72% MRP rate, which she claims is based on a recent Bloomberg projection. She also notes the use of a 3.95% risk free rate. Her explanation for the development of this rate is covered on pages 34 and 35 of her testimony.

Witness Villadsen uses these data inputs and Value Line betas as shown on her Exhibit A-14, Schedule D5.10 to develop her basic CAPM estimates of 10.1% and 8.8% for her gas group sample estimates. These results are shown on her Exhibit A-14, Schedule D5.11 Panel A and Panel B. These results and the inputs used are reasonable.

However, what is not reasonable is the use of the Hamada approach in her workpaper schedules in Exhibit A-14. In this regard, she derives a non-standard beta of approximately 1.0. This non-standard beta is approximately 18% higher than her average Value Line beta average of 0.85 and this leads to the higher CAPM ROE outcome at 11.2% under her Scenario 1.

Q. WHAT IS YOUR ASSESSMENT OF WITNESS VILLADSEN'S ECAPM RESULTS?

A. First, it is worth noting that her ECAPM results have been developed using the Hamada methodology discussed earlier and are corrupted by this faulty approach. Witness Villadsen explains the ECAPM approach beginning on page 37 of her testimony. She states that research has shown that "…low-beta stocks tend to have higher risk premiums than predicted by the CAPM…." Her equation for the ECAPM is very similar to the CAPM equation except that she introduces an alpha factor into the equation at 1.5%.[56]

I will point out that the classic CAPM approach typically uses short-term treasury rates as the risk-free rate. However, most witnesses in rate cases use the 30-year treasury bond as

[56] Villadsen testimony page 39, lines 1 and 2.

the risk-free rate, which usually is higher than short-term treasury rates. Accordingly, the corrections made within the ECAPM are unnecessary.

To my knowledge, the ECAPM is not widely accepted as a cost of equity methodology among gas and electric regulatory commissions in the United States. One of the few regulatory commissions outside of the U.S. that has spoken on the subject of ECAPM is the Alberta Utilities Commission of Canada in its order of October 7, 2016. That regulatory commission noted on page 45, paragraph 199, of the order that the ECAPM *"…appears to be a model that could contribute to the Commission's determination of a fair allowed ROE…."* However, later in the same paragraph, the commission noted the high degree of judgement required by the ECAPM methodology, and reached the conclusion that "…*Consequently, the Commission will not rely heavily on the ECAPM results in this proceeding.*"

In summary, the use of the 30-year treasury rate (not short-term rates) as the risk-free rate in the CAPM method resolves the need to use the ECAPM method and the inflated results that it produces.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE COST OF EQUITY METHODOLOGIES USED BY WITNESS VILLADSEN?

A. While witness Villadsen's various methods used to calculate the cost of equity capital are inventive, they are highly unconventional and not generally accepted. The Commission should reject these alternative approaches for the reasons previously discussed and because they are clearly a brazen attempt to inflate the Company's true cost of common equity in this case.

Utility Risk Premium Approach

Q. PLEASE EXPLAIN THE UTILITY RISK PREMIUM METHOD OF ESTIMATING THE COST OF COMMON EQUITY.

A. In general, one can estimate the cost of common equity by estimating three components and adding them together. The three components are (1) the risk-free rate of return on 30-year U. S. Treasury Bonds; (2) the historical differential between yields of the rated utility bonds of the Company and the 30-year U.S. Treasury Bonds; and (3) the average return differential of utility common stocks over utility bonds.

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-26 shows the three components required to estimate the cost of common equity under this approach. The results for this approach reflect a return on common equity of 9.82%. To arrive at this result, I used the historical spread of gas utility common stock returns relative to utility bonds of 4.05%. Also, I used a 1.67% average spread for utility bonds (A rated and BBB rated) over the 30-year U.S. Treasury bond rate. This spread is the average spread of new utility bonds issued during the 12 months ended October 2020 period over 30-year U.S. Treasuries for (1) A rated bonds of 157 basis points; and (2) BBB rated bonds of 177 basis points. For the risk-free rate, I used the projected 30-year Treasury rate of 4.1% discussed under the CAPM section of my testimony.

Q. **HOW HAS THE ECONOMIC AND INTEREST RATE ENVIRONMENT CHANGED IN RECENT YEARS FOR THE COMPANY?**

A. Despite higher interest rates, the economy remains strong. Inflation has receded from approximately 8.5% in early 2022 to approximately 3% in recent months. Lower inflation and gas prices should benefit the Company in the projected test year and further interest rate decreases are expected should inflation reach nearer to the Federal Reserve Bank's 2% target.

The Company's access to the capital markets and also for its sister company, DTE Electric, is strong as witnessed by (1) DTE Gas issuing $295 million of 7-year and 12-year long-term debt with rates ranging from 5.57% to 5.73% in October 2023; and (2) DTE Electric issuing $2.9 billion of 5-year to 30-year long-term debt at rates ranging from 5.57% to 5.73% at various times in 2023.

The Company's senior secured debt is rated at A/A1 and its commercial paper program is rated P-2 by Moody's Investor Service.

Accordingly, the Company's recommendation that the authorized rate of return on common equity should be increased to 10.25% to continue to have access to capital markets is unsupported by the evidence. The proposed ROE is largely based on unconventional methodologies applied to CAPM and DCF cost of equity calculations. The results of my DCF analysis, CAPM analysis, and Utility Risk Premium Approach point to a calculated cost of equity closer to 9.81%, which I have rounded up to 9.85%.

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE GRANTED IN 2022 AND 2023?

A. Exhibit AG-29 shows the ROEs granted by state regulatory commission to U.S. gas utilities in 2022 and 2023. The majority of the 33 ROE decisions in 2022 and 36 decisions in 2023 are at rates well below 9.9%. As noted on page three of this exhibit, only 2 decisions in 2022 and 3 decisions in 2023 are at rates of 9.9% or greater. These higher rates are from California, Florida, and Michigan. ROEs in California have been over 10%, reflecting the unique challenges of that state (wildfires and earthquakes). Decisions in Florida pertain to smaller utility companies as explained in my Exhibit AG-29.

For most of the other gas utilities that have business and financial risks comparable to DTE Gas, the ROE rates have averaged around 9.50% in the past two years. This evidence supports my proposed ROE rate of 9.85% and makes the Company's current ROE rate of 9.90% somewhat excessive. The Company's proposed ROE rate of 10.25% is even further removed from reality and clearly unsupportable.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE OF 9.85% IN THIS CASE WILL LEAD TO IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?

A. No. In recent general rate case proceedings, certain rate case applicants have raised arguments that they should receive a ROE of 10% or higher to ensure the financial soundness of the business and to maintain its strong ability to attract capital in addition to being compensated for risk. Exhibit AG-29 shows several gas utilities that have accessed the capital markets at competitive interest rates since receiving a ROE near or below the average rate of 9.50%.

Similarly, there is no evidence equity investors have abandoned utilities that have been granted ROEs below 9.9%. On the contrary, stock investors continue to migrate to utility stocks, recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-28 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past few years reflecting ROEs as low as 9.3%. Yet this group of companies has an average Market to Book common equity value ratio of nearly 1.5 times.

This information is provided to dispel the myth that the Company must receive a ROE near or above 10%, or it will face dire consequences in the financial markets.

The fact that the Company needs to raise capital because of a large capital investment program to upgrade its infrastructure and for other purposes is not unique to DTE Gas. Other gas utilities face the same issues and are able to raise capital with ROEs of 9.85% or below. Therefore, this issue is another red herring.

Q. ON PAGE 52 OF ITS SEPTEMBER 13, 2018 ORDER IN CASE NO. U-18999, THE COMMISSION POINTED TO INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO AUTHORIZE A 10% ROE RATE. SHOULD STOCK MARKET VOLATILITY OR THE VIX INDEX BE A CONCERN IN ESTABLISHING A FAIR ROE RATE FOR THE COMPANY?

A. No. Witness Villadsen discusses the stock market volatility at length on pages 29 through 31 of her direct testimony, stating "A measure of the market's expectations for volatility is the VIX index, which measures the 30-day implied volatility of the S&P 500 index." She then goes on to discuss higher levels of the VIX "…in December 2018 and again in early August 2019, each time concurrent with a significant drop in the stock market…."

The stock market has historically been very volatile. In some periods, stock prices move up and down more dramatically than at other times. The key factor is that the VIX is telling us something about risk in the market over the next 30 days and not the risk several months in the future. In setting ROE rates for utilities, the Commission's focus is the long-term financial health of the utility not the short-term gyrations of the stock market.

As a second point, in Exhibit AG-31, I have included a Value Line Funds article written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not risk. For example, he also points out that volatility in 2017 was low by historical standards and it was near normal levels in 2018. Mr. Appel goes on to say later in this article that "…volatility is only risk if you act during down times, that is, only if you sell a stock."

Additionally, I will submit that those who invest money in equity portfolios over longer periods of time and particularly in utility stocks have an aversion to market volatility and the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market. This is reflected in the average Beta value of 0.88 of the utility peer group used in the CAPM discussed earlier, in contrast with the general stock market value of 1. Therefore, the Commission should not give any weight to arguments that the Company's ROE should reflect investors' concerns with stock market volatility.

Q. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE RETURN ON EQUITY RATE THE COMMISSION SHOULD USE IN THIS CASE.

A. In Exhibit AG-23, I summarized the cost of equity rates from the three methods I discussed above. The range of returns for the industry peer group is from 9.51% at the low end, using the DCF approach and 10.42% at the high end using the CAPM approach.

As explained earlier in my testimony, I give 50% weight to the DCF method as a more reliable approach to estimating the cost of equity, which from my analysis is a rate of 9.51%. In this regard, on line 4 of Exhibit AG-23, I calculated a weighted return on equity of the three methodologies using a 50% weight for DCF and 25% for each of the other two methods. The result is a weighted average cost of common equity of 9.81%. I have rounded this result upward to 9.85%.

Q. IF THE COMMISSION APPROVES A 9.90% COST OF COMMON EQUITY IN THIS CASE (AS IT DID IN CASE NO. U-20642), WHAT IS THE COST TO CUSTOMERS COMPARED TO AN ROE OF 9.85%.

A. If the Commission were to grant a 9.90% ROE in this case versus a 9.85% ROE, the additional cost to customers is approximately $2.1 million annually. There is absolutely no need to burden customers with this additional cost, when historically the Company has been earning well above its true cost of common equity.

I recommend that the Commission take note of the evidence and arguments I have presented in my testimony and grant the Company a ROE of no more than 9.85%.

VII. Revenue Adjustment

Q. WHAT ADJUSTMENTS ARE YOU PROPOSING WITH REGARD TO THE COMPANY'S FORECASTED REVENUE FOR THE PROJECTED TEST YEAR?

A. In my analysis, I have discovered that the Company's projected revenues for Gas Sales, End-User Transportation, Midstream Services, and the Appliance Service Program are significantly understated. The total incremental revenue that I propose is $19,640,000. In the testimony below I explain further the reasons for this proposed revenue adjustment.

A. Gas Sales Revenue

Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S PROJECTED LEVEL OF GAS SALES?

A. On line 14 of page 1 of Exhibit A-15, Schedule E1, Company witness George Chapel presents the Company's forecast of gas sales for the projected test year built up from the 2022 historical year. The Company has forecasted total gas sales of 159.1 Bcf for the projected test year. This level of sales represents a decrease of approximately 3.6 Bcf, or 2.2%, from the actual weather-normalized gas sales of 162.7 Bcf in 2022.

According to Mr. Chapel, the Company calculated the forecasted sales based on various regression projection models applied to customers' historical gas consumption during the two-year period from August 2021 to July 2023. The models also make use of other historical and projected data, including number of customers, weather degree days, expected energy efficiency factors, population growth, manufacturing activity, and other econometric data. Additionally, the Company included adjustments to forecasted gas sales to take into consideration the reduction in sales from its Energy Waste Reduction (EWR) program and a slight difference in the heat content of the gas (BTU factor) between the historical gas usage period and more recent data.

After reviewing the sales forecast, I have determined that the Company has significantly underestimated the gas sales volume for residential and commercial customers and the related test year revenue.

Q. WHAT IS THE BASIS FOR YOUR CONCLUSION THAT FORECASTED GAS SALES ARE UNDERSTATED?

A. In response to discovery, the Company provided actual weather-normalized gas sales and the number of customers for each year from 2018 to 2023 and for the forecasted years 2024, 2025, and the projected test year.[57] From the data provided by the Company, in Exhibit AG-32, I calculated the average weather-normalized annual gas usage per customer for each of the customer classes. The analysis on lines 2 and 3 of Exhibit AG-32 shows that from 2018 to 2023, the average annual gas usage per residential customer (Rate A) declined from 95.67 Mcf to 92.62 Mcf, or an average of 0.6% annually. In contrast, the Company has projected a decline in gas usage of 1.0% in 2024 with an

[57] The historical normalized sales are for the 12 months ended August of each year.

additional decline of 1.6% in 2025 for a cumulative decline of 2.3% between 2023 and the projected test year. The Company's projected test year sales forecast results in average annual gas usage per residential customer of 90.52 Mcf, which is the lowest level since at least 2018.

For commercial customers (Rate GS-1), the analysis on lines 11 and 12 of Exhibit AG-32 shows that the average usage per customer decreased between 2018 and 2023 from 461.91 Mcf to 446.37 Mcf. Over this period, the average annual decrease in usage per customer was 0.7%. However, the Company's sales forecast shows the average usage per customer declining 2.0% in 2024 from 2023, with a further decrease of 1.6% in 2025, for a cumulative decline of 3.3% from 2023 to the end of the projected test year. This decline comes despite the Company forecasting an increase of approximately 462 commercial sales customers from 2023 to 2025, as shown on line 34 of Exhibit AG-32. Although the EWR program pursued by the Company will have some impact on customer usage, the forecasted increase in the number of residential and commercial customers should be a mitigating factor against the loss of sales from the 1% targeted reduction in energy conservation.

Although the same or even large inconsistencies exist with the sales forecasts for the other customer classes and rate schedules, the volume difference are significantly smaller and therefore I decided not to pursue them.

However, the decline in Rate A residential and Rate GS-1 commercial sales between 2023 and the projected test year is significant, highly unusual, and unsupported.

Q. DID THE COMPANY'S FILED TESTIMONY EXPLAIN THE CHANGES IN CUSTOMER USAGE THAT YOU HAVE HIGHLIGHTED ABOVE?

A. No. In his direct testimony, Mr. Chapel describes the forecasting process for gas sales and explain major changes in the aggregate at a high level, but does not analyze, explain, or support changes in gas volumes usage between historical and forecasted periods by rate schedule or customer class. Exhibit A-15, Schedules E3 and E4, provide customer usage data for residential and commercial customers, but no analysis of the data has been provided. In discovery, the Attorney General asked the Company to provide any adjustments to the forecasted gas deliveries made outside of the forecasting models used to develop the base forecast. In response, the Company provided two external adjustments and stated that no other adjustments were made to either historical or forecasted customer sales.[58]

The first adjustment pertains to the EWR lost sales, which the Company forecasted at approximately 1% of recent historical sales. This rate of decline appears to be overly optimistic, given that over the five-year period from 2018 to 2028 the average annual gas usage for residential customers has decline by only 0.6%, or about half the EWR assumed rate of reduction. Although customer growth may have offset some of the EWR losses, the 1% EWR loss rate does not appear realistic, and it is likely understating future customer gas usage in the Company's forecast.

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[58] Exhibit AG-33 includes DRs AGDG-4.58d-e, 4.60, 4.65a, 4.65c.

The second adjustment is relatively small, pertaining to the difference in the BTU value of the gas supply, which Mr. Chapel describes on pages 13-15 of his direct testimony.

However, more concerning is the historical gas usage period selected by the Company to forecast future gas sales. As stated above, the Company used two years of historical gas usage from August 2021 to July 2023 to develop the average customer historical gas usage factors. There are two events that impacted customer usage during this period, which negatively affected customer gas usage. First, the lingering effect of the Covid-19 pandemic continued into 2021 and likely continued to depress customer gas usage during the August to December 2021 period and potentially subsequent months into early 2022. Second, in 2022 gas prices spiked considerably, more than doubling from prior years. Such a large increase in gas bills forces customers to undertake added energy conservation steps, at least temporarily, until gas prices subside, which occurred beginning in early 2023.

With the short two-year period of gas usage used in the Company's forecasting model, one or both of those events would have significantly affected the gas forecast outcome and result in gas sales being understated for the projected test year. In discovery, the Attorney General asked the Company if it had taken into consideration the lingering impact of Covid-19 or made other adjustments to the historical or forecasted sales. In response, the Company stated that no other adjustments were necessary.[59]

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[59] Id. Includes DR AGDG-4.60.

In the response, the Company also included a chart with a graph that shows the significant decline in gas usage per customers with the start of Covid-19 in early 2020 and the partial bounce back in early 2022 before a further decline in 2022 and early 2023.[60] The graph validates my analysis above that the two years of historical gas usage has understated the Company's sales forecasted.

Given those shortcomings, the Commission should not rely on the Company's forecasted sales volumes for Rate A residential and GS-1 commercial sales. As discussed below, a better approach is to use the latest year of actual gas sales and apply the actual five-year percentage decline trend that represents the net effect of sales losses from EWR and sales increases from customer additions and other changes in customer gas usage over a longer time period than two years.

Q. DID YOU CALCULATE REVISED RESIDENTIAL AND COMMERCIAL SALES, AND THE RELATED DISTRIBUTION REVENUE ADJUSTMENTS BASED ON YOUR ANALYSIS?

A. Yes. Pages 1 and 2 of Exhibit AG-34 show the calculations of the incremental volumes and revenue for the forecasted test year for Rate A residential and Rate GS-1 commercial sales customers. To arrive at the revised volumes, I started with the actual weather-normalized sales per customer for 2023 from Exhibit AG-32 and adjusted those volumes down based on the underlying average annual rate of decline in sales from the five-year period 2018 to 2023. The calculation includes those sales volume adjustments for the 9

[60] The annual data in the graph ends in August of each year.

months ending September 2024 and for the 12 months ending September 2025. The adjusted gas usage per customer for the projected test year was then multiplied by the number of customers forecasted by the Company for the projected test year.

Based on those calculations, I forecasted Rate A residential sales of 113,767 MMcf for the projected test year, which is an increase of 1,303 MMcf over the Company's forecast. Based on the current distribution rate billed to residential customers, the additional sales result in incremental revenue of $5,063,000 for the projected test year. Similarly, for Rate GS-1 commercial sales, I forecasted higher sales of 848 MMcf for the projected test year for additional distribution sales revenue of $3,227,000.

In total, the incremental forecasted revenue for the projected test year is $ 8,290,000.

B. End-User Transportation (EUT) Revenue

Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S PROJECTED LEVEL OF GAS DELIVERIES TO END-USER TRANSPORTATION CUSTOMERS?

A. On page 1 of Exhibit A-15, Schedule E7, Mr. Decker presents the Company's forecast of gas transportation volumes for the 2025 projected test year. The Company forecasted total transportation volume of 150.7 Bcf for the projected test year. This level of transportation deliveries represents an increase of 4.1 Bcf, or 2.8%, from the actual transportation volumes billed in 2022. As shown on page 2 of the exhibit, the increase is mostly due to higher deliveries to power generation plants since 2022.

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO END-USER GAS TRANSPORTATION DELIVERIES FOR THE PROJECTED TEST YEAR?

A. Yes. In Table 2 on page 17 of his direct testimony, Company witness Henry Decker shows the annual deliveries to power generation customers during the past five years and calculates an average volume of 61.5 Bcf. As shown on page 2 of Exhibit A-15, Schedule E7, the Company uses a similar volume of 61.4 Bcf for the projected test year to compare to the 56.7 Bcf actually delivered in 2022 and determine an increase of 4.7 Bcf.

In discovery, the Attorney General asked the Company to provide the latest twelve months of gas deliveries as of March 2024 to power generation customers. The information provided by the Company shows that gas deliveries to this customer segment continued to increase since the twelve months ended August 2023 volumes of 64.1 Bcf. The gas deliveries to power generation customers for the twelve months ended March 2024 were 72.4 Bcf.[61] Using this latest information, I calculated an updated five-year average of gas deliveries of 64.1 Bcf. This updated volume is 2.6 Bcf higher than the 61.5 Bcf previously calculated by the Company and included in the EUT gas delivery forecast for the projected test year.

I recommend that the Commission adopt this adjustment to increase end-user transportation volumes by 2.6 Bcf for transportation Rate XXLT.

[61] Exhibit AG-35 includes DR AGDG-4.73a.

Q. DID YOU CALCULATE THE ADDITIONAL REVENUE FOR ADJUSTMENT TO THE GAS DELIVERIES TO CUSTOMERS IN RATE SCHEDULE XXLT FOR THE PROJECTED TEST YEAR?

A. Yes. The current volumetric rate for Rate schedule XXLT is $0.1933 per Mcf.[62] After multiplying this rate by the incremental volumes of 2,600,000 Mcf, I calculated additional revenue of $503,000. I recommend that the Commission increase the Company's forecasted end-user transportation revenue by this amount.

C. Midstream Services Revenue

Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S PROJECTED LEVEL OF REVENUE FOR MIDSTREAM SERVICES?

A. In Exhibit A-13, Schedule C3.3, Mr. Decker presents the Company's forecast of revenues for Contract Storage, Park & Loan, Off-system Transportation, and Exchange Services for the projected test year. After reviewing Mr. Decker's direct testimony and responses to discovery requests, I determined that the revenue forecasts for Contract Storage and Park & Loan are reasonable. However, I found that the revenue forecasts for Off-System Transportation and Exchange Gas services are significantly understated.

Q. PLEASE DISCUSS YOUR FINDINGS WITH REGARD TO THE SERVICES THAT ARE UNDERSTATED.

[62] Exhibit A-16, Schedule F3, page 4.

A. In determining its Midstream Services forecasted revenues for the projected test year, the Company generally used a three-year average of the actual revenues billed from 2020 to 2022. In response to discovery, the Company provided actual revenues from 2018 to 2023, with 2023 being the most recent year currently available. In addition, the Company provided the monthly adjustments made to monthly gas deliveries to DTE Electric from January 2020 to May 2022, which were previously included with Exchange Gas Services and beginning in June 2022 are included with Off-System Transportation services.[63]

In Exhibit AG-37 I calculated revised forecasted revenue for Off-System Transportation revenue of $63,779,000 using the most recent three years of actual revenues (2021-2023) after adjusting for the DTE Electric volumes. This revised revenue is $3,398,000 higher than the Company's projected test year revenue of $60,381,000. Similarly, for Exchange Gas Services, I calculated revised revenues of $15,625,000 for the projected test year. This amount is $2,832,000.

I recommend that the Commission adopt these more recent revenue forecasts and increase the Company's projected test year revenues by the total amount of $6,230,000.

D. Appliance Service Program Revenue

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO THE COMPANY'S PROJECTED REVENUE?

[63] Exhibit AG-36 includes DR AGDG-4.83 and 4.96a.

A. Yes. I propose an adjustment to the Appliance Service Program's ("ASP" or "HPP") profit margin for the projected test year.[64] The profit margin is the difference between program revenues and related program expenses. In Exhibit A-13, Schedule C3, line 11, the Company forecasted the same revenue of $99.3 million for the HPP/ASP for the projected test year as it billed for 2022.

In response to discovery, the Company provided the actual revenues for the HPP/ASP from 2018 to 2023 with related operating expenses. The revenue and cost schedule with the response shows a steady increase in revenues, with 2023 revenues reaching $103.9 million, or $4.0 million above the 2022 level.[65] The schedule also shows the profit margin or net operating income between revenues and operating expenses. From this calculation, it is apparent that the year 2022 is not representative of the revenue and profit margin earned in the most recent year of 2023, or for that matter in any of the prior five years. In other words, using the 2022 revenues, operating expenses, and profit margin as a proxy for future test year amounts would result in an inaccurate and unreasonable forecast amount.

Adopting the Company's preferred approach of using the most recent revenue amount for this item, I propose to use the actual revenue of $103,901,000 for 2023 and the related operating expenses of $73,602,000 with the profit margin of $30,299,000, as the best

[64] Company witness Henry Decker discusses the Appliance Service program beginning on page 50 of his direct testimony.
[65] Exhibit AG-38 includes DR AG 4.89a with attachment.

forecast of operating income for the projected test year. This results in an increase in operating income of $4,617,000 over the Company's forecast.

Q. HAS THE COMPANY SHOWN AN INCLINATION TO UNDERSTATE THE FORECASTED REVENUE AND OPERATING INCOME OF THE APPLIANCE SERVICE PROGRAM?

A. Yes. At least in the last three rate cases, the Company has proposed to use the actual revenue amount and related operating income from the historical test year in forecasting for the projected test year. As shown from the uptrend in revenue in Exhibit AG-38, those forecasts have fallen short of actual in every case.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission adopt the 2023 revenue and operating expenses shown in Exhibit AG-38 and increase the Company's projected operating income by $4,617,000.

VIII. O&M Expense Adjustments

Q. WHAT AMOUNT OF O&M EXPENSE DID THE COMPANY INCUR DURING 2022 AND WHAT IS THE AMOUNT OF PROJECTED EXPENSE REQUESTED FOR THE 12 MONTHS ENDING SEPTEMBER 2025?

A. In 2022, the Company had total O&M expense of $523.5 million. In this rate case, for the projected test year, the Company's total O&M expense request is $616.6 million. This amount consists of three main components. First, the Company requests recovery of $43.2

million for Company Use & LAUF gas, as shown in Exhibit A-15, Schedule E8. Second, the Company requests recovery of expenses for Uncollectible Accounts of $35.1 million, as shown in Exhibit A-13, Schedule C5.7. Third, the Company is requesting recovery of $538.3 million in Other O&M expenses, as shown in Exhibit A-13, Schedule C1. The increases in expense between the historical year and the projected test year are summarized in the following table.

	Millions of Dollars		
O&M Expense Category	**2022 Test Yr.**	**Increase (Decrease)**	**Projected 2025 Test Yr.**
Company Use & LAUF	$41.4	$1.8	$43.2
Uncollectible Accounts Exp.	19.0	16.1	35.1
Other O&M	463.1	75.2	538.3
Total O&M	**$523.5**	**$93.1**	**$616.6**

In my testimony below, I discuss each of these expense categories forecasted by the Company and propose necessary adjustments. With regard to the Other O&M expense, the $75.2 million increase in expense includes $30.4 million of projected inflation adjustments and several other projected cost increases for new or expanded programs. Some of the cost increases are not adequately justified or supported and will result in proposed cost disallowances. Exhibit AG-39 summarizes the proposed adjustments discussed in my testimony.

A. Company Use & LAUF Gas Expense

Q. THE COMPANY'S PROJECTED TEST YEAR INCLUDES COSTS FOR COMPANY USE GAS AND LAUF GAS OF $19.6 MILLION AND $23.6 MILLION RESPECTIVELY. DO YOU AGREE WITH THESE PROJECTIONS?

A. No. The Company projected these costs partially based upon NYMEX gas futures prices for the projected test year, which were determined in early September 2023. Since then, gas costs have declined substantially. In response to discovery, the Company provided updated forecasted gas prices for the projected test year as of February 2024, which shows that NYMEX gas prices have fallen from $3.831 per MMBTU assumed in the rate case filing to $3.123 per MMBTU. Based on this information, the Company calculated a change in the cost of gas of $0.28 per Mcf to reflect a revised cost of gas rate of $4.10 per Mcf.[66]

In Exhibit AG-40, I applied the reduction in the cost of gas rate to the volumes forecasted by the Company to reduce the O&M expense for both Company Use Gas and LAUF Gas by $2.8 million.

Q. DID YOU MAKE ANY OTHER CHANGES TO COMPANY USE AND LAUF GAS?

A. Yes, I reduced the LAUF volume by 529 MMcf, which represents 9.8% of the LAUF gas volume forecasted by the Company for the projected test year. Many of the Company's

[66] Exhibit AG-41 includes DR AGDG-2.24 parts a and b.

witnesses discuss programs that should result in lower LAUF gas volumes. These include efforts to reduce gas theft, the replacement of aging infrastructure, and the expected implementation of new federal government rules to improve leak detection. Also, in June 2020 the Company announced an ambitious goal to reduce greenhouse gas emissions, which includes methane emissions, to net zero by 2050 and reduce greenhouse gas emissions by customers by 35% by 2050.[67]

Given the significant expenditures by the Company for infrastructure replacement and other programs, it is reasonable to expect progressively lower LAUF gas volumes in the coming years. Working toward the goal to achieve net-zero emissions by 2050 is a reasonable approach to use in forecasting reductions in LAUF gas. In this regard, the year 2050 is 28 years into the future from the 2022 historic test year. The average improvement over this 28-year period would be 3.57% (100% / 28 = 3.57%). Multiplying this 3.57% reduction rate by the 2.75 years between the historic and projected test years in this case results in a 9.8% likely savings in LAUF gas volumes in the projected test year.

The 529 MMcf adjustment multiplied by the Company's revised $4.10 per Mcf cost of gas rate results in lower LAUF gas expense of $2.2 million.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION FOR COMPANY GAS USE AND LAUF GAS EXPENSE.

[67] Henry Decker direct testimony at page 36.

A. I recommend that the Commission reduce the expense for Company Gas Use and LAUF gas from the Company's forecasted amount of $43,209,000 to $38,276,000 for a total expense reduction of $4,932,000. This includes the cost savings of $2,762,000 due to a lower cost of gas rate and the $2,170,000 related to lower LAUF volumes.

Therefore, in total I recommend that the Commission reduce the Company's forecasted expense for Company Gas Use and LAUF gas by $4,932,000 for the projected test year.

B. Uncollectible Accounts Expense

Q. PLEASE SUMMARIZE HOW THE COMPANY ARRIVED AT ITS PROPOSED $35.1 MILLION EXPENSE AMOUNT FOR UNCOLLECTIBLE GAS ACCOUNTS FOR THE PROJECTED TEST YEAR.

A. Company witness Jason Sparks discusses the uncollectible expense beginning on page 18 of his direct testimony and also sponsors Exhibit A-13, Schedule C5.7.

Exhibit A-13, Schedule C5.7, shows that the Company started its calculation of the uncollectible expense for the test year by using the methodology previously approved by the Commission of developing an average loss ratio from the most recent three years of net charge-offs to revenues and applying the loss ratio to future revenues to develop an estimate of uncollectible accounts expense. Mr. Sparks used the loss ratios for 2020, 2021, and 2022, which averaged to 1.58%, and applied this percentage to forecasted revenues for the projected test year to arrive at $33.7 million of uncollectible accounts expense for the projected test year. He then added $1.4 million (related to other revenues) to the $33.7

million to determine the $35.1 million of uncollectible accounts expense that the Company proposes to recover in this rate case.

Q. WHAT IS YOUR PROJECTED AMOUNT FOR UNCOLLECTIBLE EXPENSE FOR THE PROJECTED TEST YEAR ENDING IN SEPTEMBER 2025?

A. In response to discovery, the Company provided the most recent revenues and net charge-offs for 2023. Using this more recent information and similar data from 2022 and 2021, I calculated uncollectible accounts expense of $26,018,000 for the projected test year. Exhibit AG-42 shows the calculation. Line 4 shows the average percentage of 1.17% as the ratio of net charge-offs to revenue for the three-year historical period. This percentage is multiplied by the projected test year revenues of $2.134 billion on line 5 to derive the forecasted amount of uncollectible expense of $24,928,000 on line 6. I then added $1.1 million to the previous amount related to write-offs of amounts not included in the test year revenues which is similar to what the Company did in its projection. The result is a total uncollectible accounts expense of $26,018,000, which is lower than the Company's forecast of $35,149,000 by $9,131,000.

I recommend that the Commission adopt my forecast of $26,018,000 for Uncollectible Accounts expense and reduce the Company's O&M expense by $9,131,000.

C. Inflation and Corporate Expense Realignment Adjustments

Q. DO YOU AGREE WITH THE COMPANY'S INFLATIONARY COST INCREASES INCLUDED IN THE PROJECTED TEST YEAR O&M EXPENSE?

A. No. In Exhibit A-13, Schedule C5, the Company shows that $30.4 million of the total other O&M expense increase of $75.2 million pertains to inflationary cost increases calculated by the Company based on a blend of the Consumer Price Index (CPI) forecasted inflation rate and a 3% forecasted annual wage increase for union, non-union, and contractor employee costs. The blended annual inflation rates developed by the Company are 3.2% for 2023, 2.9% for 2024, and 2.9% for 2025, as shown on Exhibit A-13, Schedule C12. The use of a "blended rate" inclusive of wage increases has been rejected in recent general rate cases and the Commission should do so again in this rate case. Instead, the Commission has previously adopted the use of the CPI-Urban area inflation rates to forecast future cost increases when warranted.

The Commission has made it clear that it expects utilities to create cost efficiencies from the implementation of IT systems and other technology, and that those efficiencies should translate into tangible cost savings that reduce, and potentially even fully offset, future cost increases.

In that regard and in response to discovery, the Company provided actual 2023 O&M expense information with significant cost savings achieved in 2023, which I have partially incorporated in this rate case as a new base upon which to calculate CPI inflation adjustments for 2024 and to the end of the projected test year. In the discovery response, the Company reported that actual other O&M expense for 2023 was $466.1 million and after eliminations, reclassifications, and normalizations, it incurred $452.1 million of pro-forma O&M expense.[68]

In Exhibit AG-43, I used this new base of expense adjusted for $103.6 million of cost items that are not directly affected by inflation. For the resulting adjusted O&M expense base, I applied the inflation rate of 2.6% for 2024 and 2.2% for 9 months of 2025, to calculate the cumulative inflation adjustment of $14,961,000. In comparison, the Company had calculated inflation adjustment for the same 21 months of $18,962,000. The difference is $4,001,000.

The $4,001,000 reduction in inflation adjustments reflects the change from blended inflation rates to using only the CPI forecasted inflation rate and also the lower base of O&M expense for 2023 normalized and adjusted by the Company. I recommend that the Commission adopt my inflation cost adjustment and remove $4,001,000 from the Company forecasted O&M expense for the projected test year.

Q. DID YOU MAKE OTHER O&M EXPENSE COST ADJUSTMENTS FOR THE PROJECTED TEST YEAR AS RESULT OF LOWER O&M EXPENSE EXPERIENCED BY THE COMPANY IN 2023?

[68] Exhibit AG-44 includes DR AGDG-3.43 with related attachment.

A. Yes. According to the response to DR AGDG-3.43, DTE Gas took a number of measures to reduce 2023 costs due to financial challenges at both the Company and its affiliate DTE Electric Company that resulted in lower O&M expenses.[69]

Excluding Uncollectible Accounts expense and costs for Company Gas Use and LAUF gas, the base O&M expense before reclassifications and normalizations fell from $527.2 million in 2022 to $466.1 million in 2023. The decrease in expense of $61.1 million reflects primarily avoided overtime, deferred training and expenses, lower employee levels from deferred hiring, and work with contractors also being deferred. In the discovery response, the Company normalized the actual expense for 2023 stating that most of those costs would return in subsequent years, as open employee positions are filled, overtime work resumes, and contractor services are reestablished. However, even after normalizing the 2023 O&M expenses to $452.1 million, those costs are still lower than the 2022 historical normalized expenses of $463.1 million by $11.0 million.

Q. HAVE YOU INCORPORATED SOME OF THE 2023 COST REDUCTIONS INTO THE O&M EXPENSE FOR THE PROJECTED TEST YEAR IN THIS CASE?

A. Yes. In Exhibit AG-45, I compared the normalized 2023 O&M expense of $452.1 million to the Company's forecasted O&M expenses of $474.5 million for the same year to calculate O&M expense savings of $22,431,000, which should be included in the projected test year. The Company's previously calculated O&M expense of $474.5 million for 2023 started with 2022 adjusted O&M expense of $463.1 million and added $11.5 million of

[69] Id.

inflation at the blended rate of 3.2%, to arrive at the forecasted 2023 O&M expense of $474.5 million.

Based on the actual normalized 2023 O&M expense of $452.1 million recently provided by the Company in response to DR AGDG-3.43 (Exh. AG-44), the $474.5 million forecasted by the Company is no longer reasonable. The latest information provided by the Company shows that the projected test year O&M expense filed by the Company and built-up from a stale 2022 base is overstated by $22,431,000.

Therefore, I recommend that the Commission removed this additional amount of $22,431,000 from the Company's projected test year O&M expense.

Q HAS THE COMPANY INITIATED ADDITIONAL COST REDUCTIONS IN 2024 THAT WILL FURTHER REDUCE O&M EXPENSE IN THE PROJECTED TEST YEAR?

A. Yes. In response to discovery, the Company stated that in January 2024, it offered a Voluntary Separation Incentive Plan to 422 DTE Gas employees and 1,622 DTE Corporate Services employees. Of those eligible employees, 42 DTE Gas employees and 249 Corporate Services employees accepted the separation plan, with employee reductions occurring during the first half of 2024. In the discovery responses, the Company also stated that up to $6.3 million of labor cost savings could be achieved in 2025.[70] The $6.3

[70] Exhibit AG-46 includes DR AGDG-4.49a-c.

million does not include employee benefit savings from lower active health care costs, 401K plan matching, and other benefits.

However, conservatively, I have included only half, or $3.2 million, of the currently estimated labor cost savings of $6.3 million as a reduction to the O&M expense for the projected test year. I recommend that the Commission accept this additional adjustment of $3.2 million to the forecasted O&M expense for the projected test year.

D. TIMP Pipeline Integrity

Q. PLEASE DISCUSS THE COMPANY'S TIMP PIPELINE INTEGRITY EXPENSE FOR THE HISTORICAL AND PROJECTED TEST YEAR.

A. Witness Kehoe discusses Transmission Pipeline Integrity on pages 18 and 19 of his testimony. For the historical 2022 period, the Company had expenses of $16.3 million for TIMP Pipeline Integrity.[71] For the projected test year, the Company forecasted expenses of $23.0 million, which is a $6.7 million increase over 2022. In Case No. U-20642 and specifically on page 14 (lines 16 to 23) of his direct testimony, witness Mark Johnson stated that the Company would be ramping up expenses in this area to get on a "seven-year inspection cycle" and increase the number of miles inspected by ILI.[72] In Exhibit A-13, Schedule C5.2, in Case No. U-20642, the Company forecasted an increase of $8.4 million for TIMP Pipeline Integrity for the projected test year ended September 2021 from

[71] Transmission Integrity Management Program (TIMP).
[72] ILI is a pipeline In Line Inspection electronic tool that provides information on the internal characteristics and integrity of the pipeline inspected.

the 2018 historical expense of $10.3 million. This should have placed the total expense at more than $18 million for the 12 months ended September 2021.

However, the forecasted ramp up in TIMP Pipeline Integrity expense has not materialized as forecasted. In response to discovery request AGDG-4.128b in case U-20940, the Company reported only $10.3 million of expense in 2020 and 13.5 million for 2021. This was after the Company had increased the expense level to just over $17 million in 2019.

Since 2021, when expenses reached $18.6 million, the Company has steadily reduced pipeline inspection costs to $16.3 million in 2022 and $8.6 million in 2023 with the number of inspections dropping from 12 in 2021 to only 4 in 2023.

The Company has not made a consistent commitment to a higher expense level in order to achieve the 7-year inspection cycle and will likely spend less than it requested in Case No. U-20642. This lack of consistency in spending to achieve the 7-year inspection cycle undermines the Company's credibility about its expense forecast of $23.0 million for the projected test year in this rate case. In connection with the Company's 2023 O&M expenses discussed above, the Company provided normalized Transmission pipeline inspection expenses of $16.6 million for 2023 after a normalizing adjustment of $7.5 million.[73]

The normalized expense for 2023 is $1.5 million higher than the average expense of the past three years. The $23.0 expense level forecasted by the Company for the projected

[73] Exhibit AG-44 includes DR AGDG-3.43 and the attachment showing Transmission expenses.

test year is not credible and not likely to be incurred given the historical record discussed above. Therefore, I recommend that the Commission reject the expense increase of $6.7 million from 2022 to the projected test year and remove this amount from the Company's forecasted test year O&M expense.

E. MAOP Records Remediation Expense

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED MAOP EXPENSES FOR THE PROJECTED TEST YEAR AND ANY REQUIRED ADJUSTMENTS.

A. Beginning on page 35 of his direct testimony, Mr. Janness discusses federal rules that require the Company to undertake a records review of its pipelines' MAOP to resolve records defects, including reaffirmation of MAOP if the Company does not have traceable, verifiable, and completed (TVC) records. Mr. Janness discusses the steps that the Company is taking to validate its records and take remediation action. In discovery, the Attorney General asked the Company to identify what deficiencies, inaccuracies, and other problems the Company has discovered in reviewing the pipeline records to reestablish MAOP. In response, the Company stated that it has identified pressure test records that are from incomplete to missing and also discovered other pipe material records issues. In a related discovery response, the Company stated that to review and remediate its records it plans to spend $1.3 million in 2024 and $1.9 million in 2025.[74] From these amounts, I

[74] Exhibit AG-50 includes DR AGDG-6.17a and b.

calculated the projected test year O&M expense included by the Company in this rate case to be $1,750,000.

Q. WHAT IS YOUR ASSESSMENT OF THE COSTS THAT THE COMPANY IS INCURRING TO ASCERTAIN IT HAS TRACEABLE, VERIFIABLE, AND CORRECT RECORDS TO REESTABLISH MAOP ON CERTAIN OF ITS PIPELINES?

A. As a result of federal regulatory requirements, the Company must verify that it has sufficient records to ascertain the physical and operational characteristics of its gas transmission pipelines in High Consequence Areas and be able to verify that its records can substantiate the MAOP. Where gaps in records exist, the Company must remedy the shortfalls by performing physical inspection of the pipeline, including reestablishing its MAOP through pressure tests and other procedures.

Although the requirements that transmission pipeline operators have adequate records to verify the MAOP and other pipeline operating characteristics was preliminary issued in 2011, it does not mean that DTE gas should not have kept adequate records of the construction of its pipelines and facilities prior to that date. This includes records of pressure tests performed before placing those pipelines and facilities into service. The requirements now imposed by PHMSA are basic operating requirements to ensure the safe installation and operation of high-pressure facilities, going back to the 1960s, 1950s and even prior decades.

The Company has the sole responsibility to ensure it maintains adequate records of its pipelines and related facilities, both now and in the past. The fact that adequate records do not exist is not a problem that should be remedied entirely on the backs of customers. Although a strong argument can be made that the cost to remedy the record gaps should be entirely absorbed by the Company, it is fair and reasonable for the Company to absorb at least 50% of the cost and recover the other 50% in base rates, as an accommodation for the long passage of time since the pipeline was installed.

Therefore, I recommend that the Commission remove $875,000 (50% of $1,750,000) from the O&M expense proposed by the Company for the projected test year.

F. Leak Detection and Repair (LDAR) Expense

Q. PLEASE DISCUSS THE ADJUSTMENT YOU PROPOSE TO O&M EXPENSE FOR THE PROJECTED TEST YEAR FOR THE NEWLY PROPOSED OR EXPANDED LDAR PROGRAM.

A. On pages 45 through 47 of his direct testimony, Mr. Kehoe briefly discusses the anticipated notice of rulemaking from PHMSA that will likely require the Company to undertake a more extensive program to detect and repair gas leaks. In Table 24 on page 47 of his testimony, he identifies $10.3 million of incremental O&M expense included in the projected test year. As I stated above in my testimony on this same program under the Capital Expenditures section, it is still unknown when the new rule will be issued and how soon thereafter the Company will be required to be fully comply with the requirements within the new rule. Even if the Company's expectations of an initial implementation date of March 1, 2025 were to occur, it will not likely be able to fully implement and spend the entire $10.3 million by the end of project test year ending in September 2025, which is only seven months after the initial implementation date.

Furthermore, the Company has not presented a comprehensive implementation plan that takes into consideration the leak detection and repair program that the Company currently has in place. As stated above in my testimony, the Company is currently spending about $20 million annually on leak detection and repairs that are charged to O&M expense. The Company has not explained why some or all of those costs cannot be redirected to comply with the new rule in 2025, if it becomes effective then, or why an additional $10.3 million of expense will be needed for the last seven months of the projected test year.

The Company has not adequately supported the need for the additional $10.3 million of O&M expense for the LDAR program or made a convincing case that those additional expenses are needed in the projected test year. Therefore, I recommend that the $10.3 million be removed from the Company's forecasted O&M expense in the projected test year.

G. Health Care Costs

Q. THE COMPANY FORECASTED THAT ITS ACTIVE EMPLOYEE HEALTH CARE EXPENSES (MEDICAL, DENTAL, AND VISION) WILL INCREASE FROM $18.1 MILLION IN 2022 TO $22.0 MILLION IN THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS INCREASE?

A. No. The forecasted health care O&M expense to $22.0 million for the projected test year represents a cumulative increase of approximately 21% from the adjusted actual expense of $18.1 million in 2022.[75] Mr. Cooper accomplishes this feat by taking a novel and unorthodox approach to forecasting health care costs. First, he determines an average cost per employee of $10,897 by adjusting 2018 to 2022 costs through a "constant dollar normalization" process to establish a base cost for 2022.[76] This involves escalating actual costs from 2018 to 2021 by national average health care trend rates of between 4.0% to 5.7%. It is important to point out that Mr. Cooper's constant dollar average is $759 higher per employee than the Company's actual cost per employee. Second, he multiplied the $759 cost per employee by 2,809 employees to arrive at a $1.336 million dollar adjustment after allocating 62.7% of the total amount to O&M expense and the rest to capital costs. Third, Mr. Cooper added the $1.336 million to the actual 2022 cost of $18.1 million to produce an adjusted historical 2022 cost of $19.4 million. Fourth, he then further escalated the 2022 adjusted cost by 5.1% for 2023, 5.0% for 2024 and by 4.0% for 2025.

Q. WHAT IS YOUR ASSESSMENT OF THE CALCULATIONS PERFORMED BY MR. COOPER AND THE RESULTING FORECAST?

A. The problem with Mr. Cooper's analysis and calculations is that the $10,897 constant dollar adjusted cost per employee for 2022 is divorced from reality. This amount is 7.5% higher than the actual cost of $10,138 for 2022. Mr. Cooper is simply compounding

[75] The $18.1 million excludes cost savings achieved in 2023 due to a temporary cost reduction initiative, which resulted in active medical costs decreasing to an actual amount of $16.5 million.
[76] Actual costs per employee are escalated by PWC trend rates as shown on Exh. A-13, Sch. C5.9.3.

inflationary increases on top of inflationary increases over the seven-year period from 2018 to 2025. The Commission should not accept this brazen attempt to inflate forecasted O&M expenses. In fact, the Commission has repeatedly rejected Mr. Cooper's methodology in previous rate cases for the Company and DTE Electric Company.

Q. HAVE YOU CALCULATED A MORE APPROPRIATE EXPENSE FOR HEALTH CARE FOR THE PROJECTED TEST YEAR?

A. Yes. In Exhibit AG-47, I calculated a forecasted expense of $17,157,000 for the projected test year. To arrive at this amount, I used information obtained from Exhibit A-13, Schedule C5.9.3, which has the cost of health care from 2018 to 2022. As can be seen from my exhibit, the annualized increase in the Company's costs is 2.4% between 2018 and 2022. The 2.4% average rate of increase already reflects any inflationary increase in costs year over year as actually experienced and therefore it is not necessary to further inflate it as Mr. Cooper has done.

Using the 2.4% annual rate of increase and applying it to the actual costs in 2023 of $16.5 million for subsequent years through the end of the projected test year, I calculated the forecasted expense at $17,157,000 after allocating a portion of the costs to capital expenditures. This is a reasonable forecast of health care expense for the projected test year based on actual cost trends. In contrast with the Company's artificially derived expense of $22.4 million, I recommend that the Commission remove the difference of $4,884,000 from the Company's forecasted test year O&M expense.

It is also noteworthy to point out that while starting with actual 2023 to determine the projected test year expense level captures the savings in Health Care costs due to the 2023 cost reduction initiative, it does not reflect the savings related to the Voluntary Incentive Separation Plan which became effective in 2024. As such, my forecast may be still somewhat overstated but is certainly far more reasonable than the forecast proposed by the Company.

H. Rents - Capital Use Charges

On line 15 of Exhibit A-13, Schedule C5.6, the Company shows forecasted Rents expense (capital use charges) of $56.1 million. This amount represents an increase of $4.8 million, or 9%, over the 2022 adjusted historical period. In response to discovery, the Company reported that the forecasted expense in this area was based on forecasted costs in the DTE Electric rate case, which the Commission reduced in its rate order in that rate case. The Company reported that the expense for Rents was overstated by $2.5 million.[77] Therefore, I recommend that the Commission remove this amount from the Company's forecasted O&M expense in this rate case.

I. Deferred Incentive Compensation Amortization

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED AMORTIZATION EXPENSE OF THE DEFERRED INCENTIVE COMPENSATION COSTS?

A. No. As shown in Exhibit A-13, Schedule C5.6, page 5, the Company proposes to recover $1,774,000 of amortization expense in the projected test year related the amount of

[77] Exhibit AG-48 includes DR AGDG-2.36b and d.

incentive compensation recorded in a regulatory asset account. As discussed in the Working Capital section of my testimony and shown in Exhibit AG-21, I propose an amortization expense amount of $717,000. This amount is $1,057,000 lower than the Company's proposed amount. For the reasons discussed in the Working Capital section of my testimony, I recommend that the Commission remove the $1,057,000 of excess amortization expense from the Company's O&M expense for the projected test year.

J. Incentive Compensation Expense

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S INCENTIVE PAY PLANS AND THE AMOUNT OF EXPENSE THE COMPANY SEEKS TO RECOVER IN THIS RATE CASE.

A. In this rate case, the Company seeks to recover $18.5 million of employee incentive compensation in O&M expense, which has been included in the projected test year.[78] Based upon the information provided by the Company, $3.1 million pertains to the Annual Incentive Plan (AIP), $9.5 million pertains to the Rewarding Employees Plan (REP), and $5.9 million pertains to the Long-Term Incentive Plan (LTIP). I will also point out that 62% of the $18.5 million requested is to recover costs related to the DTE Corporate Services LLC employees (the LLC employees), whose performance metrics are often related to the performance of DTE Energy (not just DTE Gas).

[78] Page 56 of Michael Cooper's revised direct testimony shows approximately $18.5 million of O&M expense for incentive compensation. The revised table does not show any column headings pertaining to each plan. I assumed that the same headings applied from Mr. Cooper's original testimony.

2023 Annual Incentive Plan – the AIP is an annual bonus program focused on the following major categories and specific measures:

1. 40% on Financial Performance: For DTE Gas employees the metrics are DTE Gas Operating Earnings, DTE Gas Adjusted Cash Flow, and DTE Energy Earnings per Share). For the LLC employees in this plan, the financial metrics are 100% dependent upon DTE Energy EPS and DTE Energy Cash Flow.

2. 20% on Customer Satisfaction (Net Promoter Score and MPSC Customer Complaints).

3. 15% on Employee Engagement (Employee Engagement Gallup rating, OSHA Incident Rate, and DTE Energy high energy, serious injury/fatality prevention).

4. 25% on Operating Excellence (Gas Open Leak balance, Gas Distribution response time, percent of HCA miles assessed with TVC, pressure test records remediated).

It should be noted that the LLC employee metrics for Customer Satisfaction and Employee Engagement are dependent on all of DTE Energy performance (not that of just DTE Gas).

These measures are for the year 2023. A review of the measures in place for the prior five years reveals that certain measures and target levels have varied from year to year. These changes make a direct comparison over the years more challenging.

2023 Rewarding Employees Plan – The REP is very similar in design and function to the AIP with some variations in the non-financial measures. Where the AIP is designed for senior level managers at DTE Gas and its affiliates, the REP covers all other non-union employees of these companies.

The REP is also applicable to the LLC employees providing support services to DTE Gas.

2023 Long Term Incentive Plan – The LTIP is an annual stock grant plan focused on achieving three-year goals and specifically on the following measures:

1. 80% on Common Stock Total Shareholder Return vs. a Peer Group.
2. 20% Three Years Cumulative Operating EPS.

The testimony of Company witness Michael Cooper provides more details on the AIP, REP, and LTIP.

Q. WHAT IS YOUR ASSESSMENT OF EACH OF THESE INCENTIVE PAY PLANS?

A. My overall assessment is that the three incentive plans are too heavily skewed toward measures that directly benefit shareholders and not customers. Additionally, the customer benefits presented by the Company are based on a faulty premise of historical cost savings and an expectation that future targets of performance will be achieved.

With regard to the AIP and REP, nearly half of the incentive payout at target level relates to the Company and its parent, DTE Energy, achieving net income, earnings per share, and cash flow goals. Despite the argument by the Company that achieving these goals somehow benefits customers, there is no direct relationship to customer benefits. These goals are in place to maximize profits and increase cash flow to pay dividends to shareholders. It is even more inappropriate to charge customers for incentive pay costs related to achieving DTE Energy earnings per share since those earnings include earnings from the electric and non-utility businesses of DTE Energy. The Commission should not allow recovery of incentive payments related to these financial goals.

As to the Customer Satisfaction grouping of measures, this category in 2023 represents 20% of the total measures. However, as shown in Exhibit A-19, Schedule I5, the benefits achieved are far less than the costs as measured by the Company.

With regard to the Employee Engagement category, the measures contained therein do not rise to the level of being measures that are visible to customers nor do they create direct customer benefits. They are primarily internal goals related to employee satisfaction and deployment of safe practices in the workplace.

As to the Operating Excellence category, the measures contained therein are basic operating goals. Again, they have no direct visibility to customers. The only measure that has a visible link to customers is the Gas Distribution Response Time metric, which represents a small portion of the expected payout.

Q. **WHAT IS YOUR ASSESSMENT OF THE LTIP?**

A. The LTIP is a plan strictly designed to induce management to create shareholder value. It is weighted heavily (80%) on total shareholder return for DTE Gas employees and 80% in the case of the LLC employees, which is stock price appreciation and dividends paid over a period of time. The Company's total return is then measured against a group of peer companies to trigger a payout. This has nothing to do with creating direct benefits for DTE Gas customers and everything to do with creating value for DTE Energy shareholders. Similarly, the other measure which is three-year cumulative operating EPS is also very removed from any quantifiable benefits that directly accrue to customers.

The arguments put forth by Mr. Cooper in his testimony that some of these measures will create a financially healthier company and therefore customers should pay for LTIP expenses are not convincing.

Q. **WHAT IS YOUR OPINION OF THE CUSTOMER BENEFITS CALCULATED BY MR. COOPER TO JUSTIFY RECOVERY OF THE INCENTIVE PAYMENTS?**

A. In Exhibit A-19, Schedule I5, Mr. Cooper presents a calculation which purports to show that the expected operating and financial cost savings in 2023 of $21.2 million will exceed the incentive plan payments by $2.8 million.

Although the Operating Excellence cost savings appear to exceed the allocation of incentive expense allocated to these measures, actual results are doubtful. For example, in 2023, the Company engaged in large cutbacks in operating expenses for its own internal reasons and its ability to achieve these non-financial metrics may have been impaired.

The Company's claim that it has realized cost savings by preventing higher interest rates by managing its credit ratings is unconvincing. It is management's basic task to manage the finances of the Company so as to maintain healthy credit ratings without an incentive to do so.

Mr. Cooper's calculated benefits for Customer Satisfaction and Employee Engagement have been determined by considering avoided costs related to customer complaints, lower employee absenteeism, higher productivity of employees, as well as fewer safety incidents. Unfortunately, the Company has generally fallen short of its performance targets in these areas.

Q. **WHAT IS YOUR RECOMMENDATION WITH REGARD TO INCENTIVE PAYMENTS BEING RECOVERED IN CUSTOMER RATES?**

A. Page 56 of Mr. Cooper's revised testimony shows the components of the incentive compensation expense that the Company has included in its O&M expense for the projected test year, which includes $12.1 million pertaining to financial measures. For the reasons described above, I recommend that the Commission remove the entire $12.1 million related to financial performance measures.

With regard to the portion of incentive compensation relating to operating measures, my initial instinct is to also disallow this portion in its entirety, as I have recommended in prior cases due to the fact that the Company has not made a sufficiently compelling case to justify recovery of these costs. However, I am cognizant of the fact that the Commission has recently allowed recovery of a portion of the short-term incentive pay related to operating performance measures for DTE Gas, DTE Electric, and Consumers Energy.

In that vein, I recommend that the Commission allow recovery of only 55% of the incentive compensation expense that the Company has identified pertaining to operating performance measures. The 55% represents the percentage of performance measures that have been achieved at target level or higher over the past five years from 2019 to 2023. In calculating the incentive compensation expense in this rate case, the Company has assumed in that it will achieve the target level for all operating performance measures. The last five years of actual performance results show that the Company was able to achieve target level performance only 55% of the time with certain years as low as 36% and some years as high as 89%. Exhibit AG-49 shows the source data provided by the

Company and the calculation of the level of the annual performance achieved at target or better along with the overall average percentage rate for the five years at the bottom of the schedule.

The Company calculated $6.4 million of incentive compensation related to operating performance measures per Mr. Cooper's revised direct testimony. However, as stated earlier, this amount assumes that 100% of the operating measures will be achieved at the 100% target level. I recommend that the Commission allow recovery of only 55% of the $6.4 million, or $3.5 million, and disallow the remaining $2.9 million.

Therefore, in total, the Commission should deny recovery of $15.0 million in incentive compensation expense proposed by the Company ($12.1 million related to financial measures and $2.9 million of operating measures).

K. Deferred OPEB Negative Expense

Q. PLEASE DISCUSS YOUR CONCERN WITH THE OPEB NEGATIVE EXPENSE THAT THE COMPANY HAS DEFERRED AND RECORDED TO A REGULATORY LIABILITY ACCOUNT.

A. Several years ago, the Company closed the OPEB retiree healthcare plan to new retirees and established a new Retiree VEBA Plan. As a result of this change and other changes to the OPEB plan, the Company has been reporting negative expense in recent years. Instead of recording the negative expense against current O&M expense, subsequent to a rate case order, the Company began to record the negative expense to a regulatory liability account. As of December 2023, the regulatory deferred liability account balance is $68,123,000. The liability balance through additional negative OPEB expense is forecasted to grow to $81.3 million by the end of December 2025.[79]

At the time when the deferred regulatory liability was proposed, the expectation was that in future years positive expense would offset the negative balance over the coming year. However, this phenomenon has not occurred. Instead, the liability balance continues to grow. In response to discovery, the Company stated that OPEB expense will likely continue to be negative through at least 2030.[80] With the new VEBA and a declining retiree base in the OPEB plan, it is more than likely that the OPEB expense will continue to be negative for many years to come and the regulatory liability will continue to grow past December 2025.

Q. WHAT DO YOU PROPOSE TO DO WITH THE LARGE NEGATIVE EXPENSE RECORDED TO THE REGULATORY LIABILITY ACCOUNT?

A. With the large increase proposed by the Company in this rate case, it is not fair or reasonable for the Company to continue to defer the OPEB negative expense and not pass through to customers a portion of the deferred regulatory liability balance in this rate case and continuing into the future.

Therefore, I propose that the Company begin to amortize the balance of $68,136,000 as of December 2023 over a seven-year period and include the resulting amortization expense

[79] Exhibit AG-51 includes DR AGDG-7.191a with attachment showing the growing liability balance.
[80] Id., includes DR AGDG-7.191b.

of $9,734,000 in the projected test year as a reduction to O&M expense. I chose a seven-year amortization as a reasonable period that will gradually reduce the liability balance and still retain a sufficient negative balance in case OPEB expense reverses from negative to positive.

In rebuttal, the Company may raise the issue that the OPEB negative expense is a non-cash item and will impact the Company's cash flow and also raise concerns with the rating agencies. Those concerns have been raised before and are not significant enough to continue to defer the negative expense indefinitely. The seven-year amortization period minimizes any impact on cash flow. It should be noted that the amortization of the OPEB liability account balance is akin to the amortization of deferred taxes that resulted from the TCJA of 2020 and is still continuing.

Therefore, I recommend that the Commission approve this proposal and accordingly reduce the Company's projected O&M expense for the projected test year ending September 2025 by $9,734,000.

Q. DID THE COMMISSION RECENTLY APPROVE A SIMILAR PROPOSAL?

A. Yes. In Case No. U-21297, I made a similar proposal in the DTE Electric rate case and the Commission found merit to the proposal and approved it. My proposal in this rate case is the same and I recommend that the Commission approve it as well.

L. Credit/Debit Card Merchant Fees

Q. ARE YOU PROPOSING ANY CHANGES TO THE COMPANY'S CREDIT/DEBIT CARD PAYMENT PROGRAM OR ADJUSTMENTS TO RELATED O&M EXPENSE?

A. Yes. The Company currently allows residential and commercial/industrial (non-residential) customers to pay their gas bills with a credit or debit card. Until about 2016, the Company charged the customer a convenience fee to use a credit or debit card given the high fees required by merchant banks and institutions that issue credit/debit cards. On or about 2016, the Company removed the convenience fee and since that time we have seen an explosive growth in the use of credit/debit cards by customers. For DTE Gas, merchant fees reached nearly $7.1 million in 2021 and have ebbed somewhat in the past two years after the Company imposed certain limitations on the use of credit/debit cards by non-residential customers.

Beginning on page 60 of his direct testimony, Mr. Decker discusses the recent history of debit/credit cards and presents data on merchant fees paid by the Company. Although, the Company in recent years began to limit the use of credit/debit cards for non-residential customers, the cost is still rather significant. For the projected test year, the Company forecasted $4,042,000 in merchant fees pertaining to residential customers and $2,218,000 for non-residential customers, for a total forecasted expense of $6,260,000.

Q. WHAT IS YOUR PROPOSAL?

A. I propose that the Commission disallow recovery of merchant fees for non-residential customers beginning with the costs included in the projected test year in this rate case. This proposal will remove $2,216,000 from forecasted expense for the projected year. Non-residential customers, which consists primarily of small to medium size commercial and industrial businesses, have more options and sophistication than residential customers to pay their gas and electric bills through other less costly means, such as Electronic Funds Transfer (EFT) and Automatic Clearing House (ACH). In response to discovery, the Company reported that an EFT or ACH transaction charge is approximately 10 to 11 cents. In contrast, the merchant fee for the use of a credit/debit card for non-residential customers is $4.72 per transaction.[81] This large disparity in cost is not reasonable and should be avoided.

In late 2023, Consumer Energy came to the realization that removing the credit/debit card convenience fee previously charged to customers was neither sustainable nor in the best interest of the majority of its customers due to the large escalation in merchant fees. Beginning in 2024, Consumers Energy reimposed a convenience fee for all customers, both residential and non-residential, who want to use a credit card. This is a step that the Company should evaluate in coming months and address accordingly. With the large escalation in merchant fees in recent years, more businesses from restaurants to retail shops are imposing a convenience fee when customers pay for goods and services with a credit

[81] Exhibit AG-52 includes DR AGDG-4.93c. The $4.72 merchant fee is stated on page 61 of Mr. Decker's direct testimony on line 16.

card. Of course, gasoline stations placed a premium on gasoline sales with a credit card long ago.

Therefore, at this time, I recommend that the Commission disallow recovery of the $2.2 million of merchant fees pertaining to non-residential customers so that the Company can take appropriate actions to avoid those costs beginning with the projected test year in this rate case.

M. Corporate Jet Travel Costs

Q. PLEASE DISCUSS THE INCLUSION OF CORPORATE JET TRAVEL COSTS IN O&M EXPENSES FOR THE PROJECTED TEST YEAR.

A. In discovery, the Attorney General asked the Company to report cost and use of privately hired corporate jet aircraft by Company employees or employees of the parent company and affiliates who bill the Company for reimbursement of those costs. In response, the Company reported that it leases a fractional share of an aircraft for use by executives at the Vice President level and above for business travel.

The information provided by the Company shows that several executives of the Company, DTE Electric, and DTE Energy, along with certain members of DTE's Board of Directors, took 16 trips on the corporate leased aircraft in 2022 to investor and security analyst meetings and conferences, as well as to out of state Board of Directors meetings. The portion of the cost billed to the Company in 2022 was $68,910. No information was provided about 2023 costs and travel activity, although the information was requested. In the response the Company stated that $74,769 of expense was included in the projected test year in this rate case.[82]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission disallow recovery of costs for privately-hired corporate jet use, particularly since the travel pertains to investor and board of director matters that do not directly benefit customers but instead may benefit shareholders. Although commercial flights may be less convenient, they are less costly and less impactful on the environment relative to the emissions of private jets for the few individuals that they carry. In 2020, DTE Energy announced its goal of achieving net zero emissions by 2050. Private jet travel certainly goes counter to that goal.

Therefore, I recommend that the Commission remove the $75,000 of costs that the Company reported it included in the projected test year.

N. Responsibly Sourced Gas Expense

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL TO RECOVER FROM CUSTOMERS THE PREMIUM PAID FOR RESPONSIBLY SOURCED GAS (RSG).

A. Beginning on page 35 of his direct testimony, Mr. Decker discusses the Company's proposal to purchase RSG at a premium over other competitively bid gas prices. Mr.

[82] Exhibit AG-53 includes DR AGDG-4.50.

Decker presents this proposal as part of the Company's corporate goal to reduce greenhouse gas emissions by 35% by 2050, from unspecified levels in 2005.

Mr. Decker's direct testimony in this rate case generally mirrors the direct testimony of other Company witnesses on this matter in Case Nos. U-21064 and U-21271. In Case No. U-21064, the Commission warned the Company that the RSG premiums paid for gas purchases were not likely to be recovered in the Gas Cost Recovery reconciliation case. In the order in that case, the Commission suggested that the Company try to make a case to recover the premiums paid in a general rate case. It appears that the Company has decided to make its attempt for recovery of RSG premium costs in this rate case. The costs that the Company seeks to recover in this rate case are $180,000. As discussed later in my testimony, this would only be the beginning of a much larger program that the Company seeks to implement if the Commission approves recovery of these initial costs.

Mr. Decker defines RSG as natural gas that, during the production stage, has gone through a third-party certification process and regular monitoring to ascertain that it was produced in a way that meets the highest standards of responsibility with respect to air, water, land, and community. The Company has met with industry peers, suppliers, and other industry participants to ascertain their position on RSG and found a wide range of familiarity and opinion. According to Mr. Decker, certification of RSG is still developing, with a wide range of options from certification of only methane intensity to assessment of Environmental, Social, and (Corporate) Governance (ESG) attributes. The Company sees itself as an ESG leader and aspires to be the "Best in the world and best for the world."

In his testimony, Mr. Decker identifies various organizations in which the Company participates and plays a role in defining standards and protocols on sustainability and RSG. He states that the intent of establishing protocols is to encourage upstream producers, processors, and transporters to report their methane intensity and opines that it may be too early to determine if this voluntary reporting is occurring. Mr. Decker admits that although much work has been done in the area of certification of RSG, the industry is still developing. He states that the Company has not committed to a specific certification process and will continue assessing its options to determine the most prudent methodology. The Company believes that unless certification of RSG is demanded by gas buyers, the industry will not evolve in this area.

On pages 44 and 45 of his direct testimony, Mr. Decker reports that the Company issued requests for information (RFI) for purchasing up to 2 Bcf of RSG and that the Company was able to purchase 1,134,200 Dth at a cost of $7,858,562 during 2022. That cost consists of the commodity cost of $7,821,754, plus a premium of $36,808 for the RSG certification. The premium paid equates to 3.2 cents per Dth ($36,808 ÷ 1,134,200).

On pages 46-47 of his testimony, Mr. Decker states that the Company made additional purchases of RSG of 1,990,200 Dth in 2023 with a premium price of $29,853. From these purchases and from the program's objectives, he concludes that the Commission should allow recovery of premium costs in general rate cases. From his testimony, it is not clear if the Company is also seeking recovery of premium costs incurred outside of the projected test year.

Mr. Decker states that during the project year, the Company anticipates purchasing 4,000,000 Dth of RSG at a premium of $0.045 per Dth, which translates to a total premium amount of $180,000. At minimum, this is the amount that the Company wants to include in rates in this rate case.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PURCHASE OF RSG GAS, THE PAYMENT OF A PREMIUM, AND THE PROPOSAL TO UNDERTAKE A WIDER RSG PROGRAM IN THE FUTURE?

A. There are four main issues that arise from the Company's RSG purchases and long-term proposal. The first issue is whether the Company should impose its corporate goal of net zero emissions on suppliers, at the expense of customers, in the absence of laws and regulations that require compliance with business practices that the Company and others in the industry seek to achieve. Second, there is the issue of whether the Company should recover excess costs over the cost of the commodity that would otherwise be avoided by purchasing alternative gas supply. Third, there is the issue of whether producers and gas suppliers should pass on costs to gas buyers in the form of premiums for selling natural gas produced with "best" environmental practices that should be integral to *all* gas produced and not only a portion of it. Fourth, although there may be some small emission gains applicable to society in general, there are no tangible or direct benefits to customers from the purchase of RSG. I will discuss each of these issues below.

Q. PLEASE DISCUSS THE ISSUE WITH THE COMPANY'S GOALS AND LACK OF MEANINGFUL MEASURES.

A. The Company has set a corporate goal to reduce greenhouse emissions to net-zero from its operations and from suppliers by 2050 and reduce customer emissions of greenhouse gas emissions by 35% by 2050 from 2005 levels. The Company has not shared what the level of greenhouse gas emissions was in 2005, how much in emission volumes the 35% reduction represents, how it plans to achieve that goal, how RSG fits into the plan, or how much it will contribute to the total reduction.

In response to discovery, the Company reported that the forecasted purchases of 4,000,000 Dth of RSG would reduce CO2e emissions by 1% of the emissions along the natural value stream. However, it is not clear what the value stream includes. Also, asked to identify how much these gas purchases would reduce the Company's total carbon footprint, the Company did not provide an answer. Therefore, the Company has put forth bits and pieces of information with little to no substance to allow an adequate assessment of whether the proposal to purchase RSG will make a significant contribution to the Company's total greenhouse gas reduction goals by 2050 or the larger benefit to society.

In his testimony, Mr. Decker admits that the purchase of RSG is still a nascent issue within the natural gas industry and for gas utilities serving consumers. RSG is fraught with controversy as to how and at what pace to proceed with embracing certification of RSG and the ensuing costs. There are no laws or regulatory mandates that require producers to implement the business practices that RSG certification attempts to ascertain. Therefore, buyers of natural gas, such as DTE Gas, are seeking to impose their own standards on producers, who in turn are demanding to be paid for the incremental cost of certifying that they follow the desired processes and policies.

Although gas producers and transporters need to do the utmost to reduce emissions in the production and transportation of natural gas, the natural gas industry and subgroups within the larger industry can establish standards that producers, transporters, and distributors should follow. Once accepted, those standards should guide parties transacting with each other by confirming that they are in compliance with those standards. If certification is necessary, that is a cost of doing business and should not require a separate premium to be paid by entities buying their product.

As I stated by way of an example in my testimony in Case No. U-21064 on this matter, in the automotive manufacturing industry, there are the International Standard of Organization (ISO) standards that equipment and parts suppliers need to meet and demonstrate that they are compliant with in order to do business in the industry.[83] However, General Motors, Ford, and Chrysler do not pay a separate premium to those suppliers that are compliant with the ISO standard, while also doing business with other suppliers that are not ISO compliant, as the Company's proposal would do.

Q. ARE THERE INITIATIVES AT THE FEDERAL LEVEL THAT COULD RENDER THE COMPANY'S PROPOSED RSG PROPOSAL UNNECESSARY?

A. Yes. The Inflation Reduction Act of 2022 (IRA), among other provisions, includes a charge on methane emissions. The emissions charge applies only to methane emissions from specific types of facilities that are required to report their greenhouse gas (GHG) emissions to the EPA's Greenhouse Gas Emissions Reporting Program (GHGRP). The

[83] ISO = The International Organization for Standardization is an international standard development organization composed of representatives from the national standards organizations of member countries.

charge starts at $900 per metric ton of methane, increasing to $1,500 after two years. This emissions charge is the first time the federal government has directly imposed a charge, fee, or tax on GHG emissions.[84] The EPA will likely promulgate new regulations to implement the provisions of the IRA on methane reductions and related fees.

In 2021, the EPA also proposed regulations that aimed to reduce methane emissions at gas production facilities.[85]

These legislative and regulatory initiatives will likely render the Company's proposal duplicative and unnecessary.

Q. IF THE COMPANY WERE TO PAY AN RSG PREMIUM FOR 50% TO 100% OF ITS GAS PURCHASES, HOW MUCH WOULD THE ADDITIONAL COST BE ANNUALLY?

A. The Company forecasted 148,816,000 Dth of gas purchases for the 2023-2024 GCR year. If the Company were to pay an RSG premium of 4.5 cents per Dth on half of the purchases, the incremental annual cost would be in excess of $3.3 million. On 100% of the volumes, the incremental cost would be more than $6.6 million annually.

Q. ARE THERE OTHER QUESTIONABLE STATEMENTS IN MR. DECKER'S TESTIMONY WITH REGARD TO RSG?

A. Yes. On page 36 of his direct testimony, Mr. Decker states that the reduction of greenhouse gas emissions and any related climate impact is one of the defining public

[84] https://crsreports.congress.gov/product/pdf/R/R47206.
[85] https://www.epa.gov/system/files/documents/2021-11/2021-oil-and-gas-proposal.-overview-fact-sheet.pdf.

policy issues of our time. If Mr. Decker's premise is true, producers should be fully embracing the reduction of CO_2 and other greenhouse gas emissions voluntarily as part of their gas production operations.

In discovery in Case No. U-21064, the Attorney General asked the Company to explain what producers are doing differently operationally to reduce the methane intensity of RSG and why they cannot do the same with all gas produced and thus avoid the need for certification. In response, the Company stated that each producer has its own criteria for RSG and there is no defined standard. The Company also could not answer why producers choose to certify only a portion of their supply instead of their entire production.

In discovery, the Company was also asked if it is likely that the natural gas produced and sold by the same producers that has not been RSG certified would have the same methane intensity as RSG. The Company admitted that it is possible that both RSG and non-RSG may have the same methane intensity.[86] Gas is a fungible commodity. Once injected in the pipelines it comingles with other gas. Therefore, there is no way for the Company to be sure that it would receive the low carbon intensity natural gas that it paid a premium to purchase. In fact, it is likely it would not receive the same gas supply it purchased at a premium. This basic problem makes the entire undertaking unappealing.

It is also befuddling why a supplier who has committed to RSG would still produce non-RSG natural gas. Such a practice raises questions about the seriousness of the entire undertaking when producers and other parties simply go along with some certification

[86] Case U-21271, Exhibit AG-8 includes DR AGDG-1.18a and b.

process for only a portion of their operations to appear to be socially and environmentally responsible.

On page 50 of his direct testimony, Mr. Decker states that the purchase of RSG will benefit Michiganders and the Company's customers. However, other than the small reduction in CO2 emissions discussed above, it is not clear what the other benefits are. In discovery in Case No. U-21271, the Attorney General asked the Company if it had surveyed its customers to determine if they are willing to pay a premium for gas purchases in order for the Company to meet its net-zero carbon goal. In response, the Company stated that it had not surveyed its customers and also stated that the Company's net-zero goal was not a regulatory program that required approval by the Commission.[87]

Q. IS AN RSG PILOT PROGRAM NECESSARY AS PREVIOUSLY RECOMMENDED BY THE COMPANY?

A. No. On page 60 of his direct testimony in Case No. U-21271, Company witness Joseph Madigan stated that the Company was piloting the RSG program and is still in the exploration, analysis, and development stages of developing a robust RSG purchase strategy. In discovery, the Attorney General asked the Company what there is further to understand about RSG purchases that requires piloting a program. In response, the Company pointed to unknowns, such as many different certifications and locations to purchase RSG and the lack of current state and federal regulations.[88] Although these may be unknown items, the solution is not to plunge into a program that entails paying

[87] Id. includes DR AGDG-1.17 and 1.21.
[88] Id. includes DR AGDG-1.20.

premiums for gas cost, but to wait for the market to sort itself out and avoid paying additional costs for gas supply.

The Company's eagerness to purchase RSG seems highly influenced by its corporate goal of achieving net-zero carbon emissions by 2050 and burnishing its image as a socially responsible ESG company. If this is true, the payment of premiums to purchase RSG is no different that advertising costs to enhance the Company's and its parent company's corporate image and those costs should be paid by shareholders.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. While reducing greenhouse gasses is a laudable goal, the Company has not made a compelling and convincing case that purchasing RSG is in the best interest of customers or that it will make a significant difference in reducing greenhouse gas emissions. Although the costs appear small now, they will grow significantly quickly if the Company is allowed to recover premium costs above the normal cost of gas. The recovery of the premium cost in a rate case is also problematic because those cost are related to the quantity of gas purchased and the timing and accuracy of the costs recovered in base rates cannot be easily ascertained and reconciled.

Therefore, I recommend that the Commission reject the Company's proposal to include $180,000 of RSG premium costs in this rate case based on a determination that the Company's RSG proposal is still incomplete and does not adequately identify a significantly beneficial impact to reduce greenhouse emissions or to customers. The Commission should also determine that the Company's RSG proposal is premature given the current state of this issue within the natural gas industry, the lack of industry standards for all participants to adhere to as part of routine business operations, and recent legislative and EPA initiatives on methane reductions in the gas production areas.

O. O&M Expense Summary

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR O&M EXPENSES.

A. Operations and maintenance expenses represent a large part of the Company's cost structure. My analysis of the expense level proposed by the Company has determined that expenses in certain areas are excessive or unnecessary and should be removed. I recommend total reductions to O&M expenses of $97.2 million as discussed above and summarized in the following table. Exhibits AG-39, AG-40, and AG-42 provide additional details of the areas where I have proposed O&M expense adjustments.

Summary of O&M Expense Reductions	Amount ($Millions)
Company Gas Use and Lost Gas	$ 4.9
Uncollectible Accounts Expense	9.1
Inflation Expense Adjustment	4.0
Corporate Expense Realignment	25.6
Pipeline Integrity and MAOP Records	7.6
Leak Detection and Repairs	10.3
Health Care Benefits	4.9
Employee Incentive Compensation	16.1
OPEB Liability Amortization Expense	9.7
Credit/Debit Card Fees	2.2
Responsibly Sourced Gas	0.2
Rents & Other Expenses	2.6
Total Reductions	**$ 97.2**

IX. Depreciation Expense

Q. **DO YOU PROPOSE AN ADJUSTMENT TO DEPRECIATION EXPENSE FOR THE PROJECTED TEST YEAR?**

A. Yes. As a result of the reductions in capital expenditures proposed above in my testimony and the impact on capital additions included in rate base, I have calculated a reduction in depreciation expense of $3,409,000. The calculation of this amount is shown in Exhibit AG-20.

I recommend that the Commission reduce the depreciation expense proposed by the Company for the projected test year by $3,409,000.

X. Property Tax Expense

Q. PLEASE DISCUSS THE PROPERTY TAX EXPENSE ADJUSTMENT THAT YOU PROPOSE.

A. In Exhibit AG-20, I identified the adjustments to be made to the Company's proposed capital expenditures. Those reductions lower the amount of property tax expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in property tax expense of $5,019,000 million. I recommend that the Commission reduce the Company's property tax expense by this amount for the projected test year.

XI. AFUDC

Q. WHAT ADJUSTMENTS TO AFUDC DO YOU PROPOSE?

A. In Exhibit A-13, Schedule C11, the Company shows $4.7 million of Allowance for Funds Used During Construction (AFUDC) pertaining to several project costs included in construction work in process for large projects that will not be in-service before the end of the projected test year. Included on this list of projects are four projects where I recommend that the Commission remove the capital expenditures from construction work in process and rate base. Those projects are (1) the Fort Street Main Replacement project, (2) the Austin-Detroit A&B Lines, (3) Oakland Resiliency (CMS Line 2700) project, and (40) the Belle River Detroit Loop Line. To avoid a duplication of reduction in the revenue requirement, I removed $2,210,000 of AFUDC from my calculation of the revenue requirement in this rate case.

XII. Adjustments To Revenue Deficiency

Q. WHAT ARE THE TOTAL ADJUSTMENTS AND THE REVISED REVENUE DEFICIENCY YOU RECOMMEND?

A. Exhibit AG-55 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $112.2 million, which is a reduction of $153.3 million from the Company's requested level of $265.5 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $112.2 million.

XIII. Rate Design

Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR RESIDENTIAL CUSTOMERS HAS THE COMPANY PROPOSED?

A. In his direct testimony, Company witness Timothy Krysinski proposes to increase the monthly service charge for residential customers (Rate Schedules A and 2A) from $13.50 to $17.60 per month. Mr. Krysinski also proposes to increase the monthly customer service charge for small commercial customers in rate schedule GS-1 from $40.00 to $50.00.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The proposed change from $13.50 to $17.60 per month represents an increase of 30%. Such a large increase could cause rate shock to customers in smaller households who use less gas than the average customer. They would see their monthly gas bill increase drastically without using any more gas.

Fixed monthly charges also discourage energy conservation. It is best to increase the volumetric rate paid by customers because the higher cost encourages conservation. The customer can take steps to reduce usage and thus lower the gas bill. The customer cannot reduce fixed monthly charges.

Similarly, small commercial customers who take service under rate GS-1 would see an increase of 25% in their monthly charge. This is also a significant increase for smaller commercial customers.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission maintain the current residential monthly customer charge of $13.50. The monthly service charge was increased $1.25 in 2022 in the Company's last rate case. The Company's proposed monthly charge of $17.60 would result in an annual charge of $211, which would represent a large portion of the total annual gas bill for small households. However, if the Commission sees some merit in increasing the monthly service charge, in the interest of rate gradualism, I recommend that the Commission not increase the monthly charge by more than $1 to $14.50.

Similarly, for the GS-1 rate, the Commission should maintain the current monthly charge of $40.00, which was increased by $8.00 in 2022. This last increase of 20% was rather large and another increase should be avoided at this time.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does. However, I reserve the right to amend, revise and supplement my testimony to incorporate new information that may become available.

Experience and Qualifications of Sebastian Coppola

Mr. Sebastian Coppola is an independent energy business consultant and president of Corporate Analytics, Inc., whose place of business is located at 5928 Southgate Rd., Rochester, Michigan 48306.

EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for 22 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

ENERGY INDUSTRY EXPERTISE

During his 27-year career at SEMCO Energy, MCN Energy and MichCon, Mr. Coppola held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

Mr. Coppola is intricately knowledgeable of capital markets and financial institutions. As Treasurer and Vice President of Finance, he directed the issuance of more than $2 billion in securities, including common stock, corporate bonds, tax-deductible preferred stock and high-equity value convertible securities. He established bank lines of credit, commercial paper and asset acquisition facilities. He has had extensive interactions with equity and debt investors, financial analysts, rating agencies and other members of the financial community.

ENERGY INDUSTRY AND REGULATORY EXPERIENCE

As a business consultant, Mr. Coppola specializes in financial and strategic business issues in the fields of energy and utility regulation. He has more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. He has testified in several regulatory proceedings before State Public Service Commissions. He has prepared and/or filed testimony in electric and gas general rate case proceedings, power supply and gas cost recovery mechanisms, revenue and cost tracking mechanisms/riders, multi-year rate plans and incentive ratemaking, and other regulatory matters.

Mr. Coppola has extensive experience with gas and electric utilities in the areas of gas operations, gas supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared

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testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General, the Maryland Office of Public Counsel, and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, DTE Electric Company, MichCon (DTE Gas Company), Michigan Gas Utilities Corp, Nicor Gas, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company, Washington Gas, and Wisconsin Public Service Company.

Mr. Coppola has also provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking. Additionally, he prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company which was filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.

As accounting manager and later financial executive for two regulated gas utilities, he has been intricately involved in construction materials procurement, gas purchase strategies and CGR reconciliation cases. He has had direct responsibility for preparing GCR reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the Michigan Public Service Commission (MPSC). He is intricately familiar with construction projects, the power supply and gas cost recovery mechanisms, gas supply and pricing issues, and regulatory issues faced by utilities.

Experience and Qualifications of Sebastian Coppola

During his long career at DTE Gas, among other responsibilities, Mr. Coppola was responsible to oversee the operation of the MichCon Wet Header System, a pipeline that transported natural gas and gas liquids from Michigan gas producing fields in the Niagaran Reef in the northern area of the lower peninsula of Michigan to processing plants in Kalkaska, MI. His responsibility included ensuring the day-to-day flow of gas and liquids, and identifying operating issues requiring corrective action.

He was also responsible for the study to assess the feasibility of building the Saginaw Bay Pipeline, a transmission line to move Praire Du Chein natural gas reserves in the eastern area of Michigan to processing plants. Prior to the construction of the pipeline, Mr. Coppola worked with operating management to prepare requests for proposal for the construction project and the selection of qualified bids. During and subsequent to the construction of the pipeline, Mr. Coppola assisted in the management and oversight of the pipeline, including review of operating performance and profitability.

Additionally, as Manager of Materials Inventory, Warehousing and Procurement at DTE Gas, Mr. Coppola worked closely with suppliers of pipe, control valves, flanges, meters, fittings, equipment and thousands of other parts and materials used in the construction, repair and maintenance of DTE Gas's transmission, distribution and storage facilities, including repairs and upgrades to compressor stations, and replacement of cast iron mains, bare and wrapped steel pipelines and service lines. His responsibilities included the review of design and construction blueprints and plans with frequent visits to construction sites during excavation of new pipeline trenches, and during replacement of defective or leaky

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of Sebastian Coppola

pipes, and replacement of control valves. Mr. Coppola also made frequent visits and inspection to storage facilities owned by DTE Gas to understand materials requirements during planned construction projects. Mr. Coppola was also responsible to ensure that materials and equipment were ordered to meet material standards and safety codes.

Through these responsibilities, Mr. Coppola gained knowledge and expertise with field construction project procedures, pipeline trenching problems, installation inspections, operation and maintenance cycles, and the material procurement of pipe, valves, flanges, meters and thousands of other parts and equipment used in the construction of natural gas transmission, distribution and storage facilities.

During his career with MCN Energy Group, Mr. Coppola was responsible for the evaluation of investments in interstate pipelines, new gas storage facilities, gas cogeneration plants, and construction of new power plants in the U.S. and India. Mr. Coppola was a key member of the negotiating team with contractors and suppliers tasked to build the power facilities, including the evaluation of Engineering, Procurement and Construction (EPC) bids and contracts.

Subsequent to his move to SEMCO Energy Corporation in 1999, Mr. Coppola was responsible for the acquisition and integration of pipeline construction companies providing services to gas utilities and interstate pipelines. In addition to its gas utility business in Michigan and Alaska, serving approximately 350,000 customers, SEMCO Energy owned SEMCO Pipeline Construction, a non-regulated business providing gas pipeline and natural gas facilities construction services to gas utilities and interstate pipelines in the Midwest and Eastern regions of the U.S.

Experience and Qualifications of Sebastian Coppola

SEMCO Pipeline Construction provided construction services similar to KS Energy, Northern Pipeline and other contractors used by the Company. During his tenure at SEMCO Energy, Mr. Coppola reviewed dozens of pipeline construction companies and acquired six companies. Mr. Coppola's responsibilities included management of the performance and profitability of the pipeline construction services business requiring field visits to construction projects and quality reviews. In this process, Mr. Coppola learned firsthand how pipeline construction companies operate, construction project challenges, their bidding practices and the bidding of construction projects, including pricing, bidding procedures and policies both from the contractor's side and the gas utility side.

Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

In his role as Treasurer and Chairman of the MCN/MichCon Risk Committee from 1996 through 1998, Mr. Coppola was involved in reviewing and deciding on the appropriate gas purchase price hedging strategies, including the use of gas future contracts, over the counter swaps, fixed price purchases and index price purchases.

In March 2001, Mr. Coppola testified before the Michigan House Energy and Technology Subcommittee on Natural Gas Fixed Pricing Mechanisms. Mr. Coppola frequently participates in natural gas issue forums sponsored by the American Gas Association and stays current on various energy supply issues through review of industry analyst reports and other publications issued by various trade groups.

Experience and Qualifications
of Sebastian Coppola

Mr. Coppola performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, he has performed analysis of power costs and filed testimony in power supply cost recovery cases, including reconciliation of annual power supply costs.

In his position as Senior Vice President of Finance at MCN, Mr. Coppola also had responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, he was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, he was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

- **Specific Regulatory Proceedings and Related Experience:**
  - Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2022-2023 GCR reconciliation in case No. U-21065.
  - Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
  - Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
  - Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
  - Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2022-2023 GCR plan in case No. U-21067.
  - Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21049.

Experience and Qualifications
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- Filed testimony on behalf of the Michigan Attorney General in Indiana Power Company 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Act 9 application in Case No. U-20993 by Saginaw Bay Pipeline Company to set transportation rates for services to DTE Gas Company.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 electric rate Case U-20836 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed rebuttal testimony on behalf the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gaslight & Coke Company (Peoples Gas) in Docket 17-0137.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan reconciliation case No. U-20554.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure

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Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2020-2021 GCR plan reconciliation case No. U-20552.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR plan reconciliation case No. U-20236.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Ameren Illinois Company (Ameren) in Docket 20-0323.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan case No. U-20822.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.

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- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including

sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance

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expenses, capital expenditures, cost of capital, rate design and other items.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.

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- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.

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- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.

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- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.

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- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CECo Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.

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- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CECo Gas Choice and End-User Transportation tariff changes case U-17900.
- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.

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- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.

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- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CECo's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington

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Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.

- o Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- o Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- o Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- o Filed testimony on behalf of the Michigan Attorney General in CECo's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- o Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- o Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- o Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.
- o Filed testimony in MichCon's 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- o Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors' compensation in the 2012 Avista general rate case.

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- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio's power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation's 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo's electric business Pilot Revenue Decoupling Mechanism in case U-16566.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.

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- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.
- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.
- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.

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- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.
- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the "Massachusetts Formula" at MichCon and at SEMCO in 1975 and 2000.
- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.

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- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

EDUCATIONAL BACKGROUND

Mr. Coppola did his undergraduate work at Wayne State University, where he received the Bachelor of Science degree in Accounting in 1974. He later returned to Wayne State University to obtain his Master of Business Administration degree with major in Finance in 1980.

Corporate Analytics

U-21291 Attorney General's Exhibits

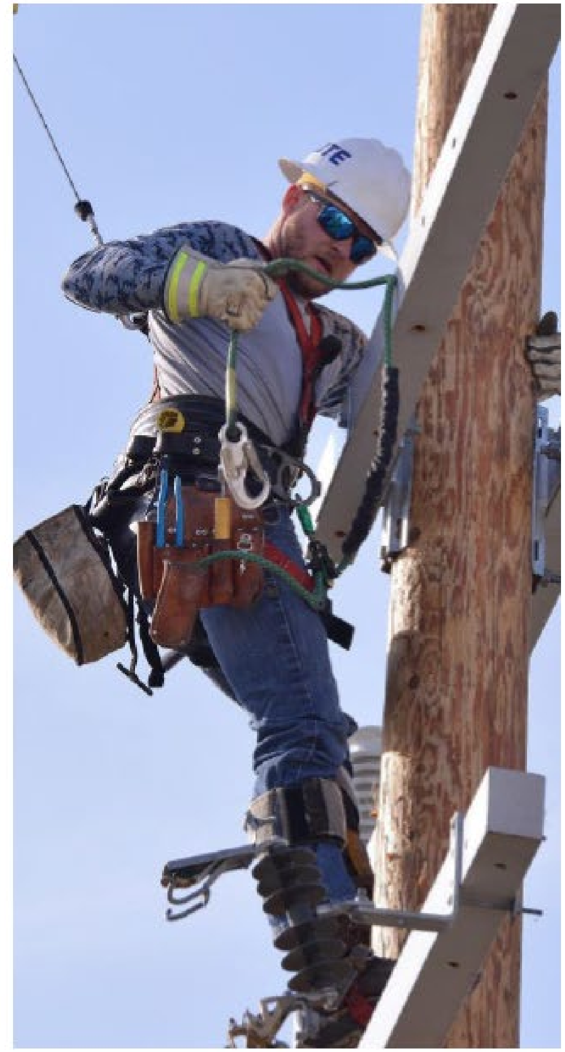
Exhibit AG-1	DTE Energy Investor Presentation April 2024 U-21291
Exhibit AG-2	**CONF Blue Chip Report March 2024 U-21291**
Exhibit AG-3	Main Renewals DRs U-21291
Exhibit AG-4	Actual Distribution Capex U-21291
Exhibit AG-5	Public Improvements U-21291
Exhibit AG-6	System Reliability Units and Costs U-21291
Exhibit AG-7	Communications & Controls Meters U-21291
Exhibit AG-8	Leak Detection & Repair LDAR Costs U-21291
Exhibit AG-9	Fort Street Replacement U-21291
Exhibit AG-10	Van Born Project Write-off U-21291
Exhibit AG-11	PRA Risked Project List U-21291
Exhibit AG-12	MRP MMO and IRM Spendig with Miles U-21291
Exhibit AG-13	Cathodic Spending in or out of IRM U-21291
Exhibit AG-14	Transmission Premature Projects U-21291
Exhibit AG-15	ILI Premature Projects U-21291
Exhibit AG-16	TCARP Overruns and Billings to DTMLC U-21291
Exhibit AG-17	Storage & Compression Projects U-21291
Exhibit AG-18	Transportation Vehicle and Equipment Purchases U-21291
Exhibit AG-19	IT Capex Savings Gas Schedule Optimz. U-21291
Exhibit AG-20	Capital Expenditures, Rate Base Reductions and Depr. U-21291
Exhibit AG-21	Working Capital U-21291
Exhibit AG-22	Overall Cost of Capital U-21291
Exhibit AG-23	Equity Cost of Capital U-21291
Exhibit AG-24	Equity Cost of Capital - DCF U-21291
Exhibit AG-25	Equity Cost of Capital - CAPM U-21291
Exhibit AG-26	Equity Cost of Capital -Risk Premium U-21291
Exhibit AG-27	Peer Group Capitalization U-21291
Exhibit AG-28	Market to Book U-21291
Exhibit AG-29	ROE Decisions U-21291
Exhibit AG-30	Cash Flow to Debt Coverage Ratio U-21291
Exhibit AG-31	Value Line - Volatility vs. Risk U-21291
Exhibit AG-32	Gas Sales Analysis U-21291
Exhibit AG-33	Adjustments to DTE Forecasting Model and Usage Trend U-21291
Exhibit AG-34	Gas Sales Revenue U-21292
Exhibit AG-35	EUT Power Geenration Load U-21291
Exhibit AG-36	Off-SystemTransportation , Storage and Park & Loan U-21291
Exhibit AG-37	Midstream Revenue Adjustments U-21291
Exhibit AG-38	HPP Appliance Service Progrm Revenue U-21291
Exhibit AG-39	O&M Summary Adjustments U-21291
Exhibit AG-40	Co. Use and LAUF U-21291
Exhibit AG-41	Revised Cost of Gas Rate U-21291
Exhibit AG-42	Uncoll Accts Expense U-21291
Exhibit AG-43	O&M Inflation Adjustment U-21291
Exhibit AG-44	O&M Cost Reductions 2023 U-21291
Exhibit AG-45	2023 O&M Reductions Normalized U-21291
Exhibit AG-46	O&M Cost Reductions Headcount Reduction U-21291

Exhibit AG-47	Active Health Care O&M Expense U-21291
Exhibit AG-48	Rents Adjustment U-21291
Exhibit AG-49	Incentive Comp Performance Measures U-21291
Exhibit AG-50	MAOP O&M Cost and TVC Records Review U-21291
Exhibit AG-51	OPEB Regulatory Liability Amortization U-21291
Exhibit AG-52	Customer Payment Transaction Cost Options U-21291
Exhibit AG-53	Corporate Jet Travel U-21291
Exhibit AG-54	DTE Gas Deferred Incentive Comp Calc U-21291
Exhibit AG-55	Revenue Deficiency Calculation U-21291

DTE

Business Update

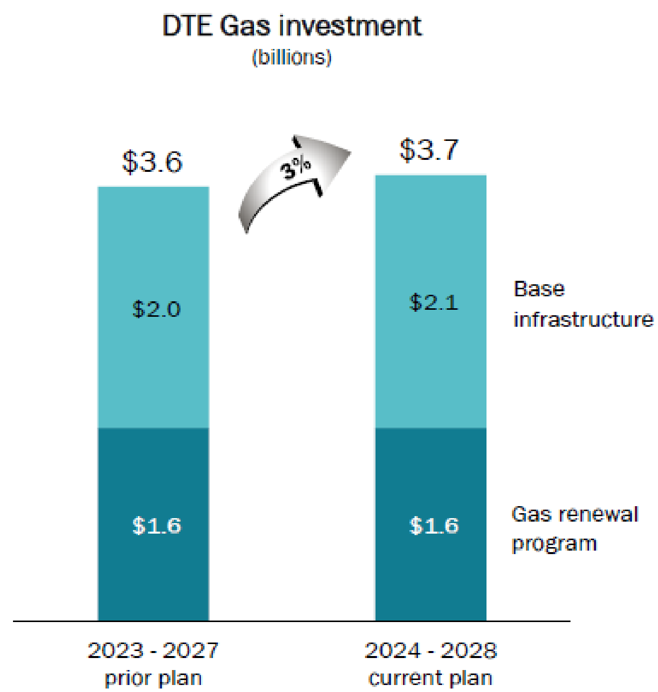
April 2 - 3, 2024



DTE Gas: replacing aging infrastructure to ensure reliability and transition to net zero emissions

Capital investment focused on infrastructure improvements and decarbonization

- Significant investment recovered through Infrastructure Recovery Mechanism (IRM) to support main renewal
  - Renewed over 1,700 miles since program inception
  - Gas renewal investments minimize leaks and reduce costs
- Base infrastructure investments enhance transmission, compression, distribution and storage
- Targeting to reduce GHG emissions by 65% by 2030, 80% by 2040 and net zero by 2050
  - Natural Gas Balance program empowers customers to manage their carbon footprint using both carbon offsets and RNG



Cash flow and capital expenditures guidance

Cash flow

(billions)

	2024 guidance
Cash from operations[1]	$3.3
Capital expenditures	(4.7)
Free cash flow	**($1.4)**
Dividends	(0.8)
Other	-
Net cash	**($2.2)**
Debt financing	
Issuances	$4.3
Redemptions	(2.1)
Total debt financing	**$2.2**

Capital expenditures

(millions)

	2024 guidance
DTE Electric	
Base infrastructure	$630
New generation	1,200
Distribution infrastructure	1,550
	$3,380
DTE Gas	
Base infrastructure	$380
Gas renewal program	335
	$715
Non-utility	**$550 - $650**
Total	**$4,645 - $4,745**

1. Includes equity issued for employee benefit programs

2024 operating EPS[1] guidance midpoint provides 7% growth over 2023 original guidance midpoint

(millions, except EPS)

	2024 guidance
DTE Electric	$1,100 - $1,120
DTE Gas	295 - 305
DTE Vantage	125 - 135
Energy Trading	30 - 40
Corporate & Other	(195) - (185)
DTE Energy	$1,355 - $1,415
Operating EPS	$6.54 - $6.83

1. Refer to the appendix for information regarding the reconciliation of operating earnings (non-GAAP) to reported earnings

Exhibit AG-2

CONFIDENTIAL

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.127	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 127. Refer to lines 9-15 on page 8 of Mr. Abona's direct testimony on routine unplanned main renewals. Please provide the number of units, miles, or projects for each year 2018 to 2023 actual and forecasted for 2024, 2025, first 9 months of 2024, and the 12 months ending September 2025. Provide this information in Excel.

Answer:

Year	Unplanned Main Renewal (feet)
2018	11,711
2019	17,916
2020	8,129
2021	17,980
2022	13,455
2023	13,599

Unplanned main renewal budget is not forecasted based on unitization, rather budget forecasting is based on total budget expenditure historical average.

Attachment: None

MPSC Case No: U-21291	
Requester: Staff	
Question No.: STDG-1.1	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: Referring to page 3, lines 7-13 of the Witness' direct testimony, please revise the following Company exhibits to include actual costs for calendar years 2018, 2019, 2020, 2021, 2022, and 2023.

- Exhibit A-12, Schedule B5.1
- Exhibit A-12, Schedule B5.11
- Exhibit A-12, Schedule B8

Answer: Refer to Exhibit A-12, Schedule B5.1, Workpaper EA-001 for 2018-2022 actuals. See attached for 2023 actuals.
For Exhibit A-12, Schedule B5.11, Please see attachment for actual costs by project. Prior to 2021, only expenditures above a routine level of spend were broken out into project level costs.

For Exhibit A-12, Schedule B8, the cost of project started in 2022.

Exhibit A-12, Schedule B8	
2022 Actuals	**2023 Actuals**
$5,818,000	$3,811,000

Attachment: U-21291 STDG-1.1-01 A-12 B5.1 with 2023 Actuals
U-21291 STDG-1.01,1.17,1.18 Routine Capital Project Detail 2021-2023

Remainder of Exhibit consists of 12 pages of actual Distribution Capex
2021-2022

Michigan Public Service Commission
DTE Gas Company
DTE Gas Detailed Routine Capital Project List for 2023 - 2025
($000)

Case No.: U-21291
Exhibit Supported: A-12
Schedule: B5.11
Witness: E. Abona
Page:

(a)

Line No.	Sub Line No.		Description	12 mos. ending 12/31/2021	12 mos. ending 12/31/2022	12 mos. ending 12/31/2023
1		**Routine Capital Requirements**				
2		**Distribution Plant**				
3			Main Renewals 1/	$ 9,503	$ 6,618	$ 5,818
4			Public Improvements 2/	16,268	28,686	29,483
	4.1	*Top 25*	*East Jefferson*	*421*	*5,002*	*8,067*
	4.2	*Top 25*	*Conner and I94*	*-*	*60*	*1,281*
	4.3	*SEMI*	*US-24 / 8 Mile: PI-21-018*	*3*	*3,910*	*2,197*
	4.4	*SEMI*	*US-24 / 7 Mile: PI-21-017*	*3*	*4,601*	*156*
	4.5	*SEMI*	*Public Improvement Blanket*	*2,925*	*1,351*	*435*
	4.6	*SEMI*	*US-24 / Grand River: PI-21-016*	*-*	*21*	*1,685*
	4.7	*SEMI*	*Cherry Hill west of Ridge Road, Canton: PI-21-005*	*109*	*1,212*	*5*
	4.8	*SEMI*	*Grand River Main Renewal: PILN20001*	*1,226*	*(1)*	*-*
	4.9	*SEMI*	*Southfield Bridge over Ecorse Creek: PI-21-020*	*-*	*35*	*941*
	4.10	*SEMI*	*Meridian Road over Thorofare Canal: PI-21-023*	*-*	*909*	*64*
	4.11	*SEMI*	*GLWA Clay, Morrow, Marston Main Relocation: PILY21001*	*120*	*731*	*-*
	4.12	*SEMI*	*US-23 / Bemis: PI-21-011*	*54*	*728*	*31*
	4.13	*SEMI*	*Warren Road at Rouge River: PIALR21001*	*226*	*313*	*3*
	4.14	*SEMI*	*Allen Road / Van Horn, Woodhaven: PI-20-022*	*480*	*26*	*-*
	4.15	*SEMI*	*PMP 10059 GLWA Bayside 24": PI-22-021*	*-*	*11*	*438*
	4.16	*SEMI*	*North Parker Culvert Replacement: PI-22-014*	*-*	*57*	*383*
	4.17	*SEMI*	*US-12 / Ecorse: PIM21002*	*417*	*7*	*-*
	4.18	*SEMI*	*PMP 10067 Barrett / I-94: PI-22-017*	*-*	*29*	*379*
	4.19	*SEMI*	*PMP 10065 5 mile over Bell Creek: PI-22-012*	*-*	*13*	*373*
	4.20	*SEMI*	*Mill Lake Drain: PI-22-013*	*-*	*9*	*376*
	4.21	*SEMI*	*State Street / Liberty: PI-22-008*	*-*	*157*	*193*
	4.22	*SEMI*	*Campbell / West Jefferson: PI-22-007*	*-*	*48*	*273*
	4.23	*SEMI*	*PMP 10073 Beard Road / I-75 16" ST*	*-*	*5*	*298*
	4.24	*SEMI*	*Mount Elliot Street (Conant to Dodge): PI-22-009*	*-*	*277*	*-*
	4.25	*SEMI*	*US-12 / US-23: PI-21-010*	*33*	*248*	*(8)*
	4.26	*SEMI*	*Gordie Howe International Bridge*	*273*	*0*	*0*
	4.27	*SEMI*	*Dixboro Main Relocation: PIMI21001*	*258*	*9*	*-*
	4.28	*SEMI*	*Van Dyke / 7 Mile: PI-20-009*	*7*	*247*	*-*
	4.29	*SEMI*	*West Commerce / Main Street: PI-22-010*	*-*	*248*	*-*
	4.30	*SEMI*	*Kensington Ridge*	*-*	*-*	*237*
	4.31	*SEMI*	*M-102 / Ryan: PI-22-011*	*-*	*9*	*182*
	4.32	*SEMI*	*Wayne / Ecorse Road: PI-23-009*	*-*	*-*	*188*
	4.33	*SEMI*	*Washtenaw / Geddes: PI-23-016*	*-*	*-*	*165*
	4.34	*SEMI*	*PMP 10072 South Huron River / I-275: PI-23-019*	*-*	*-*	*159*
	4.35	*SEMI*	*US-24 - Grand River to 8 Mile: PI-21-014*	*65*	*86*	*-*
	4.36	*SEMI*	*PMP 10055: Springfield / I-94: PI-22-019*	*-*	*30*	*117*
	4.37	*SEMI*	*PMP 10099 Elba Drive over Elba Canal: PI-23-003*	*-*	*-*	*146*
	4.38	*SEMI*	*PMP 10070 North County Line Inter-County Drain: PI-23-001*	*-*	*-*	*125*
	4.39	*SEMI*	*PMP 10064 McClellan / I-94: PI-22-020*	*-*	*35*	*88*
	4.40	*SEMI*	*Mount Elliot Street from Harper to Miller 16"*	*-*	*95*	*28*
	4.41	*SEMI*	*Wayne County Traffic Signal: PI-23-013*	*-*	*-*	*102*
	4.42	*SEMI*	*US-12 / Amercan Road: PI-23-026*	*-*	*-*	*102*
	4.43	*SEMI*	*Birch Hollow / Chelsea: PI-22-029*	*-*	*-*	*99*
	4.44	*SEMI*	*Gratiot (M-3) / Russell: PI-21-019*	*-*	*98*	*-*
	4.45	*SEMI*	*PMP 10068 Reeck Road / Midway, over Sexton-Kinfoil Drain: PI-23-002*	*-*	*-*	*98*
	4.46	*SEMI*	*PMP 10066 Ford Lake Dam: PI-23-021*	*-*	*-*	*93*
	4.47	*SEMI*	*Hillcrest / South Harris: PI-22-005*	*-*	*73*	*-*
	4.48	*SEMI*	*Stadium Boulevard: PI-21-013*	*4*	*62*	*-*
	4.49	*SEMI*	*Kercheval Pl / Cadieux: PI-23-032*	*-*	*-*	*65*
	4.50	*SEMI*	*Liberty / Zeeb: PI-21-007*	*17*	*47*	*-*
	4.51	*SEMI*	*Prospect / Cherry Hill: PI-23-017*	*-*	*-*	*61*
	4.52	*SEMI*	*Pleasant Ridge / South Harris: PI-22-004*	*-*	*60*	*-*
	4.53	*SEMI*	*Whittaker / Bemis Road Roundabout: PI-22-024*	*-*	*3*	*56*
	4.54	*SEMI*	*US-12 / US-23: PI-23-020*	*-*	*-*	*59*
	4.55	*SEMI*	*East Cross / Huron: PI-22-006*	*-*	*36*	*22*
	4.56	*SEMI*	*West River at Grosse Ile Parkway*	*54*	*1*	*-*
	4.57	*SEMI*	*Vista / Loiter Way, Belle Isle: PI-21-008*	*11*	*43*	*-*
	4.58	*SEMI*	*Hitchingham / Talladay: PI-22-003*	*-*	*54*	*-*
	4.59	*SEMI*	*SEMI Public Improvement Projects < $50k*	*17*	*180*	*(35)*
	4.60	*GRMI*	*Greater MI Master Order*	*1,929*	*2,325*	*2,216*
	4.61	*GRMI*	*EAST CENTER WEST-MSK TWNSHIP*	*-*	*24*	*1,349*
	4.62	*GRMI*	*PET COUNTRY CLUB RD PI 2021*	*966*	*364*	*0*
	4.63	*GRMI*	*COST MGT ORDER FOR SPECTRUM PI*	*9*	*1,131*	*-*
	4.64	*GRMI*	*PET ALANSON PI 2022*	*-*	*88*	*863*
	4.65	*GRMI*	*MARKET WEALTHY TO WILLIAMS 8" PI RELOCATE*	*746*	*(42)*	*-*
	4.66	*GRMI*	*Clare - Little Tobacco River at Maple St*	*586*	*4*	*-*
	4.67	*GRMI*	*TAWAS WB M55 PI 2023*	*-*	*-*	*589*
	4.68	*GRMI*	*COST MGT ORDER FOR MEADOWLANE PI*	*-*	*543*	*0*
	4.69	*GRMI*	*SSM ARLINGTON ST PI 2021*	*410*	*82*	*-*
	4.70	*GRMI*	*COST MGT FOR EASTERN PI*	*42*	*423*	*-*

Michigan Public Service Commission
DTE Gas Company
DTE Gas Detailed Routine Capital Project List for 2023 - 2025
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Line No.	Sub Line No.		Description (a)	12 mos. ending 12/31/2021	12 mos. ending 12/31/2022	12 mos. ending 12/31/2023
	4.71	GRMI	DENSMORE (PARENT ORDER)	-	32	423
	4.72	GRMI	COST MGT FOR 10 MILE PINE ISLAND TO ALGOMA PI PROJECT	-	31	418
	4.73	GRMI	COST MGT ORDER FOR FULLER PI	411	(0)	0
	4.74	GRMI	SSM 6 MILE CULVERT PI 2021	313	63	0
	4.75	GRMI	Grayling - Butman Rd - PI2021	348	0	-
	4.76	GRMI	COST MGT ORDER BRISTOL AND PANNEL	-	38	305
	4.77	GRMI	COST MGT ORDER 84TH HANNA TO EAST PARIS	-	-	321
	4.78	GRMI	MEMORIAL/WEBER LAKETON TWP	315	-	(0)
	4.79	GRMI	COST MGT ORDER FOR 32ND AVE BRETON TO SHAFFER	371	(59)	-
	4.80	GRMI	SSM EASTERDAY PI 2023	-	-	299
	4.81	GRMI	KING M95 PI 2023	-	-	294
	4.82	GRMI	HOUSTON CITY OF MUSKEGON	118	176	-
	4.83	GRMI	COST MGT ORER FOR RICHARDS	285	-	-
	4.84	GRMI	PET CHEBOYGAN US23 PI 2021 PROJECT HEADER	281	-	-
	4.85	GRMI	CALIFORNIA DREAMIN-NORTH MUSKEGON	-	251	0
	4.86	GRMI	Manistee - Maple & Merkey St Reconstruction - PI2023	-	-	214
	4.87	GRMI	COST MGT ORDR FOR MILTON CI REPLACEMENT	-	9	196
	4.88	GRMI	Ludington - Hansen Rd - Stiles to Amber - PI2022	-	201	-
	4.89	GRMI	PET MACKINAW CITY US 23 PI 2022	-	2	191
	4.90	GRMI	Traverse City - Grandview Parkway - PI2023	-	-	178
	4.91	GRMI	MEARS PROJECT	-	99	79
	4.92	GRMI	Beulah - US31 Rebuilding - PI2022	-	174	1
	4.93	GRMI	LAKE AND LAWRENCE- NORTH MUSKEGON	-	162	6
	4.94	GRMI	ALP TAWAS AND FAIR ST PI 2021	149	8	-
	4.95	GRMI	WAYNE CITY OF NORTON SHORES	143	-	-
	4.96	GRMI	COST MGT ORDER PAGE PI RELOCATE	-	141	(0)
	4.97	GRMI	PET CHX US31 PI 2021 PROJECT HEADER	134	-	-
	4.98	GRMI	Cost MGT Order Rogue River 12" Bridge Crossing	-	-	133
	4.99	GRMI	COST MGT ORDER FOR N MAIN CEDAR CREEK CROSSING	133	-	-
	4.100	GRMI	COST MGT ORDER FOR NORTHVILLE PI PROJECT	131	-	-
	4.101	GRMI	COST MGT ORDER FOR PI CEDAR AND MAIN ST OFFSETS	130	1	-
	4.102	GRMI	N PETERSON 4" MAIN RENEWAL	-	-	129
	4.103	GRMI	TAWAS PI 2022 GREEN ROAD	-	12	116
	4.104	GRMI	Traverse City - Hammon Rd at 4 Mile - PI2021	126	-	-
	4.105	GRMI	KING HARDING AVE PI 2023	-	-	124
	4.106	GRMI	WHITEHALL LAKESHORE 4" MAIN RENEWAL	-	-	121
	4.107	GRMI	MICHIGAN CITY OF MUSKEGON	121	-	-
	4.108	GRMI	Mt Pleasant - Pickard St - PI2023	-	-	121
	4.109	GRMI	COST MGT ORDER FOR BONNEVILLE DR SER RENEWALS	113	-	-
	4.110	GRMI	PARENT WO 76TH E OF HAMMOND CREEK BORE	-	111	0
	4.111	GRMI	PET N SHORE DR PI 2022 DTE DWG 01	-	9	102
	4.112	GRMI	WILSHIRE DR CITY OF WHITEHALL	110	-	-
	4.113	GRMI	EASTERN AND GEORGIA PI	-	109	-
	4.114	GRMI	ALP HARRISVILLE PI 2021	105	-	-
	4.115	GRMI	COST MGT MARKET 96" PHASE 2 PI	-	102	0
	4.116	GRMI	COST MGT ORDER FOR PLYMOUTH OFFSET	100	-	-
	4.117	GRMI	WEBER LAKETON TWP	98	-	-
	4.118	GRMI	COST MGT ORDER FOR 84TH DIV TO EASTERN PI	97	-	-
	4.119	GRMI	HARVEY-CATHERINE	1	95	0
	4.120	GRMI	COST MGT ORDER FOR GODFREY PI	87	0	-
	4.121	GRMI	PET CHX M66 CULVERT PI 2022	-	87	-
	4.122	GRMI	Traverse City - Cass Rd Box Culvert	79	7	-
	4.123	GRMI	WARNER WHITEHALL PI MAIN RENEWAL	-	-	82
	4.124	GRMI	MARKET PI PROJECT	-	81	-
	4.125	GRMI	PET BOYNE FALLS US131 PI 2021	72	-	-
	4.126	GRMI	COST MGT FOR CALHOUN AND JOURDAN RENEWALS	-	-	67
	4.127	GRMI	HANSON-CITY OF HART	11	56	-
	4.128	GRMI	MCCONNELL-PRESCOTT-CITY OF NORTH MUSKEGON	7	57	-
	4.129	GRMI	PET WING RD PI 2021	60	-	-
	4.130	GRMI	Farwell - Roundabout at Surrey & Old State - PI2023	-	-	60
	4.131	GRMI	ALP ROGERS CITY 1ST AVE PROJECT HEADER	-	59	-
	4.132	GRMI	GRMI Public Improvement Projects less than $50k	408	456	760
5			Service Abandonments 1/	5,688	6,707	6,909
6			Service Alterations 1/	21,525	29,047	30,873
7			Service Renewals 1/	11,142	11,822	11,546
8			System Reliability	25,764	29,332	36,900
	8.1	SEMI	8 Mile / Kelly - Eastland Mall	-	1,387	1,027
	8.2	SEMI	Textile / Stoney Creek	-	23	1,893
	8.3	SEMI	Packard / Woodland Hills	5	1,210	626
	8.4	SEMI	12" STL 150 PSIG Design - Chelsea	1,861	(32)	0
	8.5	SEMI	Willow / Sherwood (Karr)	-	1,641	12
	8.6	SEMI	Conant / Hamtramck	-	-	1,449
	8.7	SEMI	East Huron / 4th Avenue 100 PSIG Inlet Install	1,428	-	-

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	8.8	SEMI	Fort / 21st MDOT #10776	1,290	-	-
	8.9	SEMI	M-52 / Waterloo	-	1,388	(139)
	8.10	SEMI	Main / Old US-12 #10568, Chelsea	1,215	-	-
	8.11	SEMI	Waterloo from Stonehill to Lingane	-	-	1,115
	8.12	SEMI	Barton Shore / Whitemore Lake Road	1	1,043	12
	8.13	SEMI	PMP 10097: Carpenter / Packard, SROPPMICH23001	-	5	1,040
	8.14	SEMI	SR Blanket	621	1,307	(45)
	8.15	SEMI	Bunton / Willis vault install	929	3	-
	8.16	SEMI	Textile / Deer Creek	-	1	931
	8.17	SEMI	John Hauk / Merriman	-	0	877
	8.18	SEMI	Holmes / Prospect - NEBelt Valve	-	0	876
	8.19	SEMI	System Reliability Admin	1,067	144	43
	8.20	SEMI	Baxter / Green, Ann Arbor	-	846	2
	8.21	SEMI	2020 Synergi Model Update	563	277	-
	8.22	SEMI	Chicago / Telegraph	1	414	423
	8.23	SEMI	Ann Arbor Saline / Tower (Bennett)	2	160	666
	8.24	SEMI	Michigan Avenue / Elm Road (Brady)	-	3	763
	8.25	SEMI	Textile / Lake Road	-	4	757
	8.26	SEMI	Mitchell / Commor	472	162	0
	8.27	SEMI	Oakwood / Southfield	24	95	490
	8.28	SEMI	Gulley / Wilson	-	1	555
	8.29	SEMI	Ford / Outer Drive West	303	230	2
	8.30	SEMI	Huron River Drive / Chalmers	-	3	497
	8.31	SEMI	Carrie / McNichols	-	424	26
	8.32	SEMI	5th / West	-	-	415
	8.33	SEMI	Textile / Pineview	-	1	413
	8.34	SEMI	Annapolis / Monroe	11	378	3
	8.35	SEMI	West Outer Drive / Willow Cove	18	351	16
	8.36	SEMI	Golfside / Packard	-	377	1
	8.37	SEMI	Outer Drive / Enterprise	308	52	-
	8.38	SEMI	8th / Outer Drive	32	310	3
	8.39	SEMI	2022 System Reliabilty Tap & Stop / Corrosion Projects	-	297	8
	8.40	SEMI	PMP 10016: Plymouth Road / Nixon, SROMICH23009	-	1	290
	8.41	SEMI	Huron River and Westview valve replacement (2018 SE Carry-over)	275	-	-
	8.42	SEMI	PMP 10015: 7 Mile / Telegraph, SROALN22011	-	116	158
	8.43	SEMI	Russell / Frederick	-	11	224
	8.44	SEMI	Dexter / Scio Township	-	222	0
	8.45	SEMI	Hall / Van Horn	2	192	16
	8.46	SEMI	Beverly / Inkster	-	1	203
	8.47	SEMI	Mott Road – Milford Easement	-	0	189
	8.48	SEMI	Southern / Pardee Station Upgrades	-	107	66
	8.49	SEMI	Connor / Milbank	-	-	172
	8.50	SEMI	Cheyenne / Hannan	-	-	160
	8.51	SEMI	Pelham / Wick	-	3	134
	8.52	SEMI	Core SS Design Team	41	87	4
	8.53	SEMI	Core SS MEP Project Management	35	89	2
	8.54	SEMI	Ferry / Russell	-	-	125
	8.55	SEMI	Pressure Group	55	61	58
	8.56	SEMI	Connecticut / Oakland	-	1	102
	8.57	SEMI	PMP 10025: Kercheval / Algonguin, SROLYN23005	-	3	98
	8.58	SEMI	Woodrow Wilson and Midland	85	-	2
	8.59	SEMI	PMP 10096: Allen Road / Eureka, SROLYN22010	-	21	51
	8.60	SEMI	Fort Street Bypass at River Rouge Station	-	72	-
	8.61	SEMI	PMP 10021: 14255 Warren, SROALN23008	-	-	70
	8.62	SEMI	2022 Core SS MEP Pressure Group (Material / Labor)	-	22	44
	8.63	SEMI	PMP 10013: Geddes / Huron Parkway, SRGMICH23013	-	3	62
	8.64	SEMI	2021 CORE SS MEP Materials	5	58	-
	8.65	SEMI	Relief Valve Pilot	59	-	-
	8.66	SEMI	Evergreen / Lyndon	-	45	7
	8.67	SEMI	Grosse Ile Second Feed (costs moved to Large Capital Project)	(545)	-	-
	8.68	SEMI	SEMI SR Projects less than $50k	253	54	242
	8.69	GRMI	Charlevoix Pine River Crossing	446	2,307	2,888
	8.70	GRMI	Project Management & Support	2,370	1,016	1,712
	8.71	GRMI	GRMI MAOP Support	-	829	1,043
	8.72	GRMI	GRMI Blanket WO	-	789	912
	8.73	GRMI	East Beltline & Burton	-	37	918
	8.74	GRMI	Wing Ave & 60th	29	572	232
	8.75	GRMI	M-72	-	77	680
	8.76	GRMI	Whitehall & Bard	-	433	303
	8.77	GRMI	Perkins & Knapp	-	172	494
	8.78	GRMI	Monroe & Longbridge (Plastic)	-	-	498
	8.79	GRMI	230th Ave & US-10	-	77	504
	8.80	GRMI	River & Thompson	-	23	544
	8.81	GRMI	44th & Patterson	-	322	229
	8.82	GRMI	N Roscommon Rd	64	466	-

Michigan Public Service Commission
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Line No.	Sub Line No.		Description (a)	12 mos. ending 12/31/2021	12 mos. ending 12/31/2022	12 mos. ending 12/31/2023
	8.83	GRMI	Lincoln & 5th	61	288	155
	8.84	GRMI	Design	-	62	573
	8.85	GRMI	Reed City & Roth	-	239	223
	8.86	GRMI	Lincoln & Carmel	295	155	-
	8.87	GRMI	M-55 & Lorenz	-	282	152
	8.88	GRMI	Wood & Allen	-	21	411
	8.89	GRMI	Maryland & Michigan	-	425	-
	8.90	GRMI	Millbrook & Whiteville	-	10	411
	8.91	GRMI	East Manistee Gate Station Tie In	-	-	421
	8.92	GRMI	Rusche & 6 Mile	394	-	-
	8.93	GRMI	4 Mile & 70th Ave	-	293	81
	8.94	GRMI	Norton & Waalkes	220	134	-
	8.95	GRMI	O'Brien Rd & Butterworth	278	73	-
	8.96	GRMI	6" Coldwater	-	42	301
	8.97	GRMI	US-31 Shore Line & Fruit SRT 20098	341	-	-
	8.98	GRMI	5 Mile & Northville	-	-	338
	8.99	GRMI	LSSU Replace Vault & Meter Manifold	-	41	298
	8.100	GRMI	F-41	-	263	62
	8.101	GRMI	Alanson Supply	0	318	-
	8.102	GRMI	10 Mile & Childsdale	-	2	307
	8.103	GRMI	Plainfield & 5 Mile	301	-	-
	8.104	GRMI	Oscoda Farm Tap	-	-	300
	8.105	GRMI	Boardman & 8th V-11002 Replacement	-	129	161
	8.106	GRMI	W. County 388 Rd, Hermanville	-	-	281
	8.107	GRMI	Section 22 Road	-	-	273
	8.108	GRMI	Ball Creek & Muskegon	-	140	132
	8.109	GRMI	Cass & 14th	267	-	-
	8.110	GRMI	Cedar & Fairplains	-	-	267
	8.111	GRMI	M-88	-	261	-
	8.112	GRMI	Charlevoix Uprating	257	-	-
	8.113	GRMI	Millcreek & North Park	-	2	231
	8.114	GRMI	Pine & Simons	86	65	73
	8.115	GRMI	Camp Dagget	-	213	-
	8.116	GRMI	Lake Antoine Rd	19	189	-
	8.117	GRMI	44th & Shaffer	208	-	-
	8.118	GRMI	11 Mile & Northland	206	-	-
	8.119	GRMI	M-55 & Simmons Rd	203	-	-
	8.120	GRMI	US-31 & Villa Low Pressures	-	-	199
	8.121	GRMI	Lost Lake Woods to Harrisville	199	-	-
	8.122	GRMI	M-69 (9156 to 9603)	-	196	-
	8.123	GRMI	Lincoln & Baseline	-	101	94
	8.124	GRMI	M-115 & Gregory	-	3	189
	8.125	GRMI	4 MIle & Shunk	-	181	-
	8.126	GRMI	Burgess Rd	-	140	36
	8.127	GRMI	N Mt Pleasant Gate Station	21	154	-
	8.128	GRMI	5th & Grant	48	125	-
	8.129	GRMI	Replace SRT 20048(AKA M-119)	171	-	-
	8.130	GRMI	US-2 & B-1 Rd. Hannahville	170	-	-
	8.131	GRMI	Cathro Rd.	168	-	-
	8.132	GRMI	Maple Island & Baseline	161	-	-
	8.133	GRMI	Billman FTT 30126 & FTT30122	159	-	-
	8.134	GRMI	US-41 Nadeau	-	143	14
	8.135	GRMI	Lake Winyah Rd.	157	-	-
	8.136	GRMI	Monroe & Longbridge (Steel) (2022 Design)	-	-	152
	8.137	GRMI	Getty & Giles	151	-	-
	8.138	GRMI	M-95	-	150	-
	8.139	GRMI	Stolt Rd	-	106	42
	8.140	GRMI	28th & Division	147	-	-
	8.141	GRMI	Broadway & Richmond	-	19	122
	8.142	GRMI	Oakcrest Drive	-	141	-
	8.143	GRMI	14th Road	-	139	-
	8.144	GRMI	Boyne City MAOP Record Resolution 4" Steel	134	-	-
	8.145	GRMI	Beaver Island FTT 30111	-	-	130
	8.146	GRMI	Edson & 18th (Georgetown Station)	-	-	127
	8.147	GRMI	44th & Walma	127	-	-
	8.148	GRMI	US-2 & Sturgeon Mill Rd	-	-	127
	8.149	GRMI	Evert & Lester	33	94	-
	8.150	GRMI	9th & Broadway	-	-	120
	8.151	GRMI	US-31 & Brundage	-	119	-
	8.152	GRMI	Old US-27 FTT's	-	115	3
	8.153	GRMI	Reed City Hospital SRT Upgrade (Design Only)	-	110	-
	8.154	GRMI	Roth & Reed City Vault	109	-	-
	8.155	GRMI	279-FT053 (Lake Antoine Inlet Retirement)	-	-	104
	8.156	GRMI	Boyne City MAOP Record Resolution 6" Steel	103	-	-
	8.157	GRMI	St Martins Hill	-	-	102

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	8.158	GRMI	Evanston & Ensley	90	10	-
	8.159	GRMI	Dickerson & Milbocker	99	-	-
	8.160	GRMI	E North Down River	96	2	-
	8.161	GRMI	Bristol Rd. FTT 279-30039	97	-	-
	8.162	GRMI	US-41 & County 360 Rd.	-	97	-
	8.163	GRMI	2000 Ford	-	-	95
	8.164	GRMI	19 Mile FTT 30073	-	-	97
	8.165	GRMI	Marsh Road FTT 30079	-	-	93
	8.166	GRMI	E. Higgins Lake Rd.	16	76	-
	8.167	GRMI	4 Mile Rd MLV 50257 & 50258	-	92	-
	8.168	GRMI	Stoney Corners	3	88	-
	8.169	GRMI	Airport & Plymouth Vault	88	-	-
	8.170	GRMI	FTT 30118 & 30133 Retiral (S. Straits HWY)	-	85	-
	8.171	GRMI	Townsend Rd.	85	-	-
	8.172	GRMI	Roberts Rd. FTT 30171	84	-	-
	8.173	GRMI	M-18 & E Forest FTTs 30108 & 30125	-	40	44
	8.174	GRMI	18657 US-31	-	-	82
	8.175	GRMI	Mead Paper	-	43	36
	8.176	GRMI	Tomkins	-	4	73
	8.177	GRMI	Wheeler Lake Road	-	-	76
	8.178	GRMI	20 Mile & 40th Ave.	55	3	13
	8.179	GRMI	Sleights Rd	-	70	-
	8.180	GRMI	Waucedah Rd FTT	-	68	-
	8.181	GRMI	Jefferson & Laketon	-	67	-
	8.182	GRMI	Leelanau Gate Station	32	-	35
	8.183	GRMI	Old Mission Peninsula Supply	65	-	-
	8.184	GRMI	Nason & Vorhies	64	-	-
	8.185	GRMI	Monroe & Long Bridge (Phase 2)	-	63	-
	8.186	GRMI	US-31 & Lamb Rd	-	-	62
	8.187	GRMI	S Lake Antoine	62	-	-
	8.188	GRMI	Monroe & Long Bridge	36	25	-
	8.189	GRMI	Washington & Hudson	-	61	-
	8.190	GRMI	945 M-88	60	-	-
	8.191	GRMI	M-46 SRT Retirements	-	31	22
	8.192	GRMI	Werth Road Vault	-	-	53
	8.193	GRMI	US-2 & Hunter	-	15	36
	8.194	GRMI	GRMI System Reliability Projects less than $50k	536	384	395
	8.195		Southfield Pipeline	5,693	1,506	-
	8.196		Howard City	(11)	20	-
	8.197	Top 25	Northeast Belt Assessment	-	-	481
9		Top 25	Transmission Fittings	677	908	3,221
10			Cathodic Protection 1/	6,286	7,366	10,751
11			Communications & Control - Meters 1/	12,505	14,401	23,498
12			Advanced Metering Infrastructure 1/	2,972	2,030	2,254
13			Revenue Protection 1/	3,568	2,448	1,129
14			New Market Attachments 3/	80,427	92,469	87,543
	14.1	Top 25	Mesick-Buckley	-	-	348
	14.2	Top 25	Peach Ridge	-	6	4,223
	14.3		W COUNTY LINE BIG RAPIDS	-	5,296	4
	14.4		ARTHUR ST	-	4,712	4
	14.5		FERRY RD AEP	4,458	8	-
	14.6		GRMI AEP Blanket	639	1,473	2,235
	14.7		BLUE LAKE AEP	1	3,729	155
	14.8		Kreuter AEP	-	3,512	4
	14.9		Stonington 2023	-	-	3,502
	14.10		DTE HQ Steam Conversion	3,231	135	-
	14.11		M-72 AEP 2022	-	-	2,980
	14.12		HOLTON DUCK LAKE 2021 AEP	2,807	17	-
	14.13		HIGGINS LAKE AEP	2,321	351	1
	14.14		PERRY & 24TH	2,518	37	-
	14.15		RIVERIVEW 12 20000 GRANGE RD	-	999	1,533
	14.16		BARNHART RD AEP	2,443	(1)	-
	14.17		LAKE GEORGE AEP	-	598	1,813
	14.18		VANTYLE AEP	2,182	2	-
	14.19		19 ASSOCIATES 600 CIVIC CENTER DR (JLA)	-	1,252	613
	14.20		STONE RD	-	-	1,853
	14.21		HOXIE RD AEP	-	-	1,623
	14.22		Crossroads Distribution Center North LLC (Ashley Capital)	393	1,120	81
	14.23		KALAMAZOO AEP	-	-	1,577
	14.24		15 MILE - INDIAN LAKES	1,532	1	-
	14.25		SEMI GMA Blanket	371	562	596
	14.26		Mayfield AEP 2023	-	-	1,471
	14.27		STEPHAN - STECKERT BRIDGE AEP	1,390	23	-

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	14.28	*FORD ROUGE SEPERATION*	*1,175*	*227*	*-*
	14.29	*17 Mile 2023*	*-*	*-*	*1,389*
	14.30	*Negaunee Lake/Lake Miramichi AEP 2023*	*-*	*-*	*1,359*
	14.31	*GRMI GMA Blanket*	*158*	*561*	*551*
	14.32	*GSA IRS 477 MICHIGAN AVE*	*1,209*	*14*	*-*
	14.33	*17 Mile - Woodlawn AEP 2023*	*-*	*1*	*1,181*
	14.34	*Heintzelman - 2023 AEP*	*-*	*-*	*1,123*
	14.35	*W JONES LAKE AEP*	*1,105*	*8*	*-*
	14.36	*CEDAR VALLEY AEP*	*-*	*1,011*	*89*
	14.37	*16 Mile 2023 AEP*	*-*	*1*	*1,068*
	14.38	*PIONEER RD - 2023 AEP*	*-*	*-*	*1,050*
	14.39	*TIFFANY AVE AEP*	*-*	*971*	*3*
	14.40	*PINE LAKE AEP 2022*	*-*	*961*	*(1)*
	14.41	*1208 Woodward LLC (Hudsons Tower)*	*(3,472)*	*4,308*	*120*
	14.42	*Pine Lake 2023*	*-*	*1*	*835*
	14.43	*U OF M CTG PLANT ADDN1120 E HURON*	*645*	*139*	*17*
	14.44	*LAKE MANUKA AEP*	*776*	*0*	*-*
	14.45	*S HIGGINS LAKE*	*-*	*766*	*-*
	14.46	*Amazon NGV 30880 Smith Rd Romulus MI New Main and Service*	*26*	*349*	*358*
	14.47	*FISHERMANS PARADISE*	*-*	*728*	*-*
	14.48	*CENTER RD AEP*	*656*	*63*	*-*
	14.49	*18 Mile AEP 2023*	*-*	*-*	*693*
	14.50	*Norton Rd 2023*	*-*	*-*	*667*
	14.51	*Milton Manufacturing 19679 John R*	*617*	*19*	*-*
	14.52	*FONGER ST AEP 2022*	*-*	*623*	*(1)*
	14.53	*APPLE LANE - EVELINE ORCHARDS AEP*	*590*	*11*	*-*
	14.54	*Gaunt Rd*	*-*	*-*	*593*
	14.55	*General Service Admin 985 Michigan Ave*	*70*	*503*	*-*
	14.56	*Chestnut AEP 2023*	*-*	*-*	*543*
	14.57	*SPRINGWATER BEACH AEP 2022*	*-*	*538*	*0*
	14.58	*MISSION POINT ADDITION AEP*	*529*	*0*	*-*
	14.59	*EXTRUDED ALUM CO 7200 INDUSTRIAL DR*	*-*	*497*	*4*
	14.60	*INTERMEDIATE LAKE AEP 2022*	*-*	*498*	*0*
	14.61	*THEODORE LEVIN US COURTHOUSE 231 W LAFAYETTE*	*489*	*4*	*-*
	14.62	*M3 Commerce 9501 Conner St Detroit Main and Service*	*7*	*471*	*8*
	14.63	*170TH - HERSEY*	*484*	*2*	*-*
	14.64	*BROWN/SCRAM LAKE*	*-*	*485*	*-*
	14.65	*J STAR MOTION 13617 WOODLAWN HILLS DR*	*154*	*321*	*4*
	14.66	*N HIGGINS LAKE 2023*	*-*	*-*	*474*
	14.67	*DTW SIERRA 30500 SUPERIOR RD*	*-*	*2*	*470*
	14.68	*Redmond Rd 2023*	*-*	*-*	*466*
	14.69	*NEW HAVEN 14 8068 BUCHANAN ROAD*	*-*	*116*	*331*
	14.70	*GVSU DEVOS 401 W FULTON ST*	*-*	*421*	*1*
	14.71	*MI POTASH FACILITY 510 120TH AVE*	*-*	*303*	*104*
	14.72	*ELMER'S CRANE AND DOZER*	*393*	*4*	*-*
	14.73	*11 MILE/GRANGE AVE AEP*	*-*	*377*	*2*
	14.74	*M 76 AEP*	*376*	*0*	*-*
	14.75	*Spectrum Health Cedar Street Long Term Care - new Facility*	*-*	*(84)*	*455*
	14.76	*Speedtrack Products Walker 3060 South Industrial Dr*	*158*	*203*	*2*
	14.77	*3 and 4 MILE RD ADA*	*343*	*9*	*-*
	14.78	*Boss Plow New Powder Coat Line*	*309*	*29*	*11*
	14.79	*Schreiber Foods-2023 Expansion*	*-*	*-*	*349*
	14.80	*ALANSON AEP*	*1*	*333*	*3*
	14.81	*ATKINS RD - 2023 AEP*	*-*	*-*	*337*
	14.82	*PHELPS AEP*	*-*	*336*	*0*
	14.83	*PARTRIDGE RD - BARNHART ADDITION AEP*	*332*	*-*	*-*
	14.84	*MUNSON HOSPITAL 1201 6TH ST*	*210*	*109*	*-*
	14.85	*FIAT/CHRYSLER 4000 St Jean*	*91*	*195*	*8*
	14.86	*Spectrum Health - Cogen*	*-*	*286*	*3*
	14.87	*Andy Mast Greenhouse District Reg 2875 Heights Ravenna Rd*	*(57)*	*332*	*10*
	14.88	*OPAL FUELS SALEM 13 10611 W 5 MILE*	*-*	*(1,491)*	*1,775*
	14.89	*8309 N OLD 27 Frederic Towing*	*96*	*179*	*-*
	14.90	*Grand Rapids WWTP InterConnect Project; Biodigester*	*203*	*72*	*-*
	14.91	*Verplank Port Facility Family Holding 151 N Causeway St.*	*-*	*128*	*117*
	14.92	*ASPHALT PAVING 685 S ACCESS HWY*	*107*	*136*	*-*
	14.93	*Andy Mast Greenhouse Expansion*	*256*	*(32)*	*-*
	14.94	*1001 W Eight Mile - Construction heat*	*-*	*(61)*	*276*
	14.95	*EVELINE ORCHARDS AEP*	*-*	*198*	*0*
	14.96	*Central Michigan 1980 E Campus*	*198*	*-*	*-*
	14.97	*CANTON RENEWABLES 4345 S LILLEY RD*	*-*	*31*	*163*
	14.98	*FIAT/CHRYSLER 11851 Freud*	*164*	*30*	*-*
	14.99	*BPV 511 75TH ST SW*	*-*	*-*	*176*
	14.100	*Shoreline Fruits 10106 N US 31 Service Renewal*	*-*	*-*	*159*
	14.101	*MERCY HEALTH HACKLEY 1700 CLINTON*	*47*	*82*	*26*
	14.102	*Unifirst: 9951 Inkster Rd - Construction*	*-*	*111*	*45*

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	14.103	GRAM 524 BUTTERWORTH SW	52	87	15
	14.104	Queen Lillian II 3439 Woodward Ave New Main and Service	140	2	-
	14.105	STATE/BRICK RD AEP 2022	-	138	4
	14.106	1150 W MEDICAL CENTER DR, ANN ARBOR, MI 48109	(108)	167	82
	14.107	Amazon State Fair Grounds Project	132	4	-
	14.108	OAKLEAF VILLAGE ADULT CARE 5435 SHEFFER FARM RD	-	131	2
	14.109	GRAM Production Pharm Exp Ph 2&3 524 Butterworth St SW	-	127	4
	14.110	111 LYON, GRAND RAPIDS, MI 49505	118	0	-
	14.111	Gateway Industrial Center - Main Relocation	-	3	112
	14.112	ORCHARD VIEW CARDINAL ELEM SCHOOL 2310 MARQUETTE	115	-	-
	14.113	GREAT LAKES POTATO CHIPS 522 W COMMERCE, BLAIR	104	9	-
	14.114	DAIFFUKU 300 S M75	42	66	-
	14.115	CITY OF DETROIT 14044 SCHAEFER	-	-	106
	14.116	Unknown SE	-	-	103
	14.117	CASCADE HILLS 1221 SPAULDING AVE SE	98	3	1
	14.118	Gerald R Ford Intl Airport Authority 5630 Gateway Dr. Main Renewal	-	-	101
	14.119	NorthPoint Development Eastland Commerce Ctr. 3 Services and New Main	-	-	101
	14.120	WHITEHALL INDUSTRIES 4960 W PROGRESS	99	0	-
	14.121	MEIJER REROUTE 1031 E PICKARD ST	-	42	54
	14.122	PROJECT FOR PROJECT GREYSTONE ABANDONMENTS, HP	18	0	77
	14.123	LEWIS WELDING 3225 NORTHRIDGE DR SUITE A	72	21	-
	14.124	MYERS LAKE/PETERSON FARMS AEP	93	(0)	-
	14.125	McLaren Central Michigan 1221 South Dr. Mt Pleasant Service Renewal	-	-	89
	14.126	LUME ATTITUDE WELLNESS 9741 S INDUSTRIAL PK EVART	81	6	-
	14.127	3874 Research Park Drive - Vanguard/Sartorius Biotech	-	56	30
	14.128	Project Header 5557 McAuley Dr	83	-	0
	14.129	NBR OLTHOFF EXPANS 2725 OLTHOFF DR	-	-	79
	14.130	Kalitta Air 3631 Skyway St. New Aircraft Hanger	-	63	15
	14.131	Morningside Development 1100 Broadway Ave New Service	-	76	1
	14.132	Clark Retirement Communities Keller Lk Project	76	-	-
	14.133	SPECTRUM C&C 251 MICHIGAN ST	-	62	13
	14.134	Chaison System Enhancement	-	75	(0)
	14.135	Amazon New Sortation Facility Main and New Service	53	19	-
	14.136	5801 NORTHLAND DR BLYTHEFIELD COUNTRY CLUB	-	67	5
	14.137	1208 WOODWARD LLC 1208 WOODWARD	-	47	24
	14.138	GVSU CUB BOILER EXPANSION 11136 SERVICE DRIVE	13	57	-
	14.139	Boyne USA 21 Ramshead (2 Service Renewals 1 Main Renewal)	-	-	69
	14.140	FORD HUB	-	35	34
	14.141	West Rock Corregated Project 19661 BROWNSTOWN CTR DR.	67	1	-
	14.142	CLARE PUBLIC SCHOOLS 688 ANN ARBOR TRL	-	(2)	68
	14.143	21301 OAKWOOD BLVD DEARBORN	65	(3)	4
	14.144	BOSSET RD AEP	-	1	65
	14.145	COCA-COLA DIST FACILITY (LONE OAK KENT) 6909 RAPIDS DR GR	64	-	-
	14.146	ASHLEY CAPITAL GREYSTONE 13571 HAMILTON HP	64	-	-
	14.147	HARBOR FOAM BOILER ADD 2950 PRAIRIE ST SW	-	61	3
	14.148	Delamar Hotel and Resort LLC	64	(0)	-
	14.149	GR 36TH 4300 36TH ST	-	-	63
	14.150	Tri County Area Schools Main Renewal Project 21502 Kendaville Rd	8	50	-
	14.151	Bay Area Transportation Auth 1340 W Hammond Rd. New Service and meter	-	-	57
	14.152	GRPS - Innovation High School - 421 Fountain St. New boiler plant and generator	-	-	56
	14.153	KROGER 15675 Wahrman Rd	55	-	-
	14.154	M-72 AEP	0	55	-
	14.155	GRANDVILLE PS 4900 CANAL AVE SW	54	0	-
	14.156	KENT CO BIOENERGY 10300 S KENT DR SW	-	2	51
	14.157	STRUCTUAL CONCEPTS 5566 GRAND HAVEN RD	-	-	52
	14.158	Commerce 275 LLC/Hillwood Developers Pinnacle Park Phase 2 Site A	(254)	304	-
	14.159	CWD 4500 IVANREST	-	8	42
	14.160	GATEWAY 12600 SOUTHFIELD RD	0	(21)	-
	14.161	UNIVERSITY OF MICHIGAN 1315 E Ann St	73	6	(133)
	14.162	Marathon 301 S Fort	-	-	(64)
	14.163	FORD MOTOR 20100 OAKWOOD	-	-	(71)
	14.164	UofM Temp CCRB Rec Bldg	-	0	(79)
	14.165	LOUSIANA PACIFIC EXPANSION 8504 S M95	-	(648)	562
	14.166	GLWA WWP 2022 HVAC Improvements	-	-	(88)
	14.167	Cadillac Casting 1500 Fourth Ave New Service and meter	-	-	(116)
	14.168	GLWA Springwells gas svc line reloc (2) (NO LOAD)	-	-	(426)
	14.169	MGU Interconnect	-	-	(510)
	14.170	AMC Site 14250 Plymouth Rd	-	(710)	42
	14.171	Delray New High Pressure Line 911 W Jefferson	155	384	(1,697)
	14.172	JOHNSON FARMS INT W4697 NUMBER 25 ROAD	-	(10)	(1,546)
	14.173	New Market Attachment Projects less than $50k	1,447	421	2,016
	14.174	Routine New Market Attachments (unit based)	44,549	50,936	46,034
15		Permits and Other Adjustments	1,133	800	689
16		Sales and Use Tax Settlement	-	-	-
17		Leak Detection and Repair	-	-	-

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18		**Total Distribution Plant**	197,458	232,634	250,614
19		**Transmission Plant**			
20		Total Capital Expenditures - Transmission Plant	16,456	15,126	10,782
	20.1	*Bradley Drain Line Lowering; A-Line / B-Line, Gratiot County*	2,440	0	-
	20.2	*MLV #8 Replacment*	1,886	119	3
	20.3	*16" Loreed-Ludington Pipeline: Replace Pipe at Baldwin River*	1,942	18	-
	20.4	*West Branch Drain (16" Alpena pipeline) Line Lowering*	-	88	1,690
	20.5	*Willow Gate Station: ANR Supply Control Valve*	1,742	29	-
	20.6	*Sault Sainte Marie Gate Station: Replace heater*	1	1,330	175
	20.7	*6" Mackinaw Pipeline: Exposed Pipe, Mackinaw Mill Creek Camping facility*	13	1,428	0
	20.8	*Rapid River Gate Station: Odorant Tank*	4	1,100	280
	20.9	*Escanaba Paper GS Add Additional Heater*	982	326	11
	20.10	*MLV #14 on A & B Lines: Replace the two mainline valves*	4	1,201	1
	20.11	*MLV #C4 Replacement*	1,143	4	-
	20.12	*2021 Milford - Replace MLV8C, CT, CD - Install Piping*	1	993	24
	20.13	*Scottville Gate Station: Install Filter Separator*	6	252	627
	20.14	*A-Line: Address exposed pipe at Pine Creek*	13	819	12
	20.15	*MLV5 Replacement*	752	17	-
	20.16	*2022 Milford GLWA Gas Line Support Build*	-	662	(1)
	20.17	*2022 Willow Gate: Valve 89 / new K/L bypass Valve*	-	637	-
	20.18	*2022 Milford Install K2 Bypass Control Valve*	-	570	50
	20.19	*MLV #C3 Replacement*	566	9	-
	20.20	*Sault Sainte Marie Purchase Meter Station: Replace odorizer building*	-	4	520
	20.21	*Northeast Gate Station: Overhaul west heater*	-	408	5
	20.22	*Willow Gate Station: remove meter #106-6*	384	(0)	-
	20.23	*Alpena Gate Station Heater Replacement*	200	179	2
	20.24	*North Muskegon Rebuild*	-	167	212
	20.25	*Milford: Install 24" Weld Cap MLV1 - 2022*	-	270	81
	20.26	*Brimley / Bay Mills Gate Station: Heater overhaul*	-	2	347
	20.27	*Loreed Combo Gate Replace 2 Relief and 1 Control Valve*	0	2	328
	20.28	*Gladstone Gate Station: Replace gate valve MLV2 with ball valve; MLV2 is RCV*	-	-	324
	20.29	*Milford Junction: Replace Valve B2*	273	27	-
	20.30	*Indian River Gate Station: Replace regulator building (RTN-22-001)*	-	6	289
	20.31	*Logan Churchill RMS: Demolish Station*	-	253	1
	20.32	*Kincheloe Building*	20	163	66
	20.33	*Vulcan Gate Station: Heater overhaul*	-	285	(42)
	20.34	*Big Rapids Construction Crew Equipment*	169	60	-
	20.35	*West Bloomfield Gate Station Filter Separator valve actuator install / replace*	55	172	0
	20.36	*2022 Milford Junction: 24" Manual Valve Upgrade*	-	195	1
	20.37	*Milford Junction: Concrete foundation upgrades*	2	188	-
	20.38	*Quinnesec Take-off valve Replacement*	189	-	-
	20.39	*Niagara Gate Station: Replace regulator building*	3	164	21
	20.40	*Six Lakes Belding Station: replace valves 4B, 9A,13D*	-	6	181
	20.41	*Six Lakes Storage Field Wellpad #10 valve replacement*	-	5	181
	20.42	*Sault St Marie Gate Station: Filter Coalescer*	133	39	2
	20.43	*New Era Gate Station: Replace Regulator building*	156	10	-
	20.44	*Union River Meter Station: Replace 24" Mainline Valve #2*	-	-	148
	20.45	*Montague Gate Station: Replace emergency valves*	2	134	10
	20.46	*Carson City Gate Station: Replace NJEX unit*	-	2	143
	20.47	*Au Train Gate Station: replace the regulators with new Mooneys*	129	14	-
	20.48	*Tawas Gate Station: Replace MLV #5*	-	-	142
	20.49	*Wellpad 9: Install Pigging Jumper*	-	3	139
	20.50	*Edmore Tap/S. Mt. Pleasant Take-off: Upgrade the NJEX cabinet*	3	135	1
	20.51	*NW Station Design*	12	9	117
	20.52	*Manton Gate Station: Replace station inlet valve, replace blowoff valve*	-	6	131
	20.53	*Lyon 24 Tap Removal*	-	137	-
	20.54	*2020 Willow Gate By-Pass, VanBorn 30, Phase 2*	104	17	-
	20.55	*Willow Gate Station: replace regulators 97 / 98*	5	112	0
	20.56	*UP Kingsford Louisiana Pacific Gate Station: Heater - 2021*	115	0	-
	20.57	*Six Lakes Storage Field: replace the closure, 12" B Header trap, Wellpad #5*	1	6	109
	20.58	*Replace doors (closures) on pig traps on storage field pipelines.*	114	1	-
	20.59	*Stanwood Gate Station: Replace electrical feed into station*	-	-	106
	20.60	*Beal City Gate Station: Upgrade relief valves*	98	3	-
	20.61	*Ludington Gate Station: Remove 2 tanks*	6	94	-
	20.62	*Menominee Gate Station: MLV #1 Blow Off Ext 16" Powers*	79	20	-
	20.63	*Dagget Gate Station: Replace regulators*	-	91	7
	20.64	*Pentwater Gate Station: Replace electrical feed*	2	78	17
	20.65	*2023 TSIM North Heater Installations and Commissioning*	-	-	97
	20.66	*Baldwin Gate Station Heater Overhaul*	-	94	-
	20.67	*Canadian Lakes: Pipeline overburden, A & B Lines*	1	74	18
	20.68	*Six Lakes Storage Field Wellpad #10 closure replacement*	-	2	90
	20.69	*East Muskegon Gate Station: Replace electrical feed*	3	90	(2)
	20.70	*Kalkaska - TCARP 2023 Carryover - Platforms*	-	-	87
	20.71	*Weidman Gate Station Pipiing Modifications*	85	1	-

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Line No.	Sub Line No.		Description	12 mos. ending 12/31/2021	12 mos. ending 12/31/2022	12 mos. ending 12/31/2023
	20.72		*Brimley / Bay Mills Gate Station: Filter-Coalescer on outlet piping*	*78*	*2*	*4*
	20.73		*New Era Gate Station: Replace emergency valves*	*2*	*79*	*3*
	20.74		*Iron River Gate Station: Replace heater ignitor system*	*-*	*7*	*76*
	20.75		*Goodwell 8C: Clean out and abandon*	*1*	*82*	*-*
	20.76		*Rogers Heights Gate Station: new odorizer, regulator building, move Rosemount pressure*	*-*	*80*	*2*
	20.77		*Aetna 8 Pipeline: disconnect it, clean it, abandon it*	*2*	*79*	*-*
	20.78		*Window Glazing*	*78*	*-*	*-*
	20.79		*2024 Taggart 12" Austin -Taggart: Install Odorization at Woolfolk*	*-*	*-*	*78*
	20.80		*Six Lakes: Install OPP Protection, MLV 1.5 on A-B Lines - 2023*	*-*	*0*	*77*
	20.81		*Whittemore Gate Station: Construct Proper Station Bypass*	*-*	*-*	*76*
	20.82		*At MLV2 on the 24" Belle River to Detroit Pipeline: Replace blowoff closures*	*-*	*5*	*69*
	20.83		*Crystal Falls Gate Station: Replace heater ignitor system*	*-*	*34*	*38*
	20.84		*Gladstone Gate Station: replace ignitor system on heater*	*-*	*36*	*35*
	20.85		*MLV #12 on ABC Lines: Repair / replace 3 foundations*	*2*	*68*	*-*
	20.86		*Hersey Pipeline Abandonment*	*1*	*5*	*63*
	20.87		*Big Rapids Vehicle Hoist Replacement*	*-*	*-*	*67*
	20.88		*South Muskegon Gate Station: Replace regulator to MGU and actuator*	*-*	*-*	*66*
	20.89		*Escamaba Gate Station: install indoor heatinf for instrumentation*	*-*	*-*	*64*
	20.90		*North Muskegon Gate Station Replace Primary Regulators - 2021*	*64*	*(0)*	*-*
	20.91		*At MLV C9 on ABC Lines: Design & install supports for 2 relief valves*	*-*	*4*	*57*
	20.92		*MLV #A10 & #B10, Replace 1/2" body bleeds are tubing*	*55*	*-*	*-*
	20.93		*2023 UP SSM SOO Purchase Station Paving*	*-*	*16*	*36*
	20.94		*Six Lakes - Norwich 35 Pipeline Abandonment - 2021*	*2*	*49*	*-*
	20.95		*Willow Gate Station: Odorant tank level alarm project*	*-*	*4*	*47*
	20.96		*Transmission Projects less than $50k*	*233*	*476*	*477*
	20.97		*Union River Metering*	*1,531*	*80*	*10*
	20.98		*Henry Street*	*35*	*-*	*-*
	20.99		*Quality Assurance*	*532*	*688*	*431*
	20.100	*Top 25*	*K-Line*	*0*	*0*	*2,255*
21			Sales and Use Tax Settlement	-	-	-
22			**Total Transmission Plant**	16,456	15,126	10,782
		Storage Plant				
23			Gas Storage Capital Expenditures	3,204	3,354	3,824
	23.01		*Well Plugging*	*1,258*	*1,368*	*1,259*
	23.02		*Stimulation / Recompletion*	*724*	*815*	*796*
	23.03		*Storage Field Integrity*	*833*	*661*	*267*
	23.04		*Well Upgrade*	*270*	*348*	*1,087*
	23.05		*Well Monitoring / EFM*	*119*	*162*	*415*
24			Environmental Projects - Storage Capital Expenditures	28	-	8
25			Compression - Storage Capital Expenditures	10,433	14,934	18,328
	25.01		*2022 BRM Unit 6 Turbine Engine Replacement and Controls Retrofit*	*-*	*1,191*	*3,783*
	25.02		*Actuator Replacement*	*2,287*	*573*	*544*
	25.03		*Turbine 2200 Engine Exchange*	*-*	*-*	*3,061*
	25.04		*GMVC Boiler replacement*	*176*	*1,125*	*599*
	25.05		*Replace valves R31 ,R38, R39, R40, R41, and (1) Waterbath Heater 2" WE x FE isolation valve*	*1,552*	*150*	*5*
	25.06		*Col Replace Valves & Actuators*	*28*	*1,514*	*156*
	25.07		*Replace Unit Exhaust Silencers*	*1,087*	*95*	*1*
	25.08		*Dehy Desiccant replacement*	*1*	*928*	*27*
	25.09		*Valves and Actuators*	*31*	*615*	*226*
	25.10		*P1& P2 Vibration Remediation*	*225*	*627*	*2*
	25.11		*GMVC #2*	*-*	*705*	*(0)*
	25.12		*Plant 1 turbine fuel gas piping insulation.*	*693*	*6*	*-*
	25.13		*Milford unit 504 engine side overhaul*	*-*	*-*	*674*
	25.14		*BRM Valve & Actuator Upgrades*	*-*	*7*	*664*
	25.15		*Taggart A Header Scrubber Replace Vane &*	*271*	*394*	*0*
	25.16		*Engine 208 Overhaul*	*-*	*549*	*93*
	25.17		*3" FG ESD Valve replacement*	*12*	*278*	*329*
	25.18		*Milford unit 501 compressor Overhaul*	*-*	*592*	*-*
	25.19		*Unit 203 overhaul*	*589*	*2*	*-*
	25.20		*Taggart U202 engine overhaul*	*-*	*-*	*578*
	25.21		*Taggart Replace J2 & J3 Tanks-2021*	*523*	*11*	*-*
	25.22		*BRM Z#5 starter*	*-*	*-*	*519*
	25.23		*2024 Turbine 2100 Engine Exchange*	*-*	*-*	*516*
	25.24		*Milford - Delaval Unit #501 Compressor*	*-*	*-*	*502*
	25.25		*COL Valve & Actuator Upgrades*	*-*	*1*	*498*
	25.26		*Actuators upgrade*	*1*	*463*	*20*
	25.27		*2021 Propane Plant Upgrades*	*419*	*63*	*-*
	25.28		*ESD & SSD System Manual Isolation Valve*	*-*	*-*	*477*
	25.29		*Milford Turbine 3100 PT replacement (also listed below)*	*-*	*-*	*463*
	25.30		*GMVH #2 engine OH*	*-*	*445*	*0*
	25.31		*Heater Inspection and Upgrade*	*-*	*3*	*408*
	25.32		*Kalkaska Comp EOH Unit 1*	*399*	*0*	*-*
	25.33		*GMVC#1*	*-*	*-*	*390*
	25.34		*Inspection/re-build the Union South inline Water Bath Heaters*	*1*	*386*	*(15)*

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	25.35	*Tank Upgrades*	309	18	-
	25.36	*60kW backup generator*	4	132	186
	25.37	*2022 West Columbus - FS-2 Valve Replacement*	-	316	5
	25.38	*Actuators replacement*	-	105	206
	25.39	*Air Dryer Upgrades*	-	1	298
	25.40	*T1 Tank upgrades*	-	1	283
	25.41	*Fire and Gas Detector Upgrades*	-	22	258
	25.42	*Proplant plant upgrade*	1	244	-
	25.43	*Panel and processor*	2	213	16
	25.44	*Upgrade processor for Dehy*	1	224	0
	25.45	*2017 Milford Storage Tank Upgrades*	207	-	-
	25.46	*Relocate pressure transmitters and install electric actuators*	59	86	55
	25.47	*Allen Bradley PC's*	-	150	48
	25.48	*Taggart Replace Station Platforms-2021*	173	21	(2)
	25.49	*V Valve Replacement*	156	23	13
	25.50	*BRM Still Column Replacement*	-	187	(1)
	25.51	*Filter Sep Dump Assemblies Upgrade*	0	191	(9)
	25.52	*Backup generator control panel upgrade*	-	50	124
	25.53	*FG HEX replacement*	3	38	131
	25.54	*TAG-21-013 Lead line valve replacement*	1	150	19
	25.55	*Unit 2 Exhaust Silencer Replacement*	1	137	21
	25.56	*COL Actuators*	66	89	1
	25.57	*Control Valve Upgrade*	-	3	152
	25.58	*Lead Line Valve Actuator Upgrade*	-	3	151
	25.59	*2021 Col Valve Replace V9 WE X WE*	151	0	-
	25.60	*FG HEX PSV Replacement*	6	74	69
	25.61	*Yard Electrical Terminations*	-	36	102
	25.62	*Unit jacket water cooler Replacement*	-	0	132
	25.63	*Backup generator control panel upgrade*	34	92	-
	25.64	*Fiber Optic Upgrade*	-	11	111
	25.65	*2020 BRM Rebuild 36" Regulators*	118	5	-
	25.66	*Compressor Unit 103 Overhaul*	-	113	8
	25.67	*Dehy isolation valves upgrade*	1	119	0
	25.68	*Taggart Unit 206 (2024 Material Pre-spend)*	-	-	120
	25.69	*Wireless transmitters installation*	2	115	0
	25.70	*Compressor Unit 105 Overhaul*	-	110	5
	25.71	*Taggart Comp Unit 204, 206 Overhaul*	112	-	-
	25.72	*Rockwell payment; also listed below*	-	-	112
	25.73	*COL Dehy train 1 hot glycol exchanger replacement*	54	57	-
	25.74	*Taggart U107 compressor overhaul*	-	-	111
	25.75	*2022 BRM Control Valve Upgrade*	-	76	32
	25.76	*Facility Upgrades*	-	112	(6)
	25.77	*2019 Emergency Materials*	61	44	-
	25.78	*2021 Milford - Seal Gas Filter Replacement*	103	1	-
	25.79	*Taggart Station Control System Upgrade*	104	0	-
	25.80	*Remove existing 24" Weld Cap and install 24" WN Flange- 12" Meter Runs*	79	24	(2)
	25.81	*Add light fixtures*	5	92	-
	25.82	*2022 BRM Septic Upgrade*	-	96	-
	25.83	*MCC- Redo wiring*	12	84	-
	25.84	*Taggart Calibration Building Control System Upgrade*	92	-	-
	25.85	*Windrock replacement*	-	-	92
	25.86	*Continue program of replacing 55 to 60 year old unit jacket water coolers.*	91	-	-
	25.87	*Upgrade FG ESD Valve Indication and Control*	-	14	74
	25.88	*Taggart U108 compressor overhaul*	-	-	87
	25.89	*TAG-00011-Lead line valve replacement*	-	3	82
	25.90	*Waste gate automation*	-	29	53
	25.91	*BRM Compressor Station Emergent*	-	-	72
	25.92	*502 Packing and Rod Repair*	-	-	71
	25.93	*DeLaval Fuel Gas Heat Exchanger Upgrade*	-	3	66
	25.94	*Taggart compressor station upgrades*	-	-	68
	25.95	*P1 Actuators*	52	13	-
	25.96	*Power Gas Supply Upgrades*	-	1	61
	25.97	*Upgrade ESD Valve Indication and Control*	-	11	49
	25.98	*2020 BRM Expand Union Regulators*	56	-	-
	25.99	*Z Fuel Gas Heat Exchanger Replacement*	55	0	-
	25.100	*Install rain caps for Unit Blowdown Silencers located at Plant 1*	(9)	64	-
	25.101	*ESD System Manual Isolation Valve*	-	-	51
	25.102	*Lead Line Valve Replacement*	-	-	50
	25.103	*Projects less than $50k*	(23)	414	185
26		**Total Storage Plant - Capital Expenditures**	13,665	18,289	22,160
27		Structures and Improvements	10,027	9,809	3,752
	27.01	*Coolidge Roofing*	-	926	104
	27.02	*Allen Road Storehouse Roof*	-	908	-
	27.03	*Mt. Pleasant Roof Replacement*	-	161	(5)

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	27.04	Lynch Road Parking Lot & Spoil Yard Paving	-	593	27
	27.05	Traverse City Station Paving	-	1,375	(8)
	27.06	ORC Replace BMS Tracer SC+	-	49	1
	27.07	Allen Rd Storehouse Replace BMS Tracer SC+	-	62	1
	27.08	Six Lakes Phase II Water Infiltration Correction	-	-	578
	27.09	Six Lakes Renovation	889	214	158
	27.10	Kalkaska Renovation	35	489	2
	27.11	Kingsford Renovation	10	1,673	13
	27.12	Wealthy Station Roof	782	12	-
	27.13	Lynch Road Paving	1,487	62	-
	27.14	Muskegon Phase II HVAC Replacement	657	1	-
	27.15	Mt. Pleasant Renovation	1,273	(128)	-
	27.16	Allen Road Roof	5	-	-
	27.17	Allen Road HVAC	(9)	-	-
	27.18	Muskegon Renovation	26	-	-
	27.19	Sault Ste. Marie Renovation	3	-	-
	27.20	Coolidge Renovation	(14)	-	-
	27.21	21-0105 NIL- Welch Ct-Renovation BU	754	589	0
	27.22	19-0141-COLSC- Bldg Fa#ade inspect & res	545	51	-
	27.23	21-0114 ARDCT-Garage Bay 2 lift rplc	176	367	-
	27.24	21-0140 RRORC-ORC Roof rplc	3	29	488
	27.25	22-0091 ARDCT-Flt Garage 2023 auto lift	-	3	506
	27.26	21-0151 LYNSC- Garage Auto Lift replc	6	473	-
	27.27	MSKSC-Garage Auto Lift Replace	367	68	-
	27.28	20-0021 ARDCT-Garage Auto Lift replace	404	-	-
	27.29	22-0008 MICSC-Flt Garage Auto Lift rplc	-	27	364
	27.30	21-0039 RRGST- site drainage reno 21	371	(32)	-
	27.31	21-0106 ESCSC- Cold Storage Bldg BU	168	142	0
	27.32	20-0034 COLSC-Garage Auto Lift Replace	292	0	-
	27.33	21-0072 NIL-Walkent CR move	284	6	-
	27.34	23-0078 TRCCT-Hastings drainage H2O proo	-	-	239
	27.35	21-0013 CADSC- Parking lot Pave	131	107	-
	27.36	20-0042 ARDCT-FFG LED Lighting Project	193	37	-
	27.37	22-0154 PETCT-Yard Storm H20 Runoff 22	-	1	228
	27.38	22-0006 COLSC-technical-Bldg A Crawl Spa	-	240	(36)
	27.39	22-0030 ARDCT-Fleet Garage OH Dr (3)	-	151	32
	27.40	22-0021 ARDCT-technical-Wrhse Racking Rp	-	169	-
	27.41	20-0074 - ARDCT-Add Compactor FFG waste	232	(91)	-
	27.42	23-0100 ARDCT-ICM/HPP Area Flooding Reme	-	-	129
	27.43	23-0022 PETCT-Garage roof rplc	-	-	128
	27.44	23-0068 TRCCT-Hastings rplc yard lightin	-	-	121
	27.45	21-0008 GRRWS-SE Office rooftop HVAC rep	12	107	0
	27.46	20-0122 COLSC-San & Storm lines to St	50	64	0
	27.47	21-0006 BRMLCS- Locker Rm Renovation	120	(15)	3
	27.48	22-0065 RRORC-ORC H2O Srvce line break/r	-	187	(79)
	27.49	21-0135 GRRWS-Fleet garage lights	1	21	77
	27.50	22-0021 ARDCT-Wrhse Racking Rplc TTGW	-	96	0
	27.51	21-0007 ARDCT- Fleet Garage Screen OH Dr	64	26	-
	27.52	20-0155 GRRWS-dispatch area HVAC unit re	86	-	-
	27.53	21-0015 CADSC-Siding replace	85	-	-
	27.54	23-0029 LYNSC-Fleet Garage heating syste	-	-	81
	27.55	21-0158 SSMSC- New prop bldg BU	3	78	(2)
	27.56	21-0131 WRCS-Gas Comp sites emergency ex	1	72	1
	27.57	23-0045 RRGST-ORC SW Gate Operator Rplc	-	-	74
	27.58	21-0121 ARDCT-Rplc HVAC_1249	5	67	-
	27.59	22-0022 LYNSC-Wrhse Racking Rplc TTGW	-	71	-
	27.60	23-0021 TRCCT-Welch Ct roof rplc	-	-	68
	27.61	22-0112 NIL-3 Mile Humidity Control Upgr	-	1	65
	27.62	22-0038 ARDCT-Flt CNG Bldg power feed	-	56	1
	27.63	23-0086 GLDSC-Fuel UST Removal	-	-	55
	27.64	17-0129 - Gas sites-replace pre UL325 OH	51	-	-
	27.65	21-0009 ARDCT-Mn Bldg Fire Alarm Replace	50	0	1
	27.66	Materials & Logistics	86	60	38
	27.67	Investment Recovery	(145)	(130)	(112)
	27.68	Other non-PMO Projects less than $50k	488	307	408
28		Transportation Vehicles and Equipment	7,680	9,773	14,193
29		Tools and Equipment	1,493	4,463	1,104
	29.01	Tools & Equip - Grand Rapids	432	1,913	369
	29.02	Tools & Equip - Michigan Ave	51	1,618	22
	29.03	Tools & Equip - Allen Rd	484	211	104
	29.04	Tools & Equip - Traverse City	55	43	222
	29.05	Tools & Equip - Escanaba	87	124	80
	29.06	Tools & Equip - Mt. Pleasant	92	89	51
	29.07	Tools & Equip - ORC	61	131	17
	29.08	Tools & Equip - Coolidge	75	54	72

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	29.09	*Tools & Equip - Muskegon*	53	95	-
	29.10	*Tools & Equip - Petoskey*	56	68	10
	29.11	*Tools & Equip - HPP*	-	-	65
	29.12	*Tools & Equip - Codes and Standards*	-	56	-
	29.13	*Tools & Equip - Kalkaska*	13	11	19
	29.14	*Tools & Equip - Taggart*	14	16	10
	29.15	*Tools & Equip - Lynch*	1	24	13
	29.16	*Tools & Equip - Milford Tran*	19	-	18
	29.17	*Tools & Equip - EPM*	-	-	30
	29.18	*Tools & Equip - Belle River*	-	11	2
	29.19	*Tools & Equip - Cadillac*	0	-	(0)
30		Communications and Control Equipment	1,223	1,671	2,242
	30.01	*Electronic Volume Correctors*	3	242	218
	30.02	*Gas Chromatographs*	90	-	61
	30.03	*Control Equipment*	596	157	435
	30.04	*Telemetering Equipment*	177	178	187
	30.05	*Gas Measurement Equipment*	169	683	319
	30.06	*ACE3600*	-	-	205
	30.07	*SCADA Equipment*	188	303	82
	30.08	*TSA*	-	109	735
31		**Total General Plant Capital Expenditures**	20,422	25,717	21,291
32		**Total Routine Capital Requirements**	$ 248,001	$ 291,765	$ 304,847

1/ Detailed project lists not available as this is routine unit based work
2/ Detailed Public Improvement project list for 2024 and 2025 is not available.
3/ The Area Expanions Project subset are broken out within the New Markets category

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.128	
Respondent: E. M. Abona	
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Question: 128. Refer to lines 17-24 on page 8 and lines 1-7 on page 9 of Mr. Abona's direct testimony on public improvements. Please provide the number of units, miles, or projects for each year 2018 to 2023 actual and forecasted for 2024, 2025, first 9 months of 2024, and the 12 months ending September 2025 with the related dollar amounts and excluding the East Jefferson project. Provide this information in Excel.

Answer: Prior to 2021, only expenditures above a routine level of spend were broken out into project level costs. Please see response STDG-1.1 for 2021-2023 Public Improvement costs by project. A detailed Public Improvement project list for 2024 and 2025 is not available. Known projects are available in Exhibit A-12, Schedule B5.11.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.134	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 134. Refer to Table 6 on page 22 of Mr. Abona's direct testimony on System Reliability. Please expand the table to include 2023 actual data and provide in Excel.

Answer: See attachment U-21291 AGDG 5.134 Updated System Reliability Cost Per Unit Table for an expanded table including the 2023 actual data.

Attachment: U-21291 AGDG 5.134 Updated System Reliability Cost Per Unit Table

Case No.: U-21291
Audit Request: AGDG-5.134
Respondent: E. M. Abona
File Attachment: System Reliability Units and Costs

Table 6. System Reliabilty Cost per Unit

	2020 Actual	2021 Actual	2022 Actual	2023 Projected	2023 Actuals	2024 Projected	2025 Projected
Units	67	65	74	96	87	118	103
Capital Spend ($000)	$19,120	$20,080	$27,810	$35,470	$36,418	$34,510	$34,200
Cost / Unit	$285,373	$308,923	$375,811	$369,479	$418,600	$292,458	$332,039

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.137b	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 137. Refer to lines 12-24 on page 28 of Mr. Abona's direct testimony on Communication and Controls-Meters. Please:

b. With regard to paragraph 2, please provide the number of meters of each type and related cost for each year 2018 to 2023 actual and forecasted for 2024 and 2025 in Excel.

Answer: See attachment.

Attachment: U-21291 AGDG-5.137b Communication and Controls-Meters 2018-2025

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

DTE Gas Response to data request AGDG-5.137b

Case No: U-21291
Exhibit: AG-7
May 7, 2024

U-21291 AGDG-5.137b Communication and Controls-Meters 2018-2025

	Actual												Projected			
	Purchase Year -2018		Purchase Year -2019		Purchase Year -2020		Purchase Year -2021		Purchase Year -2022		Purchase Year -2023		Purchase Year -2024		Purchase Year -2025	
Material Description	**Qty**	**$'s**	**Qty**	**$'s**	**Qty**	**$'s**	**Qty**	**$'s**	**Qty**	**$'s**	**Qty**	**$'s**	**Qty**	**$'s**	**Qty**	**$'s**
METER_FLOW,250 AMER, 402 TMS	49,776	$2,910,350	33,449	$1,703,507	71,262	$4,865,411	20,045	$1,631,906	24,880	$2,802,836	50,020	$5,139,125	28,662	3,362,321	42,094	$4,773,586
METER_FLOW,250 AMER, 405 TMS											17,999	1,758,051	2,001	212,525		
METER_FLOW,425 AMER, 403 TMS	11,255	$1,464,160	839	$97,812			1,000	$194,907	8,770	2,287,338	11,532	2,952,148	5,760	1,668,554	5,760	1,668,554
METER_FLOW,45 LIGHT,DRESSER, D800	1,920	$1,144,492	1,840	$917,734	500	$370,800			450	370,800	240	231,874	818	916,160	818	916,160
METER_FLOW,800 AMER, 404 TMS					2,309	$1,531,671	1,498	$1,298,438	638	509,635	1,650	1,561,669	900	936,382	900	936,382
METER_FLOW, 2.4 GZ -451			230	$33,251	2,158	$318,943	2,906	$574,498								
METER_FLOW, 2.4 GZ -455					150	$23,343	432	$79,386								
METER_FLOW,ROTARY 102 M, FM					2	$43,466	3	$90,475	4	93,190	3	73,050	3	97,087	3	97,087
METER_FLOW,ROTARY 11 MTC	56	$90,094	150	$261,105	43	$77,995			1	3,019	17	37,643	56	145,103	56	145,103
METER_FLOW,ROTARY 16 M	35	$75,185	50	$115,128	25	$61,980							39	130,035	39	130,035
METER_FLOW,ROTARY 2 MTC	757	$710,136	350	$374,740	1,112	$1,359,260	190	$206,464	559	841,831	639	$835,525	173	275,333	173	275,333
METER_FLOW,ROTARY 23M LM	10	$49,229	-	$0	10	$61,440			10	64,550	18	$131,931	18	161,401	18	161,401
METER_FLOW,ROTARY 3 MTC	76	$61,638	300	$299,421	246	$252,123	60	$116,369	287	404,345	333	$431,864	83	133,769	83	133,769
METER_FLOW,ROTARY 38 M ID-175,LM	15	$105,613	3	$22,338	9	$69,015			1	32,227	7	$64,039	3	33,573	3	33,573
METER_FLOW,ROTARY 5 MTC	84	$87,700	200	$228,763	155	$206,489	120	$202,374	95	175,898	222	$338,442	68	124,065	68	124,065
METER_FLOW,ROTARY 56 M, FM	4	$37,352	4	$39,045	5	$49,569	4	$41,274	2	53,143	1	$12,069	3	44,292	3	44,292
METER_FLOW,ROTARY 7 MTC	74	$103,187	143	$215,780	25	$40,016	10	$15,749	64	238,350	140	$262,588	40	83,642	40	83,642
METER_GAS,5000 CF/HR,175 PSI MAOP,3 IN P									1	1,823						
Total Meters	**64,062**	**$6,839,134**	**37,558**	**$4,308,623**	**78,011**	**$9,331,521**	**26,268**	**$4,451,840**	**35,762**	**$7,878,986**	**82,821**	**$13,830,015**	**38,627**	**$8,324,242**	**50,058**	**$9,522,982**
Unit Cost		$ 106.76		$ 114.72		$ 119.62	22930	$ 169.48		$ 220.32		$ 166.99		$ 215.50		$ 190.24
Modules																
MODULE_ELECT,AMI 2.4GZ W/WIRES/ROTARY HEAI	10	$1,236			2,500	$203,322					1,760	170,566	270	250,037	270	250,037
MODULE_ELECT,AMI, TMS 400											800	44,018			800	44,018
MODULE_ELECT,AMI,ACT/SPRAG 009P																$0
METER_GAS,AMR GAS MOD AME COM							144	$ 12,400								
METER_GAS,AMR GASMOD RKL 16T RES							50	$ 2,731	528	52,039						
METER_GAS,AMR GASMOD SRG RES							400	$ 21,218	20	1,092						
MODULE_ELECT,AMR 100G REMOTE			400	$18,898	300	$14,369	400	$31,971			2,480	241,639				
MODULE_ELECT,AMR TMS 402 403	83,620	$3,657,882	500	$23,623	16,200	$791,349			20,000	1,076,556	38,200	2,052,382	28,824	1,971,838	28,824	1,971,838
MODULE_ELECT,AMR TMS 404	2,740	$197,554	3,000	$233,604	1000	77868			220	11,538						
MODULE_ELECT,AMR TMS 423/424					100	$7,993					1,092	62,559				
MODULE_ELECT,AMR TMS 441_445																
MODULE_ELECT,TMS 402			25,000	$1,093,603	42,500	$1,892,496	51,430	$2,364,532			16,600	913,375	59,360	3,806,004	35,500	$2,276,164
MODULE WIRES & KITS							950	$77,858	200	18,099					2,320	268,778
Total Modules	**86,370**	**$3,856,672**	**28,900**	**$1,369,728**	**62,600**	**$2,987,397**	**53,374**	**$2,510,709**	**20,968**	**$1,159,324**	**60,932**	**$3,484,539**	**88,454**	**$6,027,879**	**67,714**	**$4,810,835.2**
Unit Cost		$ 44.65		$ 47.40		$ 47.72		$ 47.04		$ 55.29		$ 57.19		$ 68.15		$ 71.05
Total Meters & Modules	**150,432**	**$10,695,806**	**66,458**	**$5,678,351**	**140,611**	**$12,318,918**	**79,642**	**$6,962,549**	**56,730**	**$9,038,310**	**143,753**	**$17,314,554**	**127,081**	**$14,352,121**	**117,772**	**$14,333,817**
Unit Cost		$ 71.10		$ 85.44		$ 87.61		$ 87.42		$ 159.32		$ 120.45		$ 112.94		$ 121.71

Unit Costs calculated by AG

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-2.30a	
Respondent: S. N. Kehoe	
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Question: 30. On page 45 of his testimony, Mr. Kehoe discusses Leak Detection and the PHSMA's Notice of Proposed Rulemaking, which the Company believes will result in $10.28 million of additional costs in the projected test year versus $0 cost in the year 2022. Please:

a. Provide the required timeline for implementation of the new rule.

Answer: The required timeline for the implementation of the Leak Detection and Repair (LDAR) Notice of Proposed Rulemaking (NPRM) is proposed by PHMSA to be six months following the publication of the final rule in the Federal Register.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-2.30c	
Respondent: S. N. Kehoe	
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Question: 30. On page 45 of his testimony, Mr. Kehoe discusses Leak Detection and the PHSMA's Notice of Proposed Rulemaking, which the Company believes will result in $10.28 million of additional costs in the projected test year versus $0 cost in the year 2022. Please:

c. Provide a copy of PHSMA's Notice of Proposed Rulemaking and identify where in the notice it indicates the timing for finalization of the rulemaking.

Answer: The Leak Detection and Repair (LDAR) Notice of Proposed Rulemaking (NPRM) can be found in the Federal Register at https://www.federalregister.gov/documents/2023/05/18/2023-09918/pipeline-safety-gas-pipeline-leak-detection-and-repair In Section B: Summary of the Regulatory Provisions, it states "PHMSA proposes an effective date for this rulemaking of 6 months following publication of a final rule in the Federal Register." The final rule is expected in the third quarter of 2024. Assuming a publication date of September 1, 2024, the rule would become effective on March 1, 2025, six months from the publication date.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.142a	
Respondent: E. M. Abona	
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Question: 142. Refer to lines 12-22 on page 36 of Mr. Abona's direct testimony on the Leak Detection and Repair (LDAR) program.

a. Does the Company consider LDAR a new program or a refinement of its existing leak detection and repair program? If a new program, explain why and show how it differs from its existing program. If a refinement, identify the changes.

Answer: The Leak Detection and Repair (LDAR) is a Notice of Proposed Rulemaking (NPRM) issued by PHMSA. This consists of amendments for the federal register for strengthened leak survey and patrolling requirements, performance standards for advanced leak detection programs, leak grading and repair criteria with mandatory repair timelines, requirements for mitigation of emissions from blowdowns, and pressure relief device design. These new rules will require additional activities by DTE Gas to meet. These new rules can be found in the federal register, and the key changes to DTE's existing program are detailed in Table 9 of my direct testimony on page 37-38.

Attachment: None

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-5.143a
Respondent: E. M. Abona
Page: 1 of 1

Question: 143. Refer to lines 6-11 and Table 9 on pages 37 and 38 of Mr. Abona's direct testimony on the LDAR program. Please:

a. Explain why the Company does not show any capital expenditures on line 16 of Exhibit A-12, Schedule B5.1, for 2022 through 2024, given that the Company has repaired gas leaks in prior years.

Answer: The capital expenditures on line 16 of Exhibit A-12, Schedule B5 do not show any capital expenditures for 2022 – 2024 because these expenditures that are listed are only for the additional cost due to the rule, which is not effective until 6 months following the issue of the final rule, which would be March 1, 2025, based on the September 1, 2024, issue date.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.143b	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 143. Refer to lines 6-11 and Table 9 on pages 37 and 38 of Mr. Abona's direct testimony on the LDAR program. Please:

b. Provide the cost of detecting and repairing gas leaks each year 2018 to 2023 and forecasted for 2024 in Excel, identifying separately the amount charged to O&M expense and capital expenditures.

Answer:

Leak Detection Costs

Year	O&M Expense ($MM)
2018 Actual	$7.9 M
2019 Actual	$9.2 M
2020 Actual	$7.9 M
2021 Actual	$9.6 M
2022 Actual	$10.0 M
2023 Actual	$9.9 M
2024 Forecast	$10.8 M

Leak Repair Costs

Year	O&M Expense ($MM)	Capital Leak Expenditures ($MM)
2018 Actual	$13.6	$8.0
2019 Actual	$14.6	$4.8
2020 Actual	$7.9	$4.0
2021 Actual	$15.6	$4.2
2022 Actual	$13.1	$3.7
2023 Actual	$9.6	$3.9
2024 Forecast	$11.2	$5.4

Attachment: None

Co-Respondent(s): S. N. Kehoe

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.143c	
Respondent: E. M. Abona	
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Question: 143. Refer to lines 6-11 and Table 9 on pages 37 and 38 of Mr. Abona's direct testimony on the LDAR program. Please:

c. If the Company has included forecasted O&M expense for gas leak detection and repair in the projected test year, identify the amount, the exhibit, and line number, and how these costs differ from the costs on line 16 of Schedule B5.1 for the projected test year.

Answer: The O&M expenses for the Gas LDAR rule are located on lines 12-24 on page 45 of Mr. Kehoe's direct testimony and detailed in Table 23 on page 46 of Mr. Kehoe's direct testimony. Additionally, the detailed evaluation of the O&M cost of the rule as currently proposed is contained in Exhibit A-27 Schedule Q1.

Attachment: None

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-5.143d
Respondent: E. M. Abona
Page: 1 of 1

Question: 143. Refer to lines 6-11 and Table 9 on pages 37 and 38 of Mr. Abona's direct testimony on the LDAR program. Please:

d. Explain what the $2.5 million for Leak Grading and Repair will be spent on and why it is a capital item.

Answer: The $2.5 million for Leak Grading and Repair is the portion of the increased leak repairs on Grade 3 leaks for both distribution and transmissions as required by the rule. This is the capital portion of the repairs – services and mains that are renewed as required by standards or field conditions dictate. The O&M portion of the repairs – services and mains that are repaired are included in Table 23 on page 46 of Mr. Kehoe's direct testimony. Main and services that are renewed and replaced are considered capital expenditures.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.143e	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 143. Refer to lines 6-11 and Table 9 on pages 37 and 38 of Mr. Abona's direct testimony on the LDAR program. Please:

e. Explain what the $11.6 million for Advance Leak Detection Program will be spent on and why it is a capital item.

Answer: The $11.6 million for the Advance Leak Detection Program is to purchase 5 new Picarro leak detection units (mobile gas survey – four for GRMI operations, one additional for SEMI operations) in order to meet the rule requirements. These units are estimated to be $1.2 million each resulting in a total of 5 units at a cost of $6 million. In addition, there are 415 leak survey handhelds that have been initially identified that do not meet the new 5ppm sensitivity requirements and will need to be replaced. At a cost of $12,500 per unit, this cost totals $5.6 million. This equipment would be a capital purchase and would total $11.6 million to meet the requirements of the rule.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.143f	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 143. Refer to lines 6-11 and Table 9 on pages 37 and 38 of Mr. Abona's direct testimony on the LDAR program. Please:

f. Identify the current equipment leak survey equipment sensitivity to detect gas leaks.

Answer: DTE Gas currently has multiple different leak survey devices that detect gas leaks at different levels of sensitivity. Their sensitivity ranges from 1 ppm to 500ppm with varying sensor capabilities and vintages. The units to be upgraded are the ones that do not meet the requirements of the rule. DTE is working closely with manufacturers to assess the life and fit for purpose of the equipment and ensure alignment with the rule.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.143g	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 143. Refer to lines 6-11 and Table 9 on pages 37 and 38 of Mr. Abona's direct testimony on the LDAR program. Please:

g. Explain what the $0.3 million for Transmission Blowdown will be spent on and why it is a capital item.

Answer: DTE Gas currently uses a variety of mitigation methods to reduce the intentional release of natural gas during projects. The $0.3 million is to utilize temporary compression on four additional capital projects during the rate case test year.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.143h	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 143. Refer to lines 6-11 and Table 9 on pages 37 and 38 of Mr. Abona's direct testimony on the LDAR program. Please:

h. Explain what the $0.6 million for Pressure Relief Devices will be spent on and why it is a capital item. Explain how the Company plans to remediate the existing devices and redesign them to minimize the release of gas.

Answer: The $0.6 million for Pressure Relief Devices will be spent to reconfigure the gas relief set up on one gate station rebuild/year. The redesign will optimize the existing regulation and relief systems at each gate station to reduce potential gas loss without sacrificing reliable customer deliverability. Items that may be included in this optimization are regulation failure modes, existing relief valve sizing, relief valve functionality, and potential replacement of pneumatic equipment where feasible.

Attachment: None

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-5.106b
Respondent: K. M. Fedele
Page: 1 of 1

Question: 106. Refer to lines 9-11 on page 33 of Ms. Fedele's direct testimony on the Fort St. main replacement program. Please:

b. Provide the timing of the I-375 Reconstruction and other municipal coordination projects based on the government agencies' schedules and how they will drive the timing of the Fort St. main replacement.

Answer: Sections of Phase 5 of the Fort St project were pulled ahead to be completed in 2023 in conjunction with City of Detroit sewer and water upgrades near the Michigan Central Train Station. Phase 7 is driven to be completed in early 2024 to meet the April 30, 2024, utility abandonment completion mandate from MDOT. The company will continue to coordinate on the I-375 Reconstruction project as more information regarding the schedule is made available from MDOT.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.129	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 129. Refer to lines 9-25 on page 9 of Mr. Abona's direct testimony on the East Jefferson public improvement project. Please explain why the project cost increased to $22.3 million in this case, as shown on page 10 of Exhibit A-12, Schedule B5.5, in comparison to the $14.99 million in Case No. U-20940, as shown on page 25 of Schedule B5.5 in that case. Provide the related cost increase for each reason with supporting evidence.

Answer: The primary reason for the cost increase was due to delays with the City of Detroit's Jefferson Road Reconstruction project, and ultimately a change in scope when the City of Detroit cancelled their project. The budget submitted for the U-20940 rate case was based on all DTE Gas work being completed within the Jefferson Right of Way in parallel with the City of Detroit's reconstruction project, which was to be completed in 2023. The original discussions with the City of Detroit had all utilities removed and placed in a designated utility corridor to be identified by the City of Detroit. Therefore, the requested $14.99 million budget in U-20940 assumed that the City of Detroit would perform all excavation, backfill and restoration associated with DTE Gas's Jefferson Gas Relocation project. The increase in the U-21291 budget is due to the following:

- $300k of material cost increase
- $5.4M of construction cost increase due to pavement removal, excavation and backfill in project scope
- $2.9M of construction cost increase due to restoration in project scope
- The above cost is offset by $1.3M of lower cost in labor, design, and overhead/burden

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.115a	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: 115. Refer to page 55 of Ms. Fedele's direct testimony on the Van Born 36" pipeline. Please:

a. Provide the approximate date when the Company decided to abandon the previous plan and proceed with Option D?

Answer: The decision to abandon the original plan and proceed with Option D was made in May 2022.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.115b	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: 115. Refer to page 55 of Ms. Fedele's direct testimony on the Van Born 36" pipeline. Please:

b. Explain in more detail how option D and the installation of the new valves and regulators would solve a supply interruption at various points along the pipeline from the Willow citygate to the River Rouge station. Provide a detailed map with your explanations. Explain also how you would use of the 30" parallel line.

Answer: The installation of new RCVs and interconnects with the parallel 30" Van Born main will allow the company to isolate affected segments of the 36" Van Born main during an incident while providing gas supply from the west from Willow Station and from the east from the new interconnect with the 30" Van Born at Rouge Station. Detailed maps are attached showing the location of new RCVs and interconnects along with an example showing how gas would be diverted during a potential incident as explained above.

Attachment: U-21291 AGDG-5.115b Van Born Project Detailed Map

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.115c	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: 115. Refer to page 55 of Ms. Fedele's direct testimony on the Van Born 36" pipeline. Please:

c. Are there still customers in the area that would not be protected from an outage on Van Born line after Option D is implemented? If yes, how many customers?

Answer: With Option D, in the event of an incident on the 36-in Van Born pipeline during a peak winter day, it has been estimated that there may be 1,400 customers that could potentially be impacted.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.117a	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: 117. Refer to lines 6-17 on page 57 of Ms. Fedele's direct testimony on the Van Born 36" pipeline.

a. If the Company withdrew the ex parte application in May 2022, why are there $6.1 million of costs in 2021 that the Company still seeks to recover in rate base? What do these costs relate to?

Answer: The original scope of the Van Born Project included a meter station at Willow Gate Station, a 7-mile pipeline, new main line valve installations with remote control capabilities, retrofitting existing mainline valves to accommodate remote control capabilities and regulation at River Rouge Station. While the meter station and pipeline were removed from the scope, the balance of the plan remained intact. The $6.1 million in 2021 that is represented in this filing is related to that portion of the project that remained in scope.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.117b	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: 117. Refer to lines 6-17 on page 57 of Ms. Fedele's direct testimony on the Van Born 36" pipeline.

b. Provide a list of costs incurred in 2020, 2021, and through May 2022 in Excel, and identify which costs the Company has included in the $1.9 million it does not seek to recover.

Answer: Refer to attachment.

Attachment: U-21291 AGDG-5.117b-01 Van Born Write Off

U-21291
AGDG 5.117b

Van Born Project ($ millions)	2020 Actuals	2021 Actuals	YTD May 2022 Actuals	Total Project Spend Through May 2022	Write-Off	Write-Off Comments
Labor (Internal)	$0.3	$0.8	$0.4	$1.5	($0.3)	Labor associated with the pipeline and willow workorders, excluding project management oversight group for March 2021 - May 2022. March 2021 marks the end of the scoping period and the beginning of the design phase of the project
Material	$0.1	$0.1	($0.1)	$0.1	$0.0	
Contract Services	$0.4	$4.4	$1.0	$5.8	($1.5)	($0.6) - outside contractor support for office activities ($0.5) - Engineering Contractor performing conceptual and detailed design for Willow Gate Meter Station and Pipeline ($0.4) - Pipeline permit fees
Overheads	$0.2	$0.7	$0.3	$1.1	($0.2)	Percentage consistent with labor associated with the pipeline and willow workorders
AFUDC	$0.0	$0.1	$0.1	$0.3	($0.1)	Percentage consistent with Pipeline and Willow portion of project
Total Project Capital Expenditures	**$0.9**	**$6.1**	**$1.8**	**$8.7**	**($2.0)**	($1.985) normalization adjustment can be found in Exhibit A-12, Schedule C5.2

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-6.167a	
Respondent: E. D. Janness	
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Question: 167. Refer to Table 6 and the other information provided on page 26 of Mr. Janness's direct testimony on the GRP and the PRA model. Please:

a. Provide the full list of all GRP projects risk-ranked under the PRA from which the 2024 and 2025 projects were selected in Excel showing the projects in risk rank order from highest to lowest with the project number and description, the total risk score, the number of miles to be retired, the number of miles to be installed, the year that the project is targeted for completion, and other relevant information used by the Company to rank and select the projects for the applicable years.

Answer: See attached.

Attachment: U-21291 AGDG-6.167a - 2024 & 2025 Risk Results and GRP Projects 1

The remainder of the exhibit consists of a 14-page listing
of Risk Ranked Projects from the Company's
Probabilistic Risk Model (PRA)

	A	B	C	D	E	F	G	H	I
1	**2024 SEMI Risk Results and GRP Projects**					U-21291 AGDG-6.167a - 2024 & 2025 Risk Results and GRP Projects 1			
2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
3	2073	SWDET3	Detroit-High	1	0.961	1.4	1.6	2024	
4	204	Milwaukee Junction 2	Detroit-High	2	0.521	1.6	1.8	2024	
5	2012	Elmwood Park 1	Detroit-High	3	0.229	3.1	3.6	2024	
6	5082	SWDET3	Detroit-High	4	0.164	6.4	7.4	2024	
7	5042		Detroit-High	5	0.155				High Complexity Target Met
8	2051	Midtown MMO	Detroit-High	6	0.153			2022	Prior GRP Grid
9	5012	CDET4	Detroit-Low	7	0.122			2023	Prior GRP Grid
10	4011	Islandview	Detroit-Low	8	0.122			2023	Prior GRP Grid
11	5081	SWDET3	Detroit-High	9	0.103	2.1	2.4	2024	5081 needs to be hydraulically com
12	2071	Woodbridge 1	Detroit-Low	10	0.099	2.9	3.3	2024	
13	5011	CDET5	Detroit-Low	11	0.094	14.2	16.3	2024	
14	5053		Detroit-High	12	0.081				High Complexity Target Met
15	102		Detroit-High	13	0.077				High Complexity Target Met
16	2013		Detroit-High	14	0.073				High Complexity Target Met
17	2072	Woodbridge 1	Detroit-Low	15	0.070	1.1	1.3	2024	
18	5092	SWDET1	Detroit-High	16	0.069			2022	Prior GRP Grid
19	4012	East Village 1	Detroit-Low	17	0.069	9.9	11.4	2024	
20	5111	SWDET2	Detroit-Low	18	0.059			2021	Prior GRP Grid
21	3072	WDET4	Detroit-Low	19	0.058	4.7	5.4	2024	
22	4023	East Village 1	Detroit-Low	20	0.056	6.7	7.7	2024	
23	4042	Hamtramck 1/2	Detroit-Low	21	0.045			2019	Prior GRP Grid
24	6252	Taylor MMO 2	Detroit-Low	22	0.042	0.0	0.0	2024	Less than 500' Legacy Main, Added to meet inside meter target, combine 6285, 6286, 6251,
25	6384	Redford MMO #6351	Detroit-Low	23	0.041			2019	Prior GRP Grid
26	5022	Highland Park 1	Detroit-Low	24	0.039	13.6	15.5	2024	
27	2062		Detroit-High	25	0.039				High Complexity Target Met
28	3063	WDET2	Detroit-Low	26	0.038			2019	Prior GRP Grid
29	7212		Washtenaw-Low	27	0.038				Less than 500' Legacy Main
30	5142	NCDET3	Detroit-Low	28	0.036			2021	Prior GRP Grid
31	6152	Trenton 1	Detroit-Low	29	0.036	4.3	5.0	2024	
32	5152	NCDET2	Detroit-Low	30	0.033			2022	Prior GRP Grid
33	3061	WDET1	Detroit-Low	31	0.033			2019	Prior GRP Grid
34	101		Detroit-High	32	0.032				High Complexity Target Met
35	408	East Village 1	Detroit-Low	33	0.031	8.5	9.8	2024	
36	5091	SWDET1	Detroit-Low	34	0.031			2022	Prior GRP Grid

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2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
37	5041	WDET4	Detroit-Low	35	0.029	8.4	9.7	2024	
38	6012	Dearborn 1/2/3	Detroit-Low	36	0.028			2017	Prior GRP Grid
39	2061		Detroit-High	37	0.026				High Complexity Target Met
40	303	CDET5	Detroit-Low	38	0.026	1.8	2.1	2024	
41	5062	CDET2	Detroit-Low	39	0.024			2021	Prior GRP Grid
42	2011		Detroit-High	40	0.024				High Complexity Target Met
43	2022		Detroit-High	41	0.023				High Complexity Target Met
44	6153	Trenton 1	Detroit-Low	42	0.023	2.2	2.5	2024	
45	4021	East Village 1	Detroit-Low	43	0.022	9.1	10.4	2024	
46	6142	Riverview MMO #6142 (2023	Detroit-Low	44	0.022	0.3	0.4	2024	2023 Carryover MMO
47	6041		Detroit-High	45	0.020				High Complexity Target Met
48	5073	CDET1	Detroit-Low	46	0.018			2020	Prior GRP Grid
49	7221		Washtenaw-Low	47	0.018				Less than 500' Legacy Main
50	6203		Detroit-Low	48	0.017				Less than 500' Legacy Main
51	5289	NWDET2	Detroit-Low	49	0.017			2022	Prior GRP Grid
52	4024	East Village 1	Detroit-Low	50	0.017	6.6	7.6	2024	
53	5153	NCDET2	Detroit-Low	51	0.017			2020	Prior GRP Grid
54	6023	Dearborn 1/2/3	Detroit-Low	52	0.017			2017	Prior GRP Grid
55	3041	Hamtramck 1/2	Detroit-Low	53	0.017			2019	Prior GRP Grid
56	203		Detroit-High	54	0.016				High Complexity Target Met
57	3042	Hamtramck 1/2	Detroit-Low	55	0.016			2019	Prior GRP Grid
58	3091	RRE1	Detroit-Low	56	0.015			2021	Prior GRP Grid
59	3064	WDET2	Detroit-Low	57	0.015			2019	Prior GRP Grid
60	5021	Highland Park 1	Detroit-Low	58	0.015	17.1	20.4	2024	
61	5178		Detroit-Low	59	0.015				Less than 500' Legacy Main
62	5154	NCDET2	Detroit-Low	60	0.014			2020	Prior GRP Grid
63	5164	NCDET1	Detroit-Low	61	0.014			2019	Prior GRP Grid
64	6131	Southgate MMO #6131	Detroit-Low	62	0.013	0.0	0.0	2024	Less than 500' Legacy Main, Added
65	5104		Detroit-Low	63	0.013				
66	6324		Detroit-Low	64	0.013				
67	4022		Detroit-Low	65	0.012				
68	6302	Dearborn Heights MMO #63(	Detroit-Low	66	0.012	1.0	1.2	2024	Added to meet inside meter target
69	3073	WDET2	Detroit-Low	67	0.011			2019	Prior GRP Grid
70	4053		Detroit-Low	68	0.011				
71	5063	CDET2	Detroit-Low	69	0.011			2021	Prior GRP Grid
72	6015	WDET2	Detroit-Low	70	0.011			2019	Prior GRP Grid

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2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
73	6262		Detroit-Low	71	0.011				Less than 500' Legacy Main
74	5141	NCDET4	Detroit-Low	72	0.011			2022	Prior GRP Grid
75	5101		Detroit-Low	73	0.011				
76	5112	SWDET 1/2	Detroit-Low	74	0.011			2021	Prior GRP Grid
77	6274	Taylor MMO 1	Detroit-Low	75	0.011	0.0	0.0	2024	Added to meet inside meter target
78	5224	NCDET3	Detroit-Low	76	0.011			2021	Prior GRP Grid
79	6408	Inkster 2	Washtenaw-Low	77	0.010	0.1	0.2	2024	
80	2021		Detroit-High	78	0.010				High Complexity Target Met
81	6283	Taylor MMO	Detroit-Low	79	0.010			2020	Prior GRP Grid
82	5074		Detroit-Low	80	0.010				
83	5134		Detroit-Low	81	0.009				
84	5155		Detroit-Low	82	0.009				
85	6253	Taylor MMO 2	Detroit-Low	83	0.009	0.0	0.1	2024	Less than 500' Legacy Main, Added
86	5177		Detroit-Low	84	0.009				
87	3071		Detroit-Low	85	0.009				
88	5303	NWDET1	Detroit-Low	86	0.008			2020	Prior GRP Grid
89	7061		Washtenaw-Low	87	0.008				Less than 500' Legacy Main
90	4092		Detroit-Low	88	0.008				
91	6032		Detroit-High	89	0.008				High Complexity Target Met
92	5143		Detroit-Low	90	0.008				
93	6141	Riverview 1	Detroit-Low	91	0.008	0.8	0.9	2024	Needs to be hydraulically complete
94	3062	WDET1	Detroit-Low	92	0.008			2019	Prior GRP Grid
95	6461	Belleville 1	Washtenaw-Low	93	0.008	1.6	1.9	2024	
96	4162	EDET1	Detroit-Low	94	0.008			2021	Prior GRP Grid
97	5123		Detroit-Low	95	0.008				
98	5225		Detroit-Low	96	0.007				
99	5113		Detroit-Low	97	0.007				
100	410		Detroit-Low	98	0.007				
101	6121	Southgate MMO #6121	Detroit-Low	99	0.007	0.0	0.0	2024	Added to meet inside meter target
102	4031		Detroit-Low	100	0.007				
103	6082	LPMMO 6082	Detroit-Low	101	0.007			2023	Prior GRP Grid
104	4041	Hamtramck 1/2	Detroit-Low	102	0.007			2019	Prior GRP Grid
105	4091		Detroit-Low	103	0.007				
106	7011		Washtenaw-High	104	0.007				High Complexity Target Met
107	5071	WCDET1	Detroit-Low	105	0.007			2021	Prior GRP Grid
108	5051		Detroit-Low	106	0.007				

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2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
109	4063	ECDET1	Detroit-Low	107	0.007			2022	Prior GRP Grid
110	5052		Detroit-High	108	0.007				
111	5332	NWDET3	Detroit-Low	109	0.007			2023	Prior GRP Grid
112	5102		Detroit-Low	110	0.007				
113	6222	Flat Rock MMO	Detroit-Low	111	0.007	0.1	0.1	2024	Added to meet inside meter target
114	5133	CDET1	Detroit-Low	112	0.007			2020	Prior GRP Grid
115	7022	Ann Arbor 7	Washtenaw-Low	113	0.006	0.7	0.8	2024	
116	5343		Detroit-Low	114	0.006				
117	6083	Lincoln Park MMO #6083	Detroit-Low	115	0.006	1.2	1.3	2024	Added to meet inside meter target
118	6485		Washtenaw-Low	116	0.006				Less than 500' Legacy Main
119	4061		Detroit-Low	117	0.006				
120	4261	NDET2-3	Detroit-Low	118	0.006			2020	Prior GRP Grid
121	421	Grosse Pointe 3	Detroit-Low	119	0.006			2019	Prior GRP Grid
122	5061	CDET3	Detroit-Low	120	0.006			2023	Prior GRP Grid
123	6351	Redford MMO #6351	Detroit-Low	121	0.006	0.2	0.2	2024	Added to meet inside meter target
124	6313		Detroit-Low	122	0.006				
125	5145		Detroit-Low	123	0.005				
126	6072	Allen Park MMO	Detroit-Low	124	0.005			2023	Prior GRP Grid
127	404		Detroit-Low	125	0.005				
128	5364		Detroit-Low	126	0.005				
129	4271		Detroit-High	127	0.005				
130	5246		Detroit-Low	128	0.005				
131	6206		Detroit-Low	129	0.005				
132	6221	Flat Rock MMO	Detroit-Low	130	0.005	0.2	0.2	2024	Added to meet inside meter target
133	4222	Grosse Pointe 3	Detroit-Low	131	0.005			2019	Prior GRP Grid
134	6151		Detroit-Low	132	0.005				
135	4151		Detroit-Low	133	0.005				
136	6482		Washtenaw-Low	134	0.005				Less than 500' Legacy Main
137	5103		Detroit-Low	135	0.005				
138	4062		Detroit-Low	136	0.005				
139	519		Detroit-Low	137	0.005				
140	5072		Detroit-Low	138	0.004				
141	6276		Detroit-Low	139	0.004				
142	6086	Lincoln Park MMO #6086 (20	Detroit-Low	140	0.004	0.9	1.0	2024	2023 Carryover MMO
143	5321		Detroit-Low	141	0.004				
144	5213		Detroit-Low	142	0.004				

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2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
145	4262		Detroit-Low	143	0.004				
146	5227		Detroit-Low	144	0.004				
147	5285		Detroit-Low	145	0.004				
148	6081	Lincoln Park MMO #6081	Detroit-Low	146	0.004	0.2	0.2	2024	Added to meet inside meter target
149	6403	INKSTER MMO 6403	Washtenaw-Low	147	0.004			2023	Prior GRP Grid
150	6412	Garden City MMO #6412	Washtenaw-Low	148	0.004	0.0	0.0	2024	Less than 500' Legacy Main, Added
151	5253		Detroit-Low	149	0.004				
152	305		Detroit-Low	150	0.004				
153	5181		Detroit-Low	151	0.004				
154	6455		Washtenaw-Low	152	0.004				Less than 500' Legacy Main
155	4202		Detroit-Low	153	0.004				
156	5125		Detroit-Low	154	0.004				
157	4043	Hamtramck 1/2	Detroit-Low	155	0.004			2019	Prior GRP Grid
158	6212		Detroit-Low	156	0.004				
159	5245		Detroit-Low	157	0.004				
160	6231		Detroit-Low	158	0.004				
161	6022		Detroit-Low	159	0.004				
162	2052		Detroit-High	160	0.004				
163	6311		Detroit-Low	161	0.004				
164	5165		Detroit-Low	162	0.004				
165	5211		Detroit-Low	163	0.004				
166	5222		Detroit-Low	164	0.004				
167	4054	Hamtramck 1/2	Detroit-Low	165	0.004			2019	Prior GRP Grid
168	4132		Detroit-Low	166	0.004				
169	6209		Detroit-Low	167	0.004				
170	4032		Detroit-Low	168	0.004				
171	5166		Detroit-Low	169	0.004				
172	5032		Detroit-Low	170	0.004				
173	6401	Inkster 1	Washtenaw-Low	171	0.004	0.3	0.3	2024	
174	5175		Detroit-Low	172	0.004				
175	6223	Flat Rock MMO	Detroit-Low	173	0.004	0.1	0.1	2024	Added to meet inside meter target
176	5355		Detroit-Low	174	0.004				
177	6325		Detroit-Low	175	0.003				
178	6323		Detroit-Low	176	0.003				
179	4065		Detroit-Low	177	0.003				
180	4052		Detroit-Low	178	0.003				

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181	6014	Dearborn 1/2/3	Detroit-Low	179	0.003			2017	Prior GRP Grid
182	6134	Southgate MMO #6134	Detroit-Low	180	0.003	0.1	0.1	2024	Added to meet inside meter target
183	610		Detroit-Low	181	0.003				
184	5031		Detroit-Low	182	0.003				
185	5284		Detroit-Low	183	0.003				
186	6113		Detroit-Low	184	0.003				
187	4201		Detroit-Low	185	0.003				
188	4194		Detroit-Low	186	0.003				
189	6286	Taylor MMO 2	Detroit-Low	187	0.003	0.3	0.4	2024	Added to meet inside meter target
190	5174		Detroit-Low	188	0.003				
191	617		Detroit-Low	189	0.003				
192	5167		Detroit-Low	190	0.003				
193	7111		Washtenaw-High	191	0.003				High Complexity Target Met
194	5286		Detroit-High	192	0.003				
195	6411	Garden City MMO 6411	Washtenaw-Low	193	0.003			2022	Prior GRP Grid
196	5354		Detroit-Low	194	0.003				
197	6232		Detroit-Low	195	0.003				
198	5182		Detroit-Low	196	0.003				
199	6404	Inkster MMO #6404	Washtenaw-Low	197	0.003	0.0	0.0	2024	Added to meet inside meter target
200	4161		Detroit-Low	198	0.003				
201	5144		Detroit-Low	199	0.003				
202	5131		Detroit-Low	200	0.003				
203	6273	Taylor MMO 1	Detroit-Low	201	0.003	0.6	0.7	2024	Added to meet inside meter target
204	5064		Detroit-Low	202	0.003				
205	6312	DRB MMO 6312	Detroit-Low	203	0.003			2019	Prior GRP Grid
206	6275		Detroit-Low	204	0.003				
207	5121		Detroit-Low	205	0.003				
208	412		Detroit-Low	206	0.003				
209	411		Detroit-Low	207	0.003				
210	5314		Detroit-Low	208	0.003				
211	5322		Detroit-Low	209	0.003				
212	3092	RRE1	Detroit-Low	210	0.003			2021	Prior GRP Grid
213	5176		Detroit-Low	211	0.003				
214	308	RRE1	Detroit-Low	212	0.003			2021	Prior GRP Grid
215	5173		Detroit-Low	213	0.003				
216	6091	Lincoln Park MMO #6091	Detroit-Low	214	0.003	0.1	0.1	2024	Added to meet inside meter target

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217	4131		Detroit-Low	215	0.003				
218	6071	LP MMO 6071	Detroit-Low	216	0.003			2023	Prior GRP Grid
219	5344		Detroit-Low	217	0.003				
220	5261		Detroit-Low	218	0.003				
221	5161		Detroit-Low	219	0.003				
222	5132		Detroit-Low	220	0.003				
223	6208		Detroit-Low	221	0.003				
224	4182		Detroit-Low	222	0.003				
225	6042		Detroit-High	223	0.003				
226	4184		Detroit-Low	224	0.003				
227	6383		Detroit-Low	225	0.003				
228	5212		Detroit-Low	226	0.003				
229	4152		Detroit-Low	227	0.003				
230	4051		Detroit-Low	228	0.003				
231	5122		Detroit-Low	229	0.003				
232	6405	Inkster 2	Washtenaw-Low	230	0.003	0.2	0.2	2024	
233	5342		Detroit-Low	231	0.003				
234	6271	Taylor MMO 1	Detroit-Low	232	0.003	0.5	0.6	2024	Added to meet inside meter target
235	6084	Lincoln Park MMO #6084	Detroit-Low	233	0.002	0.6	0.7	2024	Added to meet inside meter target
236	6111	WYD2	Detroit-Low	234	0.002			2023	Prior GRP Grid
237	5214		Detroit-Low	235	0.002				
238	6285	Taylor MMO 2	Detroit-Low	236	0.002	0.4	0.5	2024	Added to meet inside meter target
239	709	Chelsea 1	Washtenaw-Low	237	0.002	5.8	6.6	2024	
240	6031		Detroit-Low	238	0.002				
241	6321		Detroit-Low	239	0.002				
242	4072		Detroit-Low	240	0.002				
243	5202		Detroit-Low	241	0.002				
244	5226		Detroit-Low	242	0.002				
245	5242		Detroit-Low	243	0.002				
246	7292		Washtenaw-Low	244	0.002				Less than 500' Legacy Main
247	5334		Detroit-Low	245	0.002				
248	6282	Taylor MMO 3	Detroit-Low	246	0.002	0.2	0.2	2024	Added to meet inside meter target
249	5301		Detroit-Low	247	0.002				
250	6372		Detroit-Low	248	0.002				
251	5281		Detroit-Low	249	0.002				
252	5228		Detroit-Low	250	0.002				

	A	B	C	D	E	F	G	H	I
1	**2024 SEMI Risk Results and GRP Projects**					U-21291 AGDG-6.167a - 2024 & 2025 Risk Results and GRP Projects 1			
2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
253	6251	Taylor MMO 2	Detroit-Low	251	0.002	0.0	0.0	2024	Added to meet inside meter target
254	5172		Detroit-Low	252	0.002				
255	6114	Wyandotte MMO #6114	Detroit-Low	253	0.002	0.0	0.0	2024	Added to meet inside meter target
256	5275		Detroit-Low	254	0.002				
257	5294		Detroit-Low	255	0.002				
258	6381		Detroit-Low	256	0.002				
259	7112		Washtenaw-High	257	0.002				High Complexity Target Met
260	5292		Detroit-Low	258	0.002				
261	707	Dexter 1	Washtenaw-Low	259	0.002	0.7	0.8	2024	
262	5283		Detroit-Low	260	0.002				
263	5287		Detroit-Low	261	0.002				
264	302		Detroit-Low	262	0.002				
265	6407	INKSTER MMO 6407	Washtenaw-Low	263	0.002			2022	Prior GRP Grid
266	6385		Detroit-Low	264	0.002				
267	4253	Harper Woods 1	Detroit-Low	265	0.002			2018	Prior GRP Grid
268	4242	Grosse Pointe 1-4	Detroit-Low	266	0.002			2019	Prior GRP Grid
269	6406	Inkster 2	Washtenaw-Low	267	0.002	0.2	0.2	2024	
270	5331		Detroit-Low	268	0.002				
271	7203	Superior 1	Washtenaw-Low	269	0.002	0.5	0.6	2024	
272	5235		Detroit-Low	270	0.002				
273	5363		Detroit-Low	271	0.002				
274	6092	Lincoln Park MMO 6092	Detroit-Low	272	0.002	0.0	0.0	2024	Added to meet inside meter target
275	4191		Detroit-Low	273	0.002				
276	6423	Garden Ciry MMO #6423 (20	Washtenaw-Low	274	0.002	0.0	0.0	2024	2023 Carryover MMO
277	6332	Dearborn Heights MMO #633	Detroit-Low	275	0.002	0.1	0.1	2024	Added to meet inside meter target
278	414		Detroit-Low	276	0.002				
279	6442	Romulus 1	Washtenaw-Low	277	0.002	10.2	11.6	2024	
280	5163		Detroit-Low	278	0.002				
281	6322		Detroit-Low	279	0.002				
282	5351		Detroit-Low	280	0.002				
283	634		Detroit-Low	281	0.002				
284	5241		Detroit-Low	282	0.002				
285	5271		Detroit-Low	283	0.002				
286	6053	ALLEN PARK MMO	Detroit-Low	284	0.002			2022	Prior GRP Grid
287	6011		Detroit-Low	285	0.002				
288	7013	Ann Arbor 8	Washtenaw-Low	286	0.002				

	A	B	C	D	E	F	G	H	I
1	2024 SEMI Risk Results and GRP Projects					U-21291 AGDG-6.167a - 2024 & 2025 Risk Results and GRP Projects 1			
2	LSID	Project Name	Region - Complexity	SEMI Rank	Risk Score	Estimated Legacy Miles to be abandonded	Estimated Install Miles	Planned Construciton Year	Notes
289	6202		Detroit-Low	287	0.002				
290	6422	Garden City 6422	Washtenaw-Low	288	0.002	0.0	0.0	2024	Added to meet inside meter target
291	5252		Detroit-Low	289	0.002				
292	7032		Washtenaw-High	290	0.002				High Complexity Target Met
293	6314		Detroit-Low	291	0.002				
294	7041		Washtenaw-High	292	0.002				High Complexity Target Met
295	4183		Detroit-Low	293	0.002				
296	7232		Washtenaw-Low	294	0.002				Less than 500' Legacy Main
297	7235		Washtenaw-Low	295	0.002				Less than 500' Legacy Main
298	6013	Dearborn 1/2/3	Detroit-Low	296	0.002			2017	Prior GRP Grid
299	7132	Milan 1	Washtenaw-Low	297	0.002				
300	4064		Detroit-Low	298	0.002				
301	6386		Detroit-Low	299	0.002				
302	5352		Detroit-Low	300	0.002				
303	5221		Detroit-Low	301	0.002				
304	6051	Allen Park MMO 6051	Detroit-Low	302	0.002	0.0	0.0	2024	Added to meet inside meter target
305	5151		Detroit-Low	303	0.002				
306	6402	Inkster MMO 6402	Washtenaw-Low	304	0.002	0.0	0.0	2024	Added to meet inside meter target
307	649		Detroit-Low	305	0.002				
308	5124	Southcentral Detroit 2 (2023	Detroit-Low	306	0.002	6.4	7.4	2024	2023 Carryover MMO
309	7042		Washtenaw-High	307	0.002				High Complexity Target Met
310	6112	WYD2	Detroit-Low	308	0.002			2023	Prior GRP Grid
311	6052	Allen Park MMO 6052	Detroit-Low	309	0.002	0.0	0.0	2024	Added to meet inside meter target
312	6123	Southgate MMO 6123	Detroit-Low	310	0.002	0.0	0.0	2024	Added to meet inside meter target
313	301		Detroit-Low	311	0.002				
314	7311	Sylvan 1	Washtenaw-Low	312	0.002				
315	5323		Detroit-Low	313	0.002				
316	5282		Detroit-Low	314	0.002				
317	6284	Taylor MMO Only 6284	Detroit-Low	315	0.002	0.0	0.0	2024	Added to meet inside meter target
318	7233	Pittsfield 1	Washtenaw-Low	316	0.002				
319	6272	Taylor MMO Only 6272	Detroit-Low	317	0.002	0.0	0.0	2024	Added to meet inside meter target
320	6261		Detroit-Low	318	0.002				
321	6291	Dearborn MMO 6291	Detroit-Low	319	0.002	0.0	0.0	2024	Added to meet inside meter target
322	6444	Romulus 2	Washtenaw-Low	320	0.002				
323	6088		Detroit-Low	321	0.002				
324	5162		Detroit-Low	322	0.002				

	A	B	C	D	E	F	G	H	I
1	**2024 SEMI Risk Results and GRP Projects**					U-21291 AGDG-6.167a - 2024 & 2025 Risk Results and GRP Projects 1			
2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
325	6162		Detroit-Low	323	0.002				
326	5233		Detroit-Low	324	0.002				
327	5201		Detroit-High	325	0.002				
328	6293	Dearborn Heights MMO 629:	Detroit-Low	326	0.002	0.0	0.0	2024	Added to meet inside meter target
329	6413	Garden City MMO 6413	Washtenaw-Low	327	0.001	0.0	0.0	2024	Added to meet inside meter target
330	7031		Washtenaw-High	328	0.001				High Complexity Target Met
331	5288		Detroit-Low	329	0.001				
332	636		Detroit-Low	330	0.001				
333	5168	NCDET2	Detroit-Low	331	0.001			2019	Prior GRP Grid
334	5171		Detroit-Low	332	0.001				
335	6301	Dearborn MMO 6301	Detroit-Low	333	0.001	0.0	0.0	2024	Added to meet inside meter target
336	5229		Detroit-Low	334	0.001				
337	5361		Detroit-Low	335	0.001				
338	6373		Detroit-Low	336	0.001				
339	5232		Detroit-Low	337	0.001				
340	5262		Detroit-Low	338	0.001				
341	5362		Detroit-Low	339	0.001				
342	7113	YPT 6	Washtenaw-Low	340	0.001				
343	6371		Detroit-Low	341	0.001				
344	5302		Detroit-Low	342	0.001				
345	5313		Detroit-Low	343	0.001				
346	6435		Washtenaw-Low	344	0.001				Less than 500' Legacy Main
347	4251		Detroit-Low	345	0.001				
348	6021		Detroit-Low	346	0.001				
349	7216		Washtenaw-Low	347	0.001				Less than 500' Legacy Main
350	5272		Detroit-Low	348	0.001				
351	5333		Detroit-Low	349	0.001				
352	7082	Milford 1	Washtenaw-Low	350	0.001				
353	5293		Detroit-Low	351	0.001				
354	5234		Detroit-Low	352	0.001				
355	6087	Lincoln Park 6087	Detroit-Low	353	0.001	0.0	0.0	2024	Added to meet inside meter target
356	5273		Detroit-Low	354	0.001				
357	606		Detroit-Low	355	0.001				
358	6352		Detroit-Low	356	0.001				
359	6281		Detroit-Low	357	0.001				
360	6085	Lincoln Park MMO #6085 (20	Detroit-Low	358	0.001	1.3	1.5	2024	2023 Carryover MMO

	A	B	C	D	E	F	G	H	I
1	**2024 SEMI Risk Results and GRP Projects**					U-21291 AGDG-6.167a - 2024 & 2025 Risk Results and GRP Projects 1			
2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
361	4071		Detroit-Low	359	0.001				
362	6093		Detroit-Low	360	0.001				
363	6484	Canton 1	Washtenaw-Low	361	0.001				
364	4172		Detroit-Low	362	0.001				
365	4181		Detroit-Low	363	0.001				
366	5244		Detroit-Low	364	0.001				
367	705		Washtenaw-High	365	0.001				High Complexity Target Met
368	6122		Detroit-Low	366	0.001				
369	6331		Detroit-Low	367	0.001				
370	5251		Detroit-Low	368	0.001				
371	4192		Detroit-Low	369	0.001				
372	5223		Detroit-Low	370	0.001				
373	5291		Detroit-Low	371	0.001				
374	6132		Detroit-Low	372	0.001				
375	6382		Detroit-Low	373	0.001				
376	6441	Romulus 2	Washtenaw-Low	374	0.001				
377	5312		Detroit-Low	375	0.001				
378	5231		Detroit-Low	376	0.001				
379	6292		Detroit-Low	377	0.001				
380	7131	Milan 2	Washtenaw-Low	378	0.001				
381	7201		Washtenaw-Low	379	0.001				
382	6133		Detroit-Low	380	0.001				
383	6294		Detroit-Low	381	0.001				
384	6486		Washtenaw-Low	382	0.001				
385	4193		Detroit-Low	383	0.001				
386	6481		Washtenaw-Low	384	0.001				
387	5311		Detroit-Low	385	0.001				
388	5274		Detroit-Low	386	0.001				
389	7033		Washtenaw-High	387	0.001				
390	4171		Detroit-Low	388	0.001				
391	5243		Detroit-Low	389	0.001				
392	6473		Washtenaw-Low	390	0.001				
393	7062		Washtenaw-Low	391	0.001				
394	6474		Washtenaw-Low	392	0.001				
395	618		Detroit-Low	393	0.001				
396	6205		Detroit-Low	394	0.001				

	A	B	C	D	E	F	G	H	I
1	**2024 SEMI Risk Results and GRP Projects**					U-21291 AGDG-6.167a - 2024 & 2025 Risk Results and GRP Projects 1			
2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
397	7123		Washtenaw-High	395	0.001				
398	5353		Detroit-Low	396	0.001				
399	6263		Detroit-Low	397	0.001				
400	6431		Washtenaw-Low	398	0.001				
401	726		Washtenaw-Low	399	0.001				
402	7012		Washtenaw-Low	400	0.001				
403	7202		Washtenaw-Low	401	0.001				
404	7021		Washtenaw-High	402	0.001				
405	5341		Detroit-Low	403	0.001				
406	6443		Washtenaw-Low	404	0.001				
407	7231		Washtenaw-Low	405	0.001				
408	7081		Washtenaw-Low	406	0.001				
409	4252		Detroit-Low	407	0.001				
410	7102		Washtenaw-Low	408	0.001				
411	7101		Washtenaw-Low	409	0.001				
412	424		Detroit-Low	410	0.001				
413	6462		Washtenaw-Low	411	0.001				
414	6161		Detroit-Low	412	0.001				
415	6472		Washtenaw-Low	413	0.001				
416	7014		Washtenaw-Low	414	0.001				
417	4241		Detroit-Low	415	0.001				
418	7242		Washtenaw-Low	416	0.001				
419	639		Washtenaw-Low	417	0.001				
420	6207		Detroit-Low	418	0.000				
421	6211	Rockwood MMO #6221 (202	Detroit-Low	419	0.000	0.3	0.3	2024	2023 Carryover MMO
422	7213		Washtenaw-Low	420	0.000				
423	7234		Washtenaw-Low	421	0.000				
424	7122		Washtenaw-High	422	0.000				
425	6471		Washtenaw-High	423	0.000				
426	7241		Washtenaw-Low	424	0.000				
427	6421		Washtenaw-Low	425	0.000				
428	7281		Washtenaw-Low	426	0.000				
429	4221		Detroit-Low	427	0.000				
430	7321		Washtenaw-Low	428	0.000				
431	6475		Washtenaw-Low	429	0.000				
432	7284		Washtenaw-Low	430	0.000				

	A	B	C	D	E	F	G	H	I
1	**2024 SEMI Risk Results and GRP Projects**					U-21291 AGDG-6.167a - 2024 & 2025 Risk Results and GRP Projects 1			
2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
433	7291		Washtenaw-Low	431	0.000				
434	7218		Washtenaw-Low	432	0.000				
435	7215		Washtenaw-Low	433	0.000				
436	7271		Washtenaw-Low	434	0.000				
437	7121		Washtenaw-Low	435	0.000				
438	7302		Washtenaw-Low	436	0.000				
439	6204		Detroit-Low	437	0.000				
440	619		Detroit-Low	438	0.000				
441	7214		Washtenaw-Low	439	0.000				
442	7236		Washtenaw-Low	440	0.000				
443	7043		Washtenaw-Low	441	0.000				
444	4231		Detroit-Low	442	0.000				
445	733		Washtenaw-Low	443	0.000				
446	6434		Washtenaw-Low	444	0.000				
447	6432		Washtenaw-Low	445	0.000				
448	6453		Washtenaw-Low	446	0.000				
449	7283		Washtenaw-Low	447	0.000				
450	4232		Detroit-Low	448	0.000				
451	734		Washtenaw-Low	449	0.000				
452	6483		Washtenaw-Low	450	0.000				
453	6452		Washtenaw-Low	451	0.000				
454	7322		Washtenaw-Low	452	0.000				
455	7243		Washtenaw-Low	453	0.000				
456	715		Washtenaw-Low	454	0.000				
457	725		Washtenaw-Low	455	0.000				
458	7224		Washtenaw-Low	456	0.000				
459	6454		Washtenaw-Low	457	0.000				
460	6456		Washtenaw-Low	458	0.000				
461	7222		Washtenaw-High	459	0.000				
462	7272		Washtenaw-Low	460	0.000				
463	7312		Washtenaw-Low	461	0.000				
464	6201		Detroit-Low	462	0.000				
465	7282		Washtenaw-Low	463	0.000				
466	7223		Washtenaw-Low	464	0.000				
467	6433		Washtenaw-Low	465	0.000				
468	6451		Washtenaw-Low	466	0.000				

	A	B	C	D	E	F	G	H	I
1	**2024 SEMI Risk Results and GRP Projects**					U-21291 AGDG-6.167a - 2024 & 2025 Risk Results and GRP Projects 1			
2	**LSID**	**Project Name**	**Region - Complexity**	**SEMI Rank**	**Risk Score**	**Estimated Legacy Miles to be abandonded**	**Estimated Install Miles**	**Planned Construciton Year**	**Notes**
469	7211		Washtenaw-Low	467	0.000				
470	7301		Washtenaw-High	468	0.000				

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-6.177	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 177. Refer to Exhibit A-12, Schedule B6.1. Please add actual amounts for 2023 and provide in Excel.

Answer: See attachment.

Attachment: U-21291 AGDG-6.177 Exhibit A-12 6.1 2023 Actuals

Michigan Public Service Commission
DTE Gas Company
Actual Capital Cost of IRM
Compared to Targeted Levels 2016-2023
($000s)

Case No.: U-21291
Exhibit: A-12
Schedule: B6.1
Witness: E. D. Janness
Page: 1 of 1

Line No.	(a) Description	(b) Planned	(c) Actual	(d) Variance	AG Calculated Excess Spending
	2016				
1	Main Renewal Program	$ 62,500	$ 86,322	$ 23,822	
2	Meter Move Out	22,700	26,688	3,988	
3	Pipeline Integrity	7,818	11,111	3,293	
4	Total IRM	$ 93,018	$ 124,121	$ 31,103	33%
	2017				
5	Main Renewal Program	$ 93,800	$ 124,325	$ 30,525	
6	Meter Move Out	22,700	23,172	472	
7	Pipeline Integrity	11,110	13,379	2,269	
8	Total IRM	$ 127,610	$ 160,876	$ 33,266	26%
	2018				
9	Main Renewal Program	$ 105,650	$ 142,554	$ 36,904	
10	Meter Move Out	22,900	24,151	1,251	
11	Pipeline Integrity	12,040	13,750	1,710	
12	MAC MMO	2,625	5,106	2,481	
13	Total IRM	$ 143,215	$ 185,561	$ 42,346	30%
	2019				
14	Main Renewal Program	$ 169,700	$ 199,646	$ 29,946	
15	Meter Move Out	22,700	29,308	6,608	
16	Pipeline Integrity	11,120	17,139	6,019	
17	MAC MMO	20,300	16,092	(4,208)	
18	Total IRM	$ 223,820	$ 262,185	$ 38,365	17%
	2020				
19	Main Renewal Program	$ 193,000	$ 227,977	$ 34,977	
20	Meter Move Out	22,700	35,294	12,594	
21	Pipeline Integrity	11,120	11,659	539	
22	MAC MMO	20,300	17,559	(2,741)	
23	Total IRM	$ 247,120	$ 292,488	$ 45,368	18%
	2021				
24	Main Renewal Program	$ 232,400	$ 240,072	$ 7,671	
25	Meter Move Out	22,700	26,194	3,494	
26	Pipeline Integrity	11,120	11,726	606	
27	MAC MMO	16,500	22,037	5,537	
28	Total IRM	$ 282,720	$ 300,028	$ 17,307	6%
	2022				
29	Gas Renewal Program	$ 255,100	$ 293,994	$ 38,894	
30	Pipeline Integrity	11,120	20,437	9,317	
31	MAC MMO	21,040	23,195	2,155	
32	Total IRM	$ 287,260	$ 337,626	$ 50,366	18%
	2023				
33	Gas Renewal Program	$ 255,100	$ 294,144	$ 39,044	
34	Pipeline Integrity	11,120	25,730	14,610	
35	MAC MMO	21,040	27,068	6,028	
36	Total IRM	$ 287,260	$ 346,943	$ 59,683	21%

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-6.179	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 179. Refer to Exhibit A-12, Schedule B6.5. Please expand this schedule to include actual amounts for each year 2018-2023 and provide both miles retired and miles installed, also services replaced, for each year 2018 to 2029 in Excel.

Answer: See attachment.

Attachment: U-21291 AGDG 6.179 Exhibit A-12 B6.5 with 2018 - 2023 actuals

Michigan Public Service Commission
DTE Gas Company
Investment Recovery Mechanism Expenditures History and Projections
For 2020-2029

Case No.: U-21291
Exhibit: A-12
Schedule: B6.5
Witness: E. D. Janness
Page: 1 of 1

Line No.	Description (a)	Actual 2018	2019	(b) 2020	(c) 2021	(d) 2022	(e) 2023	Projected Calendar Year (1) (f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029
	MAIN RENEWAL												
1	Legacy Main Renewal - SEMI (Miles)	125	145	151	158	164	167	150	150	150	150	150	150
2	Legacy Main Renewal - GRMI (Miles)	33	39	55	56	57	57	56	56	56	56	56	56
3	Legacy Main Renewal - Total (Miles)	**157**	**183**	**206**	**214**	**222**	**224**	**206**	**206**	**206**	**206**	**206**	**206**
4	Main Renewal Costs - SEMI ($K)	$ 122,132	$ 173,677	$ 179,870	$ 191,223	$ 212,328	$ 204,213	$ 213,545	$ 210,000	$ 210,000	$ 210,000	$ 210,000	$ 210,000
5	Main Renewal Costs GRMI ($K)	$ 20,422	$ 25,969	$ 48,106	$ 48,849	$ 50,777	$ 55,588	$ 64,000	$ 64,000	$ 64,000	$ 64,000	$ 64,000	$ 64,000
6	**Main Renewal Costs - Total ($K)**	**$ 142,554**	**$ 199,646**	**$ 227,977**	**$ 240,072**	**$ 263,105**	**$ 259,801**	**$ 277,545**	**$ 274,000**	**$ 274,000**	**$ 274,000**	**$ 274,000**	**$ 274,000**
7	$/Legacy Mile Retired - SEMI ($K)	$ 980	$ 1,200	$ 1,191	$ 1,211	$ 1,293	$ 1,226	$ 1,423	$ 1,400	$ 1,400	$ 1,400	$ 1,400	$ 1,400
8	$/Legacy Mile Retired - GRMI ($K)	$ 622	$ 672	$ 879	$ 878	$ 885	$ 976	$ 1,143	$ 1,143	$ 1,143	$ 1,143	$ 1,143	$ 1,143
9	**$/Legacy Mile Retired - Total ($K)**	**$ 905**	**$ 1,088**	**$ 1,108**	**$ 1,124**	**$ 1,187**	**$ 1,162**	**$ 1,347**	**$ 1,330**	**$ 1,330**	**$ 1,330**	**$ 1,330**	**$ 1,330**
	METER MOVE OUT												
10	Inside Meter Move Outs - MMO *(1)*	12,126	12,753	11,980	12,671	11,973	11,843	20,790	18,500	18,500	18,500	6,500	6,500
11	Inside Meter Move Outs - MAC MMO	2,543	8,042	8,016	8,138	8,353	8,621	-	-	-	-	-	-
12	**Inside Meter Move Outs - Total**	**14,669**	**20,795**	**19,996**	**20,809**	**20,326**	**20,464**	**20,790**	**18,500**	**18,500**	**18,500**	**6,500**	**6,500**
13	MMO Costs ($K)	$ 24,151	$ 29,308	$ 35,294	$ 26,194	$ 30,889	$ 34,343	$ 51,600	$ 47,545	$ 47,545	$ 47,545	$ 16,705	$ 16,705
14	MAC MMO Costs ($K)	$ 5,106	$ 16,092	$ 17,559	$ 22,037	$ 23,195	$ 27,488						
15	**Meter Move Out Costs ($K)**	**$ 29,257**	**$ 45,401**	**$ 52,853**	**$ 48,230**	**$ 54,085**	**$ 61,831**	**$ 51,600**	**$ 47,545**	**$ 47,545**	**$ 47,545**	**$ 16,705**	**$ 16,705**
16	$/GRP MMO ($K)	$ 1.99	$ 2.30	$ 2.95	$ 2.07	$ 2.58	$ 2.90	$ 2.48	$ 2.57	$ 2.57	$ 2.57	$ 2.57	$ 2.57
17	$/MAC MMO ($K)	$ 2.01	$ 2.00	$ 2.19	$ 2.71	$ 2.78	$ 3.19						
18	$/MMO - Total ($K)	**$ 1.99**	**$ 2.18**	**$ 2.64**	**$ 2.32**	**$ 2.66**	**$ 3.02**	**$ 2.48**	**$ 2.57**	**$ 2.57**	**$ 2.57**	**$ 2.57**	**$ 2.57**
19	**Total GRP ($M)**	**$ 171,811**	**$ 245,046**	**$ 280,830**	**$ 288,302**	**$ 317,189**	**$ 321,632**	**$ 329,145**	**$ 321,545**	**$ 321,545**	**$ 321,545**	**$ 290,705**	**$ 290,705**
20	Pipeline Integrity	$ 13,750	$ 17,139	$ 11,659	$ 11,726	$ 20,437	$ 25,730	$ 19,990	$ 23,060	$ 13,400	$ 13,400	$ 11,120	$ 11,120
21	Cathodic Protection								$ 9,600	$ 9,600	$ 9,600	$ 9,600	$ 9,600
22	**Grand Total IRM ($M)**	**$ 185,561**	**$ 262,185**	**$ 292,488**	**$ 300,028**	**$ 337,626**	**$ 347,362**	**$ 349,135**	**$ 354,205**	**$ 344,545**	**$ 344,545**	**$ 311,425**	**$ 311,425**
23	Miles Installed - SEMI	140	172	195	187	205	204	185	200	200	200	200	200
24	Miles Installed - GRMI	31	44	74	64	62	70	65	65	65	65	65	65
25	**Total Miles Installed**	**171**	**216**	**270**	**252**	**267**	**273**	**250**	**265**	**265**	**265**	**265**	**265**
26	GRP Services Replaced - SEMI (2)	16,088	17,180	19,152	20,217	21,897	18,824	16,198					
27	GRP Services Replaced - GRMI (2)	3,364	2,740	6,424	5,750	5,951	6,531	4,566					
28	**Total Services Replaced**	**19,452**	**19,920**	**25,576**	**25,967**	**27,848**	**25,355**	**20,764**	**-**	**-**	**-**	**-**	**-**

(1) Line 10: projection excludes 2,000 yearly inside meter moveouts and costs associated with Main Renewal to align with historical actuals

(2) Services replaced only counts services that we would renew. Does not include all other service work that may be involved for main renewal. We also do not forecast beyond 1 year.

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-6.172b
Respondent: E. D. Janness
Page: 1 of 1

Question: 172. Refer to lines 21-25 on page 45 of Mr. Janness's direct testimony on the transfer of cathodic protection capital expenditures to the IRM. Please:

b. Explain what a holistic and programmatic approach to cathodic protection looks like and why it cannot be done with expenditures included in base rates.

Answer: DTE Gas has not determined that cathodic protection cannot continue to be included in base rates, we have determined that it fits within the guidelines of what we believe should go into the IRM.

Attachment: None.

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.150b	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 150. Refer to Exhibit A-12, Schedule B5.11, pages 6-7.

b. For amounts under the 12 months ending 12/31/2025 on lines 20.2, 20.3, 20.5, and 20.6, what phase of development are these projects currently in?

Answer:

- 20.2 (MLV7 Replacement):
  - Engineering in 2024 and construction in 2025
- 20.3 (Au Gres tributary pipe replacement):
  - Engineering in 2024 and construction in 2025
- 20.5 (Willow Gate Station: Replace Regs 97 and 98)
  - Engineering and construction in 2025
- 20.6 (MLV 5C Line Replacement):
  - Engineering and construction in 2025

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-6.180	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 180. Refer to Exhibit A-12, Schedule B5.5, pages 27, 29, 36, and 44. For each of the projects in the referenced pages, please identify the project development phase (Needs Assessment, Conceptual Design, Engineering, Construction, Completed/In-Service, etc.) the project is currently in and the next phase of the project with applicable start and end dates. Provide this information in Excel.

Answer:

Pipeline	Current Phase	Start Date	End Date	Next Phase	Start Date	End Date
Trufant 12	Construction	4/22/24	8/2/24	Project In-Service	8/2/24	8/2/24
Muskegon-Ludington (10) [Scott Tie In]	Conceptual Design	1/1/24	5/5/25	Construction	5/5/25	10/31/25
Belle River Field Headers (12,16)	Conceptual Design	4/11/23	9/3/24	Construction	9/3/24	11/1/24
Belle River Field Headers (24)	Conceptual Design	4/1/24	5/5/25	Construction	5/5/25	10/31/25

Attachment: None.

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.123	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: 123. Refer to pages 93 and 94 of Ms. Fedele's direct testimony on the TCARP project. In response to discovery in U-21525-AGDG-2.7 and 2.8, the Company stated that it incurred additional costs to construct certain pipeline loops to deal with moisture problems on the gas stream delivered by DT Michigan Lateral (DTML) and those costs had not been billed to DTML. Please provide the costs that should have been billed to DTML and still remain in rate base in this rate case.

Answer: Two (2) pipeline loops: one (1) around the Saginaw Bay Interconnect and one (1) the West Branch Interconnection were not part of TCARP. The cost for the Saginaw Bay Interconnect loop was $155,000 and the cost of the West Branch Interconnection loop was $168,000.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.124a	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: 124. Refer to lines 13-23 on page 95 of Ms. Fedele's direct testimony on the TCARP project cost increase. Please:

a. Explain why the one-year delay increased internal labor, contractor, material, and corporate overhead costs by $3.0 million and how much for each.

Answer: When first conceptualized in 2019, Phase 2 (Frankfort Loop) and Phase 3 (Interconnections) were to be completed in 2021. As the project progressed, a decision was made to complete Phase 2 in 2021 and move Phase 3 into 2022. This prudent decision allowed the completion of Phase 3 to more closely align with DTM's in-service date. The company did not want to prematurely begin spending capital on Phase 3 when DTM had not completed their conversion work without certainty that DTM converted assets complied with all regulatory requirements to be a natural gas pipeline. This delay also allowed the project team to execute the work safely with the existing team size. It would have been difficult to cover both phases in the same year without adding additional resources due to the geographical location of the project sites in relation to each other. This breakdown of costs for the timing change included: internal labor ($1.8M), engineering contractor ($0.05M), material ($0.05M) and overhead costs ($1.1M).

Attachment: None

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-5.145a
Respondent: E. M. Abona
Page: 1 of 1

Question: 145. Refer to page 44 of Mr. Abona's direct testimony on storage plant expenditures and the Belle River Mills Valves and Actuators project. Please:

a. Provide the number of projects or units for lines 22 and 24 of Exhibit A-12, Schedule B5.1, page 2, separately for each year 2018 to 2023 actual and forecasted for 2024 and 2025 in Excel.

Answer: Please see table below.

Description	2018	2019	2020	2021	2022	2023	2024	2025
Gas Storage	65	32	67	70	57	63	44	37
Compression - Storage	114	151	136	95	116	118	78	60

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.147a	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 147. Refer to page 50 of Mr. Abona's direct testimony on transportation vehicles and equipment. Please provide the following information in Excel:

a. Provide the number of vehicles replaces by category with related dollars for each year 2018-2023 actual and forecasted for 2024 and 2025.

Answer: See attachment.

Attachment: U-21291 AGDG-5.147a Vehicles Replaced by Category 2018 - 2025

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

DTE Gas Response to data request AGDG-5.147a

Case No: U-21291
Exhibit: AG-18
May 7, 2024

2018	Dollar Amount *	Quantity**
Class 1		
Class 2	$ 3,319,005	64
Class 3	$ 1,796,840	37
Class 4	$ 645,162	7
Class 5	$ 499,129	6
Class 6	$ 102,276	1
Class 7	$ 6,004,872	26
Class 8	$ 410,280	1
Class 9	$ 370,546	18
Class 10		
Class 11	$ 106,222	2
Class 12	$ 21,980	1
Class 13	$ 24,956	1
Class 14		
Class 15	$ 8,381	1
Class 16		
Class 17		
Class 18		
Class 19		
	$ 13,309,648	165
Unit Cost	$ 80,665	

2019	Dollar Amount	Quantity
Class 1		
Class 2	$ 518,447	10
Class 3	$ 1,303,270	28
Class 4		
Class 5	$ 141,648	1
Class 6	$ 376,060	6
Class 7	$ 1,301,036	12
Class 8	$ 2,223,239	22
Class 9	$ 499,361	29
Class 10		
Class 11	$ 96,307	2
Class 12		
Class 13	$ 13,843	1
Class 14		
Class 15		
Class 16	$ 2,141,373	18
Class 17		
Class 18		
Class 19		
	$ 8,614,583	129
Unit Cost	$ 66,780	

2020	Dollar Amount	Quantity
Class 1		
Class 2	$ 965,510	15
Class 3	$ 2,214,307	39
Class 4	$ 469,377	3
Class 5	$ 216,132	2
Class 6	$ 685,897	7
Class 7	$ 1,171,438	5
Class 8	$ 2,446,673	12
Class 9	$ 264,593	15
Class 10		
Class 11	$ 73,443	2
Class 12		
Class 13	$ 19,170	1
Class 14		
Class 15		
Class 16	$ 1,050,279	8
Class 17		
Class 18		
Class 19	$ 85,270	1
	$ 9,576,817	110
Unit Cost	$ 87,062	

U-21291 AGDG-5.147a Vehicles Replaced by Catagory 2018 - 2025
*Dollar Amount represents total spend per class per year
**Quantity Represents chassis quantity per class per year

DTE Gas Response to data request AGDG-5.147a

2021	Dollar Amount	Quantity
Class 1	$ 73,155	3
Class 2	$ 1,862,380	26
Class 3	$ 2,720,558	32
Class 4		
Class 5	$ 1,026,414	8
Class 6		
Class 7		
Class 8		
Class 9		
Class 10		
Class 11	$ 181,086	2
Class 12		
Class 13		
Class 14		
Class 15		
Class 16	$ 1,516,056	17
Class 17		
Class 18		
Class 19	$ 62,271	2
	$ 7,379,649	87
Unit Cost	$ 84,824	

2022	Dollar Amount	Quantity
Class 1		
Class 2	$ 749,985	13
Class 3	$ 4,648,322	59
Class 4	$ 831,851	11
Class 5	$ 240,723	3
Class 6		
Class 7		
Class 8	$ 447,521	2
Class 9	$ 11,041	1
Class 10		
Class 11	$ 43,916	1
Class 12		
Class 13		
Class 14		
Class 15		
Class 16		
Class 17		
Class 18		
Class 19		
	$ 6,973,360	90
Unit Cost	$ 77,482	

2023	Dollar Amount	Quantity
Class 1	$ 453,582	11
Class 2	$ 1,347,617	21
Class 3	$ 7,261,422	89
Class 4		
Class 5	$ 1,710,469	11
Class 6		
Class 7		
Class 8	$ 661,415	2
Class 9	$ 87,533	7
Class 10		
Class 11	$ 115,367	6
Class 12		
Class 13	$ 16,349	1
Class 14	$ 272,217	1
Class 15		
Class 16	$ 1,572,534	10
Class 17		
Class 18		
Class 19		
	$ 13,498,505	148
Unit Cost	$ 91,206	

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

Case No: U-21291
Exhibit: AG-18
May 7, 2024

DTE Gas Response to data request AGDG-5.147a

2024 Actual	Dollar Amount	Quantity
Class 1	$ 115,414	2
Class 2	$ 836,648	13
Class 3	$ 6,666,368	90
Class 4		
Class 5	$ 120,468	1
Class 6		
Class 7		
Class 8		
Class 9	$ 17,337	1
Class 10		
Class 11		
Class 12		
Class 13		
Class 14		
Class 15		
Class 16	$ 776,846	3
Class 17		
Class 18		
Class 19		
	$ 8,533,081	108
Unit Cost	$ 79,010	

2024 Forecast	Dollar Amount	Quantity
Class 1		
Class 2	$ 1,467,611	21
Class 3		
Class 4		
Class 5		
Class 6		
Class 7	$ 785,126	2
Class 8	$ 2,795,547	11
Class 9		
Class 10		
Class 11		
Class 12		
Class 13	$ 95,519	2
Class 14		
Class 15		
Class 16	$ 1,285,010	11
Class 17		
Class 18		
Class 19		
	$ 6,428,813	47
Unit Cost	$ 136,783	

2025 Forecast	Dollar Amount	Quantity
Class 1	$ 450,000	10
Class 2	$ 4,706,604	55
Class 3	$ 4,501,815	48
Class 4	$ 270,000	3
Class 5		
Class 6		
Class 7	$ 1,864,862	6
Class 8	$ 2,488,738	9
Class 9		
Class 10		
Class 11		
Class 12		
Class 13		
Class 14		
Class 15	$ 1,486,148	4
Class 16		
Class 17		
Class 18		
Class 19		
	$ 15,768,167	125
Unit Cost	$ 126,145	

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-5.151c	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 151. Refer to Exhibit A-12, Schedule B8. Please:

c. Provide a reference to the exhibits and line numbers where the cost savings are shown for the projected test year and in the amount.

Answer: The O&M costs savings are a known and measurable change shown in Witness Kehoe's U-21291 Exhibit A-13, Schedule C5.3, line 14, column (j). The capital savings for the test year of $450,000 was not included in 2025.

Attachment: None

Adjustments to Capital Expenditures, Rate Base and Depreciation Expense

($000)

		Capital Expenditure Reductions [1]					Rate Base		Reduction in	Property taxes [3]	
Line	Description	2022 & Prior	2023	9 M/E Sep 2024	12 M/E Sep 2025	Total	Reduction	Depreciation Rate [2]	Depreciation Expense	Rate	Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)				
1	**Distribution Plant:**										
2	Main Renewals			$ 1,392		$ 1,392	$ 1,392	2.99%	$ 42	$ 0.058250	$ 41
3	Public Improvements			1,160	2,574	3,734	2,447	2.99%	73	$ 0.058250	$ 109
4	System Reliability			7,019	6,573	13,592	10,306	2.99%	308	$ 0.058250	$ 396
5	Communications & Controls - Meters			9,472	3,534	13,006	11,239	2.99%	336	$ 0.058250	$ 379
6	Leak Detection and Repair				14,970	14,970	7,485	2.99%	224	$ 0.058250	$ 436
7	Fort Street Main Replacement				32,753	32,753	16,377	2.99%	490	$ 0.058250	$ 954
8	Van Born project	6,700				6,700	6,700	2.99%	200	$ 0.058250	$ 195
9	**Transmission Plant:**										
10	Routine Transmission Projects				6,809	6,809	3,405	1.90%	65	$ 0.058250	$ 198
11	ILI Projects			3,588	8,576	12,164	7,876	1.90%	150	$ 0.058250	$ 354
12	Austin-Detroit A&B Lines		1,341	3,485	16,181	21,007	12,917	1.90%	245	$ 0.058250	$ 612
13	Belle River Detroit Loop			747	7,378	8,125	4,436	1.90%	84	$ 0.058250	$ 237
14	Taggart Compression Replacement			508	3,492	4,000	2,254	1.90%	43	$ 0.058250	$ 117
15	Oakland Resilience Interconnect		100	1,111	4,694	5,905	3,558	1.90%	68	$ 0.058250	$ 172
16	TCARP-DTML Interconnect/Dehydration	3,323				3,323	3,323	1.90%	63	$ 0.058250	$ 97
17	Cathodic Protection				(7,400)	(7,400)	(3,700)	1.90%	(70)	$ 0.058250	$ (216)
18	**Gas Starage and Compression**			9,506	3,819	13,325	11,416	1.90%	217	$ 0.058250	$ 388
19	**Transportation Vehicles**			7,097	11,378	18,475	12,786	6.47%	827	$ 0.058250	$ 538
20	**Gas IT Projects**	-	-	-	450	450	225	20.00%	45	$ 0.058250	$ 13
21	Total	$ 10,023	$ 1,441	$ 45,085	$ 115,781	$ 172,330	$ 114,440		$ 3,409		$ 5,019
22											
23	**Working Capital** (Exhibit AG-21)						10,083				
24											
25	**Total Rate Base Deduction**						$ 124,522				

Source: (1) See AG witness Coppola Direct Testimony.
(2) Depreciation rates from Exhibit A-13, Schedule C6, page 2.
(3) Milleage rate from WP SLW-1 applied to 50% of capital expenditures.

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-21291**
DTE Gas - Gas Rate Case **Exhibit AG-21**
May 7, 2024
Working Capital - Regulatory Asset - Incentive Compensation Balance

		Thousands of Dollars			
Line	**Caption or Description**	**Non Financial Metrics Requested Amounts***	**Performance Results****	**Approp. Awards & Working Capital*****	**Notes**
	(a)	(b)	(c)	(d)	(e)
1	U-20940 Incentive Comp. Requested				
2	AIP	$ 1,277	88.90%	$ 1,135	Col (b) x (c)
3	REP	4,009	87.50%	3,508	Col (b) x (c)
4	Total Requested by Company	$ 5,286			L 2 + L 3
5	Amounts to Reccover in Rates			$ 4,643	L 2 + L 3
6	Less Amount granted in U-20940 Commission Order			1,057	L 4 x 20%
7	Appropriate Amount of Initial Deferral			$ 3,586	L 5 less L 6
8	Amortization Expense over 5 years			717	L 7 / 5
9	Balance at End of Test Year			2,869	L 7 - L 8
10	Average Deferral Balance			$ 3,227	Avg. of L7 & L 9
11	Incentive Comp. Deferral Per Company			13,310	Co. Exh. A-12, Sch B4
12	**Working Capital Reduction**			**$ (10,083)**	L 10 less L 11

* From page 53 of witness Cooper's U-20940 testimony.
** See AG Exhibit AG-49 which shows the number of Company metrics at Target or better for 2022 based on DR AGDG-3.44a.
*** Company Exhibit A-13, Schedule C5.6 page 5 starts with incentive compensation of $6.4 million vs. the $5.3 million included in U-20940 in the Company's case. Amounts paid out beyond the original request should not be recovered through this tracker.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas - Gas Rate Case

Recommended Capital Structure & Cost Rates for Projected Year Ending September 2025 (Millions of Dollars)

			Consumers Energy Capital Structure				Total		Pre-Tax
Line	Description	Note	Capital Balances	% Permenant Capital	% Total Capital	Cost Rate*	Total Cost (d) x (e)	Conversion Factors**	Pre-Tax Wtd. Cost (f) x (g)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Long Term Debt	(A)	$ 2,749	50.00%	39.59%	4.44%	1.76%	1.0000	1.76%
2	Preferred Stock		-	0.00%	0.00%	0.00%	0.00%	1.3550	0.00%
3	Common Equity	(A)	2,749	50.00%	39.59%	9.85%	3.90%	1.3550	5.28%
4	Total Permanent Capital	(B)	5,498	100.00%	79.19%		5.66%		7.04%
5	Short Term Debt	(B)	184		2.65%	5.95%	0.16%	1.0000	0.16%
6	Deferred Income Taxes	(B)	1,261		18.16%	0.00%	0.00%	1.0000	0.00%
7	JDITC								
8	Long Term Debt	(A)	-		0.00%	4.44%	0.00%	1.0000	0.00%
9	Preferred Stock		-		0.00%	4.50%	0.00%	1.3550	0.00%
10	Common Equity	(A)	-		0.00%	9.85%	0.00%	1.3550	0.00%
11	Total JDITC	(B)	-						
12	**Total Capitalization & Cost Rates**		$ 6,943		100.00%		**5.82%**		**7.20%**

Notes

* All Cost rates per Exhibit A-14, Schedule D1 except for Common Equity which is set forth on Exhibit AG-23.
** See Company Exhibit A-14, Schedule D1, column (i).
(A) Reflects the permanent capital of DTE Gas per Exhibit A-14, Sched. D1, with common equity set at 50%.
(B) Capital balances per Company Exhibit A-14, Schedule D1.

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21291**
DTE Gas - Gas Rate Case | **Exhibit AG-23**
May 7, 2024
Summary of Cost of Common Equity Analysis |

Line	Description (a)	Relative Weighting (b)	Consumers Energy Proxy Rates (c)	Note (d)
1	Discounted Cash Flow Approach (DCF)	50.00%	9.51%	1
2	Capital Asset Pricing Model Approach (CAPM)	25.00%	10.42%	2
3	Utility Equity Risk Premium Approach	25.00%	9.82%	3
4	**Calc. Cost of Common Equity (Sum of Col. (b) x (c) for Lines 1, 2 and 3)**		**9.81%**	
5	Rounding Up Result		0.04%	
6	**Cost of Common Equtiy per AG Case (L4 + L5)**		**9.85%**	

Note 1 See Exhibit AG-24
Note 2 See Exhibit AG-25
Note 3 See Exhibit AG-26

Discounted Cash Flow (DCF) Application
(See Equation Below)

Line	Company	Ticker	Average 30 Day High Low Price*	Projected 2023-24 Ann. Dividend**	Dividend Yield Col. (d)/(c)	EPS Growth Rate*** Value Line	Analysts p/Yahoo	Average of Col. (f) & (g)	DCF ROE for Each Co. Col. (e) + (h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Proxy Group								
1	Atmos Energy	ATO	$ 114.95	$ 3.35	2.91%	6.48%	7.50%	6.99%	9.90%
2	Black Hills	BKH	57.51	2.65	4.61%	3.44%	N/M	3.44%	8.05%
3	Chesapeake Utilities	CPN	103.77	2.52	2.43%	6.03%	7.60%	6.82%	9.24%
4	New Jersey Resources	NJR	42.00	1.72	4.10%	5.33%	6.00%	5.66%	9.76%
5	NiSource	NI	26.54	1.09	4.11%	3.13%	7.30%	5.22%	9.32%
6	Northwest Natural Holdings	NWN	36.95	1.96	5.30%	4.17%	2.80%	3.48%	8.79%
7	One Gas	OGS	61.47	2.86	4.65%	3.65%	5.00%	4.32%	8.98%
8	Spire	SR	59.91	3.09	5.16%	7.39%	6.36%	6.88%	12.03%
9	Average				***4.16%***	***4.95%***	***6.08%***	***5.35%***	$\boxed{\textbf{\textit{9.51\%}}}$
10	High								12.03%
11	Low								8.05%

____

* Average of High and Low prices per Yahoo from February 15 to March 31, 2024

** Value Line Projected Dividends for 2024 and 2025 (averaged) published February 23, 2024 and for Black Hills on January 19, 2024

*** For Columns (f) and (g) per workpapers

N/M Below 2% growth estimate disregarded

Equation **R = D/P + g** *Where* **R** = the required return on the equity security **D** = the next dividend on the security
P = the current price of the equity security **g** = the expected growth rate of earnings

Capital Asset Pricing Model Application
(See Equation Below)

Line	Company & Ticker		% Common Equity	Current Beta (B)	Risk Premium (R_p)	Beta x Risk Premium Col. (c) x (d)	2024/25 Risk Free Rate (R_f)	K_e or 2024-25 CAPM ROE for Each Co. Cols. (e) + (f)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)
	Proxy Group							
1	Atmos Energy	ATO	61.6%	0.85	7.17%	6.09%	4.10%	10.19%
2	Black Hills	BKH	40.3%	1.00	7.17%	7.17%	4.10%	11.27%
3	Chesapeake Utilities	CPK	54.4%	0.80	7.17%	5.74%	4.10%	9.84%
4	New Jersey Resources	NJR	41.1%	0.95	7.17%	6.81%	4.10%	10.91%
5	NiSource	NI	33.9%	0.90	7.17%	6.45%	4.10%	10.55%
6	Northwest Natural Holdings	NWN	44.4%	0.85	7.17%	6.09%	4.10%	10.19%
7	One Gas	OGS	49.4%	0.85	7.17%	6.09%	4.10%	10.19%
8	Spire	SR	40.1%	0.85	7.17%	6.09%	4.10%	10.19%
9	**Average**		**45.7%**	**0.88**	**7.17%**	**6.32%**	**4.10%**	***10.42%***
10	High							11.27%
11	Low							9.84%

Sources

Column (b) Per SEC Filings: Average for the four quarters ended December 2023
Column (c) From the Value Line Investment Survey published February 23, 2024 and for Black Hills on January 19, 2024.
Column (d) Reflects the average returns of Large Stocks (12.16%) vs Long Term Gov't Bond Income Returns (4.91%) for the period 1926 to 2022 per the Ibbotson Clasic Year Book (See workpapers)

Column (f) 30 Yr US Treasury for 2025 per March 2024 Blue Chip Report **4.10%** See AGDG-1.4 Attach.

Equation for CAPM $K_e = R_f + (B \times R_p)$

Where K_e = the Cost of Common Equity; R_f = the Risk Free Rate of Return;
B = the Beta or covariance of the stocks price to overall market ; and
R_p = the Expected Risk Premium of the overall market

Utility Equity Risk Premium Approach

Line	Description (a)	Rate Developed (b)	Note (c)
1	Number of Companies in proxy group	8	
2	Average Rating	A/BBB	1
3	Projected Average of "A" and "BBB" Bonds New Issue Rate	5.77%	2
4	Historical Spread - Gas Util. Common Stocks vs. "A" Rated Utility Bonds	4.05%	3
5	Sub Total - Rate for "A" and "BBB" rated companies (lines 3 + 4)	**9.82%**	

1 Atmos, and OneGas are "A" rated. Black Hills, NiSource and Spire are "BBB" rated and the subsidiaries of Northwest Natural Holdings and New Jersey Resources are "A" rated

2 Based on analysis of 2023 new 30 Year issues (see workpapers)

"BBB" Rated Spread to 30 Yr, Treasuries	1.77%
"A" Rated Spread to 30 Yr. Treasuries	1.57%
Average Spread	1.67%
Assumed 30 Year US Treasury Bond Rate (from CAPM Analysis)	4.10%
Projected Average of "A" / "BBB" 30 Year bonds	**5.77%**

3 Per Company Exhibit A-14 (TAW-1) page 8, line 72

Peer Group Non-Utility or Non Regulated Operations

Line	Company & Ticker		Percent Common Equity*	Current Beta (*B*)	Utility Business	Non Utility & Non Reg. Business		Measure-ment Criteria	SEC Filing Information SEC Form	Period Ending	Page
	(a)		(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)
	Proxy Group										
1	Atmos Energy	ATO	61.6%	0.85	***66.0%***	***34.0%***	A	Net Income	10-K	Sep. 23	25
2	Black Hills	BKH	40.3%	1.00	***100.0%***	***0.0%***	B	Op. Income	10-K	Dec. 23	40
3	Chesapeake	CPK	54.4%	0.80	***74.0%***	***26.0%***	C	Op. Income	10-K	Dec. 23	31
4	New Jersey Resources	NJR	41.1%	0.95	***50.0%***	***50.0%***	D	Net Income	10-K	Sep. 23	34
5	NiSource	NI	33.9%	0.90	***97.0%***	***3.0%***		Revenues	10-K	Dec. 23	60
6	Northwest Natural Gas	NWN	44.4%	0.85	***97.0%***	***3.0%***		Revenues	10-K	Dec. 23	79 & 85
7	One Gas	OGS	49.4%	0.85	***100.0%***	***0.0%***		Revenues	10-K	Dec. 23	7
8	Spire	SR	40.1%	0.85	***87.0%***	***13.0%***	E	Net Income	10-K	Sep. 23	30
9	**Average**		45.7%	**0.88**	***83.9%***	***16.1%***					

* Reflects Average Capitalization for the four quarters ended December 2023
A Pipeline and Storage
B Utility equals 48% Gas and 52% Electric
C Non Utility is primarily Propane Distribution
D Energy Services, Clean Energy Ventures, Storage and Transportation
E Gas Marketing and Storage and Pipelines

Market to Book Equity Ratios

Line	Company & Ticker		Dec. 31, 2023 Mkt. Price p/ Sh.	December 31, 2023 Book Value of Common Equity ($Mil.)	December 31, 2023 Shares Outstanding (Millions)	December 31, 2023 Book Value Per Sh.	Market to Book Ratio
	(a)		(b)	(c)	(d)	(e)	(f)
	Proxy Group						
1	Atmos Energy	ATO	115.90	11,273.0	150.8	74.75	1.6
2	Black Hills	BKH	53.95	3,215.3	68.3	47.08	1.1
3	Chesapeake Utilities	CPK	105.63	1,246.1	22.2	56.13	1.9
4	New Jersey Resources	NJR	44.58	2,066.2	93.2	22.17	2.0
5	NiSource	NI	28.55	7,783.5	447.4	17.40	1.6
6	Northwest Natural Gas	NWN	38.94	1,283.8	37.6	34.14	1.1
7	One Gas	OGS	63.72	2,765.9	56.5	48.95	1.3
8	Spire	SR	62.34	2,808.8	55.0	51.07	1.2
9	**Average**						**1.5**

Col. (b) Closing Price Per Yahoo
Col. (c) Per SEC Filings
Col. (d) Per SEC Filings
Col. (e) Equals Col. (c) divided by Col. (d)
Col. (f) Equals Col. (b) divided by Col. (e)

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21291**

DTE Gas - Gas Rate Case | **Exhibit AG-29**

May 7, 2024

Gas Regulatory Decisions - Authorized ROE's under 9.9% - 2022 and 2023 | **Page 1 of 3**

Line	Gas Company* (a)	Order Date & Jurisdiction* (b)			ROE Rate from Order* 2022 (c)	ROE Rate from Order* 2023 (d)	Parent Company (e)	Foreign,Prvt, Domestic (f)	Long Term Debt Issued Since Rate Order** (g)			
1	Delta Natural Gas	Jan	3	KY	9.25%		Essential Utilities	D	$500M	5.30%	30 Yr	(May 2022)
2	Piedmont Natural Gas	Jan	6	NC	9.60%		Duke Energy	D	$2.9 Bil	4.0 to 5.3%	10 &30 Yr.	(Aug 2022)
3	Niagra Mohawk Power	Jan	20	NY	9.00%		National Grid PLC	F	$500M	5.76%	30 Yr	(Sep 2022)
4	Public Service of N. Carolina	Jan	21	NC'	9.60%		Dominion Energy	D	$1.0 Bil	4.4 to 4.9%	10 &30 Yr.	(Aug 2022)
5	Southwest Gas	Mar	22	NV	9.40%		Southwest Gas Holdings	D	$600M	4.10%	10 Yr. Debt	(Mar 2022)
6	Southwest Gas	Mar	22	NV	9.40%		Southwest Gas Holdings	D	$600M	4.10%	10 Yr. Debt	(Mar 2022)
7	Orange & Rockland Util.	Apr	14	NY	9.20%		Consolidated Edison	D	$500M	5.20%	10 Yr. Debt	(Feb 2023)
8	Atmos Energy	May	19	KY	9.23%		Atmos Energy	D	$800M	5.45%/5.75%	10 & 30 Yr	(Sep 2022)
9	Corning Natural Gas	Jun	16	NY	9.25%		Arga Infrastructure Ptns.	PVT				
10	Northern Utilities	Jul	20	NH	9.30%		Unitil	D	$25M	5.7%/5.96%	10 &30 Yr.	(Jul 2023)
11	Northern Indiana Pub Serv	Jul	27	IN	9.85%		NISource	D	$300M	5.25%	5 Yr	(May 2023)
12	Avista	Aug	2	OR	9.40%		Avista	D	$250M	5.66%	30 Yr	(Mar 2023)
13	Elizabethtown Gas	Aug	17	NJ	9.60%		South Jersey Industries	PVT				
14	CenterPoint Energy Res.	Aug	18	MN	9.39%		CenterPoint Energy Res.	D	$800M	4.45%/4.85%	10 & 30 Yr	(Sep 2022)
15	Cascade Natural Gas	Aug	23	WA	9.40%		MDU Resources	D	$100M	5.39%	10 Yr	(Nov 2023)
16	Piedmont Natural Gas	Sep	15	SC	9.30%		Duke Energy	D	$350M	5.40%	10 Yr	(Jun 2023)
17	Black Hills Energy Arkansas	Oct	10	AR	9.60%		Black Hills	D	$450M	4.35%	11 Yr	(May 2023)
18	Delmarva Power & Light	Oct	12	DE	9.60%		Exelon	D	$1.7 Bil	5.2/5.4/5.6%	5/10/20 Yrs	(Feb 2024)
19	Northwest Natural Gas	Oct	24	OR	9.40%		Northwest Natural Hldng.	D	$130M	5.18%/5.23%	11 & 15 Yr	(Aug 2023)
20	Public Service of Colorado	Oct	25	CO	9.20%		Xcel Energy	D	$800M	5.45%	10 Yr	(Jul 2023)
21	Berkshire Gas	Oct	27	MA	9.70%		Avangrid	D	$680M	Var. Rates	Var. Mat.	(Dec 2023)
22	Northern States Power	Oct	27	ND	9.80%		Xcel Energy	D	$800M	5.45%	10 Yr	(Jul 2023)
23	Columbia Gas of Maryland	Nov	17	MD	9.65%		NISource	D	$300M	5.25%	5 Yr	(May 2023)
24	New Mexico Gas	Nov	30	NM	9.38%		Emera	F				
25	So. California Gas	Dec	15	CA	9.80%		Sempra	D	$600M	6.88%	30 Yr	(Mar 2024)
26	So. Jersey Gas	Dec	21	NJ	9.60%		South Jersey Industries	PVT				
27	Pudget Sound Energy	Dec	22	WA	9.40%		Alberta IM & Brit. Col IM	PVT				
28	Wisconsin Public Service	Dec	22	WI	9.80%		WEC Energy	D	$1.1 Bil	4.75%	3 & 5 Yr.	(Jan 2023)
29	Dominion Energy	Dec	23	UT	9.60%		Dominion Energy	D	$1.0 Bil	5/5.35%	10/30 Yr.	(Feb 2024)
30	Wisconsin Eletric Power	Dec	29	WI	9.80%		Xcel Energy	D	$800M	5.45%	10 Yr	(Jul 2023)
31	Wisconsin Gas	Dec	29	WI	9.65%		Xcel Energy	D	$800M	5.45%	10 Yr	(Jul 2023)
32	**Average for 2022**				**9.49%**							

* Per Regulatory Research Associates with Summary of All Orders on Page 4

** Per various SEC Filings

Gas Regulatory Decisions - Authorized ROE's under 9.9% - 2022 and 2023

Line	Gas Company*	Order Date & Jurisdiction*			ROE Rate from Order* 2022	2023	Parent Company	Foreign,Prvt, Domestic	Long Term Debt Issued Since Rate Order**			
	(a)	(b)			(c)	(d)	(e)	(f)	(g)			
1	Texas Gas Service	Jan	19	TX		9.60%	One Gas	D	$300M	5.10%	6 Yr	(Dec 2023)
2	Southwest Gas	Jan	23	AZ		9.30%	Southwest Gas Holdings	D	$300M	5.45%	5 Yr	(Mar 2023)
3	Columbia Gas of Ohio	Jan	26	OH		9.60%	NiSource	D	$300M	5.25%	5 Yr	(May 2023)
4	Northern States Power	Mar	23	MN		9.57%	Xcel Energy	D	$800M	5.45%	10 Yr	(Jul 2023)
5	Pivotal Utility Holdings	Mar	28	FL		9.50%	Chesapeake Utilities	D	$550M	Var. Rates	Var. Mat.	(Nov 2023)
6	Atmos Energy	May	4	CO		9.30%	Atmos	D	$900M	5.9%/6.5%	10 & 30 Yr	(Oct 2022)
7	Intermountain Gas	Jun	30	ID		9.50%	MDU Resources	D	$100M	5.39%	10 Yr	(Nov 2023)
8	Consolidated Edison of NY	Jul	20	NY		9.25%	Consolidated Edison	D				
9	Michigan Gas Utilities	Aug	30	MI		9.80%	WEC Energy	D				
10	Avista	Aug	31	ID		9.40%	Avista	D				
11	Northern Utilities	Sep	20	ME		9.35%	Unitil	D				
12	Dominion Energy SC	Sep	20	SC		9.49%	Dominion	D	$1.0 Bil	5/5.35%	10/30 Yr.	(Feb 2024)
13	Piedmont Natural Gas	Oct	5	SC		9.30%	Duke Energy	D	$150M	4.85%	3/5 Yr	(Nov 2023)
14	Chattanooga Gas	Oct	6	TN		9.80%	Southern Co.	D	$400M	5.70%	10 Yr	(Feb 2024)
15	New Youk State Elec. & Gas	Oct	12	NY		9.20%	Avangrid	D	$680M	Var. Rates	Var. Mat.	(Dec 2023)
16	Rochester Gas & Electric	Oct	12	NY		9.20%	Avangrid	D	$680M	Var. Rates	Var. Mat.	(Dec 2023)
17	Northwestern Energy	Oct	25	MT		9.55%	NorthWestern Energy	D				
18	Minnesota Energy Rescs	Oct	26	MN		9.65%	WEC Energy	D				
19	Avista	Oct	26	OR		9.50%	Avista	D				
20	Duke Energy Onio	Nov	1	OH		9.60%	Duke Energy	D	$150M	4.85%	3/5 Yr	(Nov 2023)
21	Madison Gas & Electric	Nov	3	WI		9.70%	MGE Corp	D				
22	Questar Gas	Nov	7	WY		9.65%	Dominion Energy	D	$1.0 Bil	5/5.35%	10/30 Yr.	(Feb 2024)
23	Northern States Power	Nov	9	FL		9.80%	Xcel Energy	D				
24	Wisconsin Power & Light	Nov	9	WI		9.80%	Alliant Energy	D				
25	Ameren Illinois	Nov	16	IL		9.44%	Ameren	D	$700M	4.38%	5 Yr	(Dec 2023)
26	North Shore Gas	Nov	16	IL		9.38%	WEC Energy	D	$20M	5.82%	5 Yr	(Dec 2023)
27	Northern Illinois Gas	Nov	16	IL		9.51%	Southern Co.	D	$400M	5.70%	10 Yr	(Feb 2024)
28	Peoples Gas Light & Coke	Nov	16	IL		9.38%	WEC Energy	D				
29	Piedmont Natural Gas	Dec	4	TN		9.80%	Duke Energy	D	$150M	4.85%	3/5 Yr	(Nov 2023)
30	Baltimore Gas & Electric	Dec	14	MD		9.45%	Exelon	D	$1.7 B	5.2/5.4/5.6%	5/10/20 Yrs	(Feb 2024)
31	Washington Gas Light	Dec	14	MD		9.50%	AltaGas	F				
32	Washington Gas Light	Dec	15	MD		9.65%	AltaGas	F				
33	Mountaineer Gas	Dec	21	WV		9.75%	UGI	D				
34	**Average for 2023**					**9.52%**						

* Per Regulatory Research Associates with Summary of All Orders on Page 4
** Per various SEC Filings

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas - Gas Rate Case

Case No. U-21291
Exhibit AG-29
May 7, 2024

Gas Regulatory Decisions - Authorized ROE's Summary for all Cases - 2022 and 2023

		Total Year 2022		Total Year 2023	
Line	Caption	# of Orders	Avg. ROE	# of Orde	Avg. ROE
	(a)	(b)	(c)	(d)	(e)
1	**Average Authorized ROE's page 1 and 2**	31	9.49%	33	9.52%
	ROE Orders At 9.9% or Higher				
2	Michigan Cases				
4	Consumers Energy Gas	1	9.90%	1	9.90%
6	California Case				
	San Diego Gas & Electric	1	10.20%		
7	Florida Cases			1	10.25%
	Florida Public Utilities*			1	10.15%
	Peoples Gas System**				
8	Total Number At 9.90% or Higher	2		3	
9	Tota/Avg. of All Cases	**33**	**9.52%**	**36**	**9.57%**

* Small Florida company operating in four counties with 83,000 customers

** Small Florida company operating in central Florida (near Lakeland), the west coast of Florida (Sarasota) and on the east coast of Florida (Jupiter) with approximately 400,000 customers.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas - Gas Rate Case

Rating Agency Cash Flow Ratios
(With ROE at 9.85% and a 50% Common Equity Ratio)

		2022 Adjusted Moody's Cash Flow Ratio ($ Millions)			
Line	Caption	Cash From Operations Pre-Wkg. Cap.	Debt	Ratio (e) / (f)	Note
	(a)	(b)	(c)	(d)	
1	**2022 Actual Ratio Results**	$ 575	$ 2,602	**22.1%**	1
2	Reduce Common Equity (to 50% vs 52.6%)	(13)	117		2
3	Decrease ROE (to 9.85% vs 11.5%)	(37)			3
4	**Pro Forma w/50% Common Equity, 9.85% ROE**	$ 525	$ 2,719	**19.3%**	L 1 + L 2 + L 3
5	**Ratings Downgrade Risk**			***Below 16%***	4

Notes

1 From page 1 of Moody's July 25, 2023 report on DTE Gas (see AGDE-1.16-04)

2 As noted below under "Avg. 2022 Capitalization" below, the Company's Common Equity ratio was 52.6% in 2022. Adjusting to 50% shifts $117 million from common equity to long-term debt (2.6% x $4.486 billion = $117 million).
Lower Common Equity of $117 million x the Company's earned ROE of 11.5% = $13 million in lower Net Income.

3 Decreasing the ROE from 11.5% (actual) to 9.85% produces a $37 million decrease in total Company earnings (1.65% x $2.24 billion = $37 million).
Note: The DTE Gas 2022 Net Income of $ 272 million (p. 31, 2022 form 10-K) / $2.4 billion (below) = an 11.5% ROE.

4 From page 2 of Moody's July 25, 2023 report on DTE Gas (see AGDE-1.16-04)

Average 2022 Capitalization ($ Millions)	Actual 2022		Rebalancing	2022 Rebalanced	
from Ex. A-4 Sch. D1, pg.1)	Amount	% Capital	Adjustmts.	Amount	% Capital
Long-Term Debt	$ 2,126	47.4%	$ 117	$ 2,243	50.0%
Preferred Stock	-	0.0%		-	0.0%
Common Equity	2,360	52.6%	(117)	2,243	50.0%
Total	$ 4,486	100.0%		$ 4,486	100.0%

VLF*Alert*

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Mitchell Appel
President
Value Line Funds

Dear Fellow Shareholder,

Thank you for choosing Value Line Funds as a part of your diversified investment portfolio. For over half a century, Value Line Funds has championed sound investment principles and helped thousands of investors accomplish their financial goals with our actively managed family of mutual funds.

We hope you enjoy this edition of the VLFAlert and thank you for your continued support.

Volatility is Not Risk:
Why the Difference is Critical to Long-Term Results

2017 lulled many equity investors into a comfort zone based on historically low volatility. 2018 has been more volatile—with tighter monetary policy and geopolitical and trade policy uncertainty among the drivers of the increase. But volatility levels in 2018 are actually historically normal—even with the bouts of volatility anticipated ahead of the November mid-term elections. But volatility is not risk. And recognizing the difference can be critical to your long-term investment returns.

Defining Our Terms

Volatility is simply the measure of the up and down movements of the market. For example, since 1950, when the Value Line Funds were first established, the average maximum drawdown in the broad U.S. equity market during midterm election years has been -17%, with weakness tending to be concentrated in the pre-election days. However, the good news is that there has been a consistent tendency historically for post-drawdown rallies, averaging +32% in the subsequent year.[1] Volatility? Yes! Uncertainty? Yes! But volatility is only risk if you act during down times—that is, only if you sell. To which the often-invoked quip may well be the most prudent answer: "Don't just do something, sit there."

Risk, on the other hand, is the probability of a permanent loss. You might think of risk as the possibility of having to lower your quality of life in the future.

> **"Volatility is not synonymous of risk but—for those who truly understand it—of wealth."**
> *- Francois Rochon**

Recognizing the Difference

Volatility is independent of risk. Too many investors let an investment's short-term price movements, or perceptions of short-term price movements, drive their buying and selling decisions. Too often volatility is regarded as something to be avoided. But since short-term price moves are unknowable and independent of underlying fundamentals and value, such volatility should not be a determinant.

And ALL investments have risk of some kind, including cash and CDs. One just needs to pick the risks that are best to take based on your individual tolerance level, time horizon and financial needs and goals.

As famed investor and Berkshire Hathaway CEO Warren Buffet wrote:

> "Stock prices will always be far more *volatile* than cash-equivalent holdings. *Over the long term*, however, currency-denominated instruments are *riskier* investments — far riskier investments — than widely-diversified stock portfolios that are bought over time and that are owned in a manner invoking only token fees and commissions. **That lesson has not customarily been taught in business schools, where volatility is almost universally used as a proxy for risk. Though this pedagogic assumption makes for easy teaching, it is dead wrong: Volatility is *far* from synonymous with risk.** Popular formulas that equate the two terms lead students, investors and CEOs astray."[2]

> **"Volatility is our friend. Volatility has nothing to do with risk."**
> *- Mohnish Pabrai**

(continued on back)

It's a Matter of Time, Not Timing

Most experienced investors do not fear volatility, only unrecoverable loss. But most losses, as measured by a day, a week, a quarter or a year, are recoverable over time. Declines in principal value have historically been temporary. Of course, there are true risks. A company could go totally out of business. An innovation could transform an industry so profoundly to make a once "blue chip" company a relic. A geopolitical event could happen to negate all assumptions. But these occurrences are rare. For the vast majority of investors, maintaining a long-term perspective is the real key to attaining gains over their investing lifetime. Historically, since World War II, the longer you hold stocks, the narrower the range of returns.[3] In other words, even if volatility is a concern, it decreases the longer you hold stocks. It's the old adage: what matters is time in the market, not market timing.

"You can't overlook the volatility, but you don't let it push you around in the market."

*- Boone Pickens**

solutions designed to meet a broad array of investment goals. Whether you are looking for income or long-term capital appreciation, whether you choose to invest in equities, taxabl or tax-exempt fixed income or a hybrid fund of multiple asset classes, you can rely on the solid fundamentals of Value Line Funds.

Value Line Funds Include:
Equity Funds
Premier Growth Fund
Larger Companies Focused Fund
Mid Cap Focused Fund
Small Cap Opportunities Fund
Hybrid Funds
Asset Allocation Fund
Capital Appreciation Fund
Fixed Income Funds
Tax Exempt Fund
Core Bond Fund

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

Exhibit AG-32
Case No. U-21291
Date: May 7, 2024

Comparison of Gas Sales Volumes - 2017-2022 Actuals to Sep 2024 Test Year Forecast

		Actual August Year Ending								Test Year 12 Months Ended	2020-2023	2018-2023
Line	Description	2018	2019	2020	2021	2022	2023	2024F	2025F	Sep 2025F	3-YR CAGR	5-YR CAGR
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(k)
1	**Average Gas Use Per Customer (Mcf):** [1]											
2	**Rate A Residential**	95.68	95.13	92.21	91.21	94.45	92.62	91.69	90.27	90.52		
3	*Percent Change from Prior Yr*		*-0.6%*	*-3.1%*	*-1.1%*	*3.6%*	*-1.9%*	*-1.0%*	*-1.6%*	*-2.3%*	**0.1%**	**-0.6%**
4												
5	**Rate 2A Residential Multi-Dwelling I**	238.65	254.86	219.43	219.36	216.79	218.43	659.57	645.95	211.47		
6	*Percent Change from Prior Yr*		*6.8%*	*-13.9%*	*0.0%*	*-1.2%*	*0.8%*	*202.0%*	*-2.1%*	*-3.2%*	**-0.2%**	**-1.8%**
7												
8	**Rate 2A Residential Multi-Dwelling II**	874.03	809.76	828.42	804.10	814.86	803.94	659.57	645.95	780.46		
9	*Percent Change from Prior Yr*		*-7.4%*	*2.3%*	*-2.9%*	*1.3%*	*-1.3%*	*-18.0%*	*-2.1%*	*-2.9%*	**-1.0%**	**-1.7%**
10												
11	**Rate GS-1 Small Commercial**	461.91	455.38	433.27	423.27	447.49	446.37	437.36	430.55	431.79		
12	*Percent Change from Prior Yr*		*-1.4%*	*-4.9%*	*-2.3%*	*5.7%*	*-0.2%*	*-2.0%*	*-1.6%*	*-3.3%*	**1.0%**	**-0.7%**
13												
14	**Rate GS-2 Large Commercial & Industrial**	13,166.00	23,856.35	12,488.31	12,102.43	15,967.81	19,134.82	17,426.18	17,320.15	17,356.45		
15	*Percent Change from Prior Yr*		*81.2%*	*-47.7%*	*-3.1%*	*31.9%*	*19.8%*	*-8.9%*	*-0.6%*	*-9.3%*	**15.3%**	**7.8%**
16												
17	**Rate S Schools**	6,945.82	6,968.75	6,790.47	7,088.04	7,266.69	7,690.73	7,514.82	7,387.82	7,412.88		
18	*Percent Change from Prior Yr*		*0.3%*	*-2.6%*	*4.4%*	*2.5%*	*5.8%*	*-2.3%*	*-1.7%*	*-3.6%*	**4.2%**	**2.1%**
19												
20												
21	**Gas Deliveries - Weather-Normalized:** [2,3]											
22	**(MMCF)**											
23	Rate A Residential	111,516	111,898	109,712	109,891	114,830	113,508	113,329	112,337	112,464		
24	Rate 2A Residential Multi-Dwelling I	310	325	285	296	299	305	945	920	302		
25	Rate 2A Residential Multi-Dwelling II	4,644	4,219	4,213	4,074	4,059	3,971	3,165	3,079	3,726		
26	Rate GS-1 Small Commercial	41,193	40,603	38,784	38,123	40,617	40,650	39,907	39,408	39,491		
27	Rate GS-2 Large Commercial & Industrial	716	1,215	565	610	966	1,328	1,409	1,521	1,494		
28	Rate S Schools	1,482	1,484	1,478	1,608	1,659	1,707	1,628	1,593	1,600		
29												
30	**Average Number of Customers:** [2, 3]											
31	Rate A Residential	1,165,546	1,176,299	1,189,798	1,204,853	1,215,728	1,225,539	1,235,954	1,244,512	1,242,379		
32	Rate 2A Residential Multi-Dwelling I	1,298	1,276	1,297	1,348	1,381	1,397	1,434	1,424	1,428		
33	Rate 2A Residential Multi-Dwelling II	5,314	5,211	5,086	5,067	4,981	4,940	4,799	4,767	4,774		
34	Rate GS-1 Small Commercial	89,179	89,163	89,515	90,067	90,766	91,067	91,246	91,529	91,459		
35	Rate GS-2 Large Commercial & Industrial	54	51	45	50	61	69	81	88	86		
36	Rate S Schools	213	213	218	227	228	222	217	216	216		

Source:

(1) Calculated by dividing weather-normalized deliveries by number of customers for Residential and Commercial gas deliveries

(3) Historical weather normalized sales and number of customers from DR AGDG-4.66a attachment

(4) DR AGDG-4.67b Attachment for 2024 and 2025 forecasted sales and customers. Exhibit A-15, Schedule E-1 for test year September 2025 gas deliveries and customers

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-4.58d
Respondent: G. H. Chapel
Page: 1 of 1

Question: 58. Refer to lines 8-24 on page 16 of Mr. Chapel's direct testimony on the linear forecasting model. Please:

d. Confirm that the calculations and adjustments for EWR and BTU values were done outside of the model. If not confirming, provide evidence otherwise.

Answer: EWR adjustments were developed in the Company's EWR process (outside the model) and are included as an adjustment to the usage factors. Heating value (BTU) adjustments are made outside the model and are included as an adjustment to the usage factors.

Attachment: None

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-4.58e
Respondent: G. H. Chapel
Page: 1 of 1

Question: 58. Refer to lines 8-24 on page 16 of Mr. Chapel's direct testimony on the linear forecasting model. Please:

e. Provide the source of the EWR rates of 1.05% and 1.0% and describe how they were determined. Provide the actual EWR savings achieved each year 2018 to 2023 and how the Company knows that these rates were actually achieved.

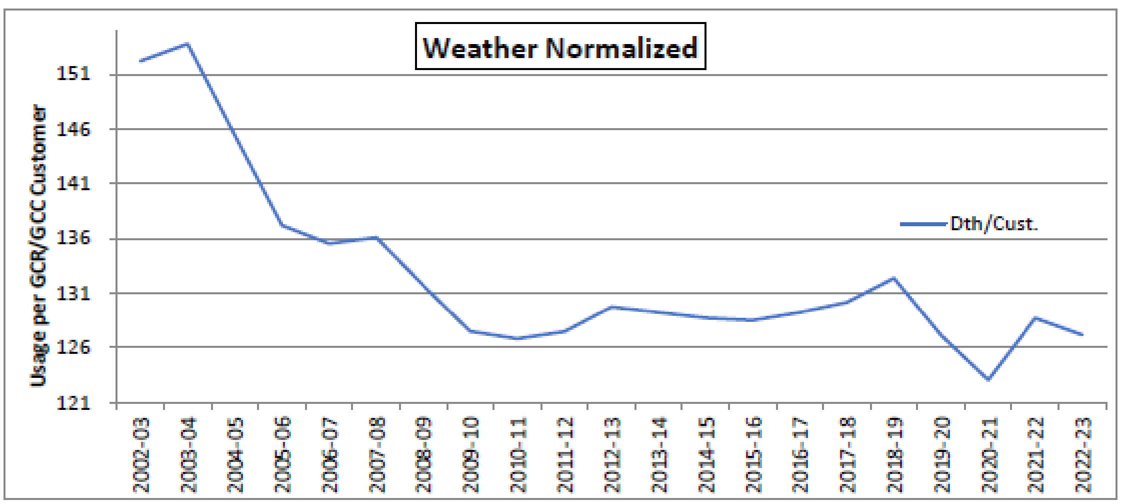
Answer: The EWR values were determined pursuant to the most recent EWR filing before the MPSC, Case No. U-21322. Please refer to the public record of that case.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-4.60	
Respondent: G. H. Chapel	
Page: 1 of 1	

Question: 60. Refer to lines 8-11 on page 20 and lines 22-24 on page 26 of Mr. Chapel's direct testimony on the impact of Covid-19 on sales in 2020, 2021, and 2022. Please identify what volume adjustments to the base historical customer gas usage or forecasted sales for the projected test year for residential and commercial customers the Company made in the gas sales forecasts in this rate case. If no adjustments were made, explain why not and identify what those adjustments should have been. Provide the supporting calculations in Excel.

Answer: No adjustments to the usage factors due to Covid-19 were necessary. The usage factors were calculated based upon customer behavior from August 2021 to July 2023. By the summer of 2021, the effects on customer behavior due to Covid-19 were largely over. See the graph below:



The x-axis represents 12-months ended August for each of the labeled periods. Normalized usage per GCR/GCC customer reduced sharply from August 2019 and bottomed out 12-months ended August 2021. It rebounded notably in the two years since. Since the usage factors were based upon these most recent two years, no adjustment to the regressed usage factors due to Covid-19 was necessary.

Attachment: None

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-4.65a
Respondent: G. H. Chapel
Page: 1 of 1

Question: 65. Refer to lines 6-11 on page 25 and lines 6-11 on page 28 of Mr. Chapel's direct testimony on EWR lost sales and other volume changes. Please:

a. Provide the calculations of EWR volumes for 2023, the 9 months ending September 2024, and 12 months ending September 2025 for the commercial and industrial classes in Excel with formulas intact.

Answer: EWR volumes are not calculated individually. Rather, EWR adjustments are factored into the base load and heat load usage factors of each rate class. As such, EWR reductions can be assumed to be a 1% reduction (1.05% for 2023) against each prior year's consumption. For instance, if a customer consumed **1,000 Mcf** in 2024 with normal weather, then for 2025 they would be forecast to consume 1,000 x 0.99 = **990 Mcf** with normal weather. This effect is compounded, so that in 2026, with normal weather, that customer would be forecast to consume 990 x 0.99 = **980.1 Mcf**.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-4.65c	
Respondent: G. H. Chapel	
Page: 1 of 1	

Question: 65. Refer to lines 6-11 on page 25 and lines 6-11 on page 28 of Mr. Chapel's direct testimony on EWR lost sales and other volume changes. Please:

c. Provide any other volume adjustments calculated outside of the forecasting model, such as customers shifting to and from transportation service or other known changes in customer usage for commercial and industrial customers for 2023, the 9 months ending September 2024, and 12 months ending September 2025.

Answer: There are none. Customers who shifted from EUT to sales service by no later than July 2023 have been included in the sales forecasts. Their volumes were projected as an average GS-2 customer.

Attachment: None

MICHIGAN PUBLIC SERVICE COMMISSION **Exhibit AG-34**
DTE Gas Company **Case No. U-21291**
Date: May 7, 2024

Incremental Revenue from Higher Rate A <u>Residential</u> Sales Volume for Forecasted Test Year

Line #	(a)	(b)	(c)	
1	Average Sales per Customer - Actual 2023 [1]		92.62	Mcf
2				
3	5-Year average rate of change in Usage per Customer [1]	-0.6%		
4				
5	Average Sales per Customer - September 2024 [2]		92.17	Mcf
6				
7	Average Sales per Customer - September 2025 [3]		91.57	Mcf
8				
9	Forecasted Test Year average number of customers [4]		1,242,379	
10				
11	AG Forecasted Sales (Line 7 x Line 9)		113,767,272	Mcf
12				
13	Compan Forecasted Sales [4]		112,464,297	Mcf
14				
15	Increase in Gas Sales (Line 13 - Line 11)		1,302,975	Mcf
16				
17	Current Distribution Rate A per Mcf [5]		$ 3.8859	
18				
19	**Incremental Rate A Revenue**		**$ 5,063,232**	

Source: (1) Exhibit AG-32.
(2) Line 1 x 9/12 of Line 3 (Represents the rate change in usage from January 2024 to September 2024.
(3) Line 5 x Line 3 (Represents a full year of rate change in usage).
(4) Exhibit AG-32.
(5) Exhibit A-16, Schedule F3, page 1.

Incremental Revenue from Higher GS-1 Commercial Sales Volume for Forecasted Test Year

Line #	(a)	(b)	(c)	
1	Average Sales Volume per Customer - Actual 2023 [1]		446.37	Mcf
2				
3	5-Year average rate of change in Usage per Customer [1]	-0.7%		
4				
5	Average Sales Volume per Customer - September 2024 [2]		444.09	Mcf
6				
7	Average Transport Volumes per Customer - September 2025 [3]		441.06	Mcf
8				
9	Forecasted Test Year average number of customers [4]		91,459	
10				
11	AG Forecasted Volumes (Line 7 x Line 9)		40,338,612	Mcf
12				
13	Company Forecasted Salest Volume [4]		39,490,927	Mcf
14				
15	Increase in Sales Volumes (Line 13 - Line 11)		847,685	Mcf
16				
17	Current Distribution Rate GS-1 per Mcf [5]		$ 3.8069	
18				
19	**Incremental Rate GS-1 Revenue**		**$ 3,227,054**	

Source: (1) Exhibit AG-32.
(2) Line 1 x 9/12 of Line 3 (Represents the rate change in usage from January 2024 to September 2024.
(3) Line 5 x Line 3 (Represents a full year of rate change in usage).
(4) Exhibit AG-32.
(5) Exhibit A-16, Schedule F3, Distribution rate for rate schedule GS-1.

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-4.73a
Respondent: H. J. Decker
Page: 1 of 1

Question: 73. Refer to Table 2 on page 17 of Mr. Decker's direct testimony on power generation volumes. Please:

a. Provide the same information with actual volumes for the 12 months ended March 2024.

Answer: Please see the table below for the same information with actual volumes for the12 months ended March 2024

12 Month Period	Customer Count at End of 12-Month Period	Actual (Bcf)	Variance (Bcf) to 5-yr average	Cooling Degree Days	Variance to 15 yr Avg.
Apr '23 ~ Mar '24	11	72.4	10.9	736	(24%)
Current 5-yr average		61.5		983	
15 Yr Avg CDD				969	

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-4.83	
Respondent: H. J. Decker	
Page: 1 of 1	

Question: 83. Refer to lines 14-17 on page 33 of Mr. Decker's direct testimony on DTE Electric revenue adjustment. Please provide the adjustment amount by month with the year identified.

Answer: Assuming the question references lines 14-17 on page 34 and not page 33, The Company would answer as follows: a monthly adjustment of $323,354.16 was made for the 29 months from January of 2020 through May of 2022.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-4.96a	
Respondent: H. J. Decker	
Page: 1 of 1	

Question: 96. Refer to Exhibit A-13, Schedule C3.3. Please:

a. Expand this schedule to include the same information for each year 2018 to 2023, and the 12 months ended March 2024 and provide it in Excel.

Answer: Please see attachment U-21291 – AGDG-4.96ab Off-System Storage & Transportation Revenue

Attachment: U-21291 – AGDG-4.96ab Off-System Storage & Transportation Revenue

DTE Gas Company
Projected Off-System Storage and Transportation Revenue

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	**Description**	**For the Year Ended 2022**	Adjustments to Revenues	**12 Mos Ended September 2025**	**For the Year Ended 2018**	**For the Year Ended 2019**	**For the Year Ended 2020**	**For the Year Ended 2021**	**For the Year Ended 2023**	**For the 12 Mos Ended Mar 2024**	**For the 3 Mos Ended Mar 2024**
Revenues ($000s)											
1	Contract Storage	$ 28,675	$ 5,403	$ 34,079	$ 31,507	$ 32,072	$ 30,944	$ 30,243	$ 27,053	$ 26,764	
2	Park & Loan	3,878	$ 512	4,390	5,160	1,138	6,540	2,750	5,100	3,667	
3	Total Midstream Storage Revenue	$ 32,554	$ 5,915	$ 38,469	$ 36,667	$ 33,210	$ 37,484	$ 32,993	$ 32,153	$ 30,431	
4											
5											
6	Off-System Transportation	$ 61,573	$ (1,192)	$ 60,381	$ 41,067	$ 63,068	$ 61,829	$ 61,181	$ 63,087	$ 63,477	
7	Exchange	16,094	$ (3,300)	12,793	10,965	12,840	13,470	18,194	18,084	17,194	
8	Total Transportation Revenue	$ 77,667	$ (4,492)	$ 73,175	$ 52,032	$ 75,908	$ 75,299	$ 79,375	$ 81,171	$ 80,671	
9											
10	Total Midstream Revenues	$ 110,221	$ 1,423	$ 111,644	$ 88,699	$ 109,118	$ 112,783	$ 112,368	$ 113,324	$ 111,102	
		-									
Capacity Sold (MMCF)											
11	Contract Storage	62,500		62,500	63,400	63,400	62,500	62,500	62,500	62,500	62,500
12	Park & Loan*										
13	Total Midstream Storage Volumes	62,500		62,500	63,400	63,400	62,500	62,500	62,500	62,500	62,500
14											
Transported Volumes (MMCF)											
15	Off-System Transportation	426,929		423,411	242,429	383,823	367,291	376,867	461,180	467,457	106,598
17	Exchange	83,558		117,966	76,418	97,082	98,390	98,092	65,810	62,844	39,609
18	Total Transportation Volumes	510,487		541,377	318,847	480,905	465,681	474,959	526,990	530,301	146,207
19											
20	Total Midstream Volumes	572,987		603,877	382,247	544,305	528,181	537,459	589,490	592,801	208,707

* Park and Loan volumes are not tracked

MICHIGAN PUBLIC SERVICE COMMISSION | **Exhibit: AG-37**
DTE Gas Company | **Case No: U-21291**
May 7, 2024
Midstream Revenue Adjustments |
$(000)

		(a)	(b)	(c)	(d)	(e)	(f)
		Exchange Gas Revenue			**Off-System Transp. Revenue**		
Line #	**Year**	**Amount Booked [1]**	**DTEE Adjust. [2]**	**Adjusted Amount**	**Amount Booked [1]**	**DTEE Adjust. [2]**	**Adjusted Amount**
1	2021	$ 18,194	$ (3,880)	$ 14,314	$ 61,181	$ 3,880	$ 65,061
2	2022	$ 16,094	$ (1,617)	$ 14,477	$ 61,573	$ 1,617	$ 63,190
3	2023	$ 18,084	$ -	$ 18,084	$ 63,087	$ -	$ 63,087
4	Average			$ 15,625			$ 63,779
5	Company Forecast			12,793			60,381
6	**AG Adjustment**			**$ 2,832**			**$ 3,398**

Source: (1) DR AGDG-4.96 (Exhibit AG-36).
(2) DR AGDG-4.83 (Exhibit AG-36).

MPSC Case No: U-21291

Requester: AG

Question No.: AGDG-4.89g

Respondent: H. J. Decker

Page: 1 of 1

Question: 89. Refer to lines 19-25 on page 51 of Mr. Decker's direct testimony on the Home Protection Plus Appliance Service program (HPP). Please provide the following information on the HPP for each year 2018 to 2025 and the projected test year in Excel:

g. The number of Company employees dedicated to the program by year actual through 2023 and forecasted for 2024 and 2025.

Answer: Please see attachment U-21291 AGDG-4.89a,d-g HPP variance explanations.

Attachment: U-21291 AGDG-4.89a,d-g HPP variance explanations

DTE Gas Company
U-21291 Discovery
AGDG-4

HPP Audit and Discovery - Variance Explanations

	Description	Historical Net Oper. Income For the Year Ended 12/31/2018	Historical Net Oper. Income For the Year Ended 12/31/2019	Historical Net Oper. Income For the Year Ended 12/31/2020	Historical Net Oper. Income For the Year Ended 12/31/2021	Historical Net Oper. Income For the Year Ended 12/31/2022	Historical Net Oper. Income For the Year Ended 12/31/2023	Fcst Net Oper. Income Fore the year Ended 12/31/2024	Fcst Net Oper. Income Fore the year Ended 12/31/2025
	Operating Revenue								
1	Other Operating Revenues	$75,434	$82,198	$86,578	$92,906	$99,257	$103,901	$99,257	$99,257
2	Total Operating Revenues	$75,434	$82,198	$86,578	$92,906	$99,257	$103,901	$99,257	$99,257
		2.80%	8.97%	5.33%	7.31%	6.84%	4.68%	-4.47%	0.00%
3	Operating Expenses								
4	Operation & Maintenance	$59,848	$62,150	$60,023	$64,334	$66,359	$64,100	$66,359	$66,359
5	State and Local Income Taxes	$935	$1,203	$1,593	$1,737	$1,718	$2,262	$1,718	$1,718
6	Federal Income Taxes	$4,512	$4,730	$5,067	$4,242	$5,498	$7,241	$5,498	$5,498
7	Total Operating Expenses	$65,296	$68,083	$66,684	$70,313	$73,575	$73,602	$73,575	$73,575
		6.30%	4.27%	-2.06%	5.44%	4.64%	0.04%	-0.04%	0.00%
8	Net Operating Income	$10,138	$14,114	$19,894	$22,593	$25,682	$30,299	$25,682	$25,682
		13.44%	17.17%	22.98%	24.32%	25.87%	29.16%	25.87%	25.87%
9	3 Year Rolling Average				$18,867	$22,723	$26,191	$27,221	$27,221
10	5 Year Rolling Average					$18,484	$22,517	$24,830	$25,987
11	Average Contracts	210,736	218,629	222,004	221,766	223,627	223,307	223,627	223,627
12	Average Headcount	82	84	82	83	81	76	81	81

Variance Explanations

2018 - 2019	9% increase in revenue due to increased revenue per contract and higher contracts
	4% increase in operating expenses due to increased repairs due to increased contracts
2019 - 2020	5% increase in revenue due to increased revenue per contract and higher contracts
	2% decrease in operating expenses due to decrease repairs due to covid restrictions
2020 - 2021	7% increase in revenue due to increased revenue per contract
	5% increase in operating expenses due to increased volume of repairs and higher cost per repair
2021 - 2022	7% increase in revenue due to increased revenue per contract and higher contracts
	5% increase in operating expenses due to increased cost per repairs
2022 - 2023	5% increase in revenue due to increased revenue per contract
	No increase in operating expenses 0.04%

Other O&M Expense Adjustments [1]

Line	Caption (a)	Millions of Dollars Proposed Changes (b)	O&M Level (c)	Reference or Note (d)
1	**O&M Per Company Exh. A-13, Sched. C5**		**$ 538.3**	
	AG Proposed Changes			
2	Eliminate Proposed Blended Inflation	$ (4.0)		Ex. AG-43
3	Corporate Expense Realignment:			
4	2023 Cost Reductions Initiative	(22.4)		Ex. AG-45
5	Voluntary Separation Savings @50%	(3.2)		Testimony
6	Pipeline Integrity Expenses	(6.7)		Testimony
7	MAOP Records Review	(0.9)		Testimony
8	Leak Detection and Repair (LDAR)	(10.3)		Testimony
9	Active Health Care	(4.9)		Ex. AG-47
10	Rents - Capital Use Charge	(2.5)		Testimony
11	Reduce Incentive Compensation:			
12	Related to Financial Metrics	(12.1)		Testimony
13	45% of Non-Financial Metrics	(2.9)		Testimony
14	Reduce Incentive Comp. Deferral Amortization	(1.1)		Testimony
15	Amortization of OPEB Lability Balance	(9.7)		Testimony
16	Credit Card Merchant Fees	(2.2)		Testimony
17	Private Jet Travel Costs	(0.1)		Testimony
18	Responsibly Sourced Gas	(0.2)		Testimony
19	Total Cost Changes	(83.2)	(83.2)	Sum Lines 2 to 18
21	**AG Proposed O&M (L1 + L19)**		**$ 455.1**	
23	***Change in O&M Expense (L21 less L1)***		***$ (83.2)***	

(1) Excludes Uncollectible, Company Gas Use and LAUF Gas Expense Adjustments provided in Exhibit AG-40 and AG-42.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas - Gas Rate Case

Company Use and LAUF Gas - Thousands of Dollars

Line	Description or Item	MMcf Volume	Cost of Gas Rate	$ Thousands Cost	Source or Note
	(a)	(b)	(c)	(d)	(e)
	Company Case				
1	Lost & Unaccounted Gas For (LAUF) Volume	5,401	$ 4.380	$ 23,656	Ex. A-15, Sch E8
2	Company Use Gas Volume	4,464	4.380	19,552	Ex. A-15, Sch E8
3	Total Volume & Cost Per Company	9,865	$ 4.380	**43,209**	L 1 + L 2
4	Result of Cost of Gas Rate Reduction Only	9,865	$ 4.100	$ 40,447	Note 1
5	Cost of Gas Rate Change		**$ (0.280)**		Rate Change L4 less L3
	AG Case Changes				
6	Cost Change Due to Cost Rate Reduction	9,865	$ (0.280)	$ (2,762)	L 4 Volume x L 5
7	Reduction of 9.8% in LAUF Volume -Emission Reductions	(529)	$ 4.100	(2,170)	Note 2
8	Total Reduction in Expense			**(4,932)**	L 6 + L 7
9	AG Cost of Company Use & LAUF			**38,276**	L 3 + L 8
10	**Reduction in Co. Use & LAUF Cost and Other O&M Expense**			**$ (4,932)**	L 9 less L 3

1 The rate change reflects a substantial change in the NYMEX Gas Price Futures
See Exhibit AG-41 and DR-AGDG-2.24b for Company witness Chapel's revised Cost of Gas rate of $4.1(

2 This is consistent with the Company's goal of reaching zero emissions by 2050. From 2022 to
2050 is a period of 28 years suggesting a 3.57% annual reduction over the 28 year period. Using the 3.57%
rate times the 2.75 years between the historic and projected test years suggests a 9.8% reduction is appropriate

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-2.24b
Respondent: G. H. Chapel
Page: 1 of 1

Question: 24. On page 30 of his direct testimony, Mr. Chapel states that he derived a $4.3812 per MCF cost of gas based on NYMEX futures prices on September 22, 2023. In this regard, please address the following.

b. Provide an updated cost of gas rate based on actual and forecasted NYMEX prices as of last five trading days of March 2024 and provide the calculations in Excel with all source data and formulas intact.

Answer: The Company's cost of gas calculation is not done in Excel. See attachment provided in response to the supplemental audit request NUR-1, Question 3, for a summary calculation of the components that make up this rate. This was a response previously submitted to an MPSC Staff audit request to update the projected Cost of Gas using the average of the NYMEX settle prices from February 12 to February 16, 2024. The projected Cost of Gas with these new assumptions is $4.1015/Mcf.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Case No. U-21291
Exhibit AG-42
May 7, 2024

Uncollectible Accounts Expense
(Thousands of Dollars)

Line	Caption or Description	Net Write-Off Amounts	Net Sales	% Charged Off & AG Projection (b) / (c)	Reference
	(a)	(b)	(c)	(d)	
1	Total Year 2021	$ 18,320	$ 1,456,245	**1.26%**	Data From AGDG 2.23
2	Total Year 2022	19,197	1,875,170	**1.02%**	Data From AGDG 2.23
3	Total Year 2023	22,044	1,803,800	**1.22%**	Data From AGDG 2.23
4	Avg. Percentage			**1.17%**	Avg. of Lines 1,2 & 3
5	Projected Test Year Revenues			**$ 2,134,324**	See Note 1 Below
6	Uncollectible Accounts Expense - Gas Business			**24,928**	Line 4 x Line 5
7	Three Year Average of Net Charge-Offs (Other Areas)			**1,090**	Data From AGDG 2.23, L 9
8	**Total Uncollectibles per AG Estimate**			**$ 26,018**	Line 6 + Line 7
9	**Uncollectibles per DTE Gas**			**35,149**	Ex. A-13, Sch. C5.7, Line 10
10	***Reduction in O & M Expense for Uncollectibles***			***$ (9,131)***	Line 8 less Line 9

Note 1 Per witness Sparks Exhibit A-13, Schedule C5.7

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Case No. U-21291
Exhibit AG-43
May 7, 2024

O&M Reduction - Limit
Inflation Increases to the CPI (AG Position)

		Thousands of Dollars				
Line	Department	Hist. 2023 O & M*	Less Non Inflat. Items**	Inflationary Items	Inflation	
	(a)	(b)	(c)	(d)	(e)	
1	Natural Gas Storage	$ 13,344	$ -	$ 13,344		
2	Transmission	58,532	-	58,532		
3	Distribution	120,584	-	120,584		
4	Customer Service	55,407	(7,453)	47,954		
5	Marketing	51,703	-	51,703		
6	Admin. & General	117,834	(61,436)	56,398		
7	Pension & Benefits	34,700	(34,700)	-		
8	Total for 2023	$ 452,104	$ (103,589)	$ 348,515		
9	2024 Inflation (2.6% of Line 8)			9,061	$ 9,061	***
10	Inflation Base - 2024			$ 357,576		
11	2025 Inflation (2.2% x 75% of Line 10)			5,900	5,900	***
12	Total			**$ 363,476**		
13	**Cumulative 2024 and 2025 Inflation at 100% of CPI (L9 + L11)**				**$ 14,961**	
14	Inflation per Ex. A-13, Sch. C5 columns (h) and (i)				18,962	
15	***O&M Inflation Elimination (L14 less L13)***				***$ (4,001)***	

* Per DR AGDG-3.43 Attachments
** Reflects Merchant Fees, Injuries & Damages, MGP Amortization, Rents and all Pensions & Benefits
*** AG Calculated inflation based on March 1, 2024 CPI Forecast.

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-3.43	
Respondent: R. M. Telang	
Page: 1 of 1	

Question: 43. Please provide Exhibit A-13, Schedules C5.1, C5.2, C5.3, C5.4, C5.5, C5.6 and C5.9 with 2023 O&M expenses in the same manner as set forth in columns (b) to (f) in Excel.

Answer: See Attachment.

2023 was a financially challenging year for DTE, driven by a much warmer than normal winter, very elevated storm activity, a much cooler than normal summer and a challenging DTE Electric rate case outcome at the end of 2022. To mitigate these significant headwinds and maintain the financial health of the Company, DTE took a number of temporary measures which resulted in lower 2023 O&M for DTE Gas as compared to 2022. These reductions included (but were not limited to) deferring building/facility maintenance work unless safety-related, limiting overtime, postponing annual salary increases, pausing employee promotions and progressions, delaying hiring to replace employees who left the Company, temporarily suspending travel and non-mandatory training, and temporarily reducing contractors and other services that did not impact the safety or reliability of gas service, and shifting timing of material and supply purchases. In addition, a reduction of certain shared services, including certain customer service operations and information technology, reduced DTE Gas's portion of those costs. Other temporary impacts that the Company expects to return to 2022 levels include accounting deferrals and lower incentives. These temporary reductions are noted in the attached file.

Attachment: U-21291 AGDG-3.43 O&M Exhibits 2023.xlsx

Co-Respondent(s): S. N. Kehoe, T. M. Uzenski, M. Cooper, M. J. Hatsios, H. J. Decker

Michigan Public Service Commission U-21291
DTE Gas Company A-13
2023 Operation and Maintenance Expenses - Summary C5
AGDG - 3.43 T. M. Uzenski
($000) 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Description**	**Exhibit Source A-13**	**2023 Actuals**	**Eliminations & Reclasses**	**Normalization Adjustments**	**Adjusted 2023 Actuals**
						sum (c) thru (e)
1	Natural Gas Storage	C5.1	19,600	(8,406)	2,150	13,344
2	Transmission	C5.2	54,176	(7,719)	12,075	58,532
3	Distribution	C5.3	105,780	(1,141)	15,945	120,584
4	Customer Service	C5.4	96,261	(46,799)	5,945	55,407
5	Marketing	C5.5	50,661	(1,158)	2,200	51,703
6	Administrative and General	C5.6	106,803	(3,292)	14,324	117,834
7	Pension and Benefits	C5.9	32,830	(3,069)	4,939	34,700
8	**Total Operation and Maintenance**		**466,112**	**(71,585)**	**57,578**	**452,105**

Michigan Public Service Commission
DTE Gas Company
2023 Operation and Maintenance Expenses - Natural Gas Storage
AGDG - 3.43
($000)

Case No.: U-21291
Exhibit: A-13
Schedule: C5.1
Witness: S. N. Kehoe
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Description**	**FERC/ MPSC Account**	**2023 Actuals**	**Eliminations & Reclasses**	**Normalization Adjustments**	**Adjusted 2023 Actual**
						sum (c) thru (e)
1	**Natural Gas Storage**					
2	**Operation**					
3	Operation Supervision and Engineering	814	$ -	$ -	$ -	$ -
4	Wells Expense	816	369	-	-	369
5	Lines Expense	817	49	-	-	49
6	Compressor Station Expenses	818	3,528	-	420	3,948
7	Compressor Station Fuel and Power	819	7,392	-	-	7,392
8	Measuring and Regulating Station Expense	820	-	-	-	-
9	Gas Losses	823	1,458	-	130	1,588
10	Other Expenses	824	290	-	-	290
11	Storage Well Royalties	825	38	-	-	38
12	Total Operation Expense		$ 13,123	$ -	$ 550	$ 13,673
13	**Maintenance**					
14	Maintenance Supervision and Engineering	830	$ 1,763	$ -	$ -	$ 1,763
15	Maintenance of Structures	831	-	-	-	-
16	Maintenance of Reservoirs and Wells	832	476	-	-	476
17	Maintenance of Lines	833	80	-	-	80
18	Maintenance of Compressor Station Equipment	834	4,158	-	1,600	5,758
19	Maintenance of Other Equipment	837	-	-	-	-
20	Total Maintenance Expense		$ 6,477	$ -	$ 1,600	$ 8,077
21	Company Use Reclass, Storage		$ -	$ (8,406)	$ -	$ (8,406)
22	**Total Natural Gas Storage**		**$ 19,600**	**$ (8,406)**	**$ 2,150**	**$ 13,344**

Normalization Adjustments	Account	Amount	
Deferred inventory purchases and maintenance	818	420	Utilized available oil inventory levels and deferred replacement of glycol until 2024. These purchases must return to ensure availability of assets. Deferred spraying of weeds that prevents encroachment at stations and well heads.
Deferred data analysis	823	130	Reduced data analysis for metering systems. This elongates the cycle time of remediation of metering data issues.
Deferred material purchases and backfilling employees that left the company or retired	834	1,600	Deferred backfilling employees who left the company or retired. Compressor station utilization increases with normal weather will require these positions to be filled. One-time material purchase reductions to return by 2025 as maintenance increases due to higher utilization of compressor stations.
		2,150	

Michigan Public Service Commission
DTE Gas Company
2023 Operation and Maintenance Expenses - Transmission
AGDG - 3.43
($000)

Case No.: U-21291
Exhibit: A-13
Schedule: C5.2
Witness: S. N. Kehoe
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description	FERC/ MPSC Account	2023 Actual	Eliminations & Reclasses	Normalization Adjustments	Adjusted 2023 Actuals
						sum (c) thru (e)
1	**Transmission Expenses**					
2	**Operation**					
3	Operation Supervision and Engineering	850	$ 14,334	$ -	9,805	$ 24,139
4	Load Dispatching	851	3,974	-	-	3,974
5	Compressor Station Labor and Expenses	853	1,033	-	-	1,033
6	Gas for Compressor Station Fuel	854	6,658	-	-	6,658
7	Mains Expense	856	1,368	-	-	1,368
8	Measuring and Regulating Station Expenses	857	1,952	-	-	1,952
9	Transmission and Compression of Gas by Others	858	12,706	-	-	12,706
10	Other Expenses	859	2,731	-	335	3,066
11	Total Operation Expense		$ 44,757	$ -	$ 10,140	$ 54,897
12	**Maintenance**					
13	Maintenance Supervision and Engineering	861	$ -	$ -	$ -	-
14	Maintenance of Structures	862	-	-	-	-
15	Maintenance of Mains	863	1,793	-	-	1,793
16	Maintenance of Compressor Station Equipment	864	1,361	-	1,080	2,441
17	Maintenance of Measuring & Reg Station Equip	865	25	-	-	25
18	Maintenance of Communication Equip	866	6,239	-	855	7,094
19	Maintenance of Other Equip	867	-	-	-	-
20	Total Maintenance Expense		$ 9,419	$ -	$ 1,935	$ 11,354
21	Company Use Reclass, Transmission		$ -	$ (7,719)	$ -	$ (7,719)
22	**Total Transmission**		**$ 54,176**	**$ (7,719)**	**$ 12,075**	**$ 58,532**

Normalization Adjustments	Account	Amount	
Pipeline Integrity	850	7,500	Change in assessment schedule. 9 assessments completed in 2022 vs. 4 in 2023. 13 and 12 assessments are planned for 2024 and 2025, respectively. This $7.5M historic adjustment does not include the $6.67M projected adjustment for the projected test year in A-13 C5.2, row 3, column J
Right-of-way maintenance and material purchases	850	1,630	Temporarily paused brushing and spraying in 2023 - costs will return to prevent right-of-way overgrowth
Deferred backfilling employees that left the company or retired	850	675	
Training	859	235	Deferred hiring resulted in lower training expense in 2023. Hiring resumed in late 2023 and early 2024 to backfill open positions. Block training to return to pre-2023 levels in 2024
Deferred backfilling employees that left the company or retired	859	100	Position has been filled in 2024
Compressor Station deferred backfilling employees that left the company or retired, overtime, and material reductions	864	1,080	Compressor station labor to return to pre-2023 levels as utilization of compressor stations increases with normal weather and demand, requiring higher maintenance and increased procurement of consumables (oil, glycol) and miscelleneous
Control Maintenance labor priortized to mandated cyber security projects /defer backfilling employees that left the company or retired, and overtime reduction	866	855	Control Maintenance labor priortized to Cyber Security projects in 2023. Deferred backfilling employees who left the company or retired - will be filled in 2024. Overtime reduced as employees focused on cyber security work in 2023.
		12,075	

Michigan Public Service Commission
DTE Gas Company
2023 Operation and Maintenance Expenses - Distribution
AGDG - 3.43
($000)

Case No.: U-21291
Exhibit: A-13
Schedule: C5.3
Witness: S. N. Kehoe
Page: 1 of 1

Line No.	Description (a)	FERC/ MPSC Account (b)	2023 Actuals (c)	Eliminations & Reclasses (d)	Normalization Adjustments (e)	Adjusted 2023 Actuals (f) sum (c) thru (e)
1	**Distribution Expenses**					
2	**Operation**					
3	Operation Supervision and Engineering	870	$ -	$ -	$ -	$ -
4	Compressor Station Labor and Expenses	872	-	-	-	-
5	Mains & Services Expenses	874	22,988	-	-	22,988
6	Measuring & Reg Station - General	875	1,081	-	600	1,681
7	Measuring & Reg Station - City Gate	877	2,743	-	-	2,743
8	Measuring & House Regulator Exp	878	11,773	-	2,000	13,773
9	Customer Installations Expenses	879	25,484	-	2,240	27,724
10	Other Expenses	880	20,822	-	4,955	25,777
11	Total Operation Expense		$ 84,891	$ -	$ 9,795	$ 94,686
12	**Maintenance**					
13	Maintenance of Structures	886	$ -	$ -	$ -	$ -
14	Maintenance of Mains	887	9,430	-	4,200	13,630
15	Measuring & Reg Station - General	889	4,624	-	-	4,624
16	Measuring & Reg Station - City Gate	891	1,383	-	-	1,383
17	Maintenance of Services	892	2,751	-	850	3,601
18	Maintenance of Meters & House Regulator	893	2,223	-	1,100	3,323
19	Maintenance of other Equipment	894	478	-	-	478
20	Total Maintenance Expense		$ 20,889	$ -	$ 6,150	$ 27,039
21	Company Use Reclass, Distribution		$ -	$ (1,141)	$ -	$ (1,141)
22	**Total Distribution**		**$ 105,780**	**$ (1,141)**	**$ 15,945**	**$ 120,584**

Normalization Adjustments	Account	Amount	
Fewer Pressure Adjustment units	875	600	Deferred non-emergent regulator inspections
Meter Orders	878 / 879	2,250	Limited overtime to only critical work and deferred non-emergent meter repair work by extending customer connection response time
Leak Repair Services	879	1,600	Fewer incoming emergency leaks
HPP	879	390	3,507 fewer service calls performed by DTE HPP technicians - primarily weather driven
Training	880	1,600	Temporarily suspended non-mandatory training
Environmental Management	880	200	Prioritized labor to support public improvement and main replacement projects
Deferred backfilling employees that left the company or retired	880	1,330	Deferred backfilling employees that left the company or retired
Outside Services and materials	880	1,550	Temporarily reduced outside services and contractors that did not impact the safety or reliability of gas service
Temporary Fleet maintenance delays	880	275	Temporarily reduced fleet vehicle parts and services. Reflects the total impact for all groups and FERC accounts for ease of presentation.
Main Repair	887	4,200	Deferred non-hazardous leak repair
Service & Manifold Repair	892	850	Deferred non-hazardous leak repair
Meters & Regulators	893	410	Deferred non-emergent work such as non-hazardous minor corrosion repair
Meter Refurbishments	893	690	One-time reduction in material purchases for indexes, meter labels, and other consumables attributed to the meter refurbishment program
		15,945	

Michigan Public Service Commission
DTE Gas Company
2023 Operation and Maintenance Expenses - Customer Service
AGDG - 3.43
($000)

Case No.: U-21291
Exhibit: A-13
Schedule: C5.4
Witness: M. J. Hatsios
Page: 1 of 1

Line No.	(a) Description	(b) FERC/ MPSC Account	(c) 2023 Historical Test Period	(d) Eliminate Energy Waste Reduction Program	(e) Normalization Adjustments	(f) Adjusted Historical Test Period
						sum (c) thru (e)
1	**Customer Accounts Expenses**					
2	**Operation**					
3	Supervision	901	$ 1,149	$ -	$ -	$ 1,149
4	Meter Reading Expenses	902	4,738	-	-	4,738
5	Customer Records and Collection Expenses	903	30,715	-	4,528	35,242
6	Customer 360 Amortization	903	1,445	-	-	1,445
7	Customer Collection-Merchant Fees	903	6,008	-	-	6,008
8	Miscellaneous Customer Accounts Expenses	905	28,308	(27,014)	-	1,294
9	Total Customer Accounts Expense		$ 72,362	$ (27,014)	$ 4,528	$ 49,876
10	**Customer Service and Informational Expenses**					
11	**Operation**					
12	Supervision	907	$ 461	$ (461)	$ -	$ (0)
13	Customer Assistance Expenses	908	20,426	(17,913)	221	2,734
14	Informational and Instructional Expenses	909	1,412	(1,412)	-	(0)
15	Misc Customer Service and Informational Exp.	910	1,600	-	1,197	2,797
16	Total Customer Service and Informational Expense		$ 23,899	$ (19,786)	$ 1,417	$ 5,531
17	**Total Customer Accounts, Customer Service and Informational Expenses**		**$ 96,261**	**$ (46,799)**	**$ 5,945**	**$ 55,407**
18	**Uncollectibles Accounts Expense**	904	**$ 16,925**	**$ -**	**$ -**	**$ 16,925**

Normalizaton Adjustments

Deferred backfilling employees that left the company or retired	1,255	Temporarily deferred backfilling employees that left the company and reduced outside service support, which impacted desired service levels while still maintaining minimum standard service level requirements
OT reductions	225	
Outside Services	2,300	
Reduced Contractors	489	
Deferred Material purchases	204	Deferred material purchases at year-end which were reinstated in Jan. 2024
Reduction Customer Outreach initiatives	624	Temporarily paused spend relating to community engagement designed to provide resources and support to customers and key stakeholders, including connecting customers to energy assistance programs
Travel / Training / etc.	263	Temporarily suspended training, travel and engagement spend related to research and best practice implementation for our customers
Customer Satisfaction Credits	239	Temporarily reduced discretionary financial accommodations for customers
Benchmarking / focus groups etc.	346	Temporarily eliminated non critical benchmarking, research and surveys that are used to improve service quality
Total	5,945	

Michigan Public Service Commission
DTE Gas Company
2023 Operation and Maintenance Expenses - Marketing
AGDG - 3.43
($000)

Case No.: U-21291
Exhibit: A-13
Schedule: C5.5
Witness: H. J. Decker
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Description**	**FERC/ MPSC Account**	**2023 Historical Test Period**	**Eliminations & Reclasses 1/**	**Normalization Adjustments 2/**	**Adjusted Historical Test Period**
						sum (c) thru (e)
1	**Sales Expenses**					
2	**Operation**					
3	Supervision	911	$ -	$ -	$ -	$ -
4	Demonstrating and Selling Expenses	912	50,661	(1,158)	2,200	51,703
5	Advertising Expenses	913	-	-	-	-
6	Miscellaneous Sales Expenses	916	-	-	-	-
7	**Total Sales Expense**		**$ 50,661**	**$ (1,158)**	**$ 2,200**	**$ 51,703**

1/ Eliminate Gas Voluntary Renewables Program

2/ Normalization Adjustments

	Account	Amount	
Temporarily suspended outside services that did not impact the safety or reliability of gas services	912	$ 600	Customer research, web updates, growth campaigns, hydrogen blending analysis project were paused or reduced in 2023
Temporarily suspended travel	912	220	Travel will return to allow Account Managers to meet with customers across the state, attend technology forums, industry conferences and training
Deferred backfilling open positions for employees that left the company or retired	912	280	Three open positions, which have been filled
5,193 fewer HPP vendor service calls in 2023	912	1,100	Primarily weather driven
		2,200	

Michigan Public Service Commission
DTE Gas Company
2023 Operation and Maintenance Expenses - Administrative and General
AGDG - 3.43
($000)

Case No.: U-21291
Exhibit: A-13
Schedule: C5.6
Witness: T. M. Uzenski
Page: 1 of 2

Line No.	Description (a)	FERC/ MPSC Account (b)	2023 Historical Test Period (c)	Rate Case Adjustments 1/ (d)	Normalization Adjustments 2/ (e)	Adjusted Historical Test Period (f) sum (c) thru (e)
1	**Administrative and General Expenses**					
2	**Operation**					
3	Administrative and General Salaries	920	$ 36,054	$ (2,579)	$ 6,950	$ 40,425
4	Office Supplies and Expenses	921	13,441	-	-	13,441
5	(Less) Administrative Expenses Transferred-Cr.	922	(15,406)	-	-	(15,406)
6	Outside Services Employed	923	8,577	(9)	5,025	13,593
7	Property Insurance	924	1,214	-	-	1,214
8	Injuries and Damages	925	9,181	-	(3,356)	5,824
9	Franchise Requirements	927	-	-	-	-
10	Regulatory Commission Expenses	928	18	-	-	18
11	(Less) Duplicate Charges-Cr.	929	-	-	-	-
12	General Advertising Expenses	930.1	974	(534)	-	440
13	MGP Amortization and Expenses	930.2	5,046			5,046
14	Miscellaneous General Expenses	930.2	1,979	(169)	-	1,810
15	Rents	931	44,862	-	5,705	50,566
16	Total Operation Expense		$ 105,940	$ (3,292)	$ 14,324	$ 116,972
17	**Maintenance**					
18	Maintenance of General Plant	935	$ 863	$ -	$ -	$ 863
19	Total Maintenance Expense		$ 863	$ -	$ -	$ 863
20	**Total Administrative and General Expense**		**$ 106,803**	**$ (3,292)**	**$ 14,324**	**$ 117,834**

1/ Rate Case Adjustments	Account	Historical Adjustment
Eliminate Top 5 Executive Incentive Compensation	920	(2,579)
Disallowed Advertising Expenses	930.1	(534)
Disallowed Corporate Memberships	930.2	(169)
Eliminate Gas Voluntary Renewables Program	923	(9)
Total Rate Case Adjustments		(3,292)

2/ Normalization Adjustments:

Description	Account	Historical Adjustment	
Deferral of base pay increases for non-union employees	920	1,211	Reflects the total impact for all groups and FERC accounts for ease of presentation.
One-time reduction of janitorial and other building services costs	923	950	
Accenture automation project - one-time credit	923	675	
Changes in project sequencing	923	1,600	
Transportion Security Authority projects - delayed penetration testing and auditing	923	800	
One-time reduction in IT Base operate expenses (delayed preventative maintenance cycles, minor upgrades, bug fixes)	923	1,000	
One-time initiatives		6,236	
Injuries & damages normalized to five year historical average	925	(3,356)	C5.6 page 2
Employee Incentive Plan Adjustment to 100% accrual	920	4,092	
U-20940 Incentive Compensation deferral above base amount	920	1,647	
Shared Asset Deferral Mechanism - reset base to recognize full cost in O&M	931	5,705	
Other temporary items / accounting adjustments		8,088	
Total Normalization Adjustments		14,324	

Michigan Public Service Commission
DTE Gas Company
Projected Operation and Maintenance Expenses - Administrative and General
Injuries and Damages Normalization Adjustment
AGDG - 3.43
($000)

Case No.: U-21291
Exhibit: A-13
Schedule: C5.6
Witness: T. M. Uzenski
Page: 2 of 2

	(a)	(b)
Line No.	**FERC/ MPSC Account 925**	**Amount**
1	2019	4,201
2	2020	4,692
3	2021	5,457
4	2022	5,592
5	2023	9,181
6	5 Year Average	$ 5,824
7	Less: 2023	9,181
8	Normalization Adjustment	$ (3,356)

DTE Gas Company
Case No. U-21291
AGDG-3.43 Employee Pensions and Benefits
($000)

Case No.: U-21291
Exhibit: A-13
Schedule: C5.9
Witness: M. Cooper

Line No.	(a) Description	(b) Historical Period Ending 12/31/23	(c) Eliminations & Reclasses	(d) 2022 Capitalization Percentages 4/	(e) Temporary Cost Reductions	(f) Normalizations	(g) Total Adjustments Cols (c)+(d)+(e)+(f)	(h) Adjusted Historical Test Period Col (b) + Col (g)
1	**Post-Retirement Benefits**							
2	Pension	-	-	-	-	-	-	-
3	Post Empl Health Care (OPEB)	-	-	-	-	-	-	-
4	New Hire Retiree VEBA	2,062	-	83	-	453 8/	536	2,598
5	Employee Savings Plan	10,171	-	559	-	-	559	10,730
6	Subtotal Post-Retirement	12,233	-	642	-	453	1,095	13,328
7	**Active Healthcare**							
8	Medical Expenses	15,283	-	1,205	206 5/	1,438 9/	2,850	18,132
9	Dental Expenses	1,088	-	71	-	101 9/	172	1,260
10	Vision Expenses	85	-	6	-	9 9/	15	99
11	Subtotal Active Healthcare	16,456	-	1,283	206	1,548	3,037	19,492
12	**Other**							
13	Accrued Vacation Expense	253	-	-	-	(503) 10/	(503)	(250)
14	Executive & Supplemental Retirement Plan	2,626	(2,626) 1/	-	-	-	(2,626)	-
15	Supplemental Severance Plan Exp	156	-	9	-	-	9	166
16	Supplemental Savings Plan	1,094	-	(12)	-	-	(12)	1,083
17	Deferred Compensation Plan	27	-	1	-	-	1	28
18	Wellness Program Expenses	997	-	24	878 6/	-	901	1,899
19	Life Insurance	233	-	(7)	-	-	(7)	226
20	Disability Expenses	340	-	14	-	-	14	354
21	Affordable Care Act	7	-	0	-	-	0	7
22	General Benefit Expenses	506	-	24	297 7/	-	321	828
23	Benefit Plan Administration Fees	1,944	-	78	-	-	78	2,022
24	Retirement Administration Fees	94	-	4	-	-	4	97
25	Subtotal Other	8,278	(2,626)	135	1,175	(503)	(1,819)	6,459
26	Total before Other Allocations	36,967	(2,626)	2,059	1,382	1,498	2,312	39,279
27	A&G Capitalization	(3,295)		-	-	-	-	(3,295)
28	Other Transfers & Allocations	(841)		-	-	-	-	(841)
29	Eliminate EWR Surcharge Program	-	(419) 2/	-	-	-	(419)	(419)
30	Eliminate Gas Voluntary Renewable Program	-	(24) 3/	-	-	-	(24)	(24)
31	Total Benefit Expense (Account 926)	32,831	(3,069)	2,059	1,382	1,498	1,869	34,700
32								
33								

Line No.	Note	Note
34	1/ Eliminate Executive & Supplemental Retirement Plan based on Commission's past practice	6/ Elimination of temporary reduction in Wellness Program
35	2/ Eliminate benefits expense included in separate surcharge mechanism	7/ Elimination of temporary reductions in Tuition Reimbursement and Service Awarc
36	3/ Eliminate Gas Voluntary Renewables Program approved in Case No. U-20839	8/ Elimination of excess True-Up recognized in 2023
37	4/ Adjusts 2023 Expense based on 2022 capitalization percentages due to non-recurring O&M reductions in 2023	9/ Normalization adjustment to reflect constant-dollar five year average.
38	5/ Elimination of one-time credit from Express Scripts	10/ Normalization adjustment to reflect five year historical average

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No. U-21291**
DTE Gas Company - Gas Rate Case | **Exhibit AG-45**
May 7, 2024

O&M Reductions - 2023 Excluding Temporary Reductions

Thousands of Dollars

			O&M Expected for the Year 2023**			
Line	**Department**	**2023 Adjusted Actual***	**Hist. 2022 O&M**	**2023 Inflation Per Company**	**Total of 2022 Plus Inflation**	**Expense Reduction Col (b) less (e)**
	(a)	(b)	(c)	(d)	(e)	(f)
1	Natural Gas Storage	$ 13,344	$ 13,662	$ 437	$ 14,099	$ (755)
2	Transmission	58,532	60,530	1,937	62,467	(3,935)
3	Distribution	120,584	121,419	3,885	125,304	(4,720)
4	Customer Service	55,407	60,816	1,708	62,524	(7,117)
5	Marketing	51,703	51,799	1,658	53,457	(1,754)
6	Admin. & General	117,834	119,912	1,825	121,737	(3,903)
7	Pension & Benefits	34,700	34,947	-	34,947	(247)
8	**Total**	**$ 452,104**	**$ 463,085**	**$ 11,450**	**$ 474,535**	**$ (22,431)**

* Through discovery (AGDG-3.43), the Company updated the AG on its actual 2023 O&M on a normalized basis The numbers in column (b) reflect Actual 2023 plus $57.7 million of cost add-backs which the Company maintains were temporary cost reductions.

** Data from Exhibit A-13, Schedule C5, columns (f) and (g).

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-4.49a
Respondent: M. S. Cooper
Page: 1 of 1

Question: 49. Refer to page 5 of Mr. Telang's direct testimony and the increase in O&M expense as partial justification for the requested rate increase. A January 10, 2024 Detroit Free Press article reported that DTE Energy offered buyouts to about 3,000 employees, or 30% of its workforce. Please provide the following information as it pertains to DTE Gas:

a. Provide the date that this buyout offer was made to employees and how many employees were targeted.

Answer: A voluntary separation incentive package (VSIP) was offered to 422 DTE Gas employees and 1,622 DTE Energy Corporate Services, LLC employees (shared services employees) on January 8, 2024.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-4.49b	
Respondent: M. S. Cooper	
Page: 1 of 1	

Question: 49. Refer to page 5 of Mr. Telang's direct testimony and the increase in O&M expense as partial justification for the requested rate increase. A January 10, 2024 Detroit Free Press article reported that DTE Energy offered buyouts to about 3,000 employees, or 30% of its workforce. Please provide the following information as it pertains to DTE Gas:

b. Provide details of the buyout offer, such as who qualified, effective date, payouts, etc.

Answer: Employees were considered eligible if they did not fall under certain criteria, including, but not limited to: represented (union) employees, engineers, operations critical employees (e.g. control room operators, cybersecurity roles). The VSIP included 25 weeks of an employee's base salary plus one additional week for every year of service up to a maximum of 44 weeks total. The effective separation date for employees varies from February 2024 through June 2024.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-4.49c	
Respondent: M. S. Cooper	
Page: 1 of 1	

Question: 49. Refer to page 5 of Mr. Telang's direct testimony and the increase in O&M expense as partial justification for the requested rate increase. A January 10, 2024 Detroit Free Press article reported that DTE Energy offered buyouts to about 3,000 employees, or 30% of its workforce. Please provide the following information as it pertains to DTE Gas:

c. Provide the number of total employee reductions, and by department, with related cost reductions for 2023, 2024, and 2025.

Answer: 42 DTE Gas employees and 249 DTE Energy Corporate Services, LLC employees accepted the VSIP. The package was not offered in 2023. There are no projected savings for 2024 due to DTE Gas's actual costs of the program (the accrued separation payments) of $8 million. A primary purpose of the VSIP was to realign the workforce to support the changing nature of the Company's work and how we do it, such as an increased focused on infrastructure investments, cybersecurity, and the clean energy transition. Because of this, DTE Gas is still evaluating potential 2025 cost reductions due to the need to fill key roles so that we can continue our progress towards building more modern infrastructure and a future with lower carbon emissions. Currently, DTE Gas estimates that up to $6.3 million in reductions could materialize in 2025. This estimate will continue to evolve due to the need to fill many key roles. This savings estimate also does not include any offset of the program costs. If actual savings are realized in 2025, they will be embedded in rates as actual costs in a future rate case.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-4.49d	
Respondent: M. S. Cooper	
Page: 1 of 1	

Question: 49. Refer to page 5 of Mr. Telang's direct testimony and the increase in O&M expense as partial justification for the requested rate increase. A January 10, 2024 Detroit Free Press article reported that DTE Energy offered buyouts to about 3,000 employees, or 30% of its workforce. Please provide the following information as it pertains to DTE Gas:

d. Provide the cost reductions in subpart (c) separately for labor cost savings, savings in employee benefits, space, and other overhead costs for each year and the projected test year.

Answer: Estimated labor expense in 2025 is a savings of $4.5 million and estimated savings in benefits expense for 2025 are $1.8 million. The estimated benefits savings presumes a continuation of the deferral mechanisms for pension and OPEB. There are no expected savings for space or other overheads.

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-4.49e	
Respondent: R. M. Telang	
Page: 1 of 1	

Question: 49. Refer to page 5 of Mr. Telang's direct testimony and the increase in O&M expense as partial justification for the requested rate increase. A January 10, 2024 Detroit Free Press article reported that DTE Energy offered buyouts to about 3,000 employees, or 30% of its workforce. Please provide the following information as it pertains to DTE Gas:

e. Identify in which exhibit and line number in this rate case the cost savings are shown for each department, or overall, for each year 2023- 2025, and for the projected test year, and the specific amount.

Answer: There are no costs or projected savings related to the VSIP in any of the Company's exhibits.

Attachment: None

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company - Gas Rate Case

Case No. U-21921
Exhibit AG-47
May 7, 2024

Active Medical Expenses
(Thousands of Dollars)

Line	Caption	2017	2018	2019	2020	2021	2022	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Historic Cost Information							
1	Gross Actual Medical, Dental & Vision	$ 25,323	$ 25,829	$ 26,201	$ 28,525	$ 28,143	$ 28,475	Note 1
2	Avg. Annualized Cost Increase			***2.40%***				

Line	Caption	Actual* 2023	Projected** 2024	Projected** 2025	Projected** Test Year	Reference
	Projected Cost Information					
3	Actual 2023 Escalated 3% per Year	27,991	28,663	29,351	$ 29,179	
4	Less Allocation to Costs Capitalized	(11,535)	(11,809)	(12,092)	(12,022)	
5	Net Cost in O & M	$ 16,456	$ 16,854	$ 17,258	$ 17,157	Line 3 less Line 4
6	Company Expense Estimate				22,041	Ex. A-13, Sch. C5.9 (L11)
7	***Reduction in Medical Expense and O & M***				***$ (4,884)***	Line 5 less Line 6

Notes
1 From U-20940 Exhibit A-13, Sch. C5.9.3, Lines 1 to 6
* Actual 2023 Costs per DR AGDG-2.40 Attachment
** 2023 expenses escalated by 2.4% each year with Test Year equal to 25% of 2024 and 75% of 2025

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-2.36d	
Respondent: T. M. Uzenski	
Page: 1 of 1	

Question: 36. Exhibit A-13, Schedule C5.6 page 1, shows actual 2022 Rents on line 15 of $45.2 million in column (c), which increases by $6.2 million in column (e) and to $51.3 million in column (f). Please:

d. Expand page 3 of the exhibit to include actual 2023 costs and provide in Excel.

Answer: Please see the attachment. It is also updated for the reduction in the projected period costs resulting from the Order in Case No. U-21297. See AGDG-2.36b. The total change from the Company's filed position is a reduction in rent expense of $2.5 million.

Attachment: U-21291 AGDG-2.36d Updated Exhibit A-13 C5.6 p3.xls

Line		AIP 2019	AIP 2020	AIP 2021	AIP 2022	AIP 2023	REP 2019	REP 2020	REP 2021	REP 2022	REP 2023	AVG.
1	**Customer Satisfaction**											
2	Customer Satisfaction Index	80.1%	0.0%	0.0%	100.0%	0.0%	86.8%	0.0%	0.0%	100.0%	0.0%	
3	& Net Promoter Score											
4												
5	Customer Satisfaction											
6	Imoprovement (DPMO)	96.9%	175.0%	N/A	N/A	N/A	97.9%	150.0%	N/A	N/A	N/A	
7												
8	Customer Satisfaction											
9	Improvement (+1 PMO)	0.0%	0.0%	N/A	N/A	N/A	0.0%	0.0%	N/A	N/A	N/A	
10												
11	MPSC Customer Complaints	36.5%	175.0%	0.0%	81.8%	0.0%	57.5%	150.0%	0.0%	87.9%	0.0%	
12												
13	**Employment Engagement**											
14	DTE Gas Employee Engagement											
15	Gallup	117.3%	57.1%	62.5%	117.3%	139.5%	N/A	N/A	N/A	N/A	N/A	
16												
17	DTE Gas OSHA Recordable											
18	Incident Rate	36.7%	175.0%	140.0%	157.1%	0.0%	57.8%	150.0%	126.7%	138.1%	0.0%	
19												
20	DTE Gas OSHA DART Rate or High											
21	Energy Serious Injury/Fatality	0.0%	131.3%	0.0%	126.0%	0.0%	0.0%	120.0%	0.0%	116.7%	0.0%	
22												
23	Nat. Safety Council Bar. Survey	137.5%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
24												
25	**Operating Excellence**											
26	Gas Open Leak Balance &											
27	Gas Distrib. System Imprvmt.	175.0%	0.0%	175.0%	113.8%	122.2%	150.0%	0.0%	150.0%	109.2%	114.8%	
28												
29	Gas Distrib. Response Time	55.7%	160.0%	127.3%	120.5%	53.0%	70.5%	140.0%	118.2%	113.8%	68.6%	
30												
31	Lost and Unaccounted For Gas	0.0%	25.0%	N/A	N/A	N/A	0.0%	50.0%	N/A	N/A	N/A	
32												
33	Gas Compression Reliab.	149.5%	175.0%	N/A	N/A	N/A	133.0%	150.0%	N/A	N/A	N/A	
34												
35	Gas Damage Prevention	175.0%	60.6%	N/A	N/A	N/A	150.0%	73.8%	N/A	N/A	N/A	
36												
37	% of HCA Accessible by ILI	N/A	N/A	175.0%	175.0%	175.0%	N/A	N/A	150.0%	150.0%	150.0%	
38												
39	Pressure Test Records Remed.	N/A	N/A	115.6%	175.0%	175.0%	N/A	N/A	110.4%	150.0%	150.0%	
40												
41	Meter Assembly Check Backlog	94.3%	118.2%	N/A	N/A	N/A	96.2%	112.1%	N/A	N/A	N/A	
42												
43	Less Than Threshold	3	3	3	0	4	3	3	3	0	4	
44	Btw. Threshold & Less Than Target	6	3	1	1	1	5	2	0	1	1	
45	Target	0	0	0	1	0	0	0	0	1	0	
46	Btw. Target and Maximum	3	3	3	5	2	2	3	3	4	1	
47	Maximum	2	4	2	2	2	2	4	2	2	2	
48	Total	14	13	9	9	9	12	12	8	8	8	
49												
50	Sum	11.55	12.52	7.95	11.67	6.65	9.00	10.96	6.55	9.66	4.83	
51	Number of Measures	14	13	9	9	9	12	12	8	8	8	
52												
53	Average	0.82	0.96	0.88	1.30	0.74	0.75	0.91	0.82	1.21	0.60	
54												
55	Performance Measures Achieved at											
56	Target or Better	5	7	5	8	4	4	7	5	7	3	
57	Percentage of Measures (Target +)	35.7%	53.8%	55.6%	88.9%	44.4%	33.3%	58.3%	62.5%	87.5%	37.5%	$\boxed{55.8\%}$

Source: DR AGDG-3.44a.

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-6.170a	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 170. Refer to lines 15-25 on page 37 and lines 2-8 on page 38 of Mr. Janness's direct testimony on MAOP reconfirmation. Please:

a. Provide the O&M expense incurred for reconfirmation of missing or incomplete traceable, verifiable, and complete (TVC) records for each year 2022, 2023, 2024, 2025, and the projected test year.

Answer:

2022	$3.6M
2023	$0.4M
2024	$1.3M
2025	$1.9M

Attachment: None.

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-6.170b	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: 170. Refer to lines 15-25 on page 37 and lines 2-8 on page 38 of Mr. Janness's direct testimony on MAOP reconfirmation. Please:

b. Identify what deficiencies, inaccuracies, and other problems the Company has discovered in reviewing its pipeline records to re- establish MAOP.

Answer: The Company has identified pressure test records ranging from incomplete to missing pressure test documentation. In addition, the company has also identified material records issues as well (grade, seam type, etc).

Attachment: None.

MPSC Case No: U-21291
Requester: AG
Question No.: AGDG-7.191a
Respondent: T. M. Uzenski
Page: 1 of 1

Question: 191. Refer to pages 39 and 40 of the direct testimony of Ms. Uzenski on the negative pension and OPEB liabilities. For each plan, please:

a. Provide the actual deferred regulatory liability balance at 12/31/21, 12/31/22, and 12/31/2023, and the forecasted monthly balances during 2023, 2024, and 2025. Provide this information in Excel.

Answer: See attachment.

Attachment: U-21291 AGDG-7.191a Pension and OPEB Reg Liabiliity.xlsx

DTE Electric Company
Working Capital
Pension & OPEB Reg Liabilities
($000)

Case No.: U-21291
Audit Request: AGDG-7.191a
Date of Request: 4/23/2024
Respondent: T. M. Uzenski

		OPEB Reg Liability	Pension Reg Liability
Actual	Dec-21	(44,301)	-
Actual	Dec-22	(62,721)	-
Actual	Jan-23	(63,032)	-
Actual	Feb-23	(63,721)	-
Actual	Mar-23	(64,120)	-
Actual	Apr-23	(64,535)	-
Actual	May-23	(64,981)	-
Actual	Jun-23	(65,431)	-
Actual	Jul-23	(65,878)	-
Actual	Aug-23	(66,326)	-
Actual	Sep-23	(66,771)	-
Actual	Oct-23	(67,224)	-
Actual	Nov-23	(67,679)	-
Actual	Dec-23	(68,136)	-
Forecast	Jan-24	(69,123)	-
Forecast	Feb-24	(69,676)	-
Forecast	Mar-24	(70,228)	-
Forecast	Apr-24	(70,781)	-
Forecast	May-24	(71,334)	-
Forecast	Jun-24	(71,886)	-
Forecast	Jul-24	(72,439)	(155)
Forecast	Aug-24	(72,991)	(867)
Forecast	Sep-24	(73,544)	(1,579)
Forecast	Oct-24	(74,096)	(2,291)
Forecast	Nov-24	(74,649)	(3,004)
Forecast	Dec-24	(75,202)	(3,716)
Forecast	Jan-25	(75,712)	(3,441)
Forecast	Feb-25	(76,223)	(3,166)
Forecast	Mar-25	(76,734)	(2,892)
Forecast	Apr-25	(77,245)	(2,617)
Forecast	May-25	(77,755)	(2,342)
Forecast	Jun-25	(78,266)	(2,068)
Forecast	Jul-25	(78,777)	(1,793)
Forecast	Aug-25	(79,288)	(1,518)
Forecast	Sep-25	(79,799)	(1,243)
Forecast	Oct-25	(80,309)	(969)
Forecast	Nov-25	(80,820)	(694)
Forecast	Dec-25	(81,331)	(419)

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-7.191b	
Respondent: T. M. Uzenski	
Page: 1 of 1	

Question: 191. Refer to pages 39 and 40 of the direct testimony of Ms. Uzenski on the negative pension and OPEB liabilities. For each plan, please:

b. Provide the year when the Company expects the expense to become positive and provide the basis for that conclusion.

Answer: Updated projections of the Company's Pension and OPEB costs through 2030 provided by Aon (the Company's actuarial consultant) indicate that the Company's Pension costs become positive in 2025 while its OPEB costs will remain negative through 2030. However, these estimates assume expected returns on assets that might or might not materialize and no change in discount rates during the projected period. Therefore, the Company cannot predict future Pension and OPEB expense with a high degree of confidence beyond the current year, which supports the continuation of the Company's deferral of actual Pension and OPEB expense.

	2024	2025	2026	2027	2028	2029	2030
Pension Costs ($000's)							
Service Costs	11,550	11,184	10,682	10,253	9,731	9,291	8,870
Interest Costs	45,543	45,211	44,820	44,350	43,775	43,103	42,390
Expected Return on Assets	(88,608)	(80,700)	(77,811)	(76,626)	(74,565)	(71,394)	(69,922)
Amortizations							
(Gain)/Loss	13,191	26,229	24,673	23,277	21,538	19,894	18,325
Prior Service Costs	(560)	(247)	(247)	(247)	(247)	(103)	-
Total Pension Costs	(18,884)	1,677	2,117	1,007	232	791	(337)
OPEB Costs ($000's)							
Service Costs	4,106	3,942	3,785	3,633	3,488	3,349	3,215
Interest Costs	13,990	13,925	13,825	13,695	13,530	13,333	13,110
Expected Return on Assets	(40,507)	(42,693)	(43,873)	(45,702)	(47,645)	(49,708)	(51,883)
Amortizations							
(Gain)/Loss	6,972	5,811	4,751	3,727	2,763	1,895	1,161
Prior Service Costs	(3,753)	111	111	2	-	-	-
Total OPEB Costs	(19,192)	(18,904)	(21,401)	(24,645)	(27,864)	(31,131)	(34,397)

Attachment: None.

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-4.93c	
Respondent: H. J. Decker	
Page: 1 of 1	

Question: 93. Refer to lines 13 to 20 and Table 6 on page 60 of Mr. Decker's direct testimony on Credit Cards merchant fees. Please:

c. Provide a comparison in Excel of the transaction fees incurred under each payment method used by customers, such as payment by check, automatic bank withdrawal, Kiosks, etc., for each year 2021, 2022, and 2023.

Answer:

	Average Fee by Payment Channel		
	2021	**2022**	**2023**
Electronic Funds Transfer (EFT)	$0.08	$0.08	$0.10
Automatic Clearing House (ACH)	$0.09	$0.09	$0.11
Check	$0.20	$0.20	$0.20
KIOSK	$4.95	$3.65	$3.92

Attachment: None

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-4.50	
Respondent: T. M. Uzenski	
Page: 1 of 1	

Question: 50. Refer to page 5 of Mr. Telang's direct testimony and the increase in O&M expense as partial justification for the requested rate increase. Please provide the cost of privately-hired corporate jet airplane travel by DTE Gas employees, DTE Energy employees, and other affiliated companies, charged to DTE Gas and included in the historical costs for 2022 and the projected test year. Provide also a list of the employees who used such private jet travel for each year 2022 and 2023, their position title, the date of travel, the individual trip cost, the reason for the travel, the cities visited, the miles traveled round trip, and the tons of CO2 carbon footprint for each trip. Provide this information in Excel.

Answer: The Company leases a fractional share of an aircraft for limited business travel by executives (typically Vice President & above) and other employees when there is an appropriate business need.

The cost of private (non-commercial) corporate jet expense charged to DTE Gas for 2022 was $68,910. There is approximately $74,769 of corporate jet expenses included in the projected test period.

Refer to the attachment for a list of employees who utilized private jet travel in 2022 including their positions, dates of travel, trip cost, business reason for travel, and the departure and destination cities. The Company does not track the miles traveled or CO2 emissions. There was no corporate jet travel in 2023.

Attachment: U-21291 AGDG-4.50 2022 Corporate Jet Travel.xlsx

DTE Gas Company
Case No. U-21291
AGDE-4.50
2022 Corporate Jet Travel Details

Business Purpose	DESTINATION	DEPARTURE	RETURN	PASSENGERS	Total Cost
National LAMPAC meeting, EEI Spring Board Meeting and Congressional visits	Washington DC (one way flight)	3/7/2022 (Willow Run Airport)	Commercial flight for return	Gerard Anderson - Chairman of Board of Directors	$ 6,811
2022 DTE Annual Shareholders Meeting/Board and Committee Meetings	Pick up at Concord NC, Hartsfied-Jackson Atlanta, GA, Final destination Fort Lauderdale, FL	5/3/2022 (Oakland County International Airport)	One Way Trip	Matt Paul - DTE Electric President & COO David Ruud - Executive VP & CFO Ruth Shaw - DTE Board of Directors David Thomas - DTE Board of Directors Valerie Williams - DTE Board of Directors	$ 21,356
2022 DTE Annual Shareholders Meeting/Board and Committee Meetings	Fort Lauderdale, FL	5/3/2022 (Oakland County International Airport)	5/5/2022 Fort Lauderdale to Oakland Cnty Intl	Gerard Anderson - Chairman of Board of Directors Trevor Lauer - DTE Vice Chairman Chip McClure - DTE Board of Directors Jerry Norcia - Chief Executive Officer JoAnn Chavez - Senior VP and Chief Legal Officer Joi Harris - President & COO - DTE Energy Mark Murray - DTE Board of Directors Lisa Muschong - VP Corporate Secretary Renee Tomina - Senior VP, Project Management Office Gary Torgow** - DTE Board of Directors Robert Skaggs** - DTE Board of Directors ** Return Flight Only	$ 62,516
RETURN FROM 2022 DTE Annual Shareholders Meeting/Board and Committee Meetings	Fort Lauderdale, FL to Hartsfied-Jackson, Atlanta, GA to Concord Regional, Concord, NC to Oakland County Intl.	5/5/2022 Fort Lauderdale, FL	5/5/2022 Plane returned to Oakland Cnty Intl	Diane Antishin - VP Human Resources Lisa Muschong - VP Corporate Secretary Matt Paul - DTE Electric President & COO David Ruud - Executive VP & CFO Ruth Shaw - DTE Board of Directors David Thomas - DTE Board of Directors Renee Tomina - Senior VP, Project Management Office	$ 10,796
Meeting with sell side analysts and various investors at the AGA conference	Miami, FL	5/16/2022 Oakland Cnty Intl	One Way Trip	Jerry Norcia - Chief Executive Officer David Ruud - Executive VP & CFO Barbara Tuckfield - Director, Investor Relations	$ 16,991
RETURN FROM: Meeting with sell side analysts and various investors at the AGA conference	Return to Oakland Cnty. Intl.	5/18/2022 - Miami, FL	return to Oakland County Airport	Jerry Norcia - Chief Executive Officer David Ruud - Executive VP & CFO Barbara Tuckfield - Director, Investor Relations	$ 6,846
Attend 2022 Mackinac Policy Conference	Mackinac Island, MI	6/1/2022 - Oakland County Intl.	One Way Trip	Joi Harris - President & COO - DTE Energy Renze Hoeksema - VP, Corporate & Government Affairs Trevor Lauer - DTE Vice Chairman Jerry Norcia - Chief Executive Officer Shawn Patterson - VP Environmental Mgmt & Safety	$ 2,854
Attend 2022 Mackinac Policy Conference	Oakland Cnty Intl. (return from Mackinac)	6/2/2022 - Mackinac Island, MI	One Way Trip - returned to Oakland Cnty Intl.	Joi Harris - President & COO - DTE Energy Renze Hoeksema - VP, Corporate & Government Affairs Trevor Lauer - DTE Vice Chairman Jerry Norcia - Chief Executive Officer Shawn Patterson - VP Environmental Mgmt & Safety	$ 7,427

MICHIGAN PUBLIC SERVICE COMMISSION | **Case No: U-21291**
DTE Gas Company | **Exhibit: AG-53**
May 7, 2024

DTE Gas Response to data request AGDG-4.50

Jerry Norcia Attend the INPO Board meeting in the morning, then Jerry, Pete and Trevor will meet with INPO team in the afternoon for a DTE/INPO CEO meeting	Atlanta GA	7/13/2022 Oakland Cnty Intl to Fulton County, Atlanta GA	7/14/2022 Fulton county, Atlanta, GA to Oakland Cnty Intl	Pete Dietrich - Senior VP & Chief Nuclear Officer Trevor Lauer - Dte Vice Chairman Jerry Norcia - Chief Executive Officer	$ 14,583
Meeting with sell side analysts and various investors during Guggenheim NDR	Teterboro, NJ	8/8/2022 Oakland Cnty Intl to Teterboro, NJ	8/8/2022 Teterboro, NJ to Oakland Cnty Intl	Jerry Norcia - Chief Executive Officer Barbara Tuckfield - Director, Investor Relations	$ 11,445
Meeting in NY under a tight time schedule, with several employees. Recent travel using commercial airlines has been erratic; need to have the flexibility to get everyone there on time and return on time. Meet with the CeO & team at GE in NY to discuss stator, relationship, schedule, extended power upgrade wind repowering, and CCUS capabilities.	New York, NY	8/22/2023 Oakland Cnty Intl to Schenectady County, NY	8/23/2022 Schenectady County, NY to Oakland Cnty Intl.	Dennis Decator - Manager, Nuclear Project Portfolio Steven Fatora - Director, Nuclear Project Management Trevor Lauer - DTE Vice Chairman Jaspreet Singh - Vice President, Corporate Services Renee Tomina - Senior VP, Project Management Office	$ 11,585
The DTE Team and a team from the Nature Conservancy (TNC) will go to the UP to tour federally protected wilderness areas, visit sustainable forestry practices, and learn about the preservation and conservation efforts and carbon program	Marquette, MI	8/29/2022 Oakland Cnty to Sawyer Intl, Marquette MI	8/29/2022 Sawyer Intl, Marquette MI to Oakland Cnty Intl.	Joi Harris - President & COO - DTE Energy Jerry Norcia - Chief Executive Officer Shawn Patterson - VP Environmental Mgmt & Safety Patrick Doran (The Nature Conservancy) Helen Taylor (The Nature Conservancy) Rich Tuzinsky (The Nature Conservancy)	$ 8,560
September DTE Energy Board Strategic Meeting and Committee Meetings bring outside directors here	Bring Directors to Detroit Metro Airport	9/20/2022 Depart Hartsfield-Jackson, Atlanta GA, to Carrollton, GA to Detroit Metro to Oakland Cnty Int.	One Way Trip	David Thomas - DTE Board of Directors Ruth Shaw - DTE Board of Directors	$ 11,832
September DTE Energy Board Strategic Meeting and Committee Meetings bring outside directors here	Bring Directors to Detroit Metro Airport	9/20/2022 Depart Houston, TX to Detroit Metro then Oakland Cnty Intl.	One Way Trip	Valerie Williams - DTE Board of Directors	$ 15,841
September DTE Energy Board Strategic Meeting and Committee Meetings outside directors return home	Raleigh-Durham Intl, Morrisville, NC	9/22/2022 Depart Oakland Cnty Intl, to Detroit Metro to Raleigh Durham Intl	One Way Trip	Ruth Shaw - DTE Board of Directors	$ 6,058
September DTE Energy Board Strategic Meeting and Committee Meetings outside directors return home	Knoxville, TN Houston, TX	9/22/2022 Depart Oakland Cnty Intl, to Detroit Metro to Knoxville, TN then to Houston TX	One Way Trip	Gail McGovern - DTE Board of Directors Valerie Williams - DTE Board of Directors	$ 17,966
Attend INPO Board meetings and CEO Conference	Atlanta, GA	11/1/2022 Depart Oakland Cnty Intl to Atlanta GA	11/2/2022 Atlanta, GA to Oakland Cnty Intl	Jerry Norcia - Chief Executive Officer Pete Dietrich (return flight only) - Senior VP and Chief Nuclear Officer	$ 12,923
					$ 246,391

MPSC Case No: U-21291	
Requester: AG	
Question No.: AGDG-7.201a	
Respondent: T. M. Uzenski	
Page: 1 of 1	

Question: 201. Refer to Exhibit A-13, Schedule C5.6, page 5, on deferred incentive compensation expense. Please:

a. Provide the supporting data and calculations showing how you determined the amounts on lines 2 and 3 under each year with component costs and provide this information in Excel.

Answer: Please see attachment for supporting data and calculations.

Line 3 represents the base amount approved in rates in Case No. U-20940. Pages 163 and 164 of the order in Case No. U-20940 describes the recovery of 20% of O&M incentive compensation related to operational metrics based on the AG's proposal, and the disallowance of the remaining amount requested by the Company. See the attachment for the calculation of the approved amount of $1.057 million.

Attachment: U-21291 AGDG-7.201a - Incentive Compensation

Michigan Public Service Commission	**Case No.:**	**U-21291**					
DTE Gas Company							
AGDG-7.201a							
Incentive Compensation							
2022					1/1/23 -	1/1/24 -	1/1/25 -
LLC to Gas Operational	4,309				12/31/23	12/31/24	9/30/25
Gas Only Operational	2,068			1/ Annual Inflation Factors	3.2%	2.9%	2.9%
Total Operational REP/AIP	6,378	line 2	See next tab.	No. of Months in Period	12	12	9
Base Incentives (U-20940)	(1,057)	line 3					
Total Amount Deferred to Regulatory Asset	5,321			Pro-rated Inflation Rate	3.2%	2.9%	2.2%
2023							
2022 Normalized Operational Incentives	5,866						
2023 Inflation 1/	188						
Total Operational REP/AIP	6,054	line 2	See next tab.				
Base Incentives (U-20940)	(1,057)	line 3					
Total Amount Deferred to Regulatory Asset	4,997						
2024							
2022 Normalized Operational Incentives	5,866						
2023 Inflation 1/	188						
2024 Inflation 1/	176						
Total Operational REP/AIP (Full Year)	6,229						
Total Operational REP/AIP (Jan - Sept)		4,672	line 2				
Base Incentives (U-20940) (Full Year)	(1,057)						
Base Incentives (U-20940) (Jan - Sept)		(793)	line 3				
Total Amount Deferred to Regulatory Asset		3,879					
Line 3 (base amount) calculation							
Company requested incentive compensation - operating metrics	5,286,000		U-20940 Exhibit AG-71 page 3				
Order adopted AG disallowance	80%		AG disallowance reflects no approval of financial metrics and 20% of operational metrics.				
	(4,228,800)						
Incentives approved	1,057,200						

Total Operational REP/AIP						
Line 2 Calculations						
2022				1/1/23 -	1/1/24 -	1/1/25 -
0388 LLC Operational REP/AIP	$21,603,900			12/31/23	12/31/24	9/30/25
LLC REP/AIP Operational - % to Gas O&M	20%		1/ Annual Inflation Factors	3.2%	2.9%	2.9%
LLC to Gas Oper REP/AIP (Accrued O&M)	$4,309,288		No. of Months in Period	12	12	9
0221 Gas Operational REP/AIP	$3,892,126		Pro-rated Inflation Rate	3.2%	2.9%	2.2%
Gas only REP/AIP Operational - % to Gas O&M	53%					
Gas only Oper REP/AIP (Accrued O&M)	$2,068,399					
Total Operational REP/AIP	$6,377,687	Line 2				
Base Incentives (U-20940)	($1,057,000)					
Total Amount Deferred to Regulatory Asset	$5,320,687					
2023						
Gas O&M Normalized Operational REP	$1,718,327					
Gas O&M Normalized Operational AIP	$142,001					
Subtotal Gas O&M Normalized Operational REP/AIP	$1,860,328					
LLC O&M Normalized to Gas Operational REP	$2,609,213					
LLC O&M Normalized to Gas Operational AIP	$1,733,748					
Subtotal LLC O&M Normalized to Gas Operational REP/AIP	$4,342,961					
Eliminate Top 5 to Gas Normalized	($337,738)					
2022 Normalized Operational Incentives Total	$5,865,551					
2023 Inflation 1/	$187,698					
Total Operational REP/AIP	$6,053,249	Line 2				
Base Incentives (U-20940)	($1,057,000)					
Total Amount Deferred to Regulatory Asset	$4,996,249					

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Gas Company

Exhibit AG-55
Case No. U-21291
Date: May 7, 2024

Computation of Revenue Deficiency for Projected Test Year Ending September 30, 2025

($000)

Line	Description	Company Filed Amount	AG Recommended Adjustments	Revised Amount
	(a)	(b)	(c)	(d)
1	Rate Base [1]	$ 6,943,963	$ (124,522)	$ 6,819,441
2	Rate of Return	6.04%	-0.22%	5.82%
3	Income Required	$ 419,693	$ (22,802)	$ 396,891
4	Adjusted Net Operating Income [2]	223,685	90,353	314,038
5	Income Deficiency (Sufficiency)	$ 196,008	$ (113,154)	$ 82,854
6	Revenue Multiplier	1.3547	1.3547	1.3547
7	**Revenue Deficiency (Sufficiency)**	**$ 265,532**	**$ (153,290)**	**$ 112,242**

[1] Rate Base Adjustments Exhibit AG-20

[2] AG adjustments to Operating Income: Increase (Decrease)

			Source
Revenue		$ 15,023	Testimony
HPP Margin		$ 4,617	Testimony
O&M Expenses		$ 97,263	Exh. AG-39-42
Property Tax		$ 5,019	Exhibit AG-20
Depreciation Expense		$ 3,409	Exhibit AG-20
AFUDC		$ (2,210)	Testimony
Total		$ 123,121	
Effective Tax Rate (1-1/1.3547)	26.18%		
Taxes		(32,237)	
Interest Synchronization on Capital Adjustments		(532)	RevDef-WP1
Adjusted Net Operating Income		$ 90,353	

PROOF OF SERVICE - U-21291

The undersigned certifies that a copy of the ***Attorney General's PUBLIC Testimony and Exhibits of Sebastian Coppola*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 7th day of May 2024.

Joel B. King Digitally signed by Joel B. King Date: 2024.05.07 15:29:53 -04'00'

Joel B. King

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