

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21860

In the matter of the application of)
DTE ELECTRIC COMPANY)
for authority to increase its rates, amend)
its rate schedules and rules governing the)
distribution and supply of electric energy)
and for miscellaneous accounting authority)

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of
Attorney General Dana Nessel

August 22, 2025

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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, and other proceedings. 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

1 have also supported other witnesses in testimony before the MPSC in various rate setting
2 and other regulatory proceedings.

3 **Q. WHAT EXPERIENCE DO YOU HAVE WITH ELECTRIC UTILITIES?**

4 A. I have performed rate case analyses and filed testimony in several electric general rate
5 cases addressing issues on revenue requirement, sales level determination, operations and
6 maintenance expenses, cost allocations, cost of capital, cost of service and rate design,
7 various cost tracking mechanisms and integrated resource plans. In addition, I have
8 performed analyses of power costs and filed testimony in power supply cost recovery
9 mechanisms, including reconciliation of annual power supply costs.

10 In my position as Senior Vice President of Finance at MCN Energy Group, I had
11 responsibility for project financing of independent power generation plants in which MCN
12 was an owner. In this regard, I was intricately involved and became knowledgeable of
13 PURPA qualified cogeneration plants in Michigan and other states. In addition, I was
14 involved in negotiating the development and financing of power generation and electricity
15 distribution plants in other countries, such as India.

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

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

- 1 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas
2 Company (DTE Gas) 2025-2026 GCR plan case No. U-21608.
- 3 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-
4 2024 GCR reconciliation in case No. U-21272.
- 5 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
6 Company (DTEE) 2023 PSCR Plan Case No. U-21594.
- 7 ○ Filed testimony on behalf of the Michigan Attorney General in Consumers
8 Energy Company (CECo) 2024 gas rate case U-21806 on several issues,
9 including sales, operation and maintenance expenses, capital expenditures, cost
10 of capital, and other items.
- 11 ○ Filed testimony on behalf of the Michigan Attorney General in Michigan Gas
12 Utilities Corporation (MGUC) 2023-2024 GCR reconciliation in case No. U-
13 21274.
- 14 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
15 Company (DTEE) 2023 PSCR reconciliation in case No. U-21260.
- 16 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2023-2024
17 GCR reconciliation in case No. U-21270.
- 18 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy
19 Gas Company (SEMCO) 2023-2024 GCR plan reconciliation in case No. U-
20 21278.
- 21 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2023 PSCR
22 reconciliation in case No. U-21258.
- 23 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2024
24 electric rate case U-21585 on several issues, including operation and maintenance
25 expenses, capital expenditures, cost of capital, and other items.
- 26 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2024
27 electric rate case U-21534 on several issues, including operation and maintenance
28 expenses, capital expenditures, cost of capital, and other items.
- 29 ○ Filed testimony on behalf of the Michigan Attorney General in the Upper
30 Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several
31 issues, including operation and maintenance expenses, capital expenditures, cost
32 of capital, and other items.
- 33 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2024 gas
34 rate case U-21540 on several issues, including operation and maintenance
35 expenses, capital expenditures, cost of capital, and other items.
- 36 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy
37 Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.

- 1 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2024
2 gas rate case U-21291 on several issues, including sales, operation and
3 maintenance expenses, capital expenditures, cost of capital, and other items.
- 4 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-
5 2023 GCR reconciliation in case No. U-21065.
- 6 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2023 gas
7 rate case U-21490 on several issues, including sales, operation and maintenance
8 expenses, capital expenditures, cost of capital, and other items.
- 9 ○ Filed testimony on behalf of the Michigan Attorney General in DTM Michigan
10 Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case
11 No. U-21525.
- 12 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 PSCR
13 reconciliation in case No. U-21051.
- 14 ○ Filed testimony on behalf of the Michigan Attorney General in Michigan Gas
15 Utilities Corporation (MGUC) 2022-2023 GCR plan in case No. U-21067.
- 16 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2023 PSCR
17 reconciliation in case No. U-21049.
- 18 ○ Filed testimony on behalf of the Michigan Attorney General in Indiana Power
19 Company 2023 electric rate Case U-21461 on several issues, including sales,
20 operation and maintenance expenses, capital expenditures, cost of capital, and
21 other items.
- 22 ○ Filed testimony on behalf of the Michigan Attorney General in DTE 2023-2024
23 GCR plan in case No. U-21271.
- 24 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2023-2024
25 GCR plan in case No. U-21269.
- 26 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2023
27 electric rate Case U-21389 on several issues, including operation and
28 maintenance expenses, capital expenditures, cost of capital, and other items.
- 29 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy
30 Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- 31 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
32 Company (DTEE) 2023 rate Case U-21297 on several issues, including operation
33 and maintenance expenses, capital expenditures, cost of capital, and other items.
- 34 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-
35 2024 GCR plan in case No. U-21273.

- 1 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas
2 rate Case U-21308 on several issues, including sales revenues, operation and
3 maintenance expenses, capital expenditures, cost of capital, and other items.
- 4 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-
5 2022 GCR plan reconciliation case No. U-20817.
- 6 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR
7 plan reconciliation case No. U-20827.
- 8 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-
9 2022 GCR plan reconciliation case No. U-20819.
- 10 ○ Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula
11 Power Company 2022 general rate case No. U-21286.
- 12 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-
13 2022 GCR plan reconciliation case No. U-20823.
- 14 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023
15 GCR plan case No. U-21062.
- 16 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-
17 2023 GCR plan case No. U-21070.
- 18 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2022
19 electric rate Case U-21224 on several issues, including operation and
20 maintenance expenses, capital expenditures, cost of capital, and other items.
- 21 ○ Filed testimony on behalf of the Public Counsel Division of Washington Attorney
22 General in the Avista 2022 electric and gas rate cases on several issues, including
23 operation and maintenance expenses, capital expenditures, and other items.

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

25 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

26 A. I have been asked by the Attorney General to perform an independent analysis of DTE
27 Electric Company's ("Company" or "DTEE") Electric Rate Case filing in Case No. U-
28 21860. This testimony presents a report of that analysis with related recommendations.

29 **Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?**

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

- 2 1. The level of proposed Rate Base and Capital Expenditures
- 3 2. The Company's Cost of Capital
- 4 3. Working Capital
- 5 4. The level of Operations and Maintenance expenses
- 6 5. The partial disallowance of rate case expenses
- 7 6. The Adjusted Revenue Deficiency
- 8 7. The adjustment to the return on deferred tree trimming costs

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

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

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

- 16 1. Exhibit AG-1 DTE Energy Investor Presentation Information
- 17 2. Exhibit AG-2 S&P Global US Economic Outlook with CPI Rates
- 18 3. Exhibit AG-3 Cost Dollar Averaging
- 19 4. Exhibit AG-4 I-375 Project Dollars and Status
- 20 5. Exhibit AG-5 Substation Risk Projects
- 21 6. Exhibit AG-6 Distribution Mobile Fleet
- 22 7. Exhibit AG-7 Monroe Fly Ash Basin Closure
- 23 8. Exhibit AG-8 Trenton Channel BESS Project Costs
- 24 9. Exhibit AG-9 CONF Trenton Channel Contracts
- 25 10. Exhibit AG-10 Trenton Channel Sea Wall Path

- 1 11. Exhibit AG-11 Slocum BESS
- 2 12. Exhibit AG-12 Generation Project Phase Prelim
- 3 13. Exhibit AG-13 Nuclear Radio and Computer
- 4 14. Exhibit AG-14 CONF Nuclear Underground Water Piping
- 5 15. Exhibit AG-15 CONF Nuclear Routine and Non-Routine project
- 6 16. Exhibit AG-16 CONF Engineering and Support Staff Augment
- 7 17. Exhibit AG-17 Corporate Facilities Renovation
- 8 18. Exhibit AG-18 Transportation Fleet
- 9 19. Exhibit AG-19 EV UMR Calculations
- 10 20. Exhibit AG-20 Capex, Rate Base Depreciation, Property Tax Adjustments
- 11 21. Exhibit AG-21 Working Capital Adjustment Summar
- 12 22. Exhibit AG-22 Interest and Taxes Payable
- 13 23. Exhibit AG-23 Overall Cost of Capital
- 14 24. Exhibit AG-24 Cost of Common Equity-Summary
- 15 25. Exhibit AG-25 Cost of Common Equity-DCF
- 16 26. Exhibit AG-26 Cost of Common Equity-CAPM
- 17 27. Exhibit AG-27 Cost of Common Equity-Risk Premium
- 18 28. Exhibit AG-28 Electric ROE Decisions by Regulatory Commissions
- 19 29. Exhibit AG-29 Midwest Utilities ROEs
- 20 30. Exhibit AG-30 Peer Group Analysis
- 21 31. Exhibit AG-31 Market to Book Ratios
- 22 32. Exhibit AG-32 Moody's Cash Flow Coverage Ratio
- 23 33. Exhibit AG-33 Not Used
- 24 34. Exhibit AG-34 S&P Jan 2025 Report
- 25 35. Exhibit AG-35 Rating Agency No Notification of Equity Rati
- 26 36. Exhibit AG-36 Moodys July 2023 Report
- 27 37. Exhibit AG-37 Company Risk Free Rate
- 28 38. Exhibit AG-38 Value Line - Volatility vs. Risk
- 29 39. Exhibit AG-39 O&M Adjustments Summary
- 30 40. Exhibit AG-40 O&M Inflation Adjustment

- 1 41. Exhibit AG-41 Distribution O&M for 2024 Build-up
- 2 42. Exhibit AG-42 Tree Trimming 2026 Detail Budget
- 3 43. Exhibit AG-43 Distribution Corrective & Preventive Maintenance
- 4 44. Exhibit AG-44 Staking and Locating Expense
- 5 45. Exhibit AG-45 Steam Power O&M Expense 2024 Buildup to 2026
- 6 46. Exhibit AG-46 Calculation of Steam Power Expense 2026
- 7 47. Exhibit AG-47 Steam Power Monroe Reliability and Coal Dumper
- 8 48. Exhibit AG-48 Other Power Gen 2024 Exp 2024-2026 and Normalization
- 9 49. Exhibit AG-49 Calculation of Other Power Expense 2026
- 10 50. Exhibit AG-50 Nuclear Exp 2024-2026 and Headcount
- 11 51. Exhibit AG-51 Calculation of Nuclear Power O&M Expense 2026
- 12 52. Exhibit AG-52 Regulated Marketing O&M 2024 and Normalizations
- 13 53. Exhibit AG-53 Calculation of Reg Marketing O&M Expense 2026
- 14 54. Exhibit AG-54 Uncollectible Expense
- 15 55. Exhibit AG-55 A&G Expense
- 16 56. Exhibit AG-56 VEBA Plan Adjustments
- 17 57. Exhibit AG-57 Health Care Costs
- 18 58. Exhibit AG-58 Incentive Comp Performance Results
- 19 59. Exhibit AG-59 Incentive Comp Metrics
- 20 60. Exhibit AG-60 Incentive Compensation Disallowance
- 21 61. Exhibit AG-61 AG Revenue Deficiency Calculation
- 22 62. Exhibit AG-62 Tree Trimming Return Calculation

23 **II. SUMMARY CONCLUSIONS & RECOMMENDATIONS**

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

1 A. The Company filed for a base rate increase of \$574.0 million. This rate increase represents
2 an overall increase in rates of 9.8%, with an 11.1% increase to residential customers. As
3 a result of the rate case adjustments that I propose in my testimony, I determined that the
4 Company has a revenue deficiency of \$158.4 million. Based on this amount of rate
5 increase, the average residential customer should see an increase of approximately 2.5%
6 in their total bill.

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

- 9 1. I propose a lower level of Operations and Maintenance expenses of \$203.4
10 million for the test year.
- 11 2. Along with other AG witnesses, I have included a reduction in capital
12 expenditures of \$890 million and a reduction in rate base of \$552.0 million,
13 including an increase in working capital of \$58.9 million, for a reduction in
14 revenue requirement of \$42 million.
- 15 3. I propose a reduction in depreciation expense of \$24.7 million pertaining to
16 the proposed reductions in capital expenditures.
- 17 4. I propose a reduction in property tax expense of \$9.0 million pertaining to
18 the proposed reductions in capital expenditures
- 19 5. I recommend an authorized rate of return on equity of 9.85% in comparison
20 to the Company's proposed ROE rate of 10.75%, and a 50% equity ratio, for
21 a reduction in the revenue deficiency of \$132.5 million.
- 22 6. I recommend that the Commission establish a new policy to disallow 50% of
23 the rate case expenses forecasted to be incurred for the current rate case.

1 7. I recommend the Commission reject the Company's calculation of the return
2 on deferred tree trimming cost at the overall cost of capital and instead
3 reaffirm the use of the short-term debt rate approved in this rate case.

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

6 **III. LARGE INCREASE IN RATE BASE**
7 **AND CAPITAL EXPENDITURES**

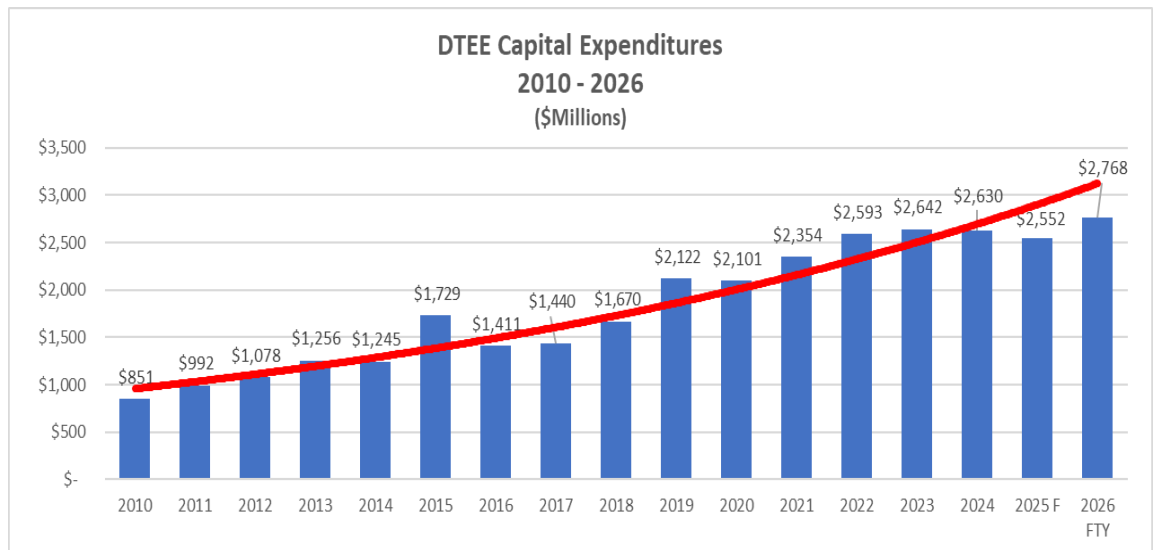
8 **Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LEVEL OF CAPITAL**
9 **EXPENDITURES PROPOSED BY THE COMPANY AND THE RESULTING**
10 **INCREASE IN RATE BASE.**

11 A. In this general rate case, DTEE has proposed capital expenditures of \$2.6 billion for 2024,
12 another \$2.6 billion for 2025, and an additional \$2.8 billion for 2026. The total proposed
13 capital expenditures over this 36-month period are \$8.0 billion.¹ These amounts exclude
14 expenditures under the Infrastructure Recovery Mechanism (IRM), which include an
15 additional \$588 million in 2027, \$814 million in 2028, and more than \$1.0 billion in 2029.²
16 These expenditures follow capital expenditures of \$5.2 billion made during the prior two
17 years, in 2022 and 2023.³ The following chart in Table 1 shows the dramatic increase in
18 capital expenditures over recent years, in comparison to more moderate amounts in prior
19 years.

¹ Exhibit A-12, Schedule B5.

² Exhibit A-33, Schedule X1.

³ DR AGDE-8.232b.



1

2

Until 2011, the Company was able to keep capital expenditures below \$1 billion annually.

3

Fifteen year later, the level of annual capital expenditures has nearly tripled.

4

The capital expenditures have fueled an alarming increase in rate base. As shown below

5

in Table 2, rate base has been growing at high-single digit to double digit rates in recent

6

years and the Company is proposing to increase rate base again in this rate case by 11%,

7

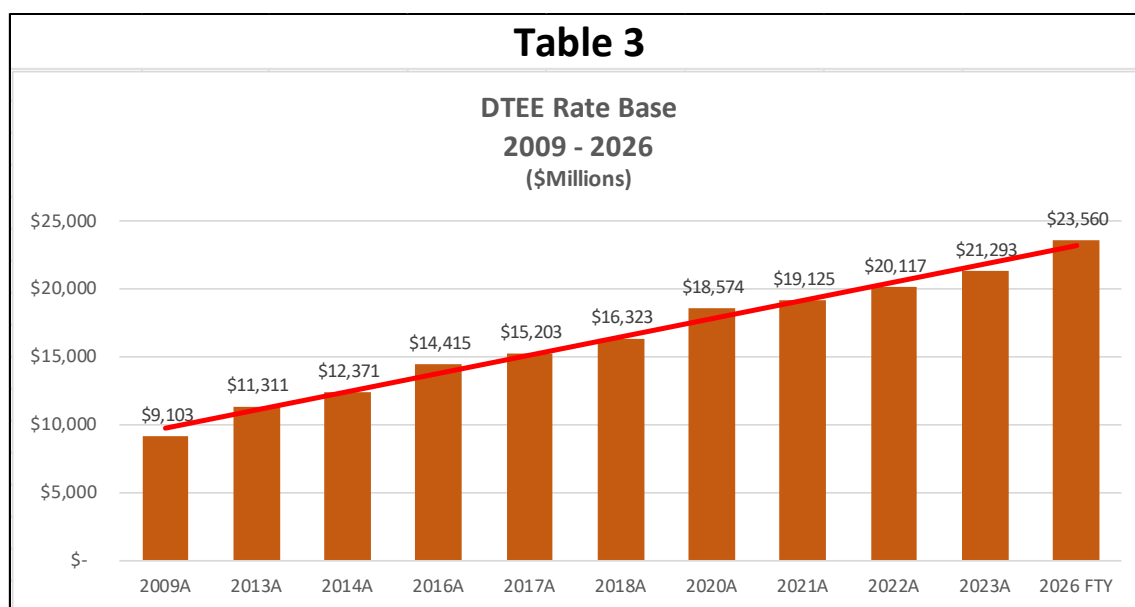
to \$23.6 billion. The proposed level of rate base in this rate case is nearly double the

8

amount of rate base the Company had just over 10 years ago, in 2014.

Table 2												
DTE Electric Rate Base Growth												
2009 to Projected 2026 Test Year												
Rate Base Year		2009A	2013A	2014A	2016A	2017A	2018A	2020A	2021A	2022A	2023A	2026 FTY
Docket No.		U-16472	U-17767	U-18014	U-18255	U-20162	U-20561	U-20836	U-21297	U-21534	U-21860	U-21860
Rate Base ¹ (Millions)	\$	9,103	\$ 11,311	\$ 12,371	\$ 14,415	\$ 15,203	\$ 16,323	\$ 18,574	\$ 19,125	\$ 20,117	\$ 21,293	\$ 23,560
Year over Year Change			24%	9%	17%	5%	7%	14%	3%	5%	6%	11%
Cumulative Change over 2009 Rate Base			24%	36%	58%	67%	79%	104%	110%	121%	134%	159%
historical actual rate base in each docket, except 2026 FTY is a 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.



Q. WHAT DO YOU BELIEVE IS DRIVING THIS DRAMATIC INCREASE IN CAPITAL EXPENDITURES AND RATE BASE SINCE 2009?

1 A. I believe there are two main drivers. First, replacement of aging infrastructure and new
2 capital spending to address market growth have required an increase in capital expenditures,
3 which have accelerated investment to some degree. The Company continues to propose
4 ever-increasing capital expenditures to replace and rebuild electrical lines, poles,
5 substations, and related facilities. Some of this work is necessary and must be done.
6 However, the Company has also proposed hundreds of millions of dollars in expensive
7 automation projects, digital projects, a dizzying number of pilot projects, information
8 technology projects, and office remodeling that raise questions about eschewing priority
9 spending toward more fundamental electrical infrastructure projects.

10 Prior to 2012, DTEE was able to manage replacement of aging infrastructure and also invest
11 in new facilities to meet market growth within a more reasonable increase in rate base.
12 Therefore, customer growth and replacement of aging infrastructure by themselves do not
13 fully explain the significant increase in capital expenditures and rate base.

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

1 The Company's parent company, DTE Energy, has been quite clear and aggressive in
2 communicating to investors and securities analysts its goal of increasing operating earnings
3 at the electric utility at an average annual rate of 6% to 8%. Exhibit AG-1 includes pertinent
4 pages from a May 2025 Investor Presentation, which shows this drive to increase earnings
5 through increased capital spending at the utility. It also shows how investors and
6 shareholders have been well rewarded. For a utility such as DTEE with limited sales and
7 revenue growth, the increase in earnings comes almost entirely from the increase in capital
8 expenditures and rate base. The presentation is devoid of any discussion about sales or
9 revenue growth to propel earnings growth at the utility.

10 **Q. DO THE HIGH CAPITAL SPENDING AND OPERATING COST INCREASES**
11 **SIGNIFICANTLY IMPACT RESIDENTIAL CUSTOMER BILLS?**

12 A. Yes. The Company has proposed to increase residential rates in this rate case by 11% over
13 current rates. This increase in annual customer bills poses a significant burden on all
14 residential customers, and especially those with fixed and low incomes. The compounding
15 effect of large additions to rate base will continue to increase customer rates to unaffordable
16 levels for many customers, particularly those in fixed and lower income brackets. Simply
17 put, this trend is not sustainable for customers. To avoid bill affordability problems in the
18 future, the Company needs to moderate and be more selective in its capital spending in the
19 coming years.

1 **IV. Review of Capital Expenditures**

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

4 A. Yes. I have analyzed the Company's forecasted capital expenditures by major department
5 or functional area and I have identified more reasonable expenditure levels that the
6 Commission should consider.

7 In projecting adjusted capital expenditures for 2025 and 2026, where applicable I applied
8 an inflation factor to the historical cost base in order to reflect inflationary cost pressure
9 that the Company may face in those years. The inflation factors are 2.8% for 2025 and
10 2.4% for 2026. These rates reflect the Consumer Price Index-Urban forecast presented in
11 the June 2025 US Economic Outlook report prepared by S&P Global Market Intelligence.⁴
12 I used those rates instead of the Company's inflation rates of 3.0% for 2025 and 3.10% for
13 2026 because they are more recent projections and the underlying prices in the CPI reflect
14 the full cost of goods and services, including wage increases paid by merchants and
15 companies. To add more wage adjustments would be duplicative.

16 **A. Distribution Plant**

17 As shown on page 1 of Exhibit A-12, Schedule B5.4, the Company forecasted nearly \$5.1
18 billion in capital expenditures for Distribution Plant for the three years 2024 to 2026. After

⁴ Exhibit AG-2 includes the report provided by DTEE in DR AGDE-2.44.

1 reviewing the testimony of Company witnesses sponsoring testimony in this area, related
2 exhibits, and responses to discovery, I have identified capital expenditure reductions
3 applicable to several capital programs and projects.

4 **1. Emergent Replacements**

5 **Q. PLEASE EXPLAIN YOUR ASSESSMENT OF CAPITAL EXPENDITURES FOR**
6 **EMERGENT REPLACEMENT PROGRAMS.**

7 A. On page 1 of Exhibit A-12, Schedule B5.4, the Company identified three categories of
8 Emergent Replacement Programs: Storm-related, Non-Storm, and Substation Reactive.
9 The total amount of capital expenditures for 2023 for these three programs was \$524.1
10 million. The Company forecasted \$472.0 million in capital expenditures for 2024, \$544.0
11 million for 2025, and \$575.9 million for 2026. The 2025 amount was reduced by \$22.3
12 million and the 2026 amount was reduced by \$23.2 million for expected reductions in
13 emergent capital spending from the anticipated benefit of strategic capital spending.

14 The Company arrived at its forecasted level of expenditures for emergent replacement
15 programs by applying retroactive inflation adjustments to historical amounts from 2019 to
16 2023 and labeling them normalization adjustments on page 3 of Exhibit A-12,
17 Schedule B5.4. It then applied additional forecasted inflation factors for 2024, 2025, and
18 2026 to the adjusted five-year average cost base to determine the capital expenditures for
19 the forecasted bridge periods and projected test year. I do not agree with that approach.

1 The Company is simply compounding inflationary increases on top of inflationary
2 increases that already occurred in the historical years.

3 The Company did not disclose the historical inflation factors in the filed testimony and the
4 exhibit. However, after reviewing the Excel version of Exhibit A-12, Schedule B5.4, it
5 shows that the Company inflated 2019 costs by 1.2% for the inflation in 2020 and then
6 again in 2021 by 4.7% for inflation in 2021, and then again by 8.0% for inflation in 2022,
7 and again by 4.1% for the inflation rate in 2023. This process is then repeated for
8 subsequent historical expenditures for 2020 to 2022. This compounding of historical
9 inflation on top of costs that already reflect inflation in the year that the capital
10 expenditures occurred is simply a methodology to increase the base costs on which the
11 Company later adds forecasted inflation for 2024 through 2026. DTEE calls this
12 adjustment process Constant Dollar Averaging.

13 **Q. DOES THE COMPANY DISCUSS THE USE OF CONSTANT DOLLAR**
14 **AVERAGING IN FILED TESTIMONY?**

15 A. Yes. Both Company witnesses Brian Hill and Timothy Lyons discuss the use of Constant
16 Dollar Averaging in their respective direct testimony. For the most part, Mr. Hill relies on
17 the direct testimony of Mr. Lyons on this matter and also presents cost trends with certain
18 specific materials and labor costs. I will address each of these topics below.

19 Regarding the increased labor and material costs of recent years, in each rate case the
20 Company has had the opportunity to include costs with appropriate forecasted labor and

1 material cost increases in the projected test year and bridge periods. Other than for
2 selective cost disallowances when the Company has not adequately supported cost
3 increases, the Company has been able to recover in rates any forecasted cost increases
4 included in forecasted capital expenditures and O&M expenses. Therefore, it is not clear
5 what the point of Mr. Hill's testimony is in showing that labor and material costs have
6 increased over time, some at rates higher than others.

7 If the point is that, given the rapid increase in prices during 2021 and 2022, the Company
8 may not have fully recovered certain costs because the forecasted rate of increase was
9 lower than the actual increase in prices and labor, this is the result of living in a real world
10 where actual events are different than forecasts. If the Company is now seeking to
11 retroactively recover some additional inflation-related costs through the Constant Dollar
12 Averaging adjustments, which is the actual effect of boosting future forecasts with
13 retroactive inflation adjustments, that goal is misguided and wholly inappropriate in the
14 regulatory setting. I will point out that, although there may be a mismatch between
15 forecasted and actual costs in a rate case, the actual costs incurred for capital projects are
16 included in rate base in the subsequent rate case and eventually recovered.

17 Regarding the Constant Dollar Averaging methodology, the Company decided to retain
18 Mr. Lyons, a consultant with the firm ScottMadden, to address this matter. His testimony
19 is primarily a theoretical discussion of what Constant Dollar Averaging is meant to
20 accomplish in forecasting but offers very limited practical application. In discovery, the
21 Attorney General asked whether the Company uses Constant Dollar Averaging in

1 forecasting costs and revenues for internal budgets and capital programs presented to its
2 Board of Directors and external parties. In response, the Company stated that it had not
3 done any research or analysis on that question. This is a clear indication that no such
4 methodology is used by the Company for internal financial purposes.

5 The Attorney General also asked if Mr. Lyons knows of any non-utility companies that
6 use Constant Dollar Averaging to set prices on their goods and services. The response was
7 the same, which means he is not aware of any other companies using the methodology.
8 Regarding the Department of Defense's (DOD) use the methodology for forecasting the
9 cost of certain programs, the Attorney General asked the Company whether Mr. Lyons had
10 any evidence that for purposes of paying its suppliers, DOD used Constant Dollar
11 Averaging to increase payments to suppliers. The answer was again negative. Exhibit
12 AG-3 includes the above responses to discovery AGDE-9.274, 9.276, and 9.277.

13 What matters with Constant Dollar Averaging is not simply preparing a forecast with
14 historical inflation adjustments but whether the methodology is used to drive actual
15 financial compensation. No evidence has been provided by Mr. Lyons or the Company
16 that Constant Dollar Averaging is widely used in business transactions with financial
17 consequences.

18 The application of the methodology to ratemaking has financial consequences. The four
19 U.S. utility cases that Mr. Lyons presents on page 9 of his direct testimony do not provide
20 compelling evidence that the Commission should adopt Constant Dollar Averaging in this

1 rate case or future rate cases. Some of the cases presented by Mr. Lyons are based on the
2 utility's own proposal with no clear indication that the commission accepted the
3 methodology. Some of the cases were settled and not litigated. The only case in which
4 Mr. Lyons participated as a witness was settled and therefore uncontested.⁵ On pages 9
5 and 10 of his direct testimony, Mr. Lyons claims that Constant Dollar Averaging is a
6 recognized practice in the utility industry. In discovery, the Attorney General asked the
7 Company to identify the total number of utilities in the U.S. under state commission
8 jurisdiction that recognize this methodology as an accepted practice for ratemaking. In the
9 response provided, none were identified other than the ones listed in his direct testimony.⁶

10 **Q. ON PAGE 4 OF HIS DIRECT TESTIMONY, MR. LYONS STATES THAT**
11 **CONSTANT DOLLAR AVERAGING ADJUSTMENTS NEED TO BE MADE TO**
12 **HISTORICAL COSTS BECAUSE OVER TIME INFLATION REDUCES THE**
13 **PURCHASING POWER OF GOODS AND SERVICES. DO YOU AGREE?**

14 **A.** No. Goods and services have no purchasing power. They are the items being purchased.
15 The volume and mix of goods and services can change every year depending on the
16 number of storms and the materials that need to be replaced. With the Company installing
17 new technology throughout the grid, the mix of materials being replaced in 2026 is
18 different from what was replaced in 2019. Adjusting historical costs that already reflect
19 the inflation in that year with a general inflation factor that occurred in a subsequent year

⁵ Exhibit AG-3 includes DR AGDE-9.279.

⁶ Id. includes DR AGDE-9.278.

1 has no relevance and is simply an artificial exercise to increase the amount of requested
2 rate increase.

3 If any inflation was experienced in those prior years, it is reflected in the actual amounts
4 paid. It is simply an unsupported fabrication to inflate historical costs to arrive at an
5 adjusted historical base and to then further inflate those costs for future years with
6 projected inflation factors. The Commission should not accept this brazen attempt to
7 inflate historical capital expenditures by improperly increasing the base on which
8 forecasted costs are calculated in either this or future rate cases. Although I agree with
9 using a five-year normalization approach to forecast capital expenditures for future years,
10 it should be done using actual capital expenditures from prior years, not by recasting
11 numbers with additional assumed costs that were not incurred based on prior year inflation
12 adjustments.

13 **Q. DID THE COMMISSION RECENTLY ADDRESS THE ISSUE OF CONSTANT**
14 **DOLLAR AVERAGING?**

15 A. Yes. In Case No. U-21534, the Company made the same Constant Dollar Averaging
16 proposal and inflated the actual historical Emergent Replacement costs with the
17 subsequent year's inflation factors. In its order dated January 23, 2025, the Commission
18 rejected the Company's proposal and stated:

19 ...[T]he Commission agrees with the Attorney General that the application of
20 historical inflation to the emergent replacement capital expenditures is unwarranted.
21 As it did with respect to these O&M costs in the December 1 order, the Commission
22 finds that DTE Electric has not provided a convincing argument that it is necessary to

1 inflate the years within the five-year average.... The Commission is not persuaded
2 and agrees with the Attorney General that if any inflation was experienced by the
3 company during those prior years, that inflation is already reflected in the actual
4 amounts. The Commission observes that its response to the use of constant dollar
5 averaging might be different if the evidence showed that these expenditure categories
6 are both volatile and consistently trending upwards. However, Exhibit A-12, Schedule
7 B5.4, p. 3, shows downward trends for emergent replacements (storm) in 2020 and
8 2022 (2 years out of 5), and for emergent replacements (substation reactive) in 2019,
9 2020, and 2022 (3 years out of 5). The costs reflect variability but no consistent
10 upward trend. The Commission finds that the application of forecasted inflation
11 factors to a simple five-year average for 2023, 2024, and 2025 is appropriate, but the
12 prior historical adjustment that the company uses in the instant case, and which DTE
13 Electric has now expanded to several other capital expenditure categories
14 (Connections and New Load, Relocations, Electric System Equipment, Normal
15 Retirement Units Changeout (NRUC) and Improvement Blankets, and General Plant,
16 Tools & Equipment) is not. See, Exhibit A-12, Schedule B5.4, pp. 4-9. The
17 Commission finds that the historical inflation adjustment for 2018-2022 to all of these
18 proposed expenditures should be removed. (The Commission makes the same finding
19 for active healthcare costs, which is discussed below.)⁷

20 The same circumstances exist in this rate case. The large variability in Emergent
21 Replacement costs continues from year to year as shown on lines 3, 10, and 18 of page 3
22 of Exhibit A-12, Schedule B5.4. The Company has not provided any new compelling
23 evidence that Constant Dollar Averaging should be adopted. Therefore, I recommend that
24 the Commission reaffirm its January 23 order and reject the Company's proposal and
25 related cost adjustments.

26 **Q. WHAT SPECIFIC ADJUSTMENTS DO YOU RECOMMEND FOR THE**
27 **COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE**
28 **EMERGENT CAPITAL PROGRAMS?**

⁷ Case No. U-21534, Commission order dated January 23, 2025 at pages 73-74.

1 A. To calculate an appropriate forecast of capital expenditures for emergent replacement
2 programs for the 2025 and 2026 forecasted periods, I used the five years historical average
3 capital expenditures from 2020 to 2024 and applied the CPI-based future inflation factors.
4 2020 to 2024 represents the most recent five years in contrast with the Company's use of
5 the capital expenditures from 2019 to 2023. On pages 1 and 3 of Exhibit A-12, Schedule
6 B5.4, the Company provided the actual historical capital expenditures for the three
7 categories of costs from 2020 to 2024.⁸ Based on this information, I calculated the
8 forecasted capital expenditures for 2025 using the latest average historical amount spent
9 and adjusting it by the inflation factors of 2.8% for 2025 and 2.4% for 2026.

10 For the Storm category, the average 5-year spending was \$230,569,000. After adjusting
11 for inflation, the forecasted amount is \$237,025,000 for 2025 and \$242,714,000 for 2026.⁹

12 For the Non-Storm category, the average 5-year spending was \$221,871,000. After
13 adjusting for inflation, the forecasted amount is \$228,083,000 for 2025 and \$233,557,000
14 for 2026.¹⁰

⁸ Although column (c) on page 1 of Schedule B5.4 is under the caption of Projected Bridge Period, the Company reported that the 2024 amounts are actual results. The 2020 through 2023 amounts are shown on lines 3, 10, and 18 of page 3 of Schedule B5.4.

⁹ $\$230,569,000 \times 1.028 = 237,025,000 \times 1.024 = \$242,714,000$.

¹⁰ $\$221,871,000 \times 1.028 = 228,083,000 \times 1.024 = \$233,557,000$.

1 For the Substation Reactive category, the average 5-year spending was \$50,946,000. After
2 adjusting for inflation, the forecasted amount is \$52,372,000 for 2025 and \$53,629,000 for
3 2026.¹¹

4 In total, for the three programs, the forecasted costs are \$517,480,000 for 2025 and
5 \$529,900,000 for 2026. In comparison, the Company forecasted \$543,980,000 for 2025
6 and \$575,852,000 for 2026. Therefore, I recommend that the Commission remove the
7 difference of \$48,795,000 for 2025 and \$69,181,000 for 2026 from the Company's
8 forecasted capital expenditures.

9 **2. Customer Connections and New Load Growth**

10 **Q. PLEASE PROVIDE YOUR ASSESSMENT OF FORECASTED CAPITAL**
11 **EXPENDITURES FOR CUSTOMER CONNECTIONS AND LOAD GROWTH**
12 **PROJECTS.**

13 A. On line 9 of page 1 of Exhibit A-12, Schedule B5.4, the Company included actual capital
14 expenditures for Customer Connections and New Load of \$261,524,000 for 2024 and
15 forecasted capital expenditures of \$238,331,000 for 2025 and \$254,834,000 for 2026.
16 Beginning on page 31 of his direct testimony, Company witness Brian Hill discusses how
17 he arrived at the forecasted amounts for 2025 and 2026. There are two issues with the
18 Company's forecasted capital expenditures in this area. First, the Company used the three-
19 year average of costs incurred from 2020 to 2023 but applied retroactive historical inflation

¹¹ \$50,946,000 x 1.028 = 52,372,000 x 1.024 = \$53,629,000.

1 rates to restate the actual historical number for the three years using its proposed constant
2 dollar averaging methodology, before applying the future inflation rates to the adjusted
3 three-year historical average spending. This is the same problem discussed above with
4 Emergent Replacements, where the Company improperly inflates actual historical capital
5 expenditures to create a larger cost base on which to add future inflation adjustments. Mr.
6 Hill also used this faulty approach to forecast capital expenditures for Relocations, Electric
7 System Equipment, NRUC and Improvements Blankets, and General Plant, Tools &
8 Equipment.

9 In his testimony, Mr. Hill states that the three-year average approach he used in this rate
10 case is consistent with the Commission decision in Case No. U-21534. That statement is
11 incorrect. Although the Commission approved the three-year historical average approach
12 I recommended in that rate case, my historical average did not include any restatement of
13 actual capital expenditures with additional historical inflationary adjustments, as Mr. Hill
14 proposes in his testimony and calculations. The Commission should again reject the
15 Company's approach to apply Constant Dollar Averaging, as it did in Case No. U-21534.
16 In this rate case, I will use the same approach to forecast customer connections, new load,
17 relocations, and other capital expenditures, as previously approved by the Commission in
18 Case Nos. U-21297 and U-21534. I will also use the most recent actual historical capital
19 expenditures for the three years 2022 to 2024 to forecast future expenditures.

20 Second, in his testimony Mr. Hill states that the capital expenditures for Customer
21 Connections and New Load include costs for Utility Make Ready (UMR) for upgrading

1 and installing equipment and facilities at customer premises to support Electric Vehicle
2 chargers under the Transportation Electrification Plan. Although line 32 on page 4 of
3 Schedule B5.4 identifies incremental costs for EV infrastructure, no actual costs for prior
4 years were reported. In my testimony below, I will address those capital expenditures in
5 more detail.

6 **Q. WHAT SPECIFIC ADJUSTMENTS DO YOU RECOMMEND TO THE**
7 **COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR CUSTOMER**
8 **CONNECTIONS AND NEW LOAD GROWTH?**

9 A. Using the information provided on page 4 of Schedule B5.4, I will explain how I forecasted
10 each component of the Customer Connections and New Load for 2025 and 2026. For
11 Small Load Growth projects, the 2022-2024 average capital spending was \$18,189,000.
12 Adjusted for the CPI-U forecasted rate of inflation of 2.8% and 2.4%, the forecasted
13 amount for 2025 is \$18,698,000, and for 2026 it is \$19,147,000.

14 For Customer Connections-Net of CIAC, the three-year 2022-2024 average capital
15 expenditures were \$117,193,000. Adjusted for the forecasted inflation rates, the
16 forecasted amount is \$120,474,000 for 2025 and \$123,365 for 2026.

17 For New Business Projects, the three-year average capital expenditure was \$71,595,000.
18 Adjusted for the CPI-U forecasted rate of inflation of 2.8% and 2.4%, the forecasted
19 amount for 2025 is \$73,600,000, and for 2026 it is \$75,366,000.

1 As shown on lines 17 and 30 of page 4 of Schedule B5.4, the Company calculated
2 incremental CIAC of \$13,519,000 for 2025 and \$27,877,000 for 2026, based on the new
3 reimbursable rate. For UMR EV Infrastructure costs, the Company included incremental
4 spending of \$9,200,000 in 2025 and \$18,600,000 in 2026. The incremental spending is
5 based on the premise that more customers will purchase significantly more EVs in 2025
6 and 2026 and will request make-ready installations. As I discuss later in my testimony
7 under the EV Program section, the Company's forecast is overly optimistic and unlikely
8 to reach the level of participation forecasted. Therefore, I removed any incremental
9 spending from the 2025 and 2026 forecasts.

10 In total, for the Customer Connections and New Load programs, I forecasted capital
11 spending of \$199,253,000 for 2025 and \$190,001,000 for 2026. The Company forecasted
12 \$197,508,000 for 2025 and \$198,807,000 for 2026. Therefore, I recommend that the
13 Commission increase the Company's forecasted capital spending for 2025 by \$1,745,000
14 and reduce the 2026 capital expenditures by \$8,806,000.

15 **Q. PLEASE EXPLAIN FURTHER THE ADJUSTMENTS YOU PROPOSE FOR**
16 **ELECTRIC VEHICLES UMR EXPENDITURES FOR 2025 AND 2026.**

17 A. As discussed above, the Company included incremental capital expenditures of \$9.2
18 million for 2025 and \$18.6 million for 2026 for Utility Make Ready customer installations
19 in the Distribution Customer Connections capital expenditures. The incremental UMR
20 capital expenditures are based on the premise that more customers, both residential and

1 non-residential, will increase their purchase of electric vehicles in 2025 and 2026 and will
2 require modifications and additions to their electrical facilities to accommodate Level 2
3 and faster chargers. In response to discovery, the Company provided the calculations
4 showing how it arrived at the incremental UMR capital expenditures.¹² The calculations
5 developed a base amount of UMR expenditures for 2022 through 2024 based on an
6 assumed level of EV charger installations in those years and then forecast higher
7 installation in 2025, 2026, and future years.

8 In discovery, the Attorney General asked the Company to provide the actual cost of UMR
9 installations completed in prior years and compare them to the forecasts made for those
10 years in prior rate cases. In response, the Company stated that it does not specifically
11 identify and track UMR costs for EV charger deployments and could not provide the
12 requested information.¹³ This lack of information makes it impossible to establish whether
13 the historical base capital expenditures for UMR assumed by the Company are accurate
14 and whether any incremental expenditures are necessary.

15 The Company has a track record of overestimating the annual registration and adoption of
16 EVs by its customers. In response to discovery, the Company provided the number of EVs
17 forecasted in this rate case and the prior three rate cases.¹⁴ The data shows that beginning
18 with Case No. U-20836, the Company forecasted 68,325 new EV registrations for 2025

¹² Exhibit AG-19 include DR AGDE-3.66a with attachment.

¹³ Id. Includes DR AGDE-3.66b.

¹⁴ Id. Includes DR AGDE-3.61b with attachment.

1 and 78,963 new registrations for 2026 in its service area. Those forecasts have declined
2 with each subsequent rate case, and in this rate case the Company now forecasts only
3 28,787 new registrations for 2025 and 37,525 new registrations for 2026. The more recent
4 numbers are less than half what was previously forecasted. The following tables provided
5 by the Company tell a more complete story for both new registrations and cumulative EV
6 adoptions.

Annual New Registrations					Cumulative EV Adoption				
	U-21860	U-21534	U-21297	U-20836		U-21860	U-21534	U-21297	U-20836
2025	28,787	34,528	36,934	68,325	2025	98,833	98,167	115,680	219,530
2026	37,525	57,425	46,621	75,963	2026	134,547	153,854	160,563	295,493
2027	50,334	80,321	57,512	83,252	2027	183,905	232,201	216,102	376,771
2028	66,608	95,504	72,210	93,014	2028	248,895	325,134	285,741	467,214
2029	86,334	112,683	90,230	103,725	2029	333,255	435,938	374,093	570,939

7
8 Although the Company continues to show “hockey stick” growth in EV registrations and
9 adoptions for future years in the testimony of Mr. Neal Foley in this rate case,¹⁵ the rate of
10 new vehicle registrations has slowed down significantly in the past year.

11 Beginning in 2024, EV manufacturers realized that electric vehicles are not selling at the
12 pace anticipated as late as 2023, and EVs are stockpiling at dealers’ lots. EV buyers often
13 have been dissatisfied with the actual driving range, particularly during the winter and hot
14 days that quickly drain the car batteries. Reliability of certain vehicles with recalls for
15 software and equipment failures has also created customer dissatisfaction and increased
16 concerns and fear with prospective EV buyers. EV manufactures have cut back production

¹⁵ Neal Foley direct testimony at page 7.

1 of EVs, delayed new models, deferred building new batteries plants, and redirected
2 resources to hybrid vehicles with batteries that self-charge during gasoline-fueled
3 operation.¹⁶

4 The current environment and demand for EVs does not support the increase in spending
5 forecasted by the Company for 2025 and 2026 for UMR. Although some level of EV sales
6 will continue, the increase in UMR installations over the actual base amount in 2024 is not
7 likely to occur. Therefore, I recommend that the incremental forecasts of \$9.2 million for
8 2025 and \$18.6 million be removed from the Company's forecasted capital expenditures.

9 **3. Relocations**

10 **Q. PLEASE PROVIDE YOUR ASSESSMENT OF FORECASTED CAPITAL**
11 **EXPENDITURES FOR LINE RELOCATION PROJECTS.**

12 A. On page 5 of Exhibit A-12, Schedule B5.4, the Company shows actual and forecasted
13 capital expenditures for small relocations, the relocation of facilities for the I-375 project,
14 and other larger relocation projects. For the small relocations, the average annual capital
15 spending from 2022 through 2024 was \$7,716,000. Adjusted for the forecasted inflation
16 rates of 2.8% and 2.4%, the forecasted capital expenditures are \$7,932,000 for 2025 and
17 \$8,122,000 for 2026. The other relocations projects, net of CIAC, averaged annual capital

¹⁶ Information gathered from recent articles in the Wall Street Journal, the Detroit News, and other publications.

1 expenditures of \$21,701,000 for the 2022-2024 period. Adjusted for future inflation rates,
2 the forecasted capital expenditures are \$22,309,000 for 2025 and \$22,844,000 for 2026.

3 **Q. WHAT ADJUSTMENTS DO YOU PROPOSE FOR THE I-375 RELOCATION**
4 **PROJECT?**

5 A. On pages 35 and 36 of his direct testimony, Mr. Hill briefly discusses the I-375 relocation
6 project, with a total forecasted cost exceeding \$42 million between 2023 and 2026. Mr.
7 Hills states that the Company was notified by the Michigan Department of Transportation
8 (MDOT) that the state plans to restructure the I-375 below-ground freeway into a grade
9 level boulevard, which will require relocation of electrical lines by the end of 2026. He
10 also stated that work began in 2023 with capital expenditures of \$6.3 million in that year
11 and an additional \$6.3 million in 2024. The Company forecasted capital expenditures of
12 \$15 million for 2025 and the same amount for 2026.

13 In discovery, the Attorney General asked the Company to provide the timeline of the
14 project and identify the total cost of the project from inception to completion. The
15 discovery also requested that the Company provide the latest project schedule from MDOT
16 showing the project start and completion dates. In response, the Company reported that
17 the total cost of the relocation project is approximately \$78 million and provided revised
18 forecasted capital expenditures of \$8.4 million for 2025 and \$12 million for 2026. These
19 amounts represent a decrease of \$6.6 million and \$3.0 Million from the amounts included
20 in Exhibit A-12, Schedule B5.4, respectively and likely reflect a delay in the timing of the

1 project. The Company provided a project schedule that shows early design and
2 construction in mid-to-late 2025 with work continuing through June 2029. The Company
3 also provided a project schedule from MDOT that shows a similar timeline.¹⁷

4 In a recent development, on August 11, 2025, the Detroit News reported that the Whitmer
5 administration was re-evaluating the entire I-375 project in light of significant cost
6 overruns and recent community pushback about the project.¹⁸ As a result of this recent
7 development, it is likely that the Company's side of the project will be put on hold and the
8 forecasted capital expenditures will not occur. Therefore, I recommend that the entire \$15
9 million of forecasted capital spending in 2025 and the same amount for 2026 be removed
10 from this rate case.

11 **Q. WHAT IS THE TOTAL AMOUNT OF CAPITAL EXPENDITURES FOR**
12 **RELOCATIONS THAT YOU PROPOSE FOR 2025 AND 2026?**

13 A. The total capital expenditures forecasted for 2025 are \$30,241,000 and for 2026 are
14 \$30,966,000. The Company forecasted \$42,491,000 for 2025 and \$42,751,000 for 2026,
15 using the three-year average capital expenditures from 2021 to 2023 and adjusted for dollar
16 cost averaging. The difference is \$12,250,000 for 2025 and \$11,785,000 for 2026. I
17 recommend that the Commission remove these amounts from the Company's forecasted
18 capital expenditures.

¹⁷ Exhibit AG-4 includes DRs AGDE-4.142a and 4.142e with attachment.

¹⁸ Id. includes a copy of the Detroit New article.

1 **4. Electric System Equipment & Meters**

2 **Q. PLEASE ASSESS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES**
3 **FOR ELECTRIC SYSTEM EQUIPMENT.**

4 A. On page 5 of Exhibit A-12, Schedule B5.4, the Company shows actual capital expenditures
5 for Electric System Equipment of \$20,680,000 for 2024 and forecasted expenditures of
6 \$11,549,000 for 2025 and \$11,908,000 for 2026. According to Mr. Hill's direct testimony,
7 the Company inflated the actual historical capital expenditures with its constant dollar
8 averaging methodology to arrive at its forecasted capital expenditures for the forecasted
9 years. As discussed above, this approach is inappropriate as it unfairly increases costs to
10 customers and should be rejected by the Commission.

11 In line with previously established practices approved by the Commission, I calculated the
12 average capital expenditures for Electric System Equipment for the three years 2022 to
13 2024 based on actual expenditures. The average annual amount is \$12,567,000. After
14 adjusting this amount for future inflation rates, I calculated the 2025 forecasted capital
15 expenditures at \$12,919,000 and the 2026 expenditures at \$13,230,000.¹⁹ These amounts
16 are above the Company's forecasts by \$1,370,000 for 2025 and \$1,322,000 for 2026. I
17 recommend that the Commission add these amounts to the Company's forecasted capital
18 expenditures.

¹⁹ Three-year average amount x 1.028 for 2025 x 1.024 for 2026.

1 For Meters, the Company shows actual capital expenditures of \$26,551,000 for 2024 and
2 forecasted expenditures of \$16,735,000 for 2025 and \$17,254,000 for 2026. The three-
3 year average capital expenditures from 2022 to 2024 were \$19,179,000. After adjusting
4 this amount for future inflation rates, the forecasted capital expenditures for 2025 are
5 \$19,716,000 and \$20,189,000 for 2026. These amounts are higher than the Company's
6 forecasted capital expenditures by \$2,981,000 for 2025 and \$2,935,000 for 2026. I
7 recommend that the Commission add these amounts to the Company's forecasted capital
8 expenditures.

9 **5. NRUC & Improvement Blankets**

10 **Q. PLEASE ASSESS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES**
11 **FOR NRUC AND IMPROVEMENT BLANKETS.**

12 A. On page 6 of Exhibit A-12, Schedule B5.4, the Company shows actual capital expenditures
13 for NRUC and Improvement Blankets of \$23,967,000 for 2024 and forecasted
14 expenditures of \$27,511,000 for 2025 and \$28,364,000 for 2026. These forecasted capital
15 expenditures also reflect the retroactive dollar cost averaging adjustments and should be
16 rejected by the Commission.

17 In line with previously established practices approved by the Commission, I calculated the
18 average capital expenditures for this program for the three years 2022 to 2024 based on
19 actual expenditures. The average annual amount is \$25,520,000. After adjusting this
20 amount for future inflation rates, I calculated the 2025 forecasted capital expenditures at

1 \$26,235,000 and the 2026 expenditures at \$26,865,000.²⁰ These amounts are lower than
2 the Company's forecasts by \$1,276,000 for 2025 and \$1,499,000 for 2026. I recommend
3 that the Commission remove these amounts from the Company's forecasted capital
4 expenditures.

5 **6. General Plant, Tools, Equipment & Miscellaneous Items**

6 **Q. PLEASE ASSESS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES**
7 **FOR GENERAL PLANT, TOOLS, EQUIPMENT & MISCELLANEOUS ITEMS.**

8 A. On page 6 of Exhibit A-12, Schedule B5.4, the Company shows actual capital expenditures
9 for General Plant, Tools, Equipment & Miscellaneous Items of \$5,633,000 for 2024,
10 forecasted capital expenditures of \$7,155,000 for 2025, and \$7,377,000 for 2026.
11 According to Mr. Hill's direct testimony, the Company applied constant dollar cost
12 averaging to the actual historical capital expenditures to arrive at its forecasted capital
13 expenditures for the forecasted years. As discussed above, this approach is inappropriate,
14 unfairly increases costs to customers, and should be rejected by the Commission.

15 In line with previously established practices approved by the Commission, I calculated the
16 average capital expenditures for this capital program category for the three years 2022 to
17 2024 based on actual expenditures.²¹ The Company spent \$6,360,000 on average during
18 2022-2024. After adjusting this amount for inflation, I calculated the 2025 forecasted

²⁰ Three-year average amount x 1.028 for 2025 x 1.024 for 2026.

²¹ Exhibit AG-5 includes DR AGDE-3.95a with attachment.

1 capital expenditures at \$6,538,000 and 2026 expenditures at \$6,695,000.²² These amounts
2 are below the Company's forecasts by \$617,000 for 2025 and \$682,000 for 2026. I
3 recommend that the Commission remove these amounts from the Company's forecasted
4 capital expenditures.

5 **7. Substation Risk Projects**

6 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES**
7 **FOR THE SUBSTATION RISK PROJECTS.**

8 A. Beginning on page 84 of his direct testimony, Company witness Joseph Robinson
9 discusses the Substation Risk Projects. He identifies 11 projects with failed or failing
10 equipment with some flood-related substations. The capital expenditures related to these
11 projects are shown on lines 19 to 29 of page 10 of Exhibit A-12, Schedule B5.4. Of those
12 projects, five have capital expenditures forecasted for 2025 and 2026. Those projects are
13 the Apache, Chestnut, Drexel, Hood, and McGraw substations. The total capital
14 expenditures forecasted by the Company for those projects are \$27,104,000 for 2025 and
15 \$5,625,000 for 2026. Most of the projects have had worked performed in prior years, as
16 evidenced by the capital expenditures in 2023 and 2024 shown on page 10 of Schedule
17 B5.4.

18 In discovery, the Attorney General asked the Company to provide the number of failures
19 and customers impacted by the substation problems during the six years from 2019 to

²² Three-year average amount x 1.028 for 2025 x 1.024 for 2025.

1 2024. The Attorney General also asked that the Company provide information on the
2 expected reduction in substation reliability measured through the SAIDI, SAIFI, and
3 CAIDI indices and the cost/benefit analysis showing that the capital investments would
4 provide a net economic benefit to customers.

5 The information provided by the Company regarding failures and customers impacted over
6 the past three years, including the historical reliability data, shows an erratic pattern with
7 power outages, durations, and frequency changing wildly from year to year with no
8 specific trend of increased deterioration or improvement, despite some work remediation
9 and spending already done at some of the substations. Regarding the request to provide
10 the expected reduction in reliability indices resulting from the planned capital
11 expenditures, the Company stated in its response that it had not performed this analysis.
12 The Company also reported that it had not performed a formal cost/benefit analysis for the
13 Substation Risk Projects.²³

14 **Q. WHAT IS YOUR ASSESSMENT OF THE JUSTIFICATION OF THE CAPITAL**
15 **SPENDING PROPOSED BY THE COMPANY FOR THE SUBSTATION RISK**
16 **PROJECTS?**

17 A. Despite the lengthy discussion and description of the projects in Mr. Robinson's direct
18 testimony and related exhibits, the Company has not adequately justified that the capital
19 spending will result in a significant improvement in reducing power outages and service

²³ Exhibit AG-5 includes DR AGDE-6.173a-c and f.

1 reliability. In fact, as discussed above, the Company cannot quantify the improvement
2 expected in the reliability indices or that the capital investment will provide a net financial
3 benefit to customers.

4 Therefore, I recommend that the Commission disallow the forecasted capital expenditures
5 of \$27,104,000 for 2025 and also the \$5,625,000 forecasted for 2026.

6 **8. Mobile Fleet Program**

7 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES**
8 **FOR THE MOBILE FLEET PROGRAM.**

9 A. Beginning on page 108 of his direct testimony, Mr. Robinson discusses the Mobile Fleet
10 Program and its components. The program mainly consists of portable generators,
11 portable switchgear, substations, poles, energy storage trailers, and other portable
12 equipment. The purpose of the mobile fleet is to provide temporary power restoration
13 during outages until full repairs are completed. Line 30 on page 10 of Exhibit A-12,
14 Schedule B5.4 shows the recent historical and forecasted capital expenditures. The
15 Company spent \$3.7 million on equipment for the program in 2023 and \$4.4 million in
16 2024. For 2025 and 2026, the Company forecasted capital expenditures of \$1.5 million
17 and \$7.0 million, respectively.

18 In discovery, the Attorney General asked the Company to provide a detailed list of the
19 equipment purchased or to be purchased under the program for each year 2019 to 2026

1 and information on the utilization of the mobile equipment. The Attorney General also
2 asked the Company to provide a cost/benefit analysis for equipment purchased at a cost of
3 \$3 million or greater. The list of equipment provided by the Company shows three items
4 to be purchased in 2025, consisting of control systems, portable generators, and a portable
5 ISO trailer, totaling to \$1.5 million. The 2026 purchases entail four items with three of
6 those items ranging in cost for \$300,000 to \$700,000. The fourth item is a portable
7 substation at a forecasted cost of \$5.5 million.²⁴

8 In response to the request for equipment utilization data, the Company stated that it does
9 not track utilization of the mobile equipment and could only provide one example of the
10 deployment of a mobile asset to reduce the power outage of 1,100 customers. Regarding
11 the request for a cost/benefit analysis for the purchase of the \$5.5 million portable
12 substation, the Company reported that no such analysis was performed.²⁵

13 The lack of pertinent information on utilization of the mobile equipment and no
14 cost/benefit analysis for the major equipment purchases make it difficult to justify the
15 purchase of large items, such as the mobile substation at a cost of \$5.5 million. Although
16 some of this equipment may reduce the length of an outage and expedite repairs, there is
17 insufficient evidence to justify the cost of major equipment purchases. Therefore, I

²⁴ Exhibit AG-6 includes DR AGDE-6.174a with attachment.

²⁵ Id. Includes DR AGDE-6.174b and c.

1 recommend that the Commission remove the \$5.5 million from the Company's forecasted
2 capital expenditures for the projected test year.

3 **B. Power Generation- Fossil Fuel Plant Projects**

4 **Q. PLEASE EXPLAIN WHAT ADJUSTMENTS YOU PROPOSE TO THE**
5 **COMPANY'S PROJECTED CAPITAL EXPENDITURES FOR POWER**
6 **GENERATION FACILITIES.**

7 A. On page 2 of Exhibit A-12, Schedule B5.1, the Company shows Non-Routine actual
8 capital expenditures in the Fossil Fuel Power Generation area of \$299.0 million for 2024
9 and forecasted expenditures of \$316.7 million for 2025 and \$87.5 million for 2026.
10 Additionally, for 2025 and 2026, the Company forecasted \$25.6 million and \$107.8
11 million, respectively for the Monroe Power Plant to be charged to the regulatory asset
12 established for future retirement of the plant. The Company also forecasted capital
13 expenditures for Routine Projects of \$241.0 million for 2025 and \$324.1 million in 2026.

14 In my review of the proposed expenditures, I identified six projects or areas where
15 adjustments to capital spending are warranted, which I discuss below.

16 **1. Monroe Fly Ash Basin Closure**

17 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES**
18 **FOR THE MONROE FLY ASH BASIN CLOSURE PROJECT.**

1 A. Beginning at the bottom of page 36 of her direct testimony, Company witness Margaret
2 Guillaumin discusses the need to close the Monroe Fly Ash Basin to comply with
3 environmental regulations and also in preparation for the pending retirement of the plant
4 in two phases in 2028 and 2032. The Company began work on this project in 2021 with
5 initial studies and engineering, and other preparations for closure of the basin. The actual
6 amount spent from 2021 to 2024 was \$9.2 million.²⁶ On line 46 of page 2 of Schedule
7 B5.1, the Company included forecasted capital expenditures of \$13,899,000 for 2025 and
8 \$107,759,000 for 2026. These amounts would be charged to a regulatory asset account
9 instead of the plant account based on the settlement agreement in the Company's last
10 Integrated Resource Plan (IRP), which contemplates eventual retirement of the coal-fired
11 plant.

12 In discovery, the Attorney General asked the Company to provide additional details on the
13 capital spending on the projects for each year 2023 to 2026 and a copy of the plan for
14 closure of the basin. In response, the Company identified certain specific costs for each
15 year with what appear to be "ballpark" cost estimates for Labor (\$102 million), Dewatering
16 (\$58 million), and Earth Moving (\$43.6 million). The Company also provided an October
17 2023 version of the basin closure plan that shows wide ranges of dates for major tasks to
18 be completed spanning from 2024 to 2028 and completion in the second quarter of 2029.
19 The Company also noted that the plan is being updated. In response to Staff's DR STDE-
20 5.1b, the Company reported that approval of the capital expenditures for the project had

²⁶ DR AGDE-3.108a.

1 not yet been obtained from the Company's Board of Directors and was expected in the
2 Fall of 2025. In response to an additional request from the Attorney General, the Company
3 stated that a contractor to work on the project has not yet been selected and the selection
4 process is still in progress.²⁷

5 **Q. WHAT IS YOUR ASSESSMENT OF THE STATUS OF THE MONROE FLY ASH**
6 **BASIN CLOSURE PROJECT AND THE INCLUSION OF THE PROPOSED**
7 **CAPITAL EXPENDITURES IN THE REGULATORY ASSET?**

8 A. From the information provided in discovery, it is apparent that the project's
9 implementation plan is still being finalized, a contractor or contractors to perform the work
10 have not yet been selected, and the Company's Board of Directors has not yet fully
11 approved the capital spending for the project. Although the Company may do some work
12 on the project in 2025 and may continue that work into 2026, it is premature to include
13 100% of the 2026 capital expenditures in the regulatory asset account and in rate base in
14 this rate case. Given the status of the project, it is unlikely that the Company will spend
15 the entire forecasted \$107,809,000 in 2026.

16 Therefore, as a more than reasonable compromise given the remaining amount of
17 uncertainty, I recommend that the Commission remove at least half of the \$107,809,000

²⁷ Exhibit AG-7 includes DR AGDE-108a and with attachment, AGDE-3.88a-b, c with attachment, and STDE-5.1b.

1 or \$53,880,000 of the capital expenditures for 2026 from the regulatory asset account.
2 This disallowance is included as a working capital adjustment.

3 **2. Trenton Channel BESS**

4 **Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED CAPITAL**
5 **EXPENDITURES FOR THE TRENTON CHANNEL BESS PROJECT.**

6 A. On page 50 of her direct testimony, Ms. Guillaumin briefly discusses the Trenton Channel
7 BESS project and the related capital spending from 2023 to 2026. Line 38 on page 2 of
8 Exhibit A-12, Schedule B5.1, shows the historical capital expenditures and the forecasted
9 spending of \$260,089,000 for 2025 and \$41,350,000 for 2026.

10 In discovery, the Attorney General asked the Company to provide the actual and planned
11 capital expenditures for the project by year from inception to completion. In response, the
12 Company reported that the total spending forecasted in the rate case filing had changed.
13 Where previously the total cost of the project was forecasted at \$409.7 million, the revised
14 cost is now \$378.5 million, or \$31.2 million less. Specifically, for 2025 the forecasted
15 capital expenditures are now \$74,311,000, or \$185,778,000 lower than the \$260,089,000
16 previously forecasted. For 2026, the new forecast is \$195,175,000 instead of \$41,350,000,
17 or \$153,825,000 higher.²⁸

²⁸ Exhibit AG-8 includes DR AGDE-3.94a.

1 In response to Staff discovery, the Company reported that the original battery supplier filed
2 for Chapter 11 bankruptcy and the Company entered into a replacement contract with a
3 new battery supplier. In response to additional discovery, the Company reported that while
4 it had finalized the BESS equipment contract, it has not yet finalized three supporting
5 contracts for engineering and construction, owner engineering services, and test energy.
6 The total amount of the three contracts is \$33,480,000.²⁹ This amount is still uncertain
7 and premature to include in rate base in this rate case. Given the major changes that have
8 occurred with this project with the involvement of a new supplier, the multiple parties
9 involved, and the still experimental nature of the technology, it is likely that further delays
10 in the implementation and the timing of capital expenditures will occur. I recommend that
11 the \$33,480,000 be removed from the 2026 forecasted capital expenditures.

12 Therefore, the net changes to the forecasted capital spending for the Trenton Channel
13 project are a decrease to the 2025 capital expenditures of \$185,778,000 and an increase of
14 \$120,345,000 to the 2026 capital expenditures (\$153,825,000 - \$33,480,000). I
15 recommend that the Commission adopt these changes to the Company's forecasted capital
16 expenditures.

17 **3. Trenton Channel Seawall & Greenway**

²⁹ Exhibit AG-9 CONF includes DR STDE-13.1b CONF and 13.2a-d CONF.

1 **Q. PLEASE DISCUSS THE FINAL COST OF THE SLOCUM BESS PROJECT.**

2 A. On page 49 of her direct testimony, Ms. Guillaumin briefly discusses the Slocum BESS
3 project, the final project closeout costs, and the start of operations in February 2025. In
4 discovery, the Attorney General asked the Company to provide a comparison of the total
5 cost of the project, and by major cost component, between the final cost and the initial cost
6 estimate. In response, the Company provided a table that shows the total actual project
7 cost was \$10.4 million higher than the initial cost estimate. Of the \$10.4 million higher
8 cost, \$6 million is attributed to higher prices of Lithium used in the batteries, \$2.7 million
9 to higher labor costs, \$0.9 million additional engineering and design, and \$1.4 million in
10 higher overheads. In other words, cost overruns occurred across the board except for
11 electrical infrastructure, which came in a bit below the initial forecast.³¹

12 **Q. WHAT IS YOUR ASSESSMENT OF THE SLOCUM BESS PROJECT**
13 **OVERRUN?**

14 A. Although, based on the explanations offered in the discovery response, the Company
15 claims that the various cost increases were beyond its control, the fact remains that the
16 project was initially approved based on a forecasted cost of \$34.7 million. The cost
17 overrun is not a minor variance to the initial estimate, but is 30% higher. The Company
18 has some responsibility to take appropriate actions to mitigate cost increases or end the
19 project if it becomes clear the project is running into significant cost increases. Although

³¹ Exhibit AG-11 includes DR AGDE-3.93a.

1 the Commission approved portions of the project costs, the Company did not disclose that
2 costs were escalating significantly or demonstrate that it was taking corrective action.
3 Additionally, the Company never performed a cost/benefit analysis, claiming only that the
4 project provided several unquantified benefits. To avoid similar recurrences of project
5 cost creep and cost overruns, the Company needs to be held accountable for its decisions
6 and not simply pass on cost increases to customers through higher customer rates.

7 Therefore, I recommend that the Commission disallow 50% of the cost overruns of \$10.1
8 million, or \$5.0 million, with \$4,345,000 removed from 2024 and \$655,000 removed from
9 2025. The 50% disallowance fairly splits the impact of the cost overruns with customers
10 and provides a clear line of cost accountability for the Company.

11 **5. BWEC Kiewit Final Payment**

12 **Q. PLEASE DISCUSS THE FINAL PAYMENT THAT THE COMPANY PLANS TO**
13 **MAKE TO KIEWIT FOR COMPLETION OF BLUE WATER ENERGY CENTER**
14 **(BWEC) PROJECT.**

15 A. On page 45 of her direct testimony, Ms. Guillaumin briefly mentions a \$6 million payment
16 to the Kiewit construction company for having reached the final milestone. Kiewit was
17 the main contractor in the construction of the BWEC, which began commercial operation
18 in June 2022. In discovery, the Attorney General asked the Company to explain what
19 milestone was achieved and why additional payments were being made to Kiewit given
20 the various construction quality problems uncovered after completion of the plant. The

1 response states that the \$6 million payment is the final payment and it is contractually
2 required when the project reaches completion. The response points to a punch list of items
3 that were completed, but does not address the work quality problems.³²

4 The construction problems at BWEC have been a matter of litigation in recent Power
5 Supply Cost Recovery reconciliation cases. In Case Nos. U-21260 and U-21051, I filed
6 direct testimony on behalf of the Attorney General recommending more than \$22 million
7 in disallowances of replacement power costs incurred because of plant outages to replace
8 faulty equipment and remediate construction problems. I incorporate that testimony in this
9 case by reference.

10 In this rate case, the Company proposed more than \$84 million in capital expenditures to
11 repair, upgrade and overhaul transformers, water pumps, heaters and controls, steam
12 turbine valves, and turbine hot gas paths.³³ These expenditures are coming three to four
13 years after the plant went into commercial operation. It is apparent that the Company is
14 not holding Kiewit accountable for poor performance and is rewarding the contractor with
15 additional payments at the expense of customers who are asked to foot the bill. The
16 Company has not adequately addressed in this case the construction deficiencies and the
17 need to undertake additional capital expenditures.

³² DR AGDE-3.91a-b.

³³ Exhibit A-12, Schedule B5.1, pages 5-7, line items labeled Blue Water Energy Center.

1 Therefore, I recommend that the Commission disallow recovery of the \$6 million payment
2 to Kiewit included in the 2025 forecasted capital expenditures. Furthermore, I recommend
3 that the Commission direct the Company to fully document and justify in the next rate case
4 why there is a need to undertake large capital expenditures in 2025 and 2026 for a plant
5 that went operational less than four years ago.

6 **6. Forecast of Routine Projects**

7 **Q. PLEASE DISCUSS THE COMPANY'S FORECASTED CAPITAL**
8 **EXPENDITURES FOR ROUTINE POWER GENERATION PROJECTS FOR**
9 **2025 AND 2026.**

10 A. On page 3 of Exhibit A-12, Schedule B5.1, the Company shows forecasted capital
11 expenditures of \$241.0 million for 2025 and \$324.1 million for 2026. The detailed list of
12 projects is provided on pages 6 and 7 of Schedule B5.1. In discovery, the Attorney General
13 asked the Company to provide the current phase of development and the completion or in
14 service date for each project of \$3.0 million or greater forecast for 2025 and 2026.
15 Although not fully compliant with the request, the information provided in response to the
16 request shows that many of the projects for 2025 have been completed and the cost of
17 projects still in progress was determined by detailed and firm price estimates.³⁴

18 However, most of the projects of \$3.0 million or greater for 2026 have been forecasted by
19 expected bid estimates or the Company's own budget estimates. Although this

³⁴ Exhibit AG-12 includes DR AGDE-3.110a.

1 information provides some insight into the Company's cost forecasting practices, it does
2 not fully comply with the request for the current phase of project development. Regarding
3 the projects labeled as Bid Estimate, there are 20 such projects. On the assumption that
4 sufficient design work has been completed on these projects, I do not recommend a cost
5 disallowance at this time.

6 However, it is apparent that projects with costs developed through budget estimates are
7 still very preliminary and in the early phase of development with no project design yet
8 completed. There are five such projects in 2026 with total capital expenditures of
9 \$63,703,000. These projects are premature to include in rate base. I recommend that the
10 Commission remove the \$63,703,000 from the Company's forecasted capital
11 expenditures.

12 **C. Nuclear Generation- Capital Projects**

13 **Q. PLEASE EXPLAIN WHAT ADJUSTMENTS YOU PROPOSE TO THE**
14 **COMPANY'S FORECASTED CAPITAL EXPENDITURES IN THE NUCLEAR**
15 **POWER GENERATION AREA.**

16 A. On page 1 of Exhibit A-12, Schedule B5.3, the Company shows actual capital expenditures
17 in the Nuclear Generation area, excluding nuclear fuel, of \$187.7 million for 2024 and
18 forecasted amounts of \$76.3 million for 2025 and \$187.1 million for 2026. The capital

1 expenditures include both routine and non-routine projects. In my review of the proposed
2 expenditures, I identified several adjustments, which I discuss below.

3 **1. Security System Computer**

4 **Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU**
5 **PROPOSE FOR THE SECURITY SYSTEM COMPUTER PROJECT.**

6 A. On line 2 of page 2 of Exhibit A-12, Schedule B5.3, the Company shows actual capital
7 expenditures for the security computer system of \$17,011,000 for 2023 and \$13,441,000
8 for 2024. For 2025, the Company shows forecasted capital expenditures of \$2,627,000
9 with no further expenditures in 2026. Company witness Jeffrey Davis discusses the project
10 beginning on page 23 of his direct testimony.

11 This project was the subject of litigation in Case No. U-21534. In that case I showed that
12 the project had mushroomed into a very costly project with significant cost overruns. In
13 its January 23, 2025 (page 62) order in Case No. U-21534, the Commission approved the
14 Company's forecasted capital expenditures through the projected test year. The total
15 cumulative amount approved by the Commission in Case No. U-21534 was \$39.2 million.
16 In response to discovery in the current case, the Company reported that the project cost
17 has now increased to \$41.6 million, or \$2.4 million above the Commission's past
18 approval.³⁵

³⁵ Exhibit AG-13 includes DR AGDE-1.24a.

1 The \$2.4 million is in excess of the Commission's prior approved amount. Therefore, I
2 recommend that the Commission disallow this amount included in the 2025 bridge period.
3 Approval of this disallowance by the Commission will provide a clear signal that repeating
4 cost overruns will not be tolerated and the Company will be held accountable to control
5 costs.

6 **2. Plant Radio System**

7 **Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU**
8 **PROPOSE FOR THE PLANT RADIO SYSTEM REPLACEMENT PROJECT.**

9 A. On line 3 of page 2 of Exhibit A-12, Schedule B5.3, the Company shows actual capital
10 expenditures for the radio system replacement project of \$6,049,000 for 2023 and
11 \$3,807,000 for 2024. Forecasted capital expenditures for 2025 are \$1,311,000 with no
12 further expenditures for 2026. This project was also the subject of litigation in Case No.
13 U-21534 and the Commission approved the Company's forecasted costs through the end
14 of that case's projected test year in the amount of \$19.4 million.

15 In response to discovery in this rate case, the Company disclosed that the project total cost
16 has again increased to \$20.7 million.³⁶ The additional cost of \$1.3 million is above the
17 project total cost approved by the Commission in the last rate case. For the same reasons

³⁶ Id. Includes DR AGDE-1.25a.

1 stated for the Security System Computer, I recommend that the Commission remove the
2 \$1.3 million from the Company's forecasted 2025 capital expenditures.

3 **3. Underground Water Piping Replacement**

4 **Q. PLEASE DISCUSS YOUR PROPOSED DISALLOWANCE OF COST**
5 **OVERRUNS FOR THE UNDERGROUND WATER PIPING REPLACEMENT**
6 **PROJECT.**

7 A. To assess the reasonableness and prudence of historical capital expenditures of projects in
8 size of \$10 million and greater completed in 2023 and 2024, the Attorney General asked
9 the Company to provide a comparison of the project final total cost to the initial cost
10 estimate and explain any variance of 10% or greater. In response, the Company identified
11 the Underground Water Piping Replacement project, which was initially estimated to cost
12 \$44.3 million and the final cost more than doubled to \$91.3 million.³⁷ The project costs
13 for 2023, 2024, and 2025 are shown on line 4 of page 4 of Schedule B5.3.

14 The explanation provided by the Company is that the project was re-evaluated after
15 completion of Refueling Outage 21 in the spring of 2022 and the project cost estimate
16 increased to \$103 million. Although the actual cost came in below the second estimate, it
17 was still more than double the initial estimate. The appropriation request provided with
18 the discovery response shows that among the main contributors to the higher cost, the
19 Company identified \$12.6 million to moving the project from "MEP to Fermi Capital." It

³⁷ Exhibit AG-14 CONF includes DR AGDE-1.32a and 1.32b Conf with attachment.

1 is not clear what this shift entailed or why it would increase the project cost by \$12.6
2 million. Due to the revised high cost of the project and the lack of justification for the
3 \$12.6 million, I recommend that the Commission remove this amount from the 2024 actual
4 capital expenditures.

5 **4. Routine Nuclear Capital Projects**

6 **Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU**
7 **PROPOSE FOR VARIOUS ROUTINE NUCLEAR PLANT PROJECTS.**

8 A. On pages 2 and 3 of Exhibit A-12, Schedule B5.3, the Company listed several Routine
9 projects with related total forecasted capital expenditures of \$29.2 million for 2025 and
10 \$72.7 million in 2026. For projects in size of \$3 million and greater, the Attorney General
11 requested the Company to provide additional information for each project, including the
12 project current phase of development, the next phase with timelines and related dollars to
13 be spent in each phase. Despite the Company's protests that the Nuclear Generation
14 operation does not use project management phases, does not keep track of costs by project
15 phase, and otherwise does not conform to generally accepted project management
16 protocols, it provided some basic information about projects completed, projects that are
17 in progress, and projects that have not been started.³⁸

18 On the list provided by the Company, there are three projects that have not been started
19 with total capital expenditures of \$24,331,000 forecasted for 2026. The three projects are

³⁸ Exhibit AG-15 includes DR AGDE-1.31a with attachment.

1 shown on lines 52, 59, and 61 of page 3 of Schedule B5.3. These projects are still in the
2 very early stage of development and premature to include in rate base in this rate case.
3 Therefore, I recommend that the Commission remove the \$24,331,000 from the
4 Company's forecasted 2026 capital expenditures.

5 **5. Non-Routine Nuclear Capital Projects**

6 **Q. PLEASE DISCUSS THE CAPITAL EXPENDITURE ADJUSTMENTS THAT YOU**
7 **PROPOSE FOR VARIOUS NON-ROUTINE NUCLEAR PLANT PROJECTS.**

8 A. On page 4 of Exhibit A-12, Schedule B5.3, the Company listed 26 Non-Routine projects
9 with related forecasted capital expenditures of \$49.1 million in 2025 and \$114.5 million
10 in 2026. For projects in size of \$3 million and greater, the Attorney General requested the
11 Company to provide additional information for each project, including the project current
12 phase of development, the next phase with timelines, and related dollars to be spent in each
13 phase. Like the routine projects discussed above, the Company's protested that the
14 Nuclear Generation operation does not use project management phases, does not keep
15 track of costs by project phase, and does not otherwise conform to generally accepted
16 project management protocols. However, it provided some basic information about
17 projects completed, projects that are in progress, and projects that have not been started.³⁹

18 On the list provided by the Company, there are three projects that have not been started
19 yet with total capital expenditures of \$8,742,000 forecasted for 2025 and \$28,298,000 for

³⁹ Id. includes DR AGDE-1.33a with attachment.

1 2026. The three projects are shown on lines 15, 22, and 25 of page 4 of Schedule B5.3.
2 These projects are still in the very early stage of development and premature to include in
3 rate base in this rate case. Therefore, I recommend that the Commission remove the
4 \$8,742,000 and \$28,298,000 from the Company's forecasted capital expenditures for 2025
5 and 2026, respectively.

6 **D. Engineering and Support Functions**

7 **Q. PLEASE DISCUSS THE IMPACT ON 2025 AND 2026 CAPITAL**
8 **EXPENDITURES OF THE COMPANY'S PROPOSAL TO AUGMENT**
9 **EMPLOYEES IN THE ENGINEERING AND SUPPORT FUNCTIONS.**

10 A. On pages 13 through 15 of his direct testimony, Company witness Allen Kryscynski
11 discusses the Company's plans to significantly increase the number of engineers and
12 support personnel to implement the Company's ever increasing capital spending programs.
13 Mr. Kryscynski identified an incremental O&M expense of \$8.3 million for the 2026
14 projected test year.

15 In discovery, the Attorney General asked the Company to provide the number of
16 employees and contractors to be added by function in 2025 and 2026 along with the
17 number of employees already in place in those same functions or areas in each of the
18 previous 5 years. The Attorney General also asked the Company to identify the new
19 projects and programs that the new employees would be working on in 2025 and 2026 and
20 show how the \$8.3 million expense for 2026 was determined.

1 In response the Company identified 157 new hires in 2025 and an additional 52 hires in
2 2026 for a total of 209 new forecasted hires over the two years along with the positions
3 that the new employees would occupy. However, the Company could not provide an
4 historical perspective of how many employees currently occupy those positions or
5 occupied them in the past five years. The Company also could not identify what new
6 projects or programs the new employees would work on.⁴⁰

7 The calculation of the incremental \$8.3 million of O&M expense for 2026 shows that a
8 larger amount of \$22,517,599 is included in capital expenditures for 2025 and 2026. Based
9 on the number of employees to be hired each year, I calculated the portion of the total cost
10 assigned to 2025 capital expenditures to be \$16,888,000 with the remaining amount of
11 \$5,630,000 assigned to 2026 capital expenditures.

12 The Company has not adequately justified that the addition of 209 employees between
13 2025 and 2026 is warranted and cannot identify which programs or projects they will be
14 working on. Due to the lack of supporting evidence, I recommend that the Commission
15 remove the \$16,888,000 and \$5,630,000 from the Company's forecasted capital
16 expenditures for 2025 and 2026, respectively, and also remove the \$8.3 million of
17 incremental O&M expense from the projected test year.

⁴⁰ Exhibit AG-16 CONF includes DR AGDE-5.161a-c with Confidential attachment.

1 **E. Corporate Capital Projects**

2 **Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL**
3 **EXPENDITURES FOR CORPORATE FACILITIES AND SERVICE CENTERS**
4 **RENOVATION PROJECTS.**

5 A. In Exhibit A-12, Schedule B5.8, the Company shows capital expenditures for corporate
6 functions of \$113.6 million for 2024, \$79.5 million for 2025, and \$128.1 million for 2026.
7 Company witness Theresa Uzenski discusses the corporate capital expenditures in her
8 revised direct testimony. Page 2 of Schedule B5.8 provides a list of major facilities
9 projects with the related capital expenditures for 2023 through 2026. In my testimony
10 below, I propose adjustments to five facility projects and the transportation fleet program.

11 WCB Building Façade - On page 62 of her revised direct testimony, Ms. Uzenski states
12 that \$3.3 million in capital expenditures are needed to repair the façade of the Walter
13 Chisler Building (WCB) over multiple years. The Company forecasted \$1.0 million of
14 capital expenditures in 2025 and \$2,254,000 in 2026. In response to discovery, the
15 Company disclosed that a 5-year inspection by the City of Detroit identified several
16 deficiencies with the façade of the building that need to be remediated.⁴¹ The cost of these
17 repairs should not be capitalized but instead expensed in the year they occur. They are

⁴¹ Exhibit AG-17 includes DR AGDE-8.222d.

1 routine repairs or remediations that should be done periodically irrespective of when the
2 City of Detroit does its inspection.

3 Therefore, I recommend that the Commission remove \$1.0 million and \$2,254,000 from
4 the Company's forecasted capital expenditures for 2025 and 2026, respectively. I also
5 recommend the Commission increase the Company's O&M expense for the projected test
6 year by \$2,254,000.

7 Plaza Renovation – On page 62 of her revised direct testimony, Ms. Uzenski identifies
8 \$7.8 million needed to optimize the open space at the headquarters building. From the
9 testimony and response to discovery, it is not clear what optimization is being done to the
10 open space, why it is necessary, and why it should cost customers \$7.8 million. The
11 response to the Attorney General discovery request points to plumbing needed to be
12 repaired due to end of life and water leaks.⁴² This description does not match with the
13 concept of space optimization.

14 The Company has not made a clear and compelling case that this renovation project is
15 needed. Therefore, I recommend that the Commission remove the \$4,001,000 and the
16 \$3,754,000 from the Company's forecasted capital expenditures for 2025 and 2026,
17 respectively.

⁴² Id. Includes DR AGDE-8.222e.

1 HQ Courtyard Space – On page 62 of her testimony, Ms. Uzenski identified \$2.3 million
2 in capital expenditures to install furniture and structures in the courtyard at the Company’s
3 headquarter building. In response to discovery, the Company stated that the Headquarters
4 courtyard is an open-air space and the improvements will allow it to be used for team
5 meetings and events, minimizing using offsite locations.⁴³

6 Spending \$2.3 million on this project seems unnecessary when the Company has many
7 higher priority projects that can use that money to improve the electric grid. The Company
8 has not presented any evidence that the use of this space will save costs elsewhere and is
9 economically beneficial. I recommend that the Commission remove the \$2,254,000 from
10 the Company’s forecasted 2026 capital expenditures.

11 Trombly Service Center Renovations – On page 64 of her testimony, Ms. Uzenski
12 discusses the Trombly Service Center renovation project and page 3, line 5, of Schedule
13 B5.8 shows \$5,254,000 of capital expenditures for 2026. In response to discovery, the
14 Company elaborated on the renovations planned at this service center with planned use of
15 the expanded facility in 2028 and 2029. The Company also reported that the project will
16 be competitively bid when the design is complete.⁴⁴ From the information provided in
17 discovery, it is evident that the project is still in the initial phase of development with no
18 design completed. It would be premature to include the capital expenditures for this

⁴³ Id. Includes DR AGDE-8.222f.

⁴⁴ Id. Includes DR AGDE-8.225b-c.

1 project in rate base in this rate case. Therefore, I recommend that the \$5,254,000 be
2 removed from the 2026 forecasted capital expenditures.

3 Other Corporate Projects – On line 54 of page 2 of Schedule B5.8, the Company included
4 capital expenditures of \$4,388,000 for 2025 and \$4,567,000 for 2026. The Attorney
5 General asked the Company to identify the projects included in those amounts. In
6 response, the Company stated that the amounts represent emergent work that may arise
7 during the year and no specific projects have yet been identified.⁴⁵ The Commission has
8 repeatedly rejected the use of placeholder amounts in forecasted capital expenditures.
9 Therefore, I recommend that the Commission remove the \$4,388,000 and the \$4,567,000
10 from the forecasted capital expenditures for 2025 and 2026, respectively.

11 **Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL**
12 **EXPENDITURES FOR THE VEHICLE FLEET TRANSPORTATION AREA.**

13 A. On page 1 of Exhibit A-12, Schedule B5.8, the Company shows actual capital expenditures
14 for the electric business Vehicle Fleet and Maintenance operation at \$33.9 million for 2023
15 and \$36.0 million for 2024. The Company forecasted capital expenditures of \$23.5 million
16 for 2025 and nearly triple that amount for 2026, to \$66.8 million. On page 61 of her direct
17 testimony, Ms. Uzenski briefly discusses the transportation fleet expenditures and points
18 to the use of a proprietary model that identifies vehicle replacement by optimizing the total
19 cost of ownership. She states that the Company deferred some of the vehicle replacements

⁴⁵ Id. Includes DR AGDE-8.234b.

1 from 2025 to 2026 and that 2026 includes the cost of bucket trucks and digger derricks
2 that have not been available for purchase due to supply shortages.

3 Ms. Uzenski did not elaborate on why vehicle purchases were deferred from 2025 to 2026
4 or what supply shortages existed with bucket trucks and digger derricks and for how long.
5 In discovery, the Attorney General asked the Company to provide the number of units
6 purchased within each vehicle type or class and the related purchase cost for each year
7 2021 to 2024 and forecasted for 2025 and 2026. The Attorney General also requested that
8 the Company provide a copy of the model that selects vehicles for replacement. In
9 response, the Company stated that the proprietary model was not available for review and
10 provided a summary schedule showing two approaches for vehicle replacement: an even
11 approach and an out of life scenario. From the description of the document, it appears that
12 the Company prefers the even replacement approach where it takes the vehicles in a class
13 to be replaced and assigns them for replacement over future years.⁴⁶ Given this approach,
14 it is perplexing to see the Company defer purchases from 2025 to 2026.

15 Regarding the request for the number and classes of vehicle purchased or forecasted to be
16 purchased with the related cost, the Company provided a detailed list of vehicles for each
17 year 2021 to 2026.⁴⁷ The information provided identifies the vehicle manufacturer and
18 model number instead of a description of vehicle type, such as bucket truck or digger
19 derrick, which makes it challenging to analyze year over year purchases. Based on the

⁴⁶ Exhibit AG-18 includes DR AGDE-8.220a with attachment.

⁴⁷ Id. Includes DR AGDE-8.220b with attachments.

1 information provided, it is apparent that the Company included considerable price
2 increases in 2026 over 2025 and over prior years for the same model vehicle. For example,
3 in 2025, the Company shows the purchase price of a Freightliner M2106 truck at \$229,409.
4 The forecasted price of that same model truck increases to \$402,000 in 2026. The 2026
5 price is a 75% increase over a single year. Other significant price increases are also
6 reflected in 2026 from 2025 and over prior years.

7 From the information provided by the Company, I calculated the average cost per vehicle
8 for each year 2021 through 2026. The following table shows the average cost per year.

Year	Total Purchase Cost	# of Units	Average Cost Per Vehicle
2026	\$66,631,426	299	\$ 222,848
2025	\$24,853,367	172	\$ 144,496
2024	\$36,016,008	379	\$ 95,029
2023	\$33,944,820	396	\$ 85,719
2022	\$46,346,506	457	\$ 101,415
2021	\$21,705,243	278	\$ 78,076
2022-2024 3 Year Average			\$ 94,054

9
10 For the most recent historical three years, the average cost per vehicle was \$94,054 and
11 the annual costs ranged in a relatively narrow band from \$86,000 to \$101,000. As evident
12 from the table, the average cost per vehicle increases by 54% in 2025 from the 3-year
13 average and more than doubles in 2026. Although a portion of the average cost increase

1 in 2025 and 2026 reflects the change in mix of vehicle purchases, that mix also changed
2 in prior years.

3 To give the Company the benefit of the doubt that 2025 prices reflect more current prices
4 than the three-year historical average cost per vehicle, I used the average cost per vehicle
5 from 2025 to calculate a reasonable forecast of vehicle purchase costs for 2026. Using the
6 average cost per vehicle of \$144,496 and adjusting it for the 2026 inflation rate of 2.4%, I
7 determined a 2026 average cost per vehicle of \$147,964, which I rounded up to \$148,000.
8 This cost multiplied by the 299 units that the Company forecasted for 2026 results in
9 forecasted capital expenditures of \$44,252,000. This amount is \$22,566,000 lower than
10 the Company's forecast of \$66,618,000. I recommend that the Commission remove the
11 \$22,566,000 from the Company's forecasted capital expenditures for 2026.

12 **F. Capital Expenditures Adjustments - Summary**

13 **Q. WHAT IS THE TOTAL AMOUNT OF ADJUSTMENTS THAT YOU**
14 **RECOMMEND TO THE COMPANY'S CAPITAL EXPENDITURES AND RATE**
15 **BASE?**

16 **A.** The chart below summarizes my proposed reductions in capital expenditures in those areas
17 where the level of capital expenditures presented by the Company is excessive,
18 unnecessary, or unsupported. It also includes capital cost disallowances proposed by other
19 witnesses presenting testimony on behalf of the Attorney General.

Summary of AG Disallowed Capital Expenditures		
		Amount (millions)
Distribution Operations	\$	590
Power Generation		150
Nuclear Operations		78
Engineering and Support Staff		22
Corporate Facilities		50
Total	\$	890

Based on my analysis and the information presented in my testimony above, the Commission should reduce the Company's proposed capital expenditures by \$889.6 million and average rate base by \$552.0 million, including an adjustment to increase working capital by \$58.9 million. 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 \$1.375 BILLION FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY'S FORECASTED AMOUNT?

A. No. I propose four adjustments, which increase the amount of working capital by \$58.9 million. The first adjustment is to correct the Company's calculation of Interest Payable. The second adjustment pertains to Taxes Payable. The third adjustment reduces the Monroe Power Plant regulatory asset balance for proposed disallowance of forecasted

1 capital expenditures. The fourth adjustment increases working capital to shift Pole Top
2 Maintenance (PTMM) costs from capital expenditures to a regulatory asset.

3 **Q. PLEASE EXPLAIN YOUR CORRECTION TO THE COMPANY'S \$113.1**
4 **MILLION INTEREST PAYABLE AMOUNT SHOWN IN EXHIBIT A-12,**
5 **SCHEDULE B4.**

6 A. The Company reflected an average balance of \$113.1 million for Interest Payable on line
7 63 of Exhibit A-12, Schedule B4. In discovery, the Attorney General asked the Company
8 to explain why Interest Payable was lower in the projected test year in comparison to the
9 historical test period, in light of the Company's debt levels increasing by 16% over the
10 same time period. In response, the Company stated that there was an error in the
11 calculation of the projected balance and provided a corrected balance for Interest Payable
12 of \$117.8 million.⁴⁸ The difference is an increase of \$4.7 million to the liability account
13 balance. Since Interest Payable is a liability account, this difference decreases Working
14 Capital by \$4.7 million.

15 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO TAXES PAYABLE OF \$2.4**
16 **MILLION SHOWN IN EXHIBIT A-12, SCHEDULE B4.**

⁴⁸ Exhibit AG-22 includes DR AGDE 7.211a.

1 A. The Company's projected test year balance of \$2.4 million for Taxes Payable is \$9.5
2 million lower than the actual historical 2023 balance of \$11.9 million. Taxes Payable are
3 shown on line 62 of Exhibit A-12, Schedule B4.

4 In discovery, the Attorney General asked the Company to explain why Taxes Payable
5 would decrease when the rate relief requested in this rate case would increase taxable
6 income. In its response, the Company stated that for calculation of Taxes Payable in this
7 rate case, it forecasted a taxable loss for the 2026 test year, as calculated in Exhibit A-13,
8 Schedule C8, and that this calculation "...does not reflect the rate relief being requested in
9 this filing."⁴⁹

10 The assumptions of a taxable loss and exclusion of any new rate relief from this case are
11 not realistic and the Company's calculation of Taxes Payable is seriously flawed. On
12 average in the most recent rate cases, the Company has received rate increases that were
13 approximately 55% of the amount requested. Although this average percent could be
14 imputed in this rate case to arrive at much higher Taxes Payable balance than forecasted
15 by the Company, a more conservative approach would be to use the actual Taxes Payable
16 balance from the historical period. Accordingly, I recommend that the Commission utilize
17 the historic balance of Taxes Payable of \$11.9 million for the projected test year.

⁴⁹ Id. Includes DR AGDE 7.208a-b.

1 This increase in Taxes Payable of \$9.5 million for the projected test year reduces working
2 capital by the same amount.

3 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE REGULATORY ASSET FOR**
4 **THE MONROE POWER PLANT.**

5 A. As discussed under the Capital Expenditures-Power Generation section of my testimony,
6 I proposed to disallow \$53,880,000 from the 2026 capital expenditures for the Monroe Fly
7 Ash Basin Closure project. Those capital expenditures were reflected in the regulatory
8 asset established by the Company for the Monroe Power Plant. The removal of the
9 \$53,880,000 reduces the 2026 average balance of the regulatory asset account by
10 \$26,940,000 and reduces working capital for the projected test year by the same amount.

11 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO WORKING CAPITAL FOR THE**
12 **ESTABLISHMENT OF A REGULATORY ASSET FOR THE PTMM PROGRAM.**

13 A. As discussed in the respective direct testimonies of AG-MN witnesses Paul Alvarez and
14 Dennis Stephens, the witnesses proposed that the \$200 million of PTMM capital
15 expenditures forecasted by the Company for 2026 be transferred to a regulatory asset
16 account for later securitization financing. The establishment of this regulatory asset
17 account in 2026 for a forecasted amount of \$200 million will increase working capital on
18 average for the year by \$100 million.

1 In total, the four proposed changes increase working capital by \$58.9 million. Exhibit AG-
2 21 shows the compilation of the total adjustment to working capital for the projected test
3 year.

4 **VI. Cost of Capital**

5 **A. Capital Structure**

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

8 A. I recommend that the capital structure shown on page 1 of Exhibit AG-23 be used in this
9 case. The first three lines show the projected long-term debt, preferred equity and common
10 equity capital of the Company, which represents the permanent capital structure for the
11 test period ending December 2026. The capital balances in this exhibit reflect the amounts
12 shown in Company Exhibit A-14, Schedule D1, with an adjustment to rebalance the capital
13 structure. The long-term debt component in Exhibit AG-23 has been increased by \$138
14 million and the common equity component has been reduced by the same amount. The
15 result is a capital structure with 50% of common equity and 50% of long-term debt.

16 Q. **WHY DID YOU INCREASE LONG TERM DEBT BY \$138 MILLION AND**
17 **OFFSET THIS CHANGE WITH A LOWER COMMON EQUITY BALANCE?**

18 A. The Company proposed a permanent capital structure with a common equity component
19 of 50.75%. This level of common equity exceeds the 50% equity ratio approved by the

1 Commission in the Company's last two fully contested rate cases, Case Nos. U-21297 and
2 U-21534.⁵⁰ The capital structure in this rate case should similarly mirror the common
3 equity ratio of 50%, which was last approved on January 23, 2025. It is interesting to note
4 that in both of these cases, the Company proposed a 50% common equity ratio in its filings,
5 which was approved by the Commission. However, in this case the Company proposed a
6 50.75% common equity ratio even though the Company's financial circumstances and risk
7 profile are generally unchanged.

8 A continuation of a 50% common equity ratio in this case is supported by several factors,
9 which include (1) the Commission's consistent directive in recent electric and gas rate
10 cases of Consumers Energy Company, which stated that a 50/50 capital structure is
11 desirable and appropriate to ensure reduced costs to customers and maintain the
12 Company's strong financial position; (2) The Company's strong cash flow to debt
13 coverage ratio and credit ratings; (3) the Company's common equity capital contributions
14 by the parent company; (4) the favorable regulatory environment in Michigan supported
15 by historical returns on common equity above industry averages and in the top tier of the
16 Company's peer group; and (5) the fact that the common equity ratio of the peer group,
17 used to assess the cost of common equity in this case, is approximately 42.5%.⁵¹

⁵⁰ Case No. U-21534 Commission order dated January 23, 2025 and Case No. U-21297 dated December 23, 2023.

⁵¹ Exhibit AG-26 shows that the equity ratio for each peer company and the peer group average ratio of 42.5%.

1 **Q. PLEASE EXPLAIN YOUR ASSESSMENT OF THE COMMISSION'S**
2 **DIRECTIVE TO CONSUMERS ENERGY TO REBALANCE ITS CAPITAL**
3 **STRUCTURE TO EQUAL AMOUNTS OF DEBT AND EQUITY CAPITAL.**

4 A. The Commission, in its order of February 17, 2017 in Case No. U-17990 stated:

5 The Commission expects that Consumers will have arrived at, or will present a
6 strategy to return to, a balanced structure within the five-year infrastructure plan time
7 period. If Consumers is unable to do so, a more complete analysis should be included
8 to explain why such a result is reasonable and prudent.

9 In subsequent litigated rate cases, the Commission continued to remind Consumers of this
10 directive as they moved slowly toward a more balanced capital structure.

11 **Q. WHAT POSITION DID THE COMMISSION TAKE IN CONSUMERS ENERGY'S**
12 **MOST RECENTLY CONTESTED RATE CASE ON THE CAPITAL**
13 **STRUCTURE?**

14 A. In the recent March 21, 2025 order in Case No. U-21585, the Commission decided to set
15 the common equity ratio at 50%, as recommended by the Administrative Law Judge (ALJ)
16 and supported by the Attorney General and other parties. On page 129 of the order, the
17 Commission stated the following:

18 Given the above, the Commission adopts the thorough and well-reasoned findings
19 and recommendations of the ALJ. The Commission finds that the balanced capital
20 structure most appropriately balances the interests of the utility's investors and
21 customers, consistent with the holdings in Bluefield and Hope. As such, the
22 Commission adopts a balanced capital structure of 50% debt to 50% equity, utilizing
23 the Attorney General's methodology. See, PFD, pp. 310-311.

24 Similarly, in its order of March 1, 2024 in Case No. U-21389, the Commission stated:

1 Notwithstanding the above, the Commission finds that the most reasonable and
2 prudent approach to achieving this goal was set forth by the Staff. Therefore, the
3 Commission finds that a common equity layer of \$10.880 billion should be adopted,
4 which equates to a 50.02% equity ratio in the permanent capital structure. See, 5 Tr
5 3623; Exhibit S-4, Schedule D-1, line 3. This equity balance is a slight reduction to
6 the 50.75% equity layer agreed to by the parties in Case No. U-21224, which is
7 consistent with prior Commission directives to gradually achieve a balanced capital
8 structure. See, 5 Tr 3616, 3624–3626; see also, January 19 order, February 28 order,
9 July 31 order, and December 22 order).

10 The Commission has been very clear that a balanced permanent capital structure at 50%
11 debt and 50% equity capital is appropriate for Michigan utilities.

12 **Q. DOES THE COMPANY MAKE A COMPELLING CASE TO SUPPORT ITS**
13 **PROPOSED 50.75% COMMON EQUITY RATIO FOR THE PERMANENT**
14 **CAPITAL STRUCTURE?**

15 A. No. Company witness Timonthy Lepczyk addresses the proposed capital structure on
16 pages 6 to 10 of his direct testimony. Other than a general discussion about the
17 components of the capital structure and the objective of maintaining a strong a balance
18 sheet and credit ratings, Mr. Lepczyk does not provide much evidence of a need to increase
19 the existing equity ratio of 50%, recently approved by the Commission, to 50.75%. His
20 statement that the Company's capital structure impacts the ability to attract capital to fund
21 capital expenditures appears to raise a concern that does not exist. The Company has not
22 had any problems raising debt capital through the financial market or equity through its
23 parent company. No evidence has been presented to the contrary. In fact, during the past
24 three years, the Company has raised \$2.7 billion in debt capital at competitive interest

1 rates.⁵² The high capital expenditures to be funded are not unique to the Company. Most
2 other electric utilities are in a capital expansion mode and are raising capital in the financial
3 market without any difficulties. Exhibit AG-28 shows recent capital-raising transactions
4 by utilities around the country.

5 On page 9 of his testimony, Mr. Lepczyk states that the peer group has an equity ratio of
6 52% and references Exhibit A-14, Schedule D1.1 with S&P Global as a source of the
7 information. The debt and equity balances used in the calculation of the 52% equity ratio
8 appear to be at a single point in time at the end of 2023. There are several problems with
9 the information in the exhibit that make it unreliable and inapplicable in setting an
10 appropriate equity ratio for the Company. First, utility equity balances change during the
11 year due to seasonality in sales and net income or net losses that add to or reduce those
12 balances. The timing of retirement and issuance of long-term debt and temporary
13 financing with short-term debt also affects the long-term debt balances. An appropriate
14 calculation of equity and debt balances and the resulting equity ratio needs to be done over
15 multiple quarter-ended balances.

16 Second, the list of utility subsidiaries in the peer group includes several small size utilities
17 that are not comparable to the Company. Smaller utilities tend to have higher equity ratios
18 to sustain them during potential volatility in their business, which larger utilities like DTE
19 Electric can better manage. Third, the information gathered from S&P Global reflects debt

⁵² Exhibit A-14, Schedule D2, lines 25 to 30.

1 and equity balances of subsidiary companies reported under Generally Accepted
2 Accounting Principles (GAAP) and not balances and equity ratios set by regulatory
3 agencies. Those subsidiary companies' debt and equity balances are set by the parent
4 company's management and do not reflect the capital structure and financial discipline of
5 publicly traded companies.

6 Fourth, there is a disconnect between establishing a capital structure and the equity ratio
7 based on GAAP financial statements of subsidiary companies and calculating the cost of
8 equity capital based on publicly traded companies in the peer group. The cost of equity
9 for the publicly traded companies in the peer group is highly dependent on the financial
10 risk reflected in their capital structure. Thus, it is critical to synchronize the capital
11 structure of the Company to the peer group average as closely as possible, in order to have
12 consistency with the cost of equity capital derived from those peer group companies. The
13 Company's subsidiary companies' common equity capital ratio of 52% creates a
14 disconnect that is not acceptable and is also more costly to customers. As shown in Exhibit
15 AG-26, the average common equity ratio of the publicly traded peer company group for
16 2024 was 42.5%.

17 In summary, Mr. Lepczyk has not provided any compelling or convincing evidence that
18 the Company's equity ratio should be increased from 50% to 50.75%, and his proposal
19 should be rejected. I recommend that the Commission maintain a balanced permanent
20 capital structure of 50% debt and 50% equity capital for the Company.

1 **Q. DO THE RATING AGENCIES’ CURRENT BUSINESS AND CREDIT OUTLOOK**
2 **FOR THE COMPANY SHOW ANY SIGNIFICANT CONCERNS?**

3 A. No. S&P in its January 2025 report provides the following outlook for the Company:

4 Our stable outlook on DTEE reflects our base case assumption that the Company will
5 generate sufficient cash flow to maintain financial measures that support S&P Global
6 Ratings – adjusted FFO to debt of 19% - 20%. The stable outlook also reflects our
7 expectation that parent DTE will focus growth on its lower risk, regulated utility
8 strategy.⁵³

9 Similarly, in its March 11, 2025 report, Moody’s provides the following rating outlook:

10 DTE Electric Company’s credit quality reflects its operating profile as a vertically
11 integrated utility that generates steady and predictable cash flow in a credit supportive
12 Michigan regulatory environment. This is offset by capital investments that will
13 remain elevated in order to maintain operational reliability, and to transform DTE
14 Electric’s majority coal-fired generation fleet into a predominantly renewable
15 technologies fleet with some continued use of natural gas fuel and nuclear. Over the
16 next couple of years, we expect DTE Electric to produce CFO pre-WC to debt of
17 between 21% and 23% compared to 20.5% and 21.8% in 2023 and 2024,
18 respectively.⁵⁴

19 Fitch Investor Service provided the following summary of the Company’s credit profile in
20 its March 28, 2025 report:

21 Constructive Regulatory Environment: Fitch views the regulatory environment for
22 electric utilities in Michigan as mostly constructive from a credit perspective. The
23 regulatory framework allows full pass-through of fuel costs, forward-looking test
24 years and a timely 10-month review period for general rate case resolution. DTE
25 Electric’s authorized return on equity (ROE) of 9.9% remains above the 2024 industry
26 average of 9.74%.⁵⁵

27 These credit reports provide a favorable outlook of the Company’s credit profile and
28 Michigan’s regulatory environment. Mr. Lepczyk did not provide any evidence to

⁵³ Exhibit AG-34 includes DR AGDE-2.43 with related attachment.

⁵⁴ Id.

⁵⁵ Id. includes AGDE-2.43 (Att. 3).

1 contradict those favorable outlooks. In fact, in discovery, the Attorney General asked if
2 any of the credit rating agencies had notified the Company regarding the need for a higher
3 equity ratio. In response, Mr. Lepczyk stated that no such notifications had been
4 received.⁵⁶ The favorable rating agencies' outlook is another clear indication that a higher
5 equity ratio of 50.75% is not warranted. In my testimony below, I elaborate more on the
6 relevant cash flow to debt coverage ratios that drive the Company's credit rating.

7 **Q. IN THE MOST RECENT MOODY'S CREDIT REPORT COVERING DTE**
8 **ELECTRIC, WHAT ARE THE REPORTED CREDIT METRICS FOR THE CASH**
9 **FLOW TO DEBT RATIO?**

10 A The most recent Moody's report of May 2025 shows the Company's operating cash flow
11 to debt coverage (CFO Pre-W/C to Debt) ratio at 21.8% for 2024 and 20.5% for 2023.⁵⁷
12 However, two events have depressed those coverage ratios. First, the Company's earnings
13 were temporarily depressed in 2023, which results in a return on equity (ROE) of 9.5%
14 versus its 9.9% authorized rate. The Company's earnings rebounded in 2024 and the
15 Company earned a ROE of 10%.

16 Second, both in 2023 and 2024, the Company increased its long-term debt above 50%,
17 which increased the amount of interest paid and negatively affected the CFO to Debt
18 coverage ratios. The higher debt leverage is evident in Exhibit A-4, Schedule D1, which

⁵⁶ Exhibit AG-35 includes DR AGDE-2.46b.

⁵⁷ Exhibit AG-34 includes DR AGDE-2.43(Att.2) with the Moody's credit report dated March 22, 2025.

1 shows the 2023 long-term debt at 51.6% and common equity at 48.4%. The Company
2 maintained a 48.7% common equity ratio and a 51.3% long-term debt ratio in 2024
3 (excluding securitization debt). As discussed below, once these items are normalized and
4 the debt and equity ratios are set at 50/50, the CFO to debt ratio improves well above the
5 minimum sustainable threshold set by Moody's.

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

9 A. Yes. On page 1 of Exhibit AG-32, I calculated the Company's CFO to debt coverage ratio
10 for the 12 months ended March 2023 adjusted for the ROE and common equity ratio levels
11 I advocate for in this case. I start with Moody's actual results for the 2023 period and
12 adjust them to reflect a 9.85% ROE and a 50% common equity ratio. I chose this 2023
13 period because this is the most recent information available from Moody's showing
14 detailed ratio components.

15 For my analysis of the 12 months ended March 2023 pro-forma cash flow ratio calculation,
16 I started with actual 2023 data (per the Moody's July 2023 report) on line 1 of Exhibit AG-
17 32. Next, on line 2, I adjust the capitalization to reflect a balanced capital structure. This
18 decreases long-term debt and increases common equity. On line 3, I adjusted the cash
19 flow upward to reflect a 9.85% ROE versus the 9.13% ROE actually achieved in the year
20 ended March 2023. The result of these adjustments is shown on line 4 with a cash flow to

1 debt ratio of 22.6%. This ratio is above the 21% downgrade threshold noted by Moody's
2 in its July 2023 report.⁵⁸ I have not presented any ratio results for S&P since the ratio
3 calculations are highly similar, and the S&P downgrade threshold is lower at 15%.

4 In summary, my analysis shows that the 9.85% ROE and 50% common equity ratio would
5 result in the Company's cash flow ratios being above the long-term threshold levels that
6 would result in a credit downgrade.

7 **Q. WHAT IS THE REVENUE REQUIREMENT SAVINGS RELATED TO A LOWER**
8 **COMMON EQUITY RATIO OF 50.0%, IN COMPARISON TO THE**
9 **COMPANY'S PROPOSED EQUITY RATIO OF 50.75%?**

10 A. The difference is approximately \$11.8 million annually. This reflects (a) the difference
11 between the pre-tax cost of common equity of approximately 14.1% versus the cost of
12 long-term debt of 4.3%; (b) the Company's proposed rate base of approximately \$23.6
13 billion; and (c) the percentage of total capital being shifted from common equity to long
14 term debt.

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

⁵⁸ Exhibit AG-36 includes the Moody's July 6, 2023 report from Case U-21534 DR AGDE-1.11 (Att.1) showing the 21% downgrade threshold.

1 A. No. For the other components of the capital structure, I adopted the balances sponsored
2 by witness Vangilder in Exhibit A-14, Schedule D1, page 1.

3 **COST OF CAPITAL**

4 **Q. WHAT RETURN ON EQUITY AND OVERALL RETURN ON CAPITAL ARE**
5 **YOU RECOMMENDING IN THIS CASE?**

6 A. I am recommending an overall return on capital of 5.61%, which includes a return on
7 common equity of 9.85%, as shown in Exhibit AG-24.

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

9 A. For the long-term debt cost rate, I used a rate of 4.24% based upon Mr. Lepczyk's
10 recommendation.

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

13 A. For Deferred Taxes, I used a zero-cost rate recommended by witness Vangilder. Cost rates
14 for JDITC reflect those rates I used for the permanent capital sources. For short-term debt,
15 I reduced the cost rate of 4.75% proposed by Mr. Lepczyk in Exhibit A-14, Schedule D3,
16 to a rate of 3.91%.

17 **Q PLEASE EXPLAIN YOUR BASIS FOR THE LOWER 3.91% SHORT-TERM**
18 **DEBT RATE.**

1 A. Beginning on page 13 of his direct testimony, Mr. Lepczyk explains that he used the
2 Company's actual short-term debt cost rate as of January 2025 to develop the 4.75%
3 interest rate. In discovery, the Attorney General pointed out that a recent S&P Economic
4 Outlook forecasted a declining Federal Funds rate for 2026 and requested that the
5 Company provide a revised short-term borrowing rate.⁵⁹ In response, the Company
6 provided a lower forecasted interest rate of 3.91% for the projected test year.

7 The lower rate reduces the Company's forecasted interest costs by \$4.8 million on \$563
8 million of short-term debt for the projected test year.

9 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF**
10 **CAPITAL IN EXHIBIT AG-23.**

11 A. To arrive at the overall cost of capital on line 11, column (f), I first developed the
12 percentage weighting of each capital component in column (d) by dividing the individual
13 capital balances in column (b) by the total of all capital components in that column. Next,
14 I multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the
15 values in column (f). The total of the individual values in column (f) is the total cost of
16 capital of 5.61%.

17 Regarding the pretax weighted cost of capital on line 11, column (h), I have multiplied
18 each cost component in column (f) by the conversion factors in column (g). These

⁵⁹ See DR AGDE-7.21 showing the Company's revised rate.

1 conversion factors are included to reflect the impact of income and other taxes paid by the
2 Company for calculation of the pretax weighted cost of 6.96% in column (h).

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

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

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

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

20 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON**
21 **EQUITY IN EXHIBIT AG-24.**

22 A. Determining the cost of common equity for an enterprise or an industry group is inexact
23 since investors can only estimate what the future cash flow from any enterprise may be
24 over time. Because of this uncertainty, most financial experts will not rely solely on any

1 particular method. To determine the cost of common equity, I used three approaches to
2 assess this cost. These are the Discounted Cash Flow (DCF) Method, the Capital Asset
3 Pricing Model (CAPM), and the Utility Risk Premium approach.

4 Q. **PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROXY GROUP OF PEER**
5 **COMPANIES.**

6 A. To develop an appropriate peer group, I started with the 38 utility companies followed by
7 the Value Line Investment Survey in its “Electric Utility Industry” sections. I removed
8 seven companies with revenues of over \$20 billion or under \$1 billion because the size of
9 these companies is not comparable to the Company’s revenue of approximately \$5 billion.
10 Other companies with no dividend growth (Dominion Energy and Hawaiian Electric) as
11 well as companies with foreign investments (Semptra, Hydro-One, and Fortis) were also
12 removed. Four additional companies, Eversource, Allete, Entergy, and TXNM Energy,
13 were also removed from the peer group due to current or recent merger or acquisition
14 activities. I also removed 14 companies with low growth or no growth in earnings,
15 exposure to frequent wildfire risk, offshore wind development risk, as well as companies
16 with large non-utility operations or less than 50% in electric operations.

17 The selection process to arrive at my peer group of comparable companies to DTE Electric
18 is shown in Exhibit AG-30. After going through this selection process, the twelve
19 remaining companies, shown in Exhibit AG-25, all have growing earnings and dividends,
20 and comprise a comparable peer group.

1 **Q. HOW DOES YOUR PEER GROUP COMPARE TO THE COMPANY’S PEER**
2 **GROUP?**

3 A. The Company’s peer group contains nine of the companies in my peer group.⁶⁰ Of the ten
4 other companies in the DTEE peer group, which should be excluded, are three companies
5 due to large size considerations. These are Duke Energy, Southern Company, and NextEra
6 Energy. These companies have revenues of between \$24.7 billion and \$30.4 billion.
7 NextEra Energy should also be excluded as a peer company due to its significant
8 investments in non-utility power production in a variety of states outside Florida, which
9 represent over 40% of its Property, Plant, and Equipment. Two other companies included
10 in the Company’s peer group that should be removed are Entergy and TXNM Energy.
11 TXNM is involved in a sale of the company to Blackstone Infrastructure, while Entergy is
12 looking to sell its Louisiana gas distribution properties. These M&A activities temporarily
13 distort the stock price and valuations and should be removed from the peer group. The
14 other four companies in the DTEE peer group that I removed primarily have poor earnings
15 history and inconsistent financial results.⁶¹

16 **Discounted Cash Flow (DCF) Cost of Equity Method**

17 **Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW (“DCF”) APPROACH.**

⁶⁰ The other three companies in my peer group which were excluded from the DTEE peer group are Consolidated Edison, Center Point Energy, and WEC Energy.

⁶¹ The companies are First Energy, PPL Corp., Avista, and Pinnacle West.

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

$$R = D/P + g$$

7 where "R" = the Required Equity Return

8 "D/P" = the Dividend Yield on the Security

9 and "g" = the expected growth rate in dividends

10 **Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.**

11 A. The results of my DCF analysis are summarized in Exhibit AG-25. The stock price
12 information in column (c) of this exhibit reflects the average of the high and low prices for
13 each of these equity securities on each of the 30 trading days from June 18 to July 31,
14 2025. The annual dividend in column (d) is the forecasted average dividend level for 2025
15 and 2026 as projected by the Value Line Investment Survey. Column (h) shows the
16 average long-term earnings growth rate based on (1) the estimate of earnings growth
17 through 2029 per Value Line; and (2) the earnings growth estimates per Yahoo.

18 The resulting calculation of the DCF Method is an average return on common equity for
19 the proxy group of 9.80%.

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

1 A. The DCF analysis relies upon financial market information for the dividend yield portion
2 of the equation. It also relies upon judgments of dividend and earnings growth prospects
3 of security analysts, which reflects the consensus of the market on which investors rely.
4 Therefore, I place a fairly high degree of reliability in the DCF results when considered in
5 conjunction with the results of other methods in determining the cost of common equity.

6 **Q. HOW DOES YOUR DCF COST OF CAPITAL ESTIMATE COMPARE TO THE**
7 **COMPANY'S DCF ESTIMATE?**

8 A. First, I will point out that Company witness Nelson has determined several DCF outcomes
9 based on stock price averages over 30 days, 90 days, and 180 days, as well as multiple
10 quarterly dividend growth approaches. My comparison below reflects the Company's "30-
11 day average" price approach without any quarterly compounding of dividends. The results
12 of my DCF analysis and those of witness Nelson are dependent in large part upon the
13 overall dividend yield in each case as well as the average growth rate of each peer sample
14 company. Witness Nelson's DCF result of 10.31% is 51 basis points higher than the
15 9.80% overall DCF result I calculated.⁶²

16 The average dividend yield in my analysis is 3.66% but the Company's is higher at 3.85%.
17 This accounts for approximately 50% of the 51 basis points of difference. Also, the

⁶² This Company's 10.31% average DCF ROE rate is shown on page 1 of Exhibit A-14 (Schedule D5.1) in column 10 as the third from last number.

1 projected growth rate is higher in the Company's case at 6.43% vs. 6.14% in my analysis.⁶³
2 The data on the dividend yield and the earnings growth rates used by the Company were
3 compiled sometime in early 2025 and are now stale. The stock prices of the utilities in the
4 peer group are now higher, thereby resulting in a lower dividend yield compared to the
5 Company's filed case. While the growth rates in the Company analysis are also stale,
6 having been selected months ago, the inclusion of some peer companies, which I believe
7 to be inappropriate, is also a factor. If the Company's analysis were adjusted to exclude
8 PPL, NextEra, and Xcel Energy, the overall average growth rate would fall from 6.43% to
9 6.28%, accounting for the majority of the growth rate difference.

10 **Capital Asset Pricing Model**

11 **Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL (CAPM)**
12 **APPROACH TO DETERMINING THE COST OF COMMON EQUITY CAPITAL.**

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

$$16 \quad k_e = R_f + (B \times R_p)$$

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

18 R_f = the "risk free" rate of return

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

⁶³ The 3.88% dividend yield and 6.43% growth rate of the Company's peer group analysis is from columns 4 and 8 on Exhibit A-14 (Schedule D5.1).

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

2 **Q. PLEASE EXPLAIN THE BETA OR “B” COMPONENT OF THE EQUATION.**

3 A. This measure of risk reflects the extent to which the price of a particular security varies in
4 relationship to the movement of the overall market. Securities that vary over time more
5 than the overall market will have a Beta that is greater than 1.00. Some securities vary
6 less in price over time than the overall market. In these cases, the Beta will be less than
7 1.00. Utility stocks tend to move less than the overall market. Reflective of this outcome,
8 the average Beta of my peer group is 0.75.

9 **Q. PLEASE EXPLAIN EXHIBIT AG-26 SHOWING THE RESULTS OF THE CAPM**
10 **APPROACH.**

11 A. Exhibit AG-26 shows the results of the CAPM method based upon (1) a 4.46% risk-free
12 rate; (2) the Betas of the companies in the Peer Group taken from Value Line; and (3) the
13 7.35% historical Market Risk Premium (R_p) return from the years 1926 to 2024.

14 Regarding the use of a risk-free rate for CAPM purposes, I used a 4.46% rate, which is
15 sourced from economic projections provided by the Company.⁶⁴

⁶⁴ Exhibit AG-37 includes DR AGDE-2.52a with the attachment showing a 4.46% 30-Year U.S. Treasury rate for 2026.

1 The result of my CAPM approach using the 5.51% adjusted risk premium (7.35% Risk
2 Premium x 0.75 Beta) plus the 4.46% risk-free rate is a cost of equity capital of 9.97% for
3 my proxy group average.

4 **Q. PLEASE ASSESS THE CAPM APPROACH.**

5 A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios
6 of stocks. As such, it can be useful. However, the key issue with CAPM is that it assumes
7 that the entire risk of a stock can be measured by the “Beta” component. As such, the only
8 risk to the investor is from fluctuations in the overall market. In actuality, investors take
9 into consideration company-specific factors in assessing the risk of each particular
10 security. Therefore, I give the CAPM approach less weight than the DCF approach in
11 determining the cost of common equity.

12 **Utility Risk Premium Approach**

13 **Q. PLEASE EXPLAIN THE UTILITY RISK PREMIUM APPROACH OF**
14 **ESTIMATING THE COST OF COMMON EQUITY.**

15 A. In general, the cost of common equity for a peer group of utility companies can be
16 estimated by (1) projecting the cost of debt for the Company and adding to this cost (2)
17 the average return differential of utility common stocks over utility bonds.

18 **Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.**

1 A. Exhibit AG-27 shows the components required to derive a cost of common equity capital
2 for the peer companies on lines 3 and 4. The 5.61% on line 3 is the projected average rate
3 for utility “A” rated bonds. This rate is determined from the 4.46% U.S. Treasury rate
4 discussed earlier, plus the average spread of 30-year “A” rated utility bonds in 2024
5 compared to 30-year U.S. Treasury bonds. The spread rate of 4.25% on line 4 of the
6 exhibit is the historical rate of electric utility returns versus “A” rated debt yields from
7 1932 to the present. The total of the two rates equals the Risk Premium return rate of
8 9.86% on line 5 of the exhibit.

9 **Q. DOES THE COMPANY PROVIDE A UTILITY RISK PREMIUM ANALYSIS?**

10 A. No, not in the traditional sense of measuring achieved returns on utility stocks relative to
11 an interest rate benchmark such as utility bonds. Instead, Company witness Nelson uses
12 an unorthodox approach she refers to as Bond Yield Plus Risk Premium (BYRP).

13 **Q. PLEASE SUMMARIZE WITNESS NELSON’S TESTIMONY ON PAGES 37**
14 **THROUGH 42 STARTING UNDER THE HEADING “BOND YIELD RISK**
15 **PREMIUM APPROACH.”**

16 A. Witness Nelson states in her testimony that she compared authorized ROEs from electric
17 utility rate case decisions from 1980 to 2025 and compared the authorized ROEs to 30-
18 year U.S. bond yields. She ran a regression model with this data and claims to have found
19 a strong relationship between these bond yields and authorized ROEs. Based on the results
20 of the three cases prepared using this approach, she concludes that the average risk

1 premium over the 1980-2025 period is 5.74%. To this risk premium, she adds the 30-year
2 U.S. bond yield of 4.46% for the projected test year to arrive at a 10.20% ROE rate for the
3 projected test year under this unorthodox approach. The calculation is shown on page 40
4 of her testimony.

5 **Q. WHAT IS YOUR ASSESSMENT OF THE BOND YIELD PLUS RISK PREMIUM**
6 **APPROACH PRESENTED BY MS. NELSON?**

7 A. There are three major flaws with Ms. Nelson's Bond Yield Plus Risk Premium
8 methodology. First, it lacks any comparison of actual utility returns achieved from price
9 appreciation and dividends to bond yields. It is the actual return on utility common equities
10 that is the key and necessary measurement in any risk premium analysis. Using authorized
11 ROEs as a substitute ignores investors' return expectations. Second, the analysis is biased
12 because it covers a period when interest rates declined from 12.1% in late 1980 to between
13 4% to 5% in 2025.

14 Third, this analysis assumes a direct relationship between declining interest rates and ROE
15 decisions as happening almost instantaneously on a monthly basis. Regulators approach
16 the serious business of establishing ROEs based on many factors including the concept of
17 gradualism in reducing or increasing ROEs that are not in lock step with interest rate
18 changes. This analysis has no validity as a tool to determine an appropriate ROE rate in
19 rate case proceedings, and the Commission should disregard it.

1 **Q. HOW DO YOUR CAPM AND MARKET RISK PREMIUM RESULTS COMPARE**
2 **TO THE RESULTS PRESENTED BY COMPANY WITNESS NELSON?**

3 A. Before engaging in comparisons of these two methods, it is important to point out that
4 witness Nelson has derived four different CAPM results, four different ECAPM results,
5 and two different Bond Yield Plus Risk Premium (BYRP) results, all of which are
6 presented on page 5 of her testimony in Table 1. This conglomeration of multiple
7 scenarios is confusing and does not yield any more accurate results than the three
8 methodologies I have employed, and which are used by most of the other cost of capital
9 experts in rate case proceedings before the Commission.

10 Ms. Nelson also uses different risk-free rates of return, apparently unsure which rate is
11 more appropriate. For example, for the CAPM methodology one half of the calculations
12 utilize the actual 4.82% 30-year U.S. Treasury Bond rate from January 2025.⁶⁵ The other
13 half of the calculated CAPM results reflect a projected 4.46% 30-year Treasury Bond rate,
14 which is more in keeping with the concept of a projected test year. She uses the two 30-
15 year U.S. Treasury Bond rates in calculating two BYRP results.

16 Another compounding effect is Ms. Nelson's use of both an historical Market Risk
17 Premium (MRP) and a projected MRP in the calculation of the CAPM and ECAPM
18 methodologies. In one scenario, she proposes the use of an adjusted historical MRP of

⁶⁵ Both the risk-free rate and the MRP are components in the CAPM formula. This formula is set forth at the bottom of my Exhibit AG-26.

1 7.71%, which is based on historical results for the stock market, as represented by the S&P
2 500 stock index with an arbitrary added premium.⁶⁶ In another scenario, she proposes a
3 projected MRP factor of 10.83% based upon projected growth rates from S&P 500
4 companies. I will discuss the flaws of the projected MRP factor later in my testimony due
5 to its short-term outlook.

6 My CAPM calculations reflect only the historical MRP and the projected risk-free rate. I
7 used the historical MRP rate because it is the most reliable proxy rate of the market risk
8 premium that spans multiple stock cycles, both up and down cycles, in the stock market
9 over a long period of time. I use the projected risk-free rate since we are dealing with a
10 projected test year in this rate case and it more reliably reflects the trend in interest rates
11 over the coming year. Also, I present no ECAPM calculations since this methodology is
12 flawed, as explained later in my testimony.

13 **Q. PLEASE EXPLAIN THE DIFFERENCE IN THE MARKET RISK PREMIUMS**
14 **USED BY THE COMPANY.**

15 A. While not addressed in her testimony, it is clear from Exhibit A-14, Schedule D5.4 (upper
16 part of the page), that witness Nelson believes that the use of a 7.35% MRP is appropriate,
17 provided that the risk-free rate is 4.82% (the historic rate from January 2025). In the lower
18 half of the same page, she increases the MRP to 7.71% to compensate for the lower

⁶⁶ Represents the 7.35% actual risk premium she sources from Kroll (formerly Ibbotson) plus a 0.31% upward adjustment reflecting her use of the projected risk-free rate of 4.46% (vs. 4.82%). These risk-free rates are discussed above.

1 projected risk-free rate of 4.46%. This is simply an adjustment that has no little or no
2 validity and assumes that MRP levels adjust as interest rates change. She provides no
3 support for this proposition.

Comparison of CAPM Results		
<u>Results Based on Historical MRP</u>	<u>CAPM Estimate of</u>	
	<u>AG</u>	<u>DTEE</u>
Market Risk Premium (MRP)	7.35%	7.71% *
Avg. Beta Factor (B)	<u>0.75</u>	<u>0.92</u>
MRP x B	5.51%	7.09%
Projected 2026 Risk Free Rate	<u>4.46%</u>	<u>4.46%</u>
Total CAPM Result	<u>9.97%</u>	<u>11.55%</u>
* MRPadjusted upward from 7.35% to 7.71% by DTEE simply to offset a lower risk free rate from 4.82% to 4.46%.		

4

5 **Q. PLEASE EXPLAIN WHY THE AG’S AVERAGE BETA FACTOR IS SO MUCH**
6 **LOWER THAN THE BETA FACTOR USED BY THE COMPANY.**

7 A. The Value Line betas which I and witness Nelson use have recently been redetermined
8 and are lower. For example, the beta factors now provided by Value Line, as shown on
9 Exhibit AG-26 are 0.75 in each case for NorthWestern Energy and Portland General
10 Electric⁶⁷. In contrast, the Value Line beta factors in the Company estimate (for these two

⁶⁷ Value Line report dated July 18, 2025, pages 2203 and 2206.

1 companies) were 1.00 and 0.95, respectively.⁶⁸ I recommend that the Commission accept
2 the more recent Beta data.

3 **Q. PLEASE PROVIDE YOUR ASSESSMENT OF THE COMPANY'S PROJECTED**
4 **CAPM MARKET RISK PREMIUM OF 10.83%.⁶⁹**

5 A. In addition to using a proven historical MRP, Ms. Nelson developed a projected MRP
6 based largely on future expected stock price growth rates and dividends for a select group
7 of companies from the S&P 500 stock index over the next three to five years. Based on
8 her subset of S&P 500 companies, Ms. Nelson calculates a forecasted stock market return
9 of 15.29%. From this percentage, she subtracts the forecasted 30-year U.S. Treasury risk-
10 free rate of 4.46% to arrive at a forecasted MRP of 10.83%.

11 This 10.83% MRP result is then multiplied by the betas for each peer company and the
12 result is then added to the 4.46% projected Treasury Bond rate to derive a 14.6% CAPM
13 cost of capital rate.

14 There are several flaws with this approach to developing an MRP. First, short-term
15 fluctuations in expectations and projections of stock market returns for the sample
16 companies can cause the forecasted MRP rates to vary significantly. Second, as can be
17 seen from an examination of pages 1 to 18 of Exhibit A-14, Schedule D5.3, many of the
18 companies with dividend yields and long-term growth estimates are omitted. Also, many

⁶⁸ The betas are shown in columns 3 and 11 of Exhibit A-14, Schedule D5.4.

⁶⁹ See Exhibit A-14, Schedule D5.4, page 2, column 14

1 large technology companies with high growth prospects have a larger than normal
2 weighting in the calculation of the 14.4% return due to their relatively large market
3 capitalization. This overweighing of large technology stocks is minimized when
4 considering the historical data from 1926 to 2024.

5 **Q. PLEASE EXPLAIN FURTHER THE SHORTCOMINGS WITH THE MARKET**
6 **RISK PREMIUM DEVELOPED BY WITNESS NELSON.**

7 A. Witness Nelson is using an extremely short period of 3 to 5 years to measure stock market
8 returns in determining the MRP. The projected MRP does not include a complete cycle
9 of economic expansion and contraction, which is what occurs over the long-term. To adopt
10 the Company's approach would be akin to only selecting the positive return years over the
11 99-year historical period of stock market returns and not the losses in the downturn years.
12 Expectedly and incorrectly, we would derive a far higher overall return for the market and
13 far higher market risk premium, which is the flawed result achieved by witness Nelson in
14 the 14.4% market return and forecasted MRP.

15 These concerns are also echoed by Dr. Roger Morin, a recognized expert on regulatory
16 finance matters, who strongly supports the use of the longest possible period for
17 calculating a market risk premium. On page 114 of his book "New Regulatory Finance"
18 Dr. Morin states the following:

19 Therefore, an historical risk premium study should consider the longest possible
20 period for which data are available. Short-run periods during which investors earn a
21 lower risk premium than they expect are offset by short-run periods during which
22 investors earn a higher risk premium than they expect. Only over long time periods

1 will investor return expectations and realizations converge. Clearly, the accuracy of
2 the realized risk premium as an estimator of the prospective risk premium is
3 enhanced by increasing the number of years used to estimate it....

4 Accordingly, Ms. Nelson's approach to calculating the projected market risk premiums is
5 not academically or practically sound.

6 For the above reasons, Ms. Nelson's development of the forecasted MRP used by the
7 Company in the CAPM and ECAPM cost of equity calculations is seriously flawed and
8 should be rejected.

9 **Q PLEASE COMMENT ON MS. NELSON'S USE OF THE ECAPM METHOD.**

10 The basic premise for the use of the ECAPM method is that the Beta factors published by
11 Value Line when used in CAPM analysis do not accurately predict stock performance.
12 However, as explained below, this argument is flawed.

13 Notwithstanding Ms. Nelson's arguments, there is academic disagreement with the
14 validity of the original studies that led to the use of ECAPM. First, the original study used
15 raw betas and not the adjusted Value Line betas, which I use, and which other cost of
16 capital experts normally rely upon. Second, the original studies relied upon short-term
17 risk-free rates. Instead, cost of capital witnesses, including myself, who have been
18 involved in the Company's rate cases use long-term risk-free rates in the CAPM model.

19 Dr. Morin points out this key difference on page 191 of his book "New Regulatory
20 Finance" where he states that "...the long-term risk-free rate version of the CAPM has a

1 higher intercept and a flatter slope than the short-term risk-free rate version which has been
2 tested.”

3 The ECAPM produces a faulty cost of equity rate with a bias toward overstating and
4 inflating the true cost of equity capital. The Commission should continue to disregard this
5 alternative approach to the traditional CAPM method.

6 **Q. HAVE OTHER REGULATORY COMMISSIONS WIDELY EMBRACED THE**
7 **ECAPM METHODOLOGY FOR SETTING RETURN ON EQUITY RATES?**

8 A. No. The Attorney General asked the Company if other regulatory commissions supported
9 ECAPM. In response the Company stated that the ECAPM methodology was accepted in
10 Mississippi, Alaska, New York, North Carolina, and Maryland.⁷⁰

11 Regarding the purported acceptance of the ECAPM in the State of Mississippi, the filing
12 requirements of the Mississippi Commission required ECAPM filings in the past. The
13 case referenced by the Company was from 2001. Therefore, the extent to which
14 Mississippi currently relies upon these estimates is unknown.

15 Regarding the Maryland commission, the Company cited case 9311 from 2013 as being
16 relevant. However, in a more recent case involving PEPCO (case 9418) with an order
17 issued on November 15, 2016, the result is different. As shown in the summary positions
18 articulated in the order in this case, no party involved in the proceedings, other than the

⁷⁰ See AGDE-2.54b.

1 company, put forth an ECAPM ROE estimate. In this case, the Maryland commission
2 basically adopted the Staff's position with no ECAPM estimate and rounded down the
3 Staff's recommended ROE of 9.57% to 9.55%.

4 Furthermore, the Maryland Commission stated on page 100 of the order the following.
5 *"Our Decision today most closely aligns with Staff's recommendation of 9.57% although*
6 *we do not expressly reach the same conclusion as Staff. We find that a slightly lower ROE*
7 *of 9.55% is both adequate and appropriate for Pepco...."* The Maryland commission
8 expressed no position on ECAPM. I am not aware of any more recent cases that show a
9 change in the commission's view of the ECAPM methodology.

10 **Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER**
11 **REGULATORY COMMISSIONS HAVE APPROVED IN THE PAST TWO**
12 **YEARS FROM JULY 2023 TO JUNE 2025.**

13 A. Exhibit AG-28 shows the ROEs approved by state regulatory commissions for U.S.
14 electric utilities during the most recent two years ended June 2025. The majority of the 50
15 ROE decisions in the 12 months ended June 2024 and the 46 decisions in the subsequent
16 12 months period ended June 2025 are at rates well below 9.9%, which is DTEE's current
17 authorized ROE.⁷¹ As shown on page three of the exhibit, ten decisions in the 12 months
18 ended June 2024 and ten decisions in the 12 months ended 2025 are at rates of 9.9% or

⁷¹ The decisions for the periods ended June 2024 and June 2025 are from RRA and exclude Limited Issue Rider cases.

1 greater. These higher rates are primarily from regulatory commissions in California,
2 Florida, and Michigan, and several pertain to small companies or other special situations.
3 ROEs in California have been at or above 10% reflecting the unique challenges for utilities
4 in that state with frequent wildfires and earthquakes risks. ROEs in Florida reflect damage
5 to utility property and financial losses from hurricanes, which is an on-going challenge for
6 the utilities in the state. High ROEs in other jurisdictions tend to reflect smaller utilities
7 or unique geographical challenges, such as in Alaska.

8 For most of the other electric utilities that have business and financial risks comparable to
9 DTE Electric's operations, the ROE rates have averaged between 9.50% and 9.60% in the
10 past two years. This evidence supports a lower overall cost of equity than the Company's
11 current ROE rate of 9.90%. This rate is excessive and "out of line" with comparable
12 electric utilities and the true cost of equity capital. The Company's proposed ROE rate of
13 10.75% is even further removed from reality and clearly unsupportable. My recommended
14 ROE rate of 9.85% in this rate case is quite reasonable and a gradual step down to the
15 Company's true cost of equity capital.

16 I will also point out that the most recent average ROE rates for electric utilities in the
17 Midwest are 9.81%. Exhibit AG-29 shows that information. This is another benchmark
18 that shows the 9.85% ROE rate I have proposed is reasonable and appropriate for the
19 Company in this rate case.

1 **Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN**
2 **AUTHORIZED ROE BELOW 9.90% IN THIS CASE WILL LEAD TO**
3 **IMPAIRMENT OF THE COMPANY’S ABILITY TO ACCESS THE CAPITAL**
4 **MARKETS?**

5 A. No. From time to time in general rate case proceedings, certain rate case applicants,
6 including the Company, have raised arguments that they should receive higher ROEs to
7 ensure the financial soundness of the business and to maintain a strong ability to attract
8 capital in addition to being compensated for risk. However, those concerns are not
9 supported by the evidence. Exhibit AG-28 shows several electric utilities that have
10 accessed the capital markets at competitive interest rates since receiving a ROE near or
11 below the average rate of 9.50%.

12 As shown on Exhibit A-18, Schedule H2, the market for new utility debt issues has been
13 very robust with over 220 new issues completed in 2024. DTE Electric issued \$500
14 million of long-term debt in February 2024 at an interest rate of 4.85% and a 3-year term.
15 Also, in February of 2024, DTE Electric issued \$500 million of new 10-year debt at an
16 interest rate of 5.2% and \$1.1 billion of new 5-year debt at a rate of 5.2%. Accordingly,
17 the debt markets have been receptive to utility companies’ capital raising activities even
18 when utilities have been granted ROEs below 9.50%.

19 Similarly, there is no evidence that equity investors have abandoned utilities that have been
20 granted ROEs near or below the industry average. On the contrary, stock investors

1 continue to migrate to utility stocks, recognizing that authorized ROEs are competitive.
2 Exhibit AG-29 shows the market to book ratios for each of the peer group companies. The
3 group of companies has an average Market to Book common equity value ratio of
4 approximately 2.0 times, meaning that they are earning returns above the expected return
5 on book equity capital. Interestingly, many of these companies received rate orders during
6 the past few years with ROEs as low as 8.72% and their stock still trades above book value.

7 A market to book value greater than 1.0 shows that investors are attracted to the return
8 (ROE) earned by utilities on their book value. A higher market to book ratio indicates that
9 the utility is earning a return on book value that is higher than the investor expects for that
10 type of investment and is willing to pay a higher market price for the stock than book value.

11 This information is provided to dispel the myth that the Company must receive a high ROE
12 above the industry average, or it will face dire consequences in the financial markets.

13 The fact that the Company needs to raise capital because of a large capital investment
14 program to upgrade its infrastructure and for other purposes is not unique to DTE Electric.
15 Most electric utilities face the same issues and are able to raise capital with ROEs at or
16 near the 9.5% average rate. Therefore, this issue is another “red herring.”

17 **Q. WITNESS NELSON RAISES THE SUBJECT OF THE VIX AS A MEASURE OF**
18 **VOLATILITY AND RISK ON PAGE 67 OF HER TESTIMONY AND SHOWS A**
19 **GRAPH (FIGURE 12) REFLECTING A VIX RATE OF 45.3 IN APRIL 2025.**
20 **WHAT IS YOUR ASSESSMENT?**

1 A. Ms. Nelson claims that the higher volatility represented by the VIX reflects a need for
2 higher returns in the market. The 45.3 VIX level she shows in Figure 12 reflects a period
3 of temporary market turmoil when the “Trump tariffs” were introduced. Since April 2025,
4 greater clarity in the markets has taken hold and the VIX fell to 14.79 by August 19, 2025,
5 which is near the lowest level so far in the year. The relevance of the VIX is discussed
6 further below.

7 **Q. ON OCCASION IN PAST RATE CASES, THE COMMISSION POINTED TO**
8 **INCREASED VOLATILITY IN THE CAPITAL MARKETS AS A REASON TO**
9 **AUTHORIZE A HIGHER ROE RATE. SHOULD STOCK MARKET**
10 **VOLATILITY OR THE VIX INDEX BE A CONCERN IN ESTABLISHING A**
11 **FAIR ROE RATE FOR THE COMPANY?**

12 A. No. The stock market has historically been very volatile. Currently, this is measured by
13 the VIX, which portrays volatility over the next 30 days. In some periods, stock prices
14 move up and down more dramatically than at other times. The key factor is that the VIX
15 is telling us something about risk in the market over the next 30 days and not the risk
16 several months in the future. In setting ROE rates for utilities, the Commission’s focus is
17 the long-term financial health of the utility not the short-term gyrations of the stock market.

18 As a supporting point, in Exhibit AG-38, I have included a Value Line Funds article written
19 by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not
20 risk. Mr. Appel goes on to say later in this article that “...volatility is only risk if you act

1 during down times, that is, only if you sell a stock.” This principle still applies to events
2 today.

3 Additionally, I will submit that those who invest money in equity portfolios over longer
4 periods of time and particularly in utility stocks have an aversion to market volatility and
5 the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty
6 and volatility because they are not as susceptible to volatility as the general stock market.
7 This is reflected in the average Beta value of 0.75 of the utility peer group used in the
8 CAPM discussed earlier, in contrast with the general stock market value of 1. The recent
9 stock market volatility in April 2025 due to the imposition of trade tariffs is an example
10 where utility stocks have outperformed the general stock market as a safer heaven for
11 investment.⁷² Therefore, the Commission should not give any weight to arguments that
12 the Company’s ROE should reflect investors’ concerns with stock market volatility.

13 **Q. PLEASE EXPLAIN YOUR CONCLUSION CONCERNING THE APPROPRIATE**
14 **RETURN ON EQUITY RATE THAT THE COMMISSION SHOULD APPROVE**
15 **IN THIS RATE CASE.**

16 A. In Exhibit AG-24, I summarized the cost of equity rates from the three methods I discussed
17 above. The range of returns for the industry peer group is from 9.8% at the low end, using
18 the DCF approach and 9.97% at the high end using the CAPM approach.

⁷² For example, from the end of 2024 and through April 15, 2025, the price of DTE Energy common stock was up 10.1% while the S&P 500 Index was down 8.2%.

1 As explained earlier in my testimony, I give 50% weight to the DCF method as a more
2 reliable approach to estimating the cost of equity for a utility, which from my analysis is a
3 rate of 9.8%. In this regard, on line 4 of Exhibit AG-24, I have calculated a weighted
4 return on equity from the three methodologies using a 50% weight for DCF and 25% for
5 each of the other two methods. The result is a weighted average cost of common equity of
6 9.86%, which I have rounded to 9.85%.

7 With the high expectations from economists that the Federal Reserve Bank will resume
8 lowering interest rates in 2025 and into 2026, the 9.85% ROE rate I recommend is a fair
9 and reasonable rate if not generous to the Company.

10 **Q. IF THE COMMISSION APPROVES A 9.90% COST OF COMMON EQUITY IN**
11 **THIS CASE, AS IT DID IN THE COMPANY'S LAST CASE, WHAT IS THE**
12 **ADDITIONAL COST TO CUSTOMERS COMPARED TO AN ROE OF 9.85%?**

13 A. If the Commission were to approve a 9.90% ROE in this case versus a 9.85% ROE, the
14 additional cost to customers is approximately \$6 million annually. There is absolutely no
15 need to burden customers with this additional cost, when historically the Company has
16 been earning well above its true cost of common equity.

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

19 **VII. O&M Expense Adjustments**

1

2 **Q. WHAT AMOUNT OF O&M EXPENSE DID THE COMPANY INCUR DURING**
3 **2023 AND WHAT IS THE AMOUNT OF EXPENSE REQUESTED FOR THE 2026**
4 **PROJECTED TEST YEAR?**

5 A. As shown in Exhibit A-13, Schedule C5, the Adjusted Historical Test Period O&M
6 expense for 2023 is \$1.173 billion. The Company forecasted that O&M expenses will
7 increase to \$1.393 billion in the test year ending December 2026. The increase over the
8 three-year period is \$220 million or nearly 19%. However, the adjusted 2023 O&M
9 expense includes nearly \$41 million of normalization adjustments that the Company has
10 added to actual expenses from 2023. Therefore, the effective increase in total O&M
11 expenses over the three years is \$261 million.

12 **Q. IN YOUR ANALYSIS, HAVE YOU IDENTIFIED AREAS WHERE EXPENSES**
13 **SHOULD BE REDUCED?**

14 Yes. As a result of my analysis, I have identified \$203.6 million of expense reductions,
15 which I will discuss in more detail below. Exhibit AG-39 provides a summary of my
16 proposed adjustments.

17 **A. Distribution - O&M Expense**

18 **Q. PLEASE DISCUSS THE ADJUSTMENTS YOU PROPOSE TO DISTRIBUTION**
19 **O&M EXPENSES FOR THE PROJECTED TEST YEAR.**

1 A. On page 1 of Exhibit A-13, Schedule C5.6, the Company shows total O&M expense for
2 Distribution operations of \$505,513,000 for the 2026 projected test year. To arrive at this
3 amount the Company started with actual expenses from 2023 and made certain
4 normalization adjustments before adding forecasted inflation cost increases and other
5 expense adjustments. Page 2 of Schedule C5.6 provides brief explanations of the
6 normalization adjustments to 2023 actual expenses and identifies the additional
7 adjustments to the 2023 inflation adjusted expenses.

8 **1. Distribution Base O&M Expense**

9 As discussed on pages 12-13 of the direct testimony of Mr. Kryscynski and in Mr. Marco
10 Bruzzano's direct testimony, the Company instituted a significant cost reduction initiative
11 in 2023 to address an expected decline in earnings. The Company considered this a
12 temporary reduction in expenses and reinstituted most of the expenses as normalization
13 adjustments in calculating the forecasted expenses for the projected test year. To arrive at
14 the normalization adjustments, the Company assumed that 2022 expenses would continue
15 into 2024 and future years.

16 Although the Company's normalization approach seems straightforward, it assumed that
17 all or most of the 2022 expenses would return in 2024 and future years. Since not all the
18 expense reductions in 2023 have been reinstated, a better approach is to use the actual 2024
19 expense level and build the projected test year expenses from that point forward. If the
20 2023 expense reductions were truly a one-year reduction, the 2024 actual expenses would

1 reflect normal level of expenses. In response to discovery, the Company provided the
2 actual expenses for 2024 and made some, but fewer, normalization adjustments, which I
3 will discuss further. The 2024 Distribution O&M expense schedule provided in response
4 to DR MNSC-3.16 is included in Exhibit AG-40 and is similar to Schedule C5.6. I will
5 use this schedule with actual 2024 expenses to build the total expense level for the 2026
6 projected test year.

7 Using the actual total distribution expense amount of \$325,675,000 from 2024, I added
8 \$23,784,000 to normalize the Storm Restoration O&M expense to a five-year average
9 amount. To calculate this normalization amount, I used the actual historical expenses
10 while the Company applied the same Constant Dollar Averaging adjustments to historical
11 amounts that it used for Emergent Replacements capital expenditures. The Company
12 normalization adjustment is much higher at \$35,828,000. As discussed in the Capital
13 Expenditures-Distribution section of my testimony, the constant dollar averaging approach
14 and the normalization amount calculated by the Company should be rejected.

15 Regarding the remaining 2024 normalization adjustments made by the Company, those
16 adjustments consist of \$1,758,000 for a hiring pause, \$1,735,000 for pausing purchases of
17 materials and advertising, reduced spending on consultants, and limiting apprentice
18 classes. If these pauses in spending and delayed hiring continued into 2024, they are no
19 longer temporary. If the Company can function for two years, 2023 and 2024, without
20 incurring those expenses, they should not occur in subsequent years and into the projected
21 test year. Therefore, I have excluded those adjustments from my calculations to arrive at

1 the 2026 forecasted O&M expenses and I recommend that the Commission reject them
2 also.

3 Exhibit AG-41 shows the calculations to arrive at a revised 2026 O&M expense amount
4 for Distribution operations of \$475,802,000. This amount is \$29,711,000 lower than the
5 Company forecast of \$505,513,000 and I recommend that it be removed from the
6 Company's forecasted O&M expense for the projected test year. To simplify the
7 presentation of the base Distribution O&M expense, I used the same 2026 special
8 adjustments of \$113,518,000 proposed by the Company. However, in my testimony
9 below, I discuss reductions to some of these adjustments.

10 **2. Tree Trimming O&M Expense**

11 **Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO TREE TRIMMING**
12 **EXPENSE FOR THE PROJECTED TEST YEAR.**

13 A. In Exhibit A-13 Schedule C5.6.1, the Company shows total test year expense for tree
14 trimming of \$180 million with an increase of \$74,602,000 over the historical 2023
15 expense. In her testimony, Company witness Rachel Steudle discusses various aspects of
16 the tree trimming program and the reasons for additional spending to expand the program
17 to increase its effectiveness in reducing damage to electrical lines and power outages. Her
18 testimony culminates on page 32 where she identifies \$145 million to be spent on the base
19 plan of tree trimming and an additional \$35 million for an expanded program. The

1 additional \$35 million would be spent on clearing trees outside the right-of-way, removing
2 overhanging branches, and removing brush and other vegetation.

3 In discovery, the Attorney General asked the Company to provide the calculations and cost
4 components of both the \$145 million and \$35 million forecasted expenses. The
5 information provided in response to discovery shows that for the base program, the
6 Company determined the number of miles of electrical lines to be cleared in the projected
7 test year based on an average trimming cycle of 5.8 years. To this number of miles, it
8 applied a forecasted cost per mile to calculate the cost of tree trimming. The \$145 million
9 also includes a reserve (Trouble) amount of \$10 million to address special requests for tree
10 trimming that occur during the year and also added \$8.5 million for Company staff and
11 program administrative costs.⁷³

12 Regarding the \$35 million new program, there are four components: Overhang Removal
13 (\$6.2 million), Increased Tree/Brush Removal (\$10.3 million), Outside of ROW Tree
14 Removal (\$15.1 million), and Supporting Costs (\$3.5 million).⁷⁴ Given the newness of
15 this program, there are no historical benchmarks to which to compare the Company's
16 forecasts. Many of the estimated costs appear to be rough order of magnitude estimates
17 and sometimes duplicative of other costs already included in the base program. Three
18 items stand out as excessive and should be removed from the \$35 million forecast.

⁷³ Exhibit AG-42 includes DR AGDE-6.201a with attachment.

⁷⁴ Id.

1 First, the Company included \$3.5 million for inspection and planning of trees outside the
2 ROW. The Company has already included in the base program \$8.5 million for program
3 management costs. Any new program planning should be done within the same staff
4 group. Inspection and removal of trees outside the ROW should occur in conjunction with
5 work in the ROW. Most of the additional cost should be the removal of trees and
6 vegetation outside the ROW. Second, the Company included \$2.5 million for customer
7 outreach and call center support. There was no explanation or basis provided for these
8 additional costs. The Company already notifies customers of tree trimming work being
9 done in or around the customer's property. The incremental cost here should be marginal,
10 including any complaints or inquiries received by the call center.

11 Third, the Company included \$2.322 million for additional trees to be removed. There is
12 no explanation for this additional cost or the necessity to clear additional trees not already
13 covered in the base program, the Trouble reserve of \$10 million, and the outside of the
14 ROW tree removal. This expense is unsupported and duplicative. The three items total to
15 \$8.322 million. I recommend that the Commission remove this amount from the Tree
16 Trimming special program of \$35 million and reduce that amount to \$26,716,000 on top
17 of the \$145 million base program.

18 **3. O&M Expense For Corrective & Preventive Maintenance**

19 **Q. PLEASE DISCUSS YOUR ADJUSTMENT TO THE COMPANY'S FORECASTED**
20 **O&M EXPENSE FOR CORRECTIVE AND PREVENTIVE MAINTENANCE.**

1 A. In footnote 6 to Exhibit A-13, Schedule C5.6, the Company shows that it added \$7.3
2 million to the forecasted test year O&M expense for Corrective Maintenance and an
3 additional \$7.3 million for Preventive Maintenance for a total amount of \$14.6 million.
4 Those same amounts are included in the 2024 O&M expense schedule in Exhibit AG-40.
5 On pages 42 and 43 of his testimony, Mr. Robinson briefly discusses both items and states
6 that the Company faces a backlog in both corrective and preventive maintenance.

7 In response to discovery, the Company stated that the backlog includes damaged or
8 defective electrical or structural system equipment that requires repair or replacement.⁷⁵
9 From Mr. Robinson's testimony and the discovery response, it is evident that the Company
10 has deferred undertaking corrective maintenance in prior years, despite receiving increases
11 in O&M expense recovery, and now has a backlog that it seeks to resolve by requesting
12 incremental O&M expense again. Customers should not pay twice for maintenance work
13 that should have been done in prior years with O&M expenses included in rates in those
14 years. The Company should undertake corrective maintenance and resolve the
15 maintenance backlog at its own cost. Therefore, I recommend that the \$7.3 million for
16 corrective maintenance expense for the projected test year should be disallowed.

17 Regarding the Preventive Maintenance adjustment of \$7.3 million proposed by the
18 Company, this issue is similar to the corrective maintenance problem as a result of the
19 Company deferring maintenance in prior years and causing a backlog of work to build up

⁷⁵ Exhibit AG-43 include DR AGDE-6.17bi.

1 instead of spending the O&M expense dollars included in rates to prevent the backlog from
2 occurring. In response to discovery, the Company identified that approximately \$5.0
3 million of the \$7.3 million pertains to clearing the backlog and the remaining \$2.3 million
4 to stay on cycle.⁷⁶ In response to additional discovery, the Company stated that there are
5 no changes proposed and the Company is carrying out the current inspection cycles shown
6 in Table 6 on page 40 of Mr. Robinson's testimony. Therefore, there should be no need
7 for incremental expense in order to stay on cycle with preventive maintenance. I
8 recommend that the Commission also disallow the incremental expense of \$7.3 million
9 proposed by the Company for the projected test year.

10 The total proposal disallowance in this area is \$14,600,000.

11 **4. Staking and Locating O&M Expense**

12 **Q. PLEASE DISCUSS YOUR ADJUSTMENT TO THE COMPANY'S FORECASTED**
13 **O&M EXPENSE FOR LINE STAKING AND LOCATING.**

14 A. On page 43 of his direct testimony, Mr. Hill states that O&M expenses for MISS DIG
15 Staking and Locating would increase by \$2.9 million in the projected test year over the
16 2023 expense. The Company also refers to this expense item as Damage Prevention. In
17 response to discovery, the Company provided the build-up in expense from 2023 to 2024.⁷⁷

⁷⁶ Id. Includes DR AGDE-6.172.

⁷⁷ Exhibit AG-44 CONF includes DR AGDE-4.144a with Confidential attachment.

1 The cost build-up includes both price increases with contractors and inflationary cost
2 increases plus forecasted higher staking and locating requests from 2023 to 2026.

3 There are several issues with the cost build-up. First, inflationary cost increases should
4 not be added to contractor cost increases because the inflation increases reflect increases
5 in prices. This is clearly a duplication worth about \$675,000. Second, the Company
6 forecasted volume increases for an additional 38,468 staking and locating requests
7 between 2023 and 2026. This increase is inordinate and appears to be driven by the surge
8 in staking and locating requests in 2021 and 2022 following the downturn in construction
9 in 2020 from Covid-19. Third, the contractor cost to complete each staking and locating
10 request increases by 41% from 2023 to 2026. This rate of increase is exorbitant and
11 unsupported.

12 In discovery, the Attorney General requested the Company to provide the contractors' bid
13 prices and related information and the Company refused to provide them, claiming it was
14 confidential, despite the fact that a protective order is in place in this rate case. The
15 Company offer to review this information in a video conference was inadequate because
16 it would not allow for detailed analysis of the data. With less than two days before filing
17 of intervenor testimony, the Company provided a few highly redacted documents with
18 insufficient time to analyze.

19 In summary, the \$2.9 million increase in Staking and Locating expense is grossly inflated,
20 partially unsupported, and unverifiable. In response to discovery, the Company also

provided the expense increase from actual 2024 to the 2026 forecasted expense.⁷⁸ In addition to the inflation adjustments the forecast includes \$1,618,000 of incremental adjustments for 2026. In the latest forecast the Company doubled the amount of MISS DIG fees from \$605,000 in 2024 to \$1,285,000 in 2026 and added an additional \$975,000 in contractor staking costs with no explanation. The same problems exist with the 2024 to 2026 forecast as described for the cost increases from 2023 to 2026. The increases are unsupported and unverifiable. Therefore, I recommend that the Commission remove the special increase in expense of \$1,618,000 proposed by the Company. I recommend this amount instead of the \$2.9 million because in my calculations above I adjusted the Base Distribution O&M expense based on the increase in expense from 2024 to 2026.

Q. WHAT IS THE TOTAL AMOUNT OF O&M EXPENSE FOR DISTRIBUTION OPERATIONS THAT YOU RECOMMEND SHOULD BE DISALLOWED FOR THE PROJECTED TEST YEAR?

A. In total, for Distribution O&M expense, I recommend that the Commission disallow \$54,251,000.

B. Engineering and Support Staff O&M Expense

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU PROPOSE TO O&M EXPENSE FOR INCREMENTAL ENGINEERING AND SUPPORT STAFF.

⁷⁸ Id. Includes DR MNSCDE-3.18.

1 A. As discussed in the Capital Expenditures – Engineering and Support Staff section of my
2 testimony, I recommend that the Commission disallow the incremental expense of
3 \$8,328,000 included by the Company in the 2026 test year O&M expense for increases in
4 engineering and support personnel.

5 **C. Steam Generation O&M Expenses**

6 **Q. IN EXHIBIT A-12, SCHEDULE C5.1, THE COMPANY FORECASTED O&M**
7 **EXPENSES FOR STEAM POWER GENERATION OF \$197.8 MILLION FOR**
8 **THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY’S**
9 **FORECASTED AMOUNT?**

10 A. No. The forecasted 2026 O&M expense build up for Steam Power Generation by the
11 Company from the 2023 actual expense suffers some of the same problems as the
12 Distribution expense discussed above with several normalization adjustments and is
13 outdated. In response to discovery, the Company provided the more recent actual 2024
14 O&M expenses with a build-up to 2026 test year expenses.⁷⁹ Although some of the
15 normalization adjustments and special 2026 adjustments included by the Company on the
16 2024 schedule need to be removed, it provides a cleaner basis to arrive at a reasonable
17 level of O&M expense for Steam Power Generation.

18 **1. Steam Generation Base O&M Expense**

⁷⁹ Exhibit AG-45 includes DR STDE-4.1 with attachment.

1 Exhibit AG-46 includes the Steam Power Generation O&M expense build-up for 2026 that
2 I have prepared from the Company's 2024 O&M expense schedule with appropriate
3 adjustments to remove items that should not be included in the expense forecast. The
4 Company reported adjusted 2024 O&M expenses of \$171,133,000. This amount includes
5 normalization adjustments for economic reserve, forced outages, periodic outages, excess
6 obsolescence, and tipping fees for BESS projects. A similar list of historical normalization
7 adjustments was included in the 2023 O&M expense in Schedule C5.1.

8 This rate case is the first time that the Company proposed normalization adjustments for
9 these items. Economic reserves, forced outages, and periodic outages occur every year in
10 varying frequencies. For the Company to propose that 2023 and 2024 were unusual years
11 and the same or similar level of activity will not occur in 2026 is simply guess work.
12 Forced outages are random occurrences that occur unexpectedly. Economic outages
13 reflect the price of energy in the year they occur. The Company has no crystal ball to
14 predict what economic reserve events will occur in 2026. The Company does not know
15 yet what planned outages will occur in 2026 and at which facilities. If it knows, it has not
16 disclosed those plans publicly.

17 Furthermore, steam power generation is on the decline as the Company continues to retire
18 coal power plants. The outages that occurred in 2021 or 2022 are not likely to occur at the
19 same level in 2026. The historical normalization adjustments for the three types of outages
20 proposed by the Company are inappropriate. They total \$8,888,000. In my analysis to

1 arrive at the forecasted O&M expense for the projected test year, I have removed them,
2 and I recommend that the Commission also reject them.

3 Regarding the excess obsolescence and BESS tipping fees adjustments, the Company did
4 not explain or provide justification for these adjustments. Since they are unsupported, I
5 have removed them from my analysis and recommend that the Commission also reject
6 them. After removing the historical normalization adjustments, the adjusted 2024 expense
7 level is \$157,836,000. To this amount, I added two years of inflation for 2025 and 2026
8 and also temporarily added the Other Adjustments of \$17,201,000 proposed by the
9 Company. I will discuss these items later. The result is a forecasted base O&M expense
10 of \$183,280,00 for 2026. This amount is \$14,551,000 lower than the Company's forecast
11 of \$197,831,000. I recommend that the Commission adopt this adjustment and reduce the
12 Company's O&M expense by \$14,551,000 plus other adjustments discussed below.

13 **2. Monroe Reliability Maintenance Expense**

14 In footnote 7 to Exhibit A-13, Schedule C5.1, and also in the 2024 updated Steam Power
15 Generation schedule in Exhibit AG-45, the Company included a special adjustment to
16 increase 2026 O&M expense by \$7,686,000 for Monroe Reliability Maintenance. In
17 response to discovery, the Company provided the items that comprise this amount. The
18 list shows sootblower preventive maintenance, coal mill inspections, polisher resin
19 replacement, blade restoration, and equipment cleaning.⁸⁰ These items for the most part

⁸⁰ AG-47 includes DR AGDE-4,128cii and STDE-4.9a with attachment.

1 are routine maintenance items that should be part of annual maintenance and those costs
2 should already be included in the 2024 O&M expenses I used to develop the 2026 O&M
3 expense forecast. Therefore, I recommend that the Commission remove the \$7,686,000
4 from the 2026 forecasted expense. This is an additional adjustment to the Base Steam
5 Power Generation expense adjustment recommend above.

6 **3. Monroe Coal Equipment Maintenance Expense**

7 In footnote 7 to Exhibit A-13, Schedule C5.1, and in the 2024 updated Steam Power
8 Generation schedule in Exhibit AG-45, the Company included a special adjustment to
9 increase 2026 O&M expense by \$3,294,000 for Monroe Coal Equipment Maintenance. In
10 response to discovery, the Company provided an explanation for the higher expense in
11 2026 that still leaves questions unanswered.⁸¹ The Company claims that after MERC shuts
12 down all coal will be delivered by rail and reliability of the coal dumper is critical,
13 requiring an overhaul in 2026 at a cost of \$3.3 million. The Company did not disclose
14 when MERC will shut down or why additional coal delivered by rail versus other means
15 will somehow overtax the coal dumper. There is no explanation as to how the cost was
16 developed or why the overhaul needs to be done in 2026. Given the limited information
17 provided by the Company, the incremental expense remains unsupported. Therefore, I
18 recommend that the Commission remove this expense item of \$3,294,000 from the 2026

⁸¹ Id. Includes DR AGDE-3.101a and STDE-4.9a with attachment.

1 O&M expense forecast. This is an additional adjustment to the Base Steam Power
2 Generation expense adjustment recommend above.

3 **Q. WHAT IS THE TOTAL AMOUNT OF O&M EXPENSE FOR STEAM POWER**
4 **GENERATION THAT YOU RECOMMEND SHOULD BE DISALLOWED FOR**
5 **THE PROJECTED TEST YEAR?**

6 A. In total, for Steam Power Generation, I recommend a reduction of \$25,531,000 to the
7 Company's forecasted O&M expense for the projected test year.

8 **D. Other Power Generation O&M Expenses**

9 **Q. IN EXHIBIT A-12, SCHEDULE C5.5, THE COMPANY FORECASTED O&M**
10 **EXPENSES FOR OTHER POWER GENERATION OF \$39.6 MILLION FOR**
11 **THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY'S**
12 **FORECASTED AMOUNT?**

13 A. No. The forecasted 2026 O&M expense for Other Power Generation prepared by the
14 Company from 2023 actual expense is outdated. In response to discovery, the Company
15 provided the more recent actual 2024 O&M expenses with a build-up to 2026 test year
16 expenses.⁸² Although some of the normalization adjustments and special 2026 adjustments

⁸² Exhibit AG-48 includes DR STDE-4.1 with attachment.

1 included by the Company on the 2024 schedule need to be removed, it provides a cleaner
2 basis to arrive at a reasonable level of O&M expense for the projected test year.

3 Exhibit AG-49 includes the Steam Power Generation O&M expense build-up for 2026 that
4 I have prepared from the Company's 2024 O&M expense schedule with appropriate
5 adjustment to remove items that should not be included in the expense forecast. The first
6 item is the historical adjustment of \$368,000 for BWEC maintenance. From the
7 information provided by the Company in response to discovery, it appears that the
8 Company is expecting that routine maintenance performed at BWEC during the warranty
9 period and paid by the contractor will continue into 2026 and will no longer be reimbursed
10 by the contractor.⁸³

11 This assumption may not be true for 2026. As discussed above under the Capital
12 Expenditures – Kiewit Payment section of my testimony, the Company has experienced
13 equipment and construction quality problems after BWEC went into commercial operation
14 in June 2022. After three years of operation, it would seem reasonable to expect that most
15 of those problems have been resolved, and the level of routine maintenance performed
16 during the warranty period would diminish going into 2026. Therefore, I have removed
17 this expense adjustment from my calculation in Exhibit AG-49. With an adjusted
18 historical 2024 O&M expense of \$26,464,000 I applied inflation adjustments for 2025 and
19 2026 and temporarily included the Other Adjustments of \$13,230,000 to arrive at the 2026

⁸³ Id. Include DR STDE-4.12.

1 expense of \$41,087,000. This amount is \$637,000 lower than the Company's forecast of
2 \$41,724,000 in Schedule C5.5. I recommend that the Commission adopt this reduction in
3 expense along with the other adjustments discussed next.

4 Regarding the Other Adjustments of \$13,230,000, the first Company proposed adjustment
5 to the 2026 expense is \$3,562,000 for BWEC normalization of periodic spend. On page
6 124 of her direct testimony, Ms. Guillaumin describes the adjustment as a normalization
7 of expenses to be incurred in 2026 for a periodic outage that occurs every four years. In
8 response to discovery, the Company provided a schedule showing various expenses it
9 expects to incur during the next major periodic outage in 2026. The expenses total to
10 approximately \$14,000,000 and the Company has taken one-fourth of those expenses and
11 added them to the 2026 O&M expense forecast.⁸⁴

12 Although the Company may incur some expenses with the major periodic outage, the
13 normalization adjustment fails to consider that during the major outage the plant is not
14 operating and not incurring normal operation and maintenance expenses. The Company
15 has not considered those cost savings, which may offset all or most of the \$14.0 million.
16 In fact, the Company has been through several periodic major outages for its coal plants
17 in prior years and has not proposed similar adjustments for the projected test year, which
18 is an indication that the incremental costs were offset by other cost savings. I recommend

⁸⁴ Id. Include DR STDE-4.12 with attachment.

1 that the Commission reject this adjustment and remove the \$3,562,000 from the forecasted
2 2026 O&M expense.

3 The next special adjustment is the Peaker Increase Maintenance for \$8,606,000. On page
4 125 of her testimony, Ms. Guillaumin states that in 2023 and 2024 there was an increase
5 in the operation of peaker generation units and those units will require more maintenance
6 in 2026 if the higher frequency of use continues. To the extent that peaker units
7 experienced higher maintenance costs in 2024, those costs are already included in the
8 calculations of O&M expense for 2026 and the need for any incremental adjustment is
9 unknown. Also, peaker units are typically dispatched during periods of high power
10 demand driven primarily by hot weather. This demand is random and can occur more one
11 year and not the next. To assume that higher costs will be incurred in 2026 is purely
12 guesswork.

13 In response to discovery, the Company provided a list of items that comprise the additional
14 expense of \$8,605,000. Most of the items listed are routine maintenance items. Only two
15 items can be considered unusual and incremental to routine maintenance. Those items are
16 the Renaissance Unit 2 compressor blade crack and the Dean Peaker Flex Seal
17 replacement. These items total to \$4,063,000. The remaining amount of \$4,542,000 is for
18 routine maintenance that is already reflected in the 2024 O&M expense. Therefore, I
19 recommend that the Commission remove the \$4,542,000 from the Company's forecasted
20 O&M expense for the projected test year.

1 **Q. WHAT IS THE TOTAL AMOUNT OF O&M EXPENSE FOR OTHER POWER**
2 **GENERATION THAT YOU RECOMMEND SHOULD BE DISALLOWED FOR**
3 **THE PROJECTED TEST YEAR?**

4 A. In total, for Other Power Generation, I recommend that the Commission disallow
5 \$8,741,000 of O&M expense for 2026.

6 E. Nuclear Generation O&M Expenses

7 **Q. IN EXHIBIT A-12, SCHEDULE C5.3, THE COMPANY FORECASTED O&M**
8 **EXPENSES FOR NUCLEAR GENERATION OF \$160.0 MILLION FOR THE**
9 **PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY’S**
10 **FORECASTED AMOUNT?**

11 A. No. The forecasted 2026 O&M expense for Nuclear Generation prepared by the Company
12 from 2023 actual expense is outdated. In response to discovery, the Company provided
13 the more recent actual 2024 O&M expenses with a partial build-up to 2026 test year
14 expenses.⁸⁵ Although some of the historical normalization adjustments included by the
15 Company on the 2024 schedule need to be removed, it provides a cleaner basis to arrive at
16 a reasonable level of O&M expense for the projected test year.

Exhibit AG-51 includes the Nuclear Generation O&M expense build-up for 2026 that I have prepared from the Company's 2024 O&M expense schedule with appropriate

⁸⁵ Exhibit AG-50 includes DR STDE-4.1 with attachment.

1 adjustments to remove items that should not be included in the expense forecast. The only
2 item I removed is the historical adjustment of \$4,861,000 for lower staff levels in 2024.
3 Apparently, the nuclear operation participated in the Company's temporary cost reduction
4 efforts in 2023 and reduced some staff members. Those reductions in staff continued into
5 2024. In response to discovery, the Company reported the employee headcount from 2022
6 to 2026.⁸⁶ The information shows that total headcount in 2023 decreased to 709 from 741
7 in 2022.

8 However, total headcount declined further in 2024 to 708 and declined again as of June
9 2025 to 703. This is not a one-year or temporary reduction in headcount. Although the
10 Company forecasted that it would increase headcount to 716 by the end of 2025 and up to
11 720 by the end of 2026, it has not done so yet. The 2026 headcount is still 20 employees
12 lower than at the end of 2022. It is evident from the delayed hiring that the nuclear plant
13 can operate comfortably at a lower employee level. Therefore, I do not give credence to
14 the Company's proposed adjustment of \$4,861,000 and recommend that the Commission
15 disallow it from inclusion in the 2026 O&M expense forecast.

16 Based on the outcome of the calculations in Exhibit AG-51, I propose that the 2026 O&M
17 expense for the Nuclear Generation be set at \$154,153,00, which is \$5,845,000 lower than
18 expense forecasted by the Company in Exhibit A-13, Schedule C5.3. Therefore, I

⁸⁶ Id. Includes DR AGDE-1.36diii.

1 recommend that the Commission remove the \$5,845,000 from the Company's forecasted
2 expense for the projected test year.

3 **F. Regulated Marketing O&M Expenses**

4 **Q. IN EXHIBIT A-12, SCHEDULE C5.9, THE COMPANY FORECASTED O&M**
5 **EXPENSES FOR REGULATED MARKETING OF \$32.1 MILLION FOR THE**
6 **PROJECTED TEST YEAR. DO YOU AGREE WITH THE COMPANY'S**
7 **FORECASTED AMOUNT?**

8 A. No. The forecasted 2026 O&M expense build up for Regulated Marketing by the
9 Company from the 2023 actual expense suffers some of the same problems as other
10 operations discussed above with several normalization adjustments and is outdated. In
11 response to discovery, the Company provided the more recent actual 2024 O&M expenses
12 with a build-up to 2026 test year expenses.⁸⁷ Although some of the normalization
13 adjustments and special 2026 adjustments included by the Company on the 2024 schedule
14 need to be removed, it provides a cleaner basis to arrive at a reasonable level of O&M
15 expense for the projected test year.

16 Exhibit AG-53 includes the Steam Power Generation O&M expense build-up for 2026 that
17 I have prepared from the Company's 2024 O&M expense schedule, with appropriate
18 adjustments to remove items that should not be included in the expense forecast. The

⁸⁷ Exhibit AG-52 includes DR TMS-2.1 with attachment.

1 Company reported adjusted 2024 O&M expenses of \$25,322,000. This amount includes
2 normalization adjustments for temporary reductions in customer outreach to promote clean
3 energy and deferred backfilling of employee positions. As seen in other operations, the
4 Company continued the reduction in expense past 2023 and into 2024. At this point, the
5 reductions are no longer temporary but reflective of a more permanent level of expense.
6 The proposed normalization to a higher expense level is no longer credible. Therefore, I
7 have removed the historical normalization expense of \$4,909,000 from my calculations of
8 the 2026 O&M expense for Regulated Marketing and recommend that the Commission
9 also reject those adjustments.

10 After applying inflation for 2025 and 2026 to the adjusted 2024 expense base and
11 temporarily including the Other Adjustments of \$7,990,000, I have calculated a base
12 Regulated Marketing O&M expense of \$29,358,000. This amount is \$2,739,000 lower
13 than the Company's forecasted expense of \$32,097,000 for the projected test year.
14 Therefore, I recommend that the Commission remove the \$2,739,000 from the Company's
15 projected test year expense.

16 Additionally, in the Other Adjustments to 2026 expense, the Company included
17 \$4,066,000 of demand response costs and \$1,340,000 for the Charging Forward program
18 expansion. These amounts are unchanged from the same amounts proposed from the 2023
19 historical expense base even though another year of cost increase occurred in 2024. In
20 response to discovery, the Company provided annual spending on these programs from
21 2021 to 2024. The amount spent on demand response programs increased by \$2.3 million

1 in 2024 over 2023. Similarly, spending on the Charging Forward program increased by
2 \$1.0 million in 2024 from 2023.⁸⁸ Further increases in expense in future years is
3 speculative at this time. Therefore, I have removed the Company's proposed adjustments
4 of \$4,006,000 and \$1,340,000 from the 2026 forecasted O&M expense and recommend
5 that the Commission reject those adjustments.

6 In total, for Regulated Marketing, I recommend the disallowance of \$8,085,000 from the
7 Company's forecasted O&M expense for the projected test year.

8 **G. Credit/Debit Card Merchant Fees**

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

12 A. Yes. In its November 7, 2024 order in Case No. U-21291, the Commission ruled that non-
13 residential credit card merchant fees should not be socialized across the DTE Gas customer
14 base and removed the related costs from the revenue requirement. In that order, the
15 Commission also stated that although the residential customer credit card merchant fees
16 were not contested, the same reasoning applied to those fees and it is not reasonable or
17 prudent to socialize those costs over the utility's customer base.⁸⁹

⁸⁸ Id. Includes DR AGDE-3.81a with attachment.

⁸⁹ U-21291 November 7, 2024 Commission Order, page 158.

1 In this rate case, the Company is not requesting recovery of non-residential credit card
2 merchant fees but continues to request recovery of residential merchant fees. The amount
3 requested for the projected test year is \$7,013,000. Among other reasons to continue the
4 current credit card program, both Mr. Foley and Mr. Sparks in their respective direct
5 testimony state that low income customers are the largest users of credit card payments
6 and point to the potential increase in uncollectible account expense and the negative impact
7 on those customers. What Mr. Foley and Mr. Sparks' testimonies do not acknowledge, is
8 that by using credit cards low-income customers may be building up large unpaid balances
9 and may be paying exorbitant interest on those balances, often at or above a 20% interest
10 rate. The Company is not doing those customers any favors by encouraging the use of
11 credit cards.

12 Regarding higher uncollectible costs, in past rate cases the Company stated that there was
13 no meaningful impact on uncollectible costs from increased use of credit cards by
14 customers. It is now perplexing why the Company is concerned about this issue and the
15 potential increase in uncollectible expense.

16 In line with the Commission order in Case U-21291, I recommend that the Commission
17 deny recovery of credit and debit card merchant fees for residential customers and remove
18 the proposed expense of \$7,013,000 from the 2026 O&M expense in this rate case.

19 **H. Uncollectible Accounts Expense**

1 **Q. PLEASE SUMMARIZE HOW THE COMPANY ARRIVED AT ITS PROPOSED**
2 **\$48.1 MILLION EXPENSE FOR UNCOLLECTIBLE ACCOUNTS FOR THE**
3 **PROJECTED TEST YEAR.**

4 A. Company witness Jason Sparks discusses uncollectible accounts expense beginning on
5 page 51 of his direct testimony and sponsors Exhibit A-13, Schedule C5.8. The Company
6 started its calculation of the uncollectible expense of \$45.8 million for the projected test
7 year by using three years of net write-offs of bad debts as a percentage of revenues for
8 2021, 2022, and 2023. The resulting average ratio of 0.72% was applied to projected
9 revenues of \$6.4 billion to calculate uncollectible account expense of \$45.8 million. To
10 this amount the Company added (1) an additional \$1.2 million of net write-offs charged
11 directly to other expenses, and (2) an additional \$1.0 million for amortization of costs
12 related to the Low Income Payment Stability Plan Pilot previously approved by the
13 Commission. The total of the three amounts is the total uncollectible expense of \$48.0
14 million proposed by the Company.

15 **Q. WHAT APPROACH DO YOU PROPOSE TO SET UNCOLLECTIBLE**
16 **ACCOUNTS EXPENSE FOR THE PROJECTED TEST YEAR?**

17 My approach is similar to the Company's except that I incorporated results for the three
18 years ended 2024 into my analysis based on information received from the Company for
19 2024.⁹⁰ The Commission has stated in several cases that the use of a three-year average

⁹⁰ DR AGDE-4.17 and SMR-2.4 plus attachment.

1 ratio of charge-offs to revenues is the most appropriate way to forecast uncollectible
2 accounts expense.

3 **Q. WHAT IS YOUR PROJECTED AMOUNT FOR UNCOLLECTIBLE ACCOUNTS**
4 **EXPENSE FOR THE PROJECTED TEST YEAR?**

5 For the projected test year, I forecasted uncollectible accounts expense of \$46.4 million
6 using the three-year historical ratio of net charge offs to revenue for 2022, 2023, and 2024.
7 Exhibit AG-54 shows the net charge-offs of \$37.7 million for 2022, \$44.1 million for 2023,
8 and \$43.8 million for 2024.

9 Line 4 of my exhibit shows the average percentage of 0.71% as the ratio of net charge-offs
10 to revenue for the three-year historical period. This percentage is multiplied by the
11 projected test year revenues of \$6.4 billion on line 5 to derive the forecasted amount of
12 uncollectible accounts expense of \$45.4 million on line 6. To this amount, I added \$1.0
13 million to reflect the amortization of the Low-Income Pilot Program previously discussed
14 to arrive at a total cost of \$46.4 million. This amount is lower than the Company's forecast
15 by \$1.6 million.

16 Therefore, the Commission should set the uncollectible accounts expense for the projected
17 test year at \$46.4 million and reduce the Company's forecast O&M expense by \$1.6
18 million.

19 **I. Administrative and General Expenses**

1 **Q. ON EXHIBIT A-13, SCHEDULE C5.10, THE COMPANY SHOWS**
2 **ADMINISTRATIVE AND GENERAL EXPENSES OF \$224.1 MILLION IN 2026.**
3 **DO YOU AGREE WITH THIS EXPENSE PROJECTION?**

4 A. No. The Company's forecast is derived by adjusting 2023 costs to arrive at the 2026
5 expense level. It should be recognized that in 2023 the Company made significant cost
6 reductions that were to be temporary in order to bolster earnings. Additionally, in 2024,
7 the Company undertook a program to reduce its expense levels through the implementation
8 of an employee reduction program (the VSIP). This program was not implemented until
9 the March/April 2024 timeframe. Therefore, utilizing 2024 normalized expenses instead
10 of 2023 historical expenses is a more appropriate approach to estimating future expenses,
11 since most or all of the cost adjustments that the Company undertook are included in 2024,
12 whereas they could only be estimated after the fact using 2023 information.

13 Using 2024 as a starting point, I forecasted the projected test year expenses for this area to
14 be \$194.5 million, which is lower than the Company's forecast by \$29.6 million.

15 **Q. PLEASE EXPLAIN HOW YOU DEVELOPED YOUR FORECAST.**

16 A. Exhibit AG-55 shows the development of my projected test year forecast. Column (b) of
17 the exhibit reflects the normalized 2024 expense levels provided by the Company.⁹¹
18 Columns (c) and (d) reflect inflation adjustments based on the CPI-Urban index. Column

⁹¹ See AGDE 4.127a with the 2024 presentation attached.

(e) reflects some of the special adjustments proposed by the Company in Exhibit A-13, Schedule C5.10, page 1, column (j).

Q. PLEASE EXPLAIN THE DIFFERENCE IN THE SPECIAL ITEMS IN YOUR EXHIBIT IN COLUMN (E) AND THE COMPANY’S EXHIBIT A-13, SCHEDULE C5.10 IN COLUMN (J).

A. The key items of difference are as follows. First, the Company forecasted \$1.0 million in expense to manage new federal funding programs. Most of the federal funds are currently under review by the new administration and no significant additional work in this area is necessary. Any current work should be easily handled within the Company’s treasury function. Second, the Company estimates its VSIP savings at \$9.6 million on a full year basis for 2023. Since the program reductions took place after one quarter in 2024, I reflected only one-fourth of the Company’s calculated savings (or \$2.4 million) as being applicable to 2024. Third, the Company stated in response to discovery that the NICE software was implemented in 2024 and as such this item, which affected the expense in 2023, should not be a factor in the 2024 forecast.⁹² Fourth, I adjusted the annual amortization for the Incentive Compensation Tracker from a negative \$459,000 calculated by the Company to a negative expense of \$1,084,000 based on my calculation. Page 2 of the exhibit shows the revised calculation and this subject is further addressed below. Fifth,

⁹² See DR AGDE 4.127 e.

1 the Company includes a new expense item for 2026 that it called Cost to Achieve (CTA)
2 new IT projects. This expense is not adequately supported and I removed it.

3 **Q. PLEASE COMMENT ON THE COMPANY'S APPROACH TO COMPUTING ITS**
4 **INCENTIVE PLAN PERFORMANCE FOR 2024 AS COMPARED TO THE**
5 **ATTORNEY GENERAL'S APPROACH.**

6 A. In discovery, the Company provided the actual result of operating performance
7 measures.⁹³ The Company totaled its performance scores for its different metrics to
8 determine overall performance. This enables the Company to utilize metric scores of
9 between 100% and 200% (above target performance) to offset performance below target
10 levels on other metrics. This is contrary to the approach that the Commission approved
11 when it established the two-way tracking mechanism for incentive compensation. The
12 Attorney General's approach, which the Commission adopted, gives credit at the 100%
13 level for all metrics at the target level or above and no credit to actual performance below
14 the target level.

15 The adjustment I show above of \$1,084,000 complies with the Commission's approved
16 approach. Therefore, I recommend that the Commission accept my adjustment and reject
17 the Company's calculated amount.

⁹³ Exhibit AG-58 includes DR AGDE 8.255 with attachment

1 The net result is a decrease in 2026 expense of \$30.8 million compared to the Company's
2 forecast of \$224.1 million. I recommend that the Commission remove the \$30.8 million
3 from the Company's forecasted O&M expense for the projected test year.

4 **J. New Hire VEBA**

5 **Q. WITNESS COOPER ON EXHIBIT A-13, SCHEDULE C5.11, PROJECTS THAT**
6 **EXPENSES FOR THE NEW HIRE VEBA WILL INCREASE FROM \$5.4**
7 **MILLION IN 2023 TO \$7.8 MILLION IN THE PROJECTED TEST YEAR. DO**
8 **YOU AGREE WITH HIS FORECAST?**

9 A. No. Mr. Cooper's discusses the New Hire VEBA on page 9 of his direct testimony but
10 sponsors no exhibit to support his calculations. Page 2 of Exhibit A-13, Schedule C5.11,
11 shows a normalization adjustment in column (d) in the amount of \$1.375 million. In
12 column (j), he shows a \$1.3 million increase between 2023 and 2026, which he describes
13 as growth in new participants and for other factors.

14 Starting on page 10 of his testimony, he explains that this normalization adjustment is due
15 to an unusually high number of "true-ups" in 2023. Mr. Cooper's adjustment to the VEBA
16 expense is excessive and is at odds with normal historical growth of 1.5%.⁹⁴

⁹⁴ DR AGDE-4.115a. The attachment shows total capitalized and expense costs of \$9.7 million in 2020 and \$10.3 million in 2024 reflecting a 1.5% annualized growth rate.

1 **Q. PLEASE EXPLAIN HOW YOU DETERMINED YOUR ESTIMATE FOR 2026**
2 **NEW HIRE VEBA EXPENSES.**

3 A. In Exhibit AG-56, I calculated a New Hire VEBA expense for 2026 of \$5.969 million by
4 starting with actual 2024 expenses of \$5.605 million. By starting with actual 2024
5 expenses, I avoided the problem of 2023 “True up” credits that were a factor in Mr.
6 Cooper’s analysis. On lines 2 and 3 of the exhibit, I increased the 2024 expense at a 1.5%
7 annual rate to reflect historic growth as previously noted. This produces a cost of \$5.773
8 million prior to accounting for any population changes. In this regard, I further increased
9 the cost by an additional 1.7% per year over two years to reflect the expected employee
10 population growth.⁹⁵ This increased my forecast to \$5.969 million which is lower than the
11 Company’s projection by \$1.8 million.

12 I recommend that the Commission remove the \$1.8 million from the Company forecasted
13 O&M expense for the projected test year.

14 **K. Active Employee Health Care Expense**

15 **Q. IN EXHIBIT A-13, SCHEDULE C5.11, THE COMPANY FORECASTED THE**
16 **ACTIVE EMPLOYEE HEALTH CARE EXPENSE (MEDICAL, DENTAL, AND**
17 **VISION) AT \$50.0 MILLION FOR THE PROJECTED TEST YEAR. DO YOU**
18 **AGREE WITH THIS AMOUNT?**

⁹⁵ DR AGDE 4.112c provided actual and projected headcount data through 2026.

1 **A.** No. The Company's forecasted Active Health Care expense forecast of \$50.0 million for
2 the projected test year is an increase of \$6.8 million, or 16%, over the actual expense of
3 \$43.2 million in 2023. Witness Cooper addresses this topic starting on page 13 of his
4 testimony. There are two major problems with the Company's active health care expense
5 projection and the approach taken to forecast the expense. First, the Company continues
6 to apply inflationary factors to historical costs, which it misnames as constant dollar
7 averaging or as a normalization adjustment. This is simply a process that increases actual
8 historical costs in a way that is divorced from reality. This approach has been repeatedly
9 rejected by the Commission, but the Company continues to propose it in rate case after
10 rate case.

11 Second, Mr. Cooper uses national health care cost trend rates of 6.3% to 6.5% adjusted
12 down to cost increase rates of 3.5% to 4.6% to forecast future health care costs, instead of
13 using historical health care cost increases actually experienced by the Company or the CPI-
14 Urban inflation rate typically applied to other costs. The combination of these factors
15 unnecessarily inflates the forecasted expense for the projected test year.

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

18 **A.** Yes. In Exhibit AG-57, I calculated a forecasted expense of \$49.5 million for the projected
19 test year. To determine this result, I started with the actual 2024 expense level of \$45.4
20 million on line 1. On lines 2 and 4, I increased the base level by the CPI inflation rate,

1 adding \$1.3 million for 2025 and \$1.1 million for 2026. This increases the 2024 base
2 expense to \$47.8 million based on a constant employee population. As mentioned in my
3 testimony under the New Hire VEBA section, the Company expects to grow its employee
4 base at a 1.7% annual rate. I have taken this into account on line 6 of the exhibit. The
5 result is a \$49.5 million expense level, which is lower than the Company's estimate of \$50
6 million by \$0.5 million.

7 I recommend that the Commission approve the \$49.5 million forecasted active health care
8 expense for the test year and remove the \$0.5 million difference from the Company's
9 forecasted O&M expense.

10 **L. WCB Façade Repairs**

11 **Q. PLEASE DISCUSS YOUR ADJUSTMENT TO THE COMPANY'S FORECASTED**
12 **O&M EXPENSE FOR WCB FAÇADE REPAIRS.**

13 A. As discussed in the Capital Expenditures-Corporate section of my testimony, I proposed
14 that the repairs being made to the façade of the Walter Chisler Building (WCB) should be
15 expensed instead of capitalized. The Company forecasted repair costs of \$2,254,000 for
16 2026. Therefore, I have included here that increase in O&M expense.

17 **M. Rate Case Expenses**

18 **Q. PLEASE DISCUSS YOUR PROPOSAL FOR PARTIAL RECOVERY OF RATE**
19 **CASE EXPENSES INCURRED BY THE COMPANY.**

1 A. With the Company filing rate cases nearly every year, the costs incurred to prepare, file,
2 and litigate each case are becoming significant. Currently, the Company expenses those
3 costs and they become part of the base O&M expenses that it recovers in rates. In this rate
4 case, the Attorney General asked the Company to provide the total costs incurred to
5 complete each of the last three rate cases and the number of hours spent on the case by
6 Company employees. The Company was also asked to provide the amount paid to external
7 consultants retained to work on the rate cases. In response, the Company provided the
8 amounts paid to external consultant but stated that it does not track time or internal costs
9 spent on rate cases and could not provide that information. In a subsequent request, the
10 Attorney General asked the Company to provide an estimate of the time spent by each
11 witness in recent cases to prepare testimony and perform other tasks pertaining to the rate
12 case. The Company again responded that it was not able to provide a time or cost estimate.

13 **Q. WHAT DO THE EXTERNAL CONSULTANT COSTS REVEAL?**

14 A. In Case Nos. U-20836 and U-21297, which took place primarily during 2022 and 2023,
15 external consultant costs ranged between \$170,000 and \$175,000. In Case No. U-21534,
16 occurring primarily in 2024, the cost for rate case consultants increased to nearly \$570,000.
17 In the current case No. U-21860, the expected cost of rate case consultants is \$1.3 million.

18 **Q. WHAT INSIGHTS INTO THE TOTAL COST OF COMPLETING A RATE CASE**
19 **DO THE EXTERNAL CONSULTANT COSTS PROVIDE?**

1 A. The five external consultants in the current rate case filed 421 pages of testimony and
2 exhibits. Based on the \$1.3 million of consulting fees, the cost per page filed is
3 approximately \$3,085. This cost would include the time for research, discussions, case
4 strategy, data analysis, preparation of testimony, review of testimony, responding to
5 discovery requests, assisting with legal briefs, and several other tasks. These are the same
6 tasks performed by the Company's employees plus legal and other support resources.

7 In the current rate case, Company employees filed approximately 4,230 pages of testimony
8 and exhibits, which they prepared or were prepared by others in the company. The
9 testimony and exhibits most likely went through multiple levels of review and analysis
10 involving more people than the 30 witnesses who filed testimony in the case. By applying
11 the \$3,085 cost per page to the 4,230 pages of testimony and exhibits filed by Company
12 employees, I determined that the internal cost to complete the current rate case could
13 exceed \$13 million. This is before the external consultant cost, which would add another
14 \$1.3 million, for a total cost of \$14.3 million.

15 Such a cost is a significant burden to customers if the utility continues to recover 100% of
16 that expense.

17 **Q. ARE YOU AWARE OF ANY REGULATORY PRACTICES IN OTHER STATES**
18 **THAT SHARE THE BURDEN OF RATE CASE EXPENSES BETWEEN**
19 **CUSTOMERS AND SHAREHOLDERS?**

1 A. Yes. My understanding is that the states of Connecticut and Colorado have statutes that
2 exclude rate case expenses from rate recovery. New Jersey and Missouri have regulatory
3 commission precedents splitting rate case expenses 50/50 between customers and
4 shareholders.

5 **Q. WHAT IS YOUR RECOMMENDATION?**

6 A. I recommend that the Commission disallow recovery of 50% of the \$14.3 million, or \$7.1
7 million, from the projected test year O&M expense in this rate case. Additionally, I
8 recommend that the Commission direct the Company to establish a mechanism to keep
9 track of all costs to complete future rate cases and provide that cost with each new rate
10 case filing.

11 **N. Incentive Compensation Expense**

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

15 A. In this rate case covering the projected test year for the twelve months ending December
16 2026, the Company seeks to recover \$56.3 million of employee incentive payments. Based
17 upon the information provided on page 39 of the direct testimony of Mr. Fix, \$8.1 million
18 pertains to the Annual Incentive Plan (AIP), \$30.7 million to the Rewarding Employees
19 Plan (REP), and \$17.6 million pertains to the Long-Term Incentive Plan (LTIP).

1 2024 Annual Incentive Plan – for DTE Electric (excluding Nuclear) the AIP is an annual
2 bonus program focused on the following major categories and specific measures:

- 3 1. 40% on Financial Performance (DTE Electric Earnings, DTE Electric Cash From
4 Operations, and DTE Energy Earnings per Share).
- 5 2. 15% on Customer Satisfaction (Net Promoter Score).
- 6 3. 15% on Employee Safety & Engagement (DTE Energy Employee Engagement,
7 DTE Energy OSHA Incident Rate, and DTE Energy High Energy Serious Injury
8 or Fatality Rate).
- 9 4. 30% on Operating Excellence (Storm Customers Restored in 48 Hours), Nuclear
10 Annual Unit Capability Factor (UCF), and Customers Experiencing Multiple
11 Interruptions (CEMI4).

12 The operating measures for the nuclear employees are substantially similar except that
13 65% of the weight is based on Operating Excellence, zero weight on Customer
14 Satisfaction, 15% on Safety and Engagement, and only 20% is based on Financial
15 Performance.

16 These measures described above are for the year 2024. A review of the measures in place
17 for the prior five years reveals that certain measures and target levels have varied from
18 year to year. These changes make a direct comparison over the years more challenging.

19 2024 Rewarding Employees Plan – The REP is very similar in design and function to the
20 AIP with some variations in the non-financial measures. Where the AIP is designed for

1 senior level managers at DTE Electric and its affiliates, the REP covers all other employees
2 of these companies.

3 Both the AIP and REP are also applied to DTE Energy Corporate Services employees
4 providing support services to DTE Electric.

5 2024 Long Term Incentive Plan – The LTIP for DTE Electric and for DTE Energy
6 Corporate Services employees is an annual performance unit and stock grant plan focused
7 primarily on achieving multi-year goals and specifically on the following measures:

- 8 1. 80% on Common Stock Total Shareholder Return vs. a Peer Group.
- 9 2. 20% Three Year Cumulative Operating EPS.

10 For employees in the Company's Nuclear Division, the financial goals are 30%. Safety
11 and Engagement represents 25% of the total weighting, and Operating Excellence
12 represents the remaining 45%.

13 The testimony of Company witness Matthew Fix provides more details on the AIP, REP,
14 and LTIP.

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

16 A. My overall assessment is that the three incentive plans are too heavily skewed toward
17 measures that directly benefit shareholders and not customers. In this regard, page 39 of
18 Mr. Fix's testimony shows that \$35.8 million out of the \$56.3 million of incentive
19 compensation expense requested pertains to the Company's financial metrics.

1 Additionally, the customer benefits presented by the Company are based on a faulty
2 premise of historical cost savings and an expectation that future targets of performance
3 will be achieved.

4 Regarding the AIP and REP, nearly half of the incentive payout at target level relates to
5 DTE Electric achieving earnings and cash flow goals and DTE Energy achieving operating
6 earnings per share. Despite the argument by the Company that achieving these goals
7 somehow benefits customers, there is no direct relationship to customer benefits. These
8 goals are in place to maximize profits and increase cash flow to pay dividends to
9 shareholders. It is even more inappropriate to charge customers for incentive pay costs
10 related to achieving DTE Energy earnings since they are based in part on earnings from
11 the gas and non-utility businesses of DTE Energy. The Commission should not allow
12 recovery of incentive payments related to these financial goals.

13 As to the Customer Satisfaction grouping of measures, this category in 2024 represents
14 just 15% of the total weighting (down from 20% in prior years).

15 Regarding the Safety & Engagement category, the measures contained therein, although
16 worthy goals, do not rise to the level of being measures that are visible to customers nor
17 do they create direct customer benefits. They are primarily internal goals related to
18 employee satisfaction and deployment of safe practices in the workplace.

19 As to the Operating Excellence category, the measures contained therein are basic
20 operating goals. Again, these are worthy internal goals to measure performance of the

1 departments responsible for those operations, but they have limited direct visibility to
2 customers. The only measures that have a direct link to customers are the Electric outage
3 metrics (Storm Customers Restored in 48 Hours) and the metrics addressing multiple
4 customer outages, which represent a small portion of the expected payout. Moreover,
5 improvements in this area will be largely a function of a more aggressive tree trimming
6 program and capital spending programs, which are paid for through increases in customer
7 rates.

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

9 A. The LTIP is a plan strictly designed to induce management to create shareholder value. It
10 is weighted heavily (80%) on total shareholder return, which is stock price appreciation
11 and dividends paid over a period of time. The Company's total return is then measured
12 against a group of peer companies to trigger a payout. This has nothing to do with creating
13 direct benefits for DTE Electric customers and everything to do with creating value for
14 DTE Energy shareholders. Similarly, the other measure, DTE Electric return on equity, is
15 also very removed from any quantifiable benefits that directly accrue to customers. To
16 some degree this last item is actually duplicative of the Operating Earnings and Cash Flow
17 measures included in the AIP and REP plans.

18 The arguments that some of these measures will create a healthier company and therefore
19 customers should pay for LTIP expenses are not convincing.

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

3 A. In Exhibit A-21, Schedule K6, Mr. Fix included a calculation which purports to show that
4 recent operating and financial cost savings are exceeding adjusted incentive plan payments
5 by \$45.0 million. However, the largest benefits showing in this exhibit are in the areas of
6 (1) Operating Excellence (\$48.5 million) with a large part of this category being highly
7 dependent upon a more aggressive tree trimming program and capital spending program,
8 which should in turn reduce the SAIDI outage metric; and (2) \$13.4 million of benefits
9 related to Employee Engagement Gallup results whereby better employee survey results
10 should (according to Gallup) lead to reduced absenteeism, higher productivity, and a better
11 safety record.

12 Q. **PLEASE COMMENT ON THE COMPANY'S PERFORMANCE ON THE**
13 **OPERATING METRICS IN 2024.**

14 A. In response to discovery, the Company provided the results of the incentive performance
15 measures for the year 2024. The 2024 results show that DTE Electric's performance on 9
16 of the 23 metrics was below target. Nuclear Generation's performance measures were
17 below target in 3 of the 8 metrics, and DTE LLC's performance was below target in 3 of

1 the 7 metrics.⁹⁶ On average in 2024, target performance was reached for only one-third of
2 the performance metrics.

3 **Q. DO THE 2024 PERFORMANCE LEVELS RAISE UNCERTAINTY WITH**
4 **RESPECT TO WHAT WILL BE PAID OUT UNDER THE INCENTIVE PLANS**
5 **DURING THE PROJECTED TEST YEAR PERIOD?**

6 A. Yes. Mr. Fix stated on page 38 of his testimony that the \$56.4 million of incentive
7 compensation expense is based on “Target” performance levels. Therefore, if the
8 Company’s sub-standard performance levels continue into the projected test period, then
9 a substantial portion of the incentive payments anticipated by Mr. Fix will not happen.

10 Mr. Fix’s testimony and exhibits provide little assurance that all operating performance
11 measures can be achieved at 100% of target level in the future with any consistency, as he
12 has assumed in calculating the incentive compensation expense that the Company seeks to
13 recover in this case.

14 In summary, my assessment is that the Company has failed to show that it has achieved
15 consistent performance at target levels to justify recovery of 100% of incentive pay
16 expenses relating to the operating performance measures.

⁹⁶ Exhibit AG-58 includes DR AGDE-8.255 with attachment.

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

3 A. On page 39 of his direct testimony, Mr. Fix has included a table showing the components
4 of the incentive compensation expense that the Company has included in the O&M
5 expense for the projected test year. For the reasons described above, I recommend that the
6 Commission remove the entire \$35.8 million related to financial performance measures.

7 I am cognizant of the fact that the Commission has in recent cases allowed recovery of a
8 portion of the short-term incentive pay related to operating performance measures for
9 DTEE and Consumers Energy. In that vein, I recommend that the Commission allow
10 recovery of a portion of incentive compensation expense pertaining to operating
11 performance measures.

12 In Exhibit AG-59, I have calculated the percentage of non-financial metrics achieved at
13 target or better over the past five years ending in 2024. The overall percentage achieved
14 by the three organizations over the five-year period ending in 2024 is approximately
15 49.4%. The total amount of incentive compensation calculated by the Company at target
16 for operating measures relating to the incentive compensation plans is \$20,531,000, as
17 shown in Table 2 on page 39 of Mr. Fix's direct testimony. Therefore, I recommend that
18 the Commission only approve recovery of compensation expense for 49.4% of the
19 \$20,531,000, or \$10,142,000, and make recovery of the remaining \$10,389,000 for the

1 operational metrics subject to recovery under the 2-way Tracker Mechanism previously
2 approved by the Commission.

3 As shown in Exhibit AG-60, I recommend a total disallowance of incentive compensation
4 expense of \$46,277,000 and the same reduction to the Company's forecasted O&M
5 expense for the projected test year.

6 **O. O&M Expense Summary**

7 **Q. WHAT ARE THE TOTAL ADJUSTMENTS THAT YOU RECOMMEND TO THE**
8 **COMPANY'S FORECASTED O&M EXPENSES?**

9 A. I recommend total reductions to O&M expenses of \$200.8 million as discussed above.
10 Exhibit AG-39 and the table below provide a summary of the areas where I proposed O&M
11 expense adjustments.

<u>Summary of O&M Expense Reductions</u>	<u>Amount (\$Millions)</u>
Distribution Operations	\$ 54.2
Engineering & Support Staff	8.3
Steam Power Generation	25.5
Other Power Generation	8.7
Nuclear Power	5.8
Regulated Marketing	8.1
Credit Card Merchant Fees	7.0
Uncollectible Accounts Expense	1.6
Administrative & General	30.8
VEBA Plan	1.8
Health Care Plan	0.5
WCB Façade Repairs	(2.2)
Rate Case Expenses	7.1
Employee Incentive Compensation	<u>46.2</u>
Total Reduction	<u>\$203.4</u>

VIII. 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 \$24,712,000. The calculation of this amount is shown in Exhibit AG-20 and is based on the same depreciation rates used by the Company on page 2 of Exhibit A-13, Schedule C6.

1 I recommend that the Commission reduce the depreciation expense proposed by the
2 Company for the projected test year by \$24,706,000.

3 **IX. Property Tax Expense**

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

6 A. In Exhibit AG-20, I identified the adjustments to be made to the Company's proposed
7 capital expenditures. Those reductions lower the amount of property tax expense that the
8 Company will incur during the projected test year. On the same exhibit, I have calculated
9 the reduction in property tax expense of \$9,005,000. I recommend that the Commission
10 reduce the Company's property tax expense by this amount for the projected test year.

11 **X. Adjustments To Revenue Deficiency**

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

14 A. Exhibit AG-61 summarizes the adjustments to rate base and operating income. The net
15 result is a revised revenue deficiency of \$158.4 million, which is a reduction of \$415.6
16 million from the Company's requested level of \$574.0 million.

17 I recommend the Commission adopt these adjustments and issue an order granting rate
18 relief to the Company in an amount not exceeding \$158.4 million.

1 **XI. Return on Deferred Tree Trimming Costs**

2 **Q. DO YOU AGREE WITH THE COMPANY'S CALCULATION OF THE RETURN**
3 **ON DEFERRED TREE TRIMMING COSTS FROM THE SURGE?**

4 A. No. In Exhibit A-11, Schedule A1.1, the Company calculated the return on deferred tree
5 trimming cost from the surge and applied the overall permanent capital rate of return of
6 9.45% to arrive at a return amount of \$11,916,000. The rate of return applied to the
7 deferred balance is contrary to the Commission order in Case No. U-20162. In that order
8 the Commission approved the use of the short-term interest rate.

9 In Exhibit AG-62, I calculated the appropriate return by using the 3.91% short-term
10 interest rate provided by the Company in response to discovery and referenced in the Cost
11 of Capital section of my testimony. The revised return amount is \$4,928,000. I
12 recommend that the Commission adopt this amount and reject the Company's proposed
13 amount.

14 **Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

15 A. Yes, it does. However, I reserve the right to amend, revise and supplement my testimony
16 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

Experience and Qualifications of Sebastian Coppola

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

**Experience and Qualifications
of Sebastian Coppola**

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

Experience and Qualifications 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) 2025-2026 GCR plan case No. U-21608.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-2024 GCR reconciliation in case No. U-21272.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 PSCR Plan Case No. U-21594.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2024 electric rate case U-21806 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 Michigan Gas Utilities Corporation (MGUC) 2023-2024 GCR reconciliation in case No. U-21274.

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of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 PSCR reconciliation in case No. U-21260.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2023-2024 GCR reconciliation in case No. U-21270.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan reconciliation in case No. U-21278.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2023 PSCR reconciliation in case No. U-21258.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2024 electric rate case U-21585 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 DTEE 2024 electric rate case U-21534 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 the Upper Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 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 2024 gas rate case U-21540 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 Gas 2024 gas rate case U-21291 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

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of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 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 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 CEC Co 2023 PSCR reconciliation in case No. U-21049.
- 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 CEC Co 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 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 (DTE) 2023 rate Case U-21297 on several issues,

Experience and Qualifications of Sebastian Coppola

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 CEC0 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 CEC0 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 CEC0 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.

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- 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 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 CEC Co 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.

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of Sebastian Coppola**

- 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 CEC Co 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.
- Filed testimony on behalf of the Michigan Attorney General in DTE 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 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 CEC Co 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTE 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.

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- Filed testimony on behalf of the Michigan Attorney General in CEC0 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 CEC0 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 CEC0 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 PSR Reconciliation in case U-20203.

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- Filed testimony on behalf of the Michigan Attorney General in CEC0 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 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 CEC0 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.

**Experience and Qualifications
of Sebastian Coppola**

- 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 CEC Co 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 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.
- 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 CEC Co 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 CEC Co 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTE 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 CEC Co 2018 Tax Credit B refund for the Electric Division in case U-20286.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 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 CEC Co 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.
- 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 CEC Co 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 CEC Co 2018 PSCR Plan case U-18402.

**Experience and Qualifications
of Sebastian Coppola**

- 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 CEC Co 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 CEC Co 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.
- 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 CEC Co 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

**Experience and Qualifications
of Sebastian Coppola**

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.
- 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 UMEREC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMEREC 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.

**Experience and Qualifications
of Sebastian Coppola**

- 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.
- 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 CEC Co 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 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 CEC Co 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 CEC Co Gas Choice and End-User Transportation tariff changes case U-17900.

**Experience and Qualifications
of Sebastian Coppola**

- 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 CEC0 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.
- 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 CEC0 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 CEC0 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 CEC0 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 CEC0 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.

**Experience and Qualifications
of Sebastian Coppola**

- 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 CEC Co 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.
- 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 CEC Co 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 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 CEC Co 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 CEC Co'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.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in CEC0 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 Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- 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.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CEC0'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.
- 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.
- 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.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.

**Experience and Qualifications
of Sebastian Coppola**

- 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.
- 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.
- 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 CEC’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 CEC’s electric business Pilot Revenue Decoupling Mechanism in case U-16566.

**Experience and Qualifications
of Sebastian Coppola**

- 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.
- 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.

**Experience and Qualifications
of Sebastian Coppola**

- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

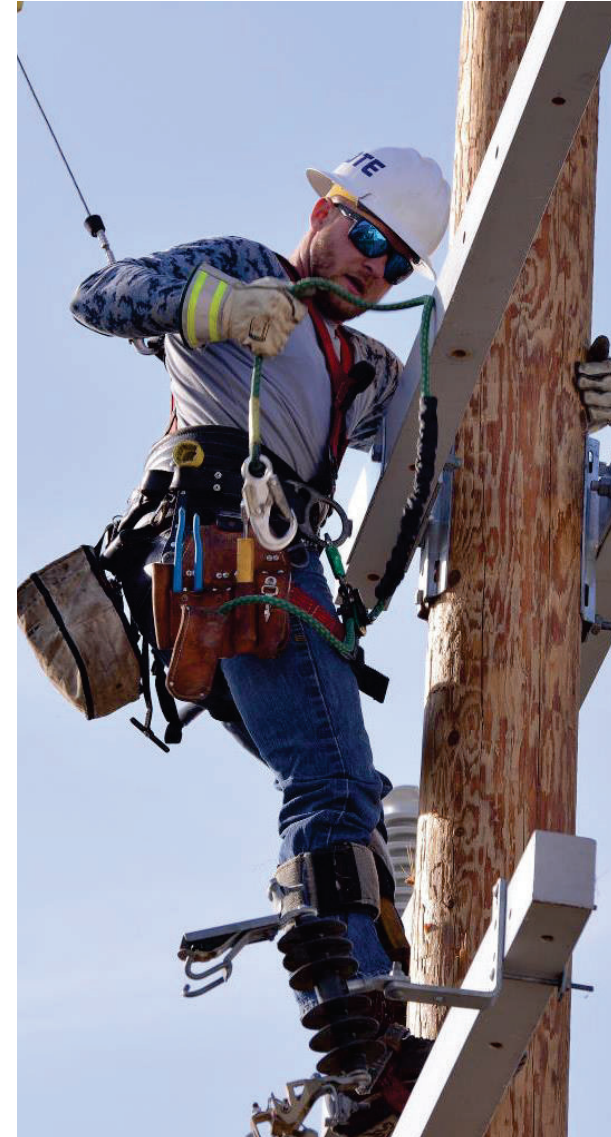
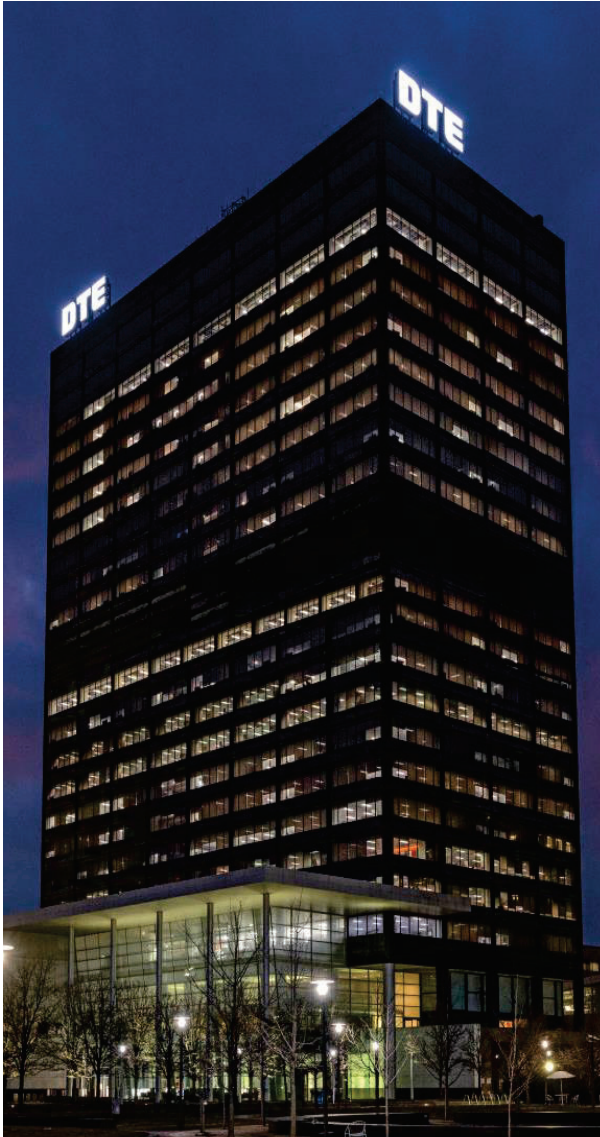
- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.
- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance 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.



SEE ATTACHED



Safe harbor statement

The information contained herein is as of the date of this document. DTE Energy expressly disclaims any current intention to update any forward-looking statements contained in this document as a result of new information or future events or developments. Words such as “anticipate,” “believe,” “expect,” “may,” “could,” “projected,” “aspiration,” “plans” and “goals” signify forward-looking statements. Forward-looking statements are not guarantees of future results and conditions but rather are subject to various assumptions, risks and uncertainties that may cause actual future results to be materially different from those contemplated, projected, estimated or budgeted. Many factors may impact forward-looking statements including, but not limited to, the following: the impact of regulation by the EPA, EGLE, the FERC, the MPSC, the NRC, and for DTE Energy, the CFTC and CARB, as well as other applicable governmental proceedings and regulations, including any associated impact on rate structures; the amount and timing of cost recovery allowed as a result of regulatory proceedings, related appeals, or new legislation, including legislative amendments and retail access programs; economic conditions and population changes in our geographic area resulting in changes in demand, customer conservation, and thefts of electricity and, for DTE Energy, natural gas; the operational failure of electric or gas distribution systems or infrastructure; impact of volatility in prices in international steel markets and in prices of environmental attributes generated from renewable natural gas investments on the operations of DTE Vantage; the risk of a major safety incident; environmental issues, laws, regulations, and the increasing costs of remediation and compliance, including actual and potential new federal and state requirements; the cost of protecting assets and customer data against, or damage due to, cyber incidents and terrorism; health, safety, financial, environmental, and regulatory risks associated with ownership and operation of nuclear facilities; volatility in commodity markets, deviations in weather and related risks impacting the results of DTE Energy’s energy trading operations; changes in the cost and availability of coal and other raw materials, purchased power, and natural gas; advances in technology that produce power, store power or reduce or increase power consumption; changes in the financial condition of significant customers and strategic partners; the potential for losses on investments, including nuclear decommissioning trust and benefit plan assets and the related increases in future expense and contributions; access to capital markets and the results of other financing efforts which can be affected by credit agency ratings; instability in capital markets which could impact availability of short and long-term financing; impacts of inflation, tariffs, and the timing and extent of changes in interest rates; the level of borrowings; the potential for increased costs or delays in completion of significant capital projects; changes in, and application of, federal, state, and local tax laws and their interpretations, including the Internal Revenue Code, regulations, rulings, court proceedings, and audits; the effects of weather and other natural phenomena, including climate change, on operations and sales to customers, and purchases from suppliers; unplanned outages at our generation plants; employee relations and the impact of collective bargaining agreements; the availability, cost, coverage, and terms of insurance and stability of insurance providers; cost reduction efforts and the maximization of generation and distribution system performance; the effects of competition; changes in and application of accounting standards and financial reporting regulations; changes in federal or state laws and their interpretation with respect to regulation, energy policy, and other business issues; successful execution of new business development and future growth plans; contract disputes, binding arbitration, litigation, and related appeals; the ability of the electric and gas utilities to achieve goals for carbon emission reductions; and the risks discussed in DTE Energy’s public filings with the Securities and Exchange Commission. New factors emerge from time to time. We cannot predict what factors may arise or how such factors may cause results to differ materially from those contained in any forward-looking statement. Any forward-looking statements speak only as of the date on which such statements are made. We undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. This document should also be read in conjunction with the Forward-Looking Statements section in DTE Energy’s public filings with the Securities and Exchange Commission.

Highly engaged team committed to delivering best-in-class results for our stakeholders

Continuing best-in-class engagement, health and safety of our employees

- ✓ Received Gallup Exceptional Workplace Award for 13th consecutive year

Addressing our customers' most vital needs

- ✓ Progressing on our goal of reducing power outages by 30% and cutting outage time in half by 2029, significantly improving reliability for customers
- ✓ Nearly 60% improvement in customers time spent without power YTD 2025 vs. YTD 2024 following a nearly 70% improvement from 2023 to 2024

Supporting our communities

- ✓ Continuing focus on Michigan investments; invested nearly \$1 billion with Detroit suppliers and \$3.3 billion with Michigan businesses in 2024

Delivering premium shareholder returns

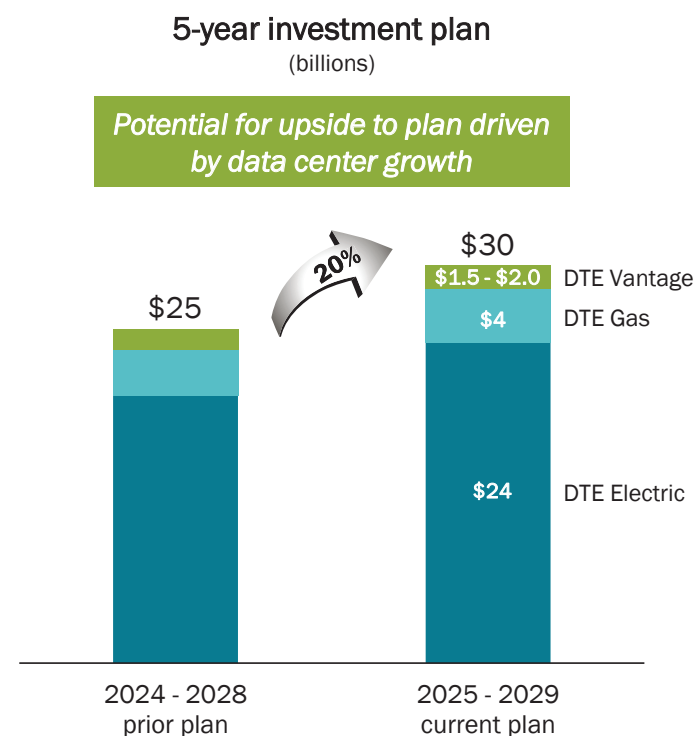
- ✓ 2025 operating EPS¹ guidance midpoint provides 7% growth over 2024 original guidance midpoint; currently positioned to achieve high end of guidance in 2025
- ✓ Long-term operating EPS growth rate target of 6% - 8% through 2029 from 2025 original guidance midpoint; RNG tax credits provide confidence we will reach the high end of our growth rate 2025 through 2027 and provide flexibility to exceed the high end and support future years
- ✓ Solid financial strength allows us to make the necessary investments for improved reliability and cleaner generation
- ✓ \$30 billion 5-year capital investment plan supports future growth

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



Increased customer-focused utility investment, combined with a shift to more utility-like investments at DTE Vantage, provides higher quality 6% - 8% long-term operating EPS¹ growth

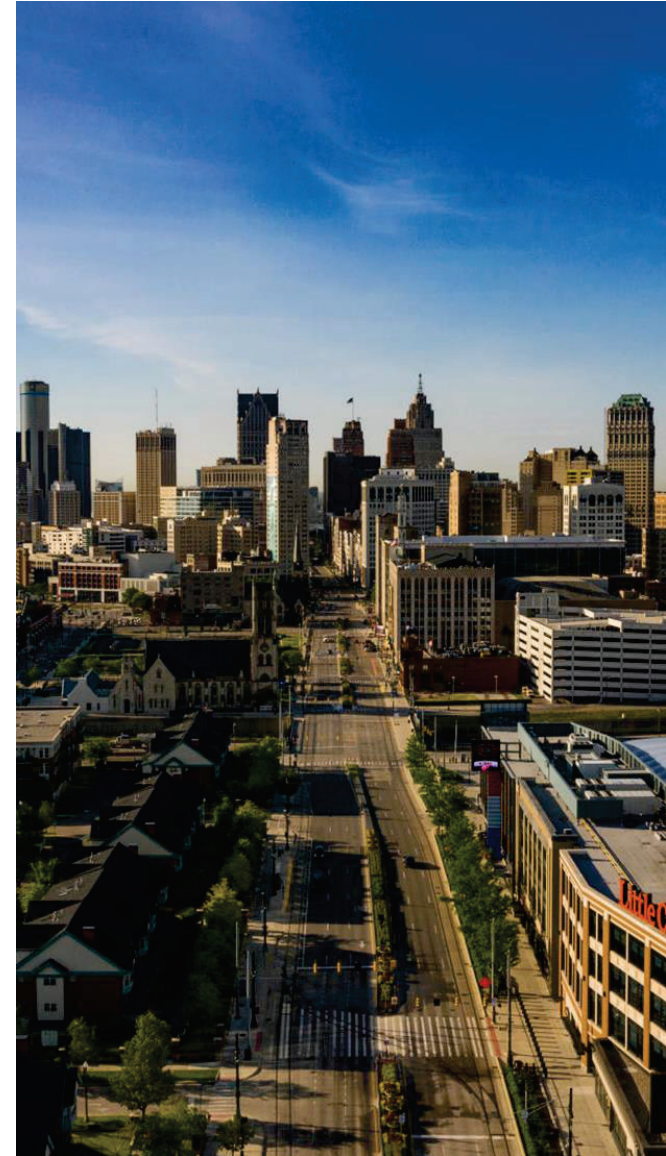
- Increased generation and reliability investment over the next 5 years drives \$5 billion increase from prior plan
 - The overwhelming success of the voluntary renewables program combined with the 2023 Integrated Resource Plan (IRP) settlement and the Michigan Clean Energy legislation drives the need for increased generation investment
 - Additional grid investment required to improve customer reliability as supported by the recent MPSC electric distribution audit
- Increased utility investment provided the flexibility to shift focus of DTE Vantage growth to more utility-like, long-term, fixed-fee contracted projects
- Current plan provides higher quality 6% - 8% operating EPS growth with potential upside
 - Potential longer-term upside to plan from data center growth
 - RNG tax credits provide confidence we will reach the high end of our growth rate 2025 through 2027 and provide flexibility to exceed the high end and support future years



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

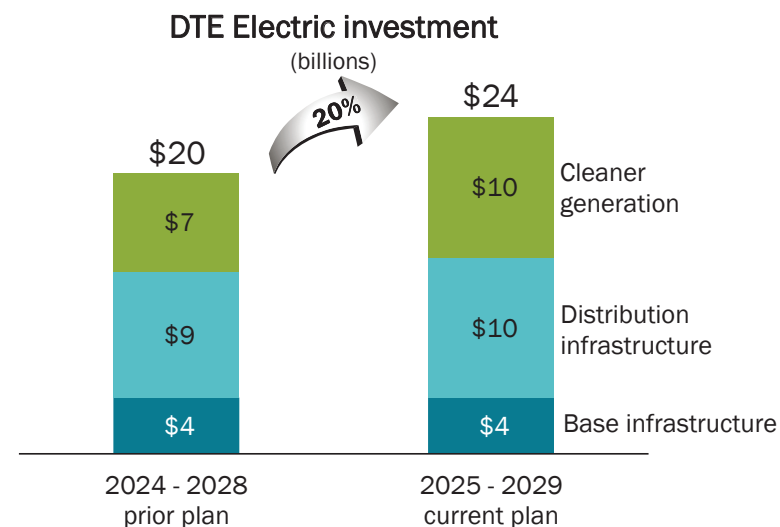
Economic development fuels Michigan's growth

- Significant investment in Michigan, supporting thousands of jobs
 - General Motors investment to convert an assembly plant to produce full-size electric pickup trucks
 - Henry Ford Health, Detroit Pistons and Michigan State University investment in Detroit for hospital expansion, research facility and neighborhood redevelopment
 - Ilitch Organization and University of Michigan investment for an innovation campus
 - LG Energy Solution investment to expand battery manufacturing facility
 - Multiple data center opportunities which could provide additional growth
- Positive economic indicators in Michigan 1Q 2025 vs. 1Q 2024
 - Housing permits up nearly 10% in Southeast Michigan
 - Estimated real state GDP up 2.6%
 - Southeast Michigan's payroll employment up 0.7%
- Customer growth continues in DTE service territory
 - Residential and commercial customer count growth of ~0.5% 1Q 2025 vs. 1Q 2024

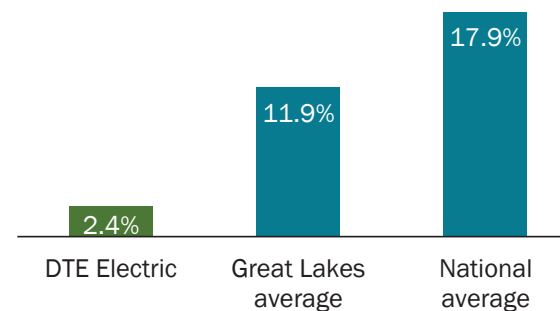


DTE Electric: executing on our customer-focused investment plan in reliability and cleaner generation

- Increasing efforts to improve reliability in 2025 following significant progress in 2024
 - Enhancing grid automation by installing 600 smart grid devices to greatly reduce outage duration
 - Upgrading existing infrastructure including 950 miles of pole top maintenance and 5,500 utility poles
 - Further advancement of infrastructure rebuild by accelerating the replacement of 4.8kV system
 - Continuing robust tree trimming program; planning to trim over 6,500 miles of trees in 2025
- Investments to improve reliability for our customers are working
 - Nearly 60% improvement in customers time spent without power YTD 2025 vs. YTD 2024 following a nearly 70% improvement from 2023 to 2024
 - On track with goal to reduce power outages by 30% and cut outage time in half by 2029
- Rate case filing supports our 5-year \$10 billion grid reliability investment commitment while maintaining affordability
 - Requesting ~\$1 billion of distribution spend to be included in the IRM by 2029



Top Tier Affordability
Total electric residential bill change % from 2021 to 2024¹



1. Source: Energy Information Administration (EIA). DTE Electric ending point is through 2025 and includes impact of 2025 rate order. Great Lakes and National average ending point is Nov 2023 – Oct 2024 average

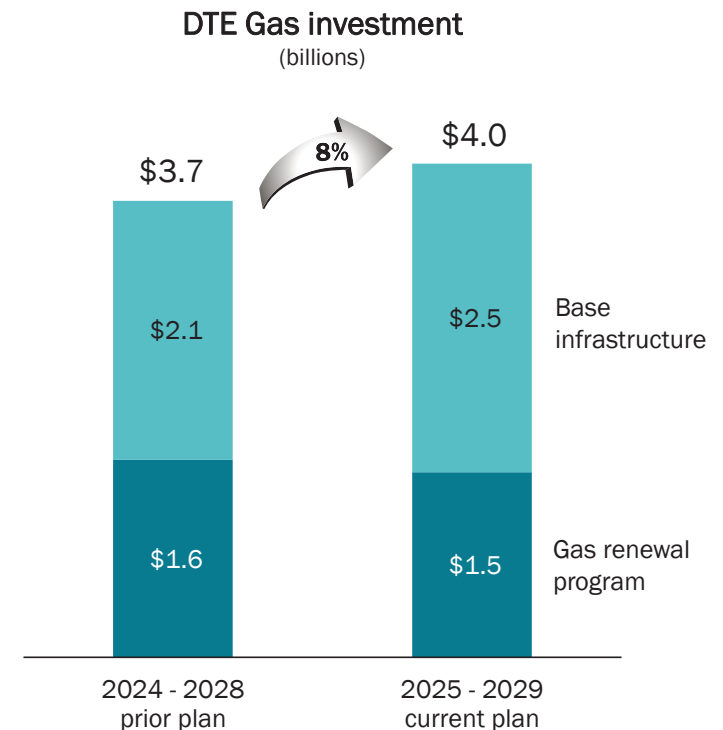
Renewable investments support voluntary program and legislated clean energy plan with potential upside from data centers

- Robust renewable energy development supported by strong land positions and positive community relationships
 - Reached settlement agreement for 2024 Renewable Energy Plan (REP) filing that supports IRP and voluntary renewables investments
 - 2,300 MW of renewable generation in service; 10 new solar projects coming online adding over 1,000 MW through 2026; adding ~800 MW (1,250 MW including PPAs) of renewables per year on average over the next 5 years
 - Clear line of sight on panels, land positions and permitting; safe harbored investment tax credits through 2027
- Data center opportunities provide potential upside to plan through additional investments in renewable energy, energy storage and new generation
 - Executed multiple non-binding agreements to serve significant data center load of ~2,100 MW
 - Ongoing discussions with multiple additional data center opportunities
 - Data center load ramp supported by up to ~1 GW of existing capacity and will also require new investment in the near-term; longer term investment opportunity will be supported by the 2026 IRP
 - Data center growth will help drive affordability headroom for existing customers



DTE Gas: replacing aging infrastructure to ensure reliability and safety for our customers

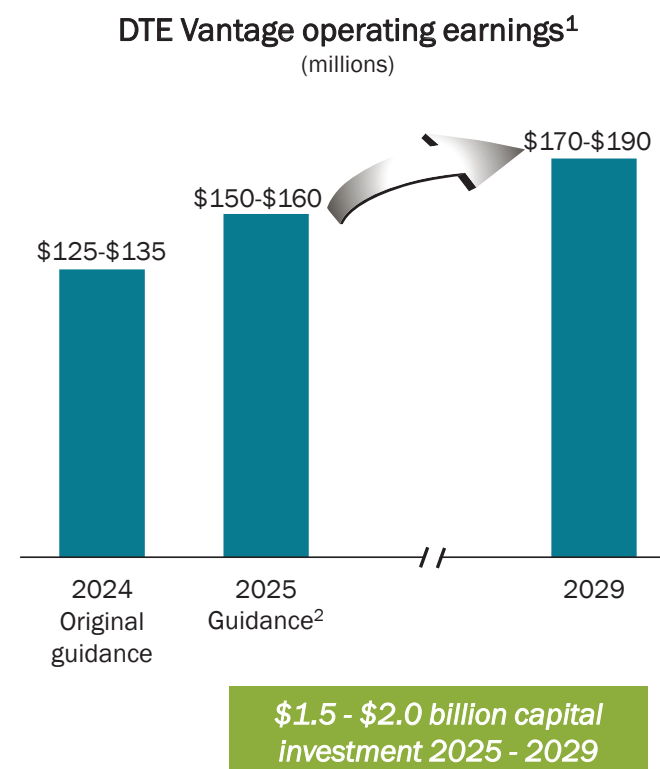
- Continuing to improve customer service excellence and progress on main renewal
 - Ranked #1 in customer satisfaction for business natural gas service in the Midwest by J.D. Power¹
 - Continued progress on main renewal program; renewed nearly 2,000 miles since program inception
- Long-term capital investment plan focused on infrastructure improvements including main renewal investments to minimize leaks and reduce costs for our customers
 - Significant investment to support main renewal recovered through Infrastructure Recovery Mechanism
 - Base infrastructure investments enhance distribution, transmission, compression and storage
 - Continued focus on safety and affordability for customers



1. J.D. Power 2024 Gas Utility Business Customer Satisfaction Study. Visit [jdpower.com](https://www.jdpower.com)

DTE Vantage: shifting strategic focus to more utility-like projects supports consistent long-term earnings growth

- Progressing on project development
 - Continuing construction on the long-term, fixed-fee custom energy solutions project with Ford Motor Company; expecting commercial operation in 2026
 - Progressing on project to design, build, own, operate and maintain a 42 MW combined heat and power project serving a large industrial customer; expect construction to begin later this year
 - Strong development pipeline of projects to support continued growth
- Increased utility investment provides the flexibility to shift focus of DTE Vantage growth to more utility-like, long-term, fixed-fee contracted projects
 - Targeting ~\$20 million of average annual base earnings growth from 2025 – 2029 excluding tax credits, consistent with historical development execution
 - RNG tax credits provide confidence we will reach the high end of our growth rate 2025 through 2027 and provide flexibility to exceed the high end and support future years
 - New projects coming on-line in 2026 and 2027, combined with a solid development pipeline, provide confidence we can achieve our DTE 6% - 8% operating EPS growth through 2029



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

2. Approximately \$50 - \$60 million of 45z RNG tax credits assumed in 2025 guidance

2025 operating EPS¹ guidance midpoint provides 7% growth over 2024 original guidance midpoint; positioned to achieve high end

(millions, except EPS)

2025 operating earnings

DTE Electric	\$1,205 - \$1,225
DTE Gas	310 - 320
DTE Vantage	150 - 160
Energy Trading	50 - 60
Corporate & Other	(255) - (245)

- Utility growth driven by customer-focused investment supporting building the grid of the future and cleaner energy transition
- DTE Vantage guidance supported by new project development in the custom energy solutions space and production tax credit opportunities
- Continued strength in contracted physical power and gas portfolios at Energy Trading

DTE operating earnings guidance	\$1,475 - \$1,505
DTE operating EPS guidance	\$7.09 - \$7.23

Positioned to achieve high end of operating EPS guidance in 2025

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

Cash flow and capital expenditures guidance

Cash flow

(billions)

	2025 guidance
Cash from operations ¹	\$3.3
Capital expenditures	(4.9)
Free cash flow	(\$1.6)
Dividends	(0.9)
Other	(0.3)
Net cash	(\$2.8)
Debt financing	
Issuances	\$4.1
Redemptions	(1.3)
Total debt financing	\$2.8

Capital expenditures

(millions)

	2025 guidance
DTE Electric	
Base infrastructure	\$765
Cleaner generation	1,450
Distribution infrastructure	1,520
	\$3,735
DTE Gas	
Base infrastructure	\$345
Gas renewal program	315
	\$660
Non-utility	\$375 - \$575
Total	\$4,770 - \$4,970

1. Includes equity issued for employee benefit programs

Maintaining strong cash flows, balance sheet and credit profile

Strong balance sheet supports robust customer-focused investment agenda

- Customer-focused capital investment plan is supported by consistent, healthy cash flows
- Targeting minimal equity issuances of \$0 - \$100 million annually through 2027; expect modest increases to equity issuances beginning in 2028 to support our significant capital investment plan
- Effectively managing debt maturities to support long-term plan
- Maintaining solid investment-grade credit ratings; targeting 15% - 16% FFO / Debt¹

Credit ratings	S&P	Moody's	Fitch
DTE Energy (unsecured)	BBB	Baa2	BBB
DTE Electric (secured)	A	Aa3	A+
DTE Gas (secured)	A	A1	A



1. Funds from Operations (FFO) is calculated using operating earnings, debt excludes a portion of DTE Gas' short-term debt and considers 50% of the junior subordinated notes as equity

Executive Summary

To learn more or to request a demo, visit www.spglobal.com/marketintelligence.

S&P Global US Economic Outlook – June 2025

Forecast at a glance

Base forecast (December 2024) 2024:Q4 - 2028:Q4

	Major economic indicators																	
	% ch. from prior quarter, annual rate						% ch. from prior year, or annual average						% ch. from fourth quarter of prior year, or fourth-quarter average					
	2024.2	2024.3	2024.4	2025.1	2025.2	2025.3	2023	2024	2025	2026	2027	2028	2023.4	2024.4	2025.4	2026.4	2027.4	2028.4
Key indicators of real activity																		
Real gross domestic product	3.0	2.8	1.7	1.7	1.6	1.6	2.9	2.7	1.9	1.8	1.7	1.8	3.2	2.3	1.7	1.8	1.7	1.9
Contributions to growth (% points):																		
Final sales to domestic purchasers	2.8	3.5	2.0	2.0	1.4	1.3	2.8	3.0	2.0	1.4	1.6	2.0	3.5	2.8	1.5	1.5	1.8	2.1
Net exports of goods & services	-0.9	-0.6	0.1	-0.3	-0.1	0.0	0.5	-0.4	-0.2	0.3	0.1	-0.2	0.1	-0.5	0.0	0.3	0.0	-0.2
Change in private inventories	1.1	-0.1	-0.3	0.1	0.3	0.3	-0.4	0.1	0.1	0.1	0.0	0.0	-0.4	0.0	0.2	0.0	0.0	0.0
Major components of real GDP																		
Personal consumption expend.	2.8	3.5	2.7	2.5	1.8	1.6	2.5	2.7	2.4	1.7	2.2	2.6	3.0	2.7	1.9	1.9	2.4	2.6
Nonres. fixed investment	3.9	3.8	-1.8	2.6	2.6	2.1	6.0	3.7	1.9	1.7	1.3	1.6	5.0	2.6	2.3	1.5	1.3	1.7
Residential investment	-2.8	-5.0	6.7	-3.4	-4.0	-2.5	-8.3	4.2	-1.5	-0.6	0.7	1.9	2.5	2.9	-2.3	-0.2	1.2	2.9
Change in private inventories *	71.7	64.1	44.3	49.0	66.4	83.3	33.1	49.5	72.1	98.2	95.2	92.0	44.6	44.3	89.8	100.9	92.3	91.1
Exports of goods & services	1.0	7.5	-1.1	6.1	3.3	1.5	2.8	3.0	3.2	1.9	2.9	3.3	2.0	2.3	3.2	2.1	3.2	3.3
Imports of goods & services	7.6	10.2	-1.4	7.3	3.2	1.1	-1.2	5.3	3.9	-0.4	1.7	4.0	1.2	5.5	2.7	-0.5	2.9	4.3
Govt consump. & gross invest.	3.1	5.0	0.9	0.7	-0.2	0.1	3.9	3.3	1.1	0.0	-0.2	-0.3	4.3	2.7	0.2	-0.1	-0.3	-0.3
Pvt. housing starts (thous. units)	1340	1331	1327	1325	1313	1299	1421	1351	1307	1281	1273	1306	1481	1327	1292	1275	1270	1331
Light vehicle sales (mil. units)	15.7	15.6	16.3	16.0	16.1	16.3	15.5	15.8	16.2	16.5	16.6	16.6	15.6	16.3	16.3	16.6	16.7	16.5
Industrial production, total	2.5	-0.6	-0.8	1.6	0.6	0.6	0.2	-0.3	0.6	1.2	1.4	1.3	-0.1	-0.2	1.0	1.5	1.2	1.3
Industrial production, mfg	1.3	-0.6	-0.9	1.3	1.4	1.4	-0.5	-0.5	0.7	1.8	1.6	1.4	-0.4	-0.3	1.4	1.9	1.4	1.5
Capacity utilization (mfg, %)	77.1	76.8	76.3	76.3	76.3	76.3	78.2	76.9	76.3	76.4	76.3	76.0	77.6	76.3	76.3	76.4	76.2	76.0
Nonfarm payroll employ. (mil.)	158.4	158.8	159.3	159.7	160.0	160.1	156.1	158.6	160.0	159.9	159.8	160.0	157.1	159.3	160.0	159.8	159.8	160.2
Average monthly chg. (thous.)	147	159	135	132	71	14	251	177	48	-20	2	40	212	135	-25	-11	13	59
Private nonfarm hours	0.9	1.2	0.3	1.0	0.5	-0.1	1.1	0.6	0.6	-0.4	-0.2	0.1	0.6	0.8	0.2	-0.4	-0.1	0.3
Civilian unemployment rate (%)	4.0	4.2	4.2	4.3	4.4	4.5	3.6	4.0	4.4	4.7	4.8	4.7	3.8	4.2	4.5	4.7	4.8	4.6
Prices, Productivity, & Costs																		
CPI, all items, all urban	2.8	1.2	2.9	2.0	4.4	3.6	4.1	2.9	2.9	3.4	2.2	1.8	3.2	2.7	3.3	3.1	1.8	2.1
CPI excl food & energy, all urban	3.2	2.2	3.3	2.4	4.2	4.2	4.8	3.4	3.3	3.4	2.1	2.1	4.0	3.2	3.7	2.7	2.1	2.1
PCE price index	2.5	1.5	2.4	1.9	4.0	3.7	3.8	2.5	2.7	3.1	2.0	1.8	2.8	2.5	3.3	2.6	1.7	1.9
PCE price excl food & energy	2.8	2.1	2.7	2.2	3.9	4.0	4.1	2.8	3.0	3.1	1.9	1.9	3.2	2.9	3.5	2.4	1.9	1.9
PPI finished goods	0.1	0.2	-0.9	-0.6	2.8	3.1	1.5	0.9	0.8	2.0	1.2	1.6	-0.4	0.7	2.0	1.4	1.3	1.7
Compensation per hour	1.0	3.0	4.7	4.4	5.8	7.5	4.0	4.9	4.9	6.3	3.6	3.7	4.8	4.5	6.4	4.8	3.8	3.6
Output per hour	2.1	2.2	1.4	0.7	1.0	1.7	1.8	2.2	1.4	2.2	2.2	2.0	2.7	1.6	1.4	2.4	2.1	1.9
Unit labor cost	-1.1	0.8	3.3	3.7	4.8	5.7	2.2	2.7	3.5	4.0	1.4	1.7	2.1	2.8	4.9	2.3	1.6	1.7
Fed Financial Accounts HPI **	1.4	1.0	0.2	0.3	0.8	1.0	1.7	6.8	2.7	3.5	3.3	3.9	5.1	5.4	3.1	3.2	3.5	4.1
Price of WTI crude oil (\$/barrel)	81.40	76.24	70.19	67.87	67.12	65.34	77.62	76.35	65.88	63.93	65.38	68.77	78.34	70.19	63.17	67.02	66.43	70.10
Price of Brent crude oil (\$/barrel)	84.65	79.86	74.63	73.50	73.00	71.67	82.50	80.52	71.87	69.02	70.05	72.87	83.77	74.63	69.33	72.00	70.90	74.05
Selected Financial Variables																		
Federal funds rate (%)	5.33	5.26	4.66	4.31	4.07	3.85	5.02	5.15	4.02	3.72	3.14	3.13	5.33	4.66	3.86	3.45	3.13	3.13
Yield on 10-Yr Treasury Notes (%)	4.44	3.95	4.21	4.26	4.16	4.16	3.96	4.19	4.18	4.00	3.87	3.87	4.44	4.21	4.15	3.92	3.86	3.88
Baa corporate bond yield (%)	5.97	5.68	5.75	5.90	5.98	6.10	5.92	5.79	6.04	6.17	6.08	6.02	6.23	5.75	6.19	6.12	6.05	6.00
Broad trade-wld US\$ (Jan 2006=100)	122.9	122.9	126.1	127.3	126.1	124.8	120.5	123.2	125.5	122.0	121.2	120.5	121.8	126.1	123.9	121.3	121.1	120.4
S&P 500 stock index, period end	5460	5762	6025	5944	5814	5655	4770	6025	5505	5241	5040	4877	4770	6025	5505	5241	5040	4877
S&P 500 stock index, average	5254	5546	5894	5985	5879	5734	4284	5422	5794	5367	5106	4960	4472	5894	5580	5275	5051	4898
Incomes & Related Measures																		
Corporate profits w/ IVA & CCAdj	15.2	-1.1	2.2	0.6	-3.8	-6.4	6.9	6.7	-0.6	-3.2	1.9	2.4	10.5	2.1	-4.0	0.2	1.4	3.1
Real disposable personal income	1.0	0.8	2.9	3.5	1.8	6.3	5.1	2.8	2.8	2.9	2.9	2.9	4.6	2.6	3.4	2.5	3.1	2.7
Personal saving rate (%)	4.9	4.3	4.4	4.6	4.7	5.7	4.7	4.8	5.2	6.4	7.1	7.3	4.5	4.4	5.9	6.5	7.2	7.3
Fed. surplus (unified, FY, bil. \$)	-834	-2236	-2254	-2720	-792	-1985	-1695	-1832	-1938	-1954	-2111	-2337	-2040	-2254	-2276	-2343	-2629	-2467

* billions of chained 2017 \$

** % change, not annualized, HPI= house price index

Source: S&P Global Market Intelligence

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MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-9.274

Respondent: T. Lyons

Page: 1 of 1

Question: 274. Refer to lines 1-7 on page 7 of Mr. Lyons' direct testimony on constant dollar averaging inflation adjustments to historical costs as an economic principle. Please identify any non-utility companies that Mr. Lyons is aware of that apply constant dollar averaging in setting new prices for their services and goods. Provide evidence to support your answer.

Answer: Mr. Lyons has not prepared research and analysis on non-utilities companies that apply constant dollar averaging in setting prices.

Attachment: None

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-9.276

Respondent: T. Lyons

Page: 1 of 1

Question: 276. Refer to lines 6-17 on page 8 of Mr. Lyons' direct testimony on constant dollar averaging inflation adjustments to historical costs. Please identify all companies that Mr. Lyons is aware of that applying constant dollar averaging in forecasting costs and revenues for internal budgets and external forecasted income statements presented to the board of directors, security analysts, and investors. Provide evidence to support your answer.

Answer: Mr. Lyons has not prepared research and analysis on this topic.

Attachment: None

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-9.277

Respondent: T. Lyons

Page: 1 of 1

Question: 277. Refer to lines 3-6 on page 9 of Mr. Lyons' direct testimony on constant dollar averaging inflation adjustments to historical costs used by the Department of Defense (DoD). Provide evidence whether the DoD uses constant dollar averaging to adjust historical costs when making payments to its suppliers.

Answer: Mr. Lyons has not prepared research and analysis on DoD payment practices to its suppliers.

Attachment: None

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-9.278

Respondent: T. Lyons

Page: 1 of 1

Question: 278. Refer to pages 9-10 of Mr. Lyons' direct testimony on constant dollar averaging inflation adjustments to historical costs as a purported recognized practice in the utility industry. Please provide the total number of gas utilities in the U.S. under state commission jurisdiction and the number that recognize dollar averaging as an accepted practice for ratemaking.

Answer: I have not prepared research on every jurisdiction within the United States. Refer to the research on the practice of constant dollar averaging in the utility industry in my testimony at pages 9-10.

Attachment: None

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-9.279

Respondent: T. Lyons

Page: 1 of 1

Question: 279. Refer to Exhibit A-32, Schedule V1, containing Mr. Lyons' professional experience. Please provide a copy of the testimony filed by Mr. Lyons about dollar cost averaging in other utility rate cases in the U.S. and a copy of the rate order by the applicable commission showing the disposition of that testimony with reference to a page number.

Answer: In Southwest Gas Company's Application A.19-08-015 before the California Public Utilities Commission (CPUC), Mr. Lyons sponsored testimony to support the Company's forecast of expenses that in certain cases was based on an average of historical costs that reflected dollar cost averaging.¹ Revenue requirement schedules were filed for the Company's three rate jurisdictions: Southern California,² Northern California,³ and South Lake Tahoe.⁴ The filing resulted in a settlement agreement that was subsequently approved by the Commission. The settlement agreement notes on pages 5-6 "With the exception of a [correction] of Other Distribution Expenses (Account 880), Southwest Gas' distribution expenses were uncontested."⁵ The CPUC order discussing development of forecast expenses starts on p. 7.⁶

In addition, Mr. Lyons has prepared class cost of service studies on several occasions that relied on inflation adjustments to historical plant for classification of costs.

Attachment: None

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-4.142a

Respondent: B. Hill

Page: 1 of 1

Question: 142. Refer to lines 1–5 on page 36 of Mr. Hill's direct testimony on the I-75 electrical infrastructure relocation project. Please: a. Provide the total capital expenditures by year from inception to completion.

Answer: The Company notes that the question incorrectly asks about I-75 when the project referenced on lines 1-5 of page 36 of my direct testimony is actually on I-375. See the table below for the Company's most recent project cost projection by year (in \$000s).

2023	2024	2025	2026	2027	2028	2029	Projected Total Cost
6,334	6,314	8,400	12,000	14,000	15,500	15,500	78,048

Attachment: None.

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-4.142e

Respondent: B. Hill

Page: 1 of 1

Question: 142. Refer to lines 1–5 on page 36 of Mr. Hill’s direct testimony on the I-75 electrical infrastructure relocation project. Please: e. Provide a copy of the project schedule from MDOT and the Company work schedule that matches the MDOT schedule.

Answer: The Company notes that the question incorrectly asks about I-75 when the project referenced on lines 1-5 of page 36 of my direct testimony is actually on I-375. See the attachment labelled “U-21860 AGDE-4.142e I-375 MDOT Project Schedule” for the project schedule provided by MDOT which utilizes a progressive design-build structure where geographical work packages are designed and built in phases, as shown in the schedule. See the table below for the Company’s work schedule.

DTE Electric I-375 Relocation Project Work Schedule

Work Package	Milestone	Start	End
1- Early Works	Design	1/3/2025	7-1-2025
1- Early Works	Construction	3/5/2025	12-31-2025
2 - Jefferson	Design	3/1/2024	3-11-2026
2 - Jefferson	Construction	8/27/2025	12-31-2026
3 & 4 - Blvd & Int	Design	3/1/2024	6-8-2026
3 & 4 - Blvd & Int	Construction	4/3/2025	12-31-2027
5 - Gratiot	Design	3/1/2024	3-3-2027
5 - Gratiot	Construction	6-1-2026	12-31-2028
DTE Go Back Work	Design	9-1-2025	12-31-2027
DTE Go Back Work	Construction	6-1-2026	6-1-2029

Attachment: U-21860 AGDE-4.142e I-375 MDOT Project Schedule

Discovery Response AGDE-1.42e

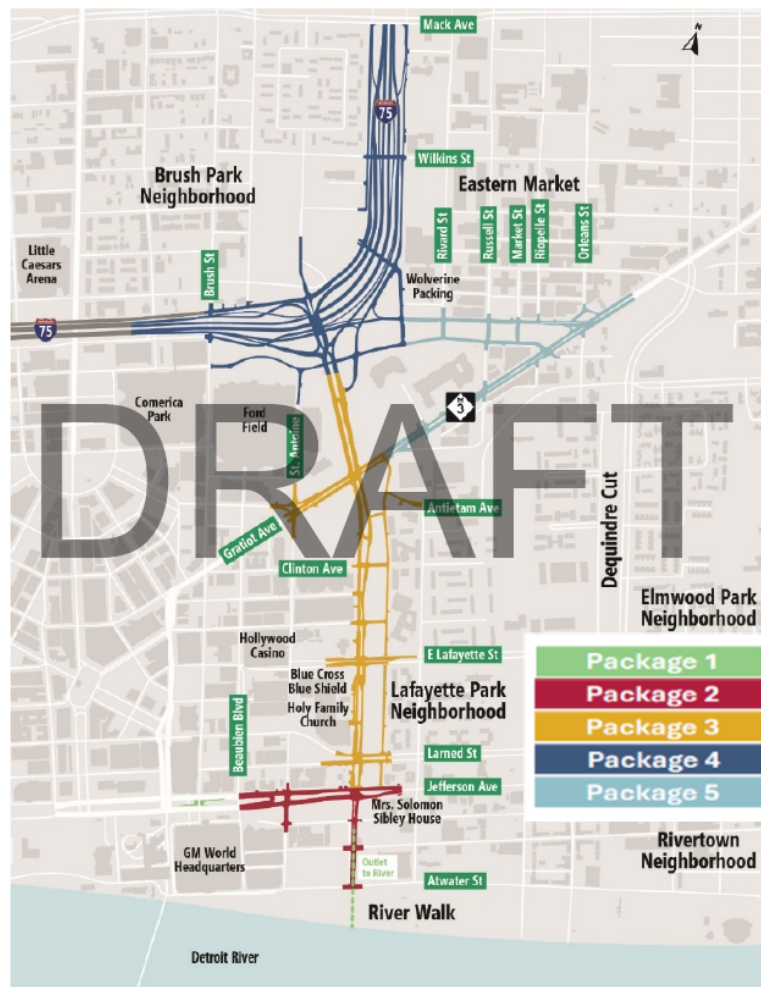
Preliminary Work Package Plan

I-375 Reconnecting Communities Project
Job Number: 130035

Following is our anticipated Work Packages that describe our approach to design progression and construction packaging.

1.1 Draft Construction Phasing Packages

The following graphic is a summary of our proposed Work Packages and Construction Schedule. Generally speaking, this work package plan and sequence is driven by the maintenance of traffic schemes contemplated within the Basis of Design Report.



Anticipated Construction Phasing Timelines Include:

- Work Package 1 (Early Works) – 2025/2026
- Work Package 2 (Jefferson Avenue) – 2026
- Work Package 3 (New Boulevard) – 2026/2027
- Work Package 4 (Interchange) – 2026/2027
- Work Package 5a (Gratiot Avenue) – 2028
- Work Package 5b (Eastern Market) – 2028

8/17/25, 4:17 PM

Whitmer administration re-evaluating I-375 project in Detroit

The Detroit News

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POLITICS

Whitmer administration re-evaluating I-375 reconstruction project in downtown Detroit

Craig Mauger and Julia Cardi The Detroit News

Updated Aug. 11, 2025, 4:04 p.m. ET

Lansing — The Michigan Department of Transportation says it's "taking a step back to re-evaluate" a \$300 million project to overhaul Interstate 375 in downtown Detroit, according to a Monday email obtained by The Detroit News.

The project has been years in the making in Detroit. In 2022, MDOT won a \$105 million grant from Democratic then-President Joe Biden's administration. At the time, then-U.S. Transportation Secretary Pete Buttigieg said the sunken I-375 freeway spur was an example of how "a piece of infrastructure has become a barrier."

Michigan Gov. Gretchen Whitmer's office previously said the reconstruction would replace the "outdated I-375 freeway with an accessible boulevard" and reconnect "prominent Black communities split apart by highway construction nearly 60 years ago." In the late 1950s and early 1960s, Detroit used eminent domain to raze two predominantly Black neighborhoods, Black Bottom and Paradise Valley, in order to make way for the freeway spur.

But an employee of the state Department of Transportation shared in a Monday email to individuals involved with the project a statement from the "executive leadership" at the agency. The project was being re-evaluated "as a whole" and officials were "working to determine our next steps," the statement said.

Detroit News Article on I-375 Project – 8/11/2025

8/17/25, 4:17 PM

Whitmer administration re-evaluating I-375 project in Detroit

"Key factors for this reconsideration are rising costs, longevity of final project product, public consternation and responsible investment of taxpayer dollars," the statement added.

Jocelyn Garza, a spokeswoman for the Michigan Department of Transportation, confirmed Monday the agency is planning to "take a step back" on the I-375 reconstruction project. Garza said while it's clear work is needed to improve I-375, it's not certain, at this point, what the project will ultimately be.

U.S. Rep. Shri Thanedar's office said an MDOT engineer familiar with the project informed the Detroit congressman's team Monday that the primary driver behind the decision was the increased cost, saying the initial \$300 million estimate had ballooned to \$500 million due to inflation and other factors.

The engineer also cited the community pushback to the design, said Haraden Bottomley, a spokesman for Thanedar.

Whitmer told reporters Monday afternoon that the final decision on the fate of I-375 was "still in process."

"There's a lot of things that go into projects like that," Whitmer said. "There's a lot of community feedback that is important. And I think with a change in the White House, there are some policies that are different as well."

Whitmer didn't specify what policy changes might have impacted her administration's move on Monday. But it came less than a week after she met with Republican President Donald Trump privately at the White House on Aug. 5.

Asked if she discussed the I-375 project with Trump last week, Whitmer said, "Not specifically."

In September 2022, Whitmer said her administration had "fought hard to secure" federal funding for the project "to create a corridor of economic opportunity in Detroit and build on the city's growing economic momentum."

Detroit News Article on I-375 Project – 8/11/2025

8/17/25, 4:17 PM

Whitmer administration re-evaluating I-375 project in Detroit

It wasn't immediately clear what would become of the \$105 million grant from the federal government. The future of the money might depend on what a potentially revised I-375 project looks like, according to officials.

In June, MDOT officials said they planned to begin work later this year on reconstructing the mile-long sunken freeway, which connects Jefferson Avenue and Interstate 75, into a four-lane, street-level boulevard lined with businesses, residential housing and open space.

A state website set up for the project said the existing freeway is "old and doesn't meet current standards for safety."

"Due to its age and condition, I-375 is ready to be transformed into a vibrant urban boulevard complete with modern amenities to serve all modes of travel," the state website said.

Todd Scott, the executive director of the Detroit Greenways Coalition, said Monday he was shocked and disappointed to hear about the new snags in the plans. The coalition has been largely supportive of the project, and Scott said he felt the project officials listened to concerns about accessibility and safety for pedestrians and cyclists in the road design. Some updates included making intersections smaller and plans to develop bicycle routes along the eastern edge of downtown Detroit.

"They laid out some pretty generic reasons why they're reevaluating it. I'd like to know more," Scott said.

"It's very disappointing to hear this, and I just hope it works out for the best, still."

However, the project had been criticized by some high-ranking local elected officials, including Wayne County Executive Warren Evans. In part, he's said plans for reparations to displaced Black residents and descendants of the Black Bottom and Paradise Valley neighborhoods have not been specific.

Detroit News Article on I-375 Project – 8/11/2025

8/17/25, 4:17 PM

Whitmer administration re-evaluating I-375 project in Detroit

"There's nothing in the design or the forecast for what would happen that would give anybody even remotely an idea that some reckoning for past injustices is built into it," Evans said in June. "It's just not."

Evans said in a statement Monday he thinks putting the redevelopment on pause is the right decision. He reiterated his concern that the project hasn't had enough clear direction, and said the money could be better spent. Evans said he'd be interested for his office to take part in future planning discussions about the project.

"I believe there are better ways to spend more than \$500 million than on a project with no clear direction and few visible supporters in the community," he said in a statement.

"Perhaps moving forward my administration can be included in whatever planning discussions come about. I honestly think we could help."

Likewise, at the Mackinac Public Policy Conference this spring, Detroit Mayor Mike Duggan said plans had changed so much for reinventing I-375, that it wasn't a priority for his administration. Duggan is leaving office at year's end and is running as an independent for governor.

When asked whether he thought bringing I-375 to grade is still the right plan, Duggan replied: "At this point, I have no idea."

"375, you know, it's been changed and delayed so many times that it's not my priority," Duggan told The News.

State Sen. Stephanie Chang, D-Detroit, said there were concerns in the community about the construction and she is glad the Whitmer administration is taking a step back.

"This project does not appear dead," Chang said, adding that she was awaiting more information.

cmauger@detroitnews.com

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.173a

Respondent: J. Robinson

Page: 1 of 1

Question: 173. Refer to pages 94-108 of Mr. Robinson's direct testimony on Substation Risk Projects. For each project, please: a. Provide the number of failures and customers impacted each year 2019-2024 in Excel.

Answer: Please see the attachment.

Attachment: *U-21860 AGDE-6.173a-01 Substation Reliability Metrics.xlsx*

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

Case No: U-21860
Exhibit: AG-5
August 22, 2025
Page 2 of 5

Discovery Response AGDE-6.173a

U-21860 AGDE-6.173a-01 - Substation Reliability Metrics												
Substation	Year	Customers	AW Outages	AW Duration (min)	ExMED Outages	ExMED Duration (min)	AW SAIDI	AW SAIIFI	AW CAIDI	ExMED SAIDI	ExMED SAIIFI	ExMED CAIDI
APACE	2019	10,244	9,980	2,152,002	9,850	2,105,002	210.074	0.9742	215.6	205.486	0.9615	210.9
APACE	2020	10,798	8,911	1,370,784	6,662	1,103,851	126.948	0.8252	153.8	102.227	0.6170	123.9
APACE	2021	11,281	20,613	5,321,829	12,014	1,591,729	471.752	1.8272	258.2	141.098	1.0650	77.2
APACE	2022	11,418	13,983	7,678,798	10,139	1,721,468	672.517	1.2246	549.2	150.768	0.8880	123.1
APACE	2023	11,367	13,284	6,875,342	9,501	1,765,623	604.851	1.1686	517.6	155.329	0.8358	132.9
APACE	2024	11,525	13,962	4,248,298	8,713	1,744,482	368.616	1.2115	304.3	151.365	0.7560	124.9
BELVL	2019	4,192	8,149	2,261,258	6,044	1,887,477	539.422	1.9439	277.5	450.257	1.4418	231.6
BELVL	2020	4,329	32,754	9,234,652	26,636	4,499,905	2133.207	7.5662	281.9	1039.479	6.1529	137.4
BELVL	2021	4,152	5,988	1,836,699	5,272	1,092,872	442.365	1.4422	306.7	263.216	1.2697	182.5
BELVL	2022	4,158	2,021	702,603	1,591	295,912	168.976	0.4861	347.7	71.167	0.3826	146.4
BELVL	2023	4,115	13,464	11,417,842	8,385	1,963,645	2774.688	3.2719	848.0	477.192	2.0377	145.8
BELVL	2024	4,126	14,450	5,340,062	6,882	697,733	1294.247	3.5022	369.6	169.106	1.6680	48.3
CHINT	2019	10,709	13,027	3,121,346	11,162	1,418,566	291.469	1.2165	239.6	132.465	1.0423	108.9
CHINT	2020	10,832	16,125	5,279,094	14,865	4,350,448	487.361	1.4886	327.4	401.629	1.3723	269.8
CHINT	2021	10,816	14,413	5,060,468	5,246	763,867	467.869	1.3326	351.1	70.624	0.4850	53.0
CHINT	2022	10,817	9,078	3,232,958	7,476	1,108,231	298.877	0.8392	356.1	102.453	0.6911	122.1
CHINT	2023	10,781	9,962	13,913,360	3,948	811,839	1290.544	0.9240	1396.6	75.303	0.3662	81.5
CHINT	2024	10,888	17,645	7,399,743	12,752	2,422,649	679.624	1.6206	419.4	222.506	1.1712	137.3
DREXL	2019	4,565	4,795	1,882,099	3,948	483,394	412.289	1.0504	392.5	105.891	0.8648	100.8
DREXL	2020	4,642	6,887	964,079	3,921	420,767	207.686	1.4836	140.0	90.643	0.8447	61.1
DREXL	2021	3,740	16,892	6,376,150	14,115	2,019,051	1704.853	4.5166	377.5	539.853	3.7741	119.5
DREXL	2022	3,743	6,053	2,460,777	3,818	487,362	657.434	1.6172	406.5	130.206	1.0200	80.5
DREXL	2023	3,739	8,835	6,855,666	5,289	996,192	1833.556	2.3629	776.0	266.433	1.4145	112.8
DREXL	2024	3,786	2,994	770,683	2,933	603,573	203.561	0.7908	257.4	159.422	0.7747	201.6
HOOD	2021	1,616	3,628	2,052,379	3,205	408,113	1270.037	2.2450	565.7	252.545	1.9833	112.5
HOOD	2022	1,901	6,417	344,503	6,405	343,976	181.222	3.3756	53.7	180.945	3.3693	53.6
HOOD	2023	1,890	4,797	1,110,620	2,520	247,912	587.630	2.5381	231.5	131.171	1.3333	51.7
HOOD	2024	1,917	2,174	329,131	2,030	225,495	171.690	1.1341	151.4	117.629	1.0589	103.7
SAVGE	2019	2,736	3,787	590,911	3,697	553,725	215.976	1.3841	156.0	202.385	1.3512	146.2
SAVGE	2020	2,774	3,222	376,836	3,192	362,222	135.846	1.1615	117.0	130.577	1.1507	112.4
SAVGE	2021	2,771	425	74,795	414	70,325	26.992	0.1534	176.0	25.379	0.1494	165.5
SAVGE	2022	2,770	1,151	567,135	1,038	273,544	204.742	0.4155	492.7	98.752	0.3747	237.7
SAVGE	2023	2,767	1,822	603,894	1,817	597,496	218.249	0.6585	331.4	215.936	0.6567	327.9
SAVGE	2024	2,779	1,048	153,150	1,041	144,546	55.110	0.3771	146.1	52.014	0.3746	137.9
SEVLE	2019	5,081	7,408	697,524	7,388	680,914	137.281	1.4580	94.2	134.012	1.4540	91.9
SEVLE	2020	5,140	5,662	455,877	5,543	204,876	88.692	1.1016	80.5	39.859	1.0784	36.2
SEVLE	2021	5,077	10,364	4,259,977	7,759	1,053,444	839.074	2.0414	411.0	207.493	1.5283	101.6
SEVLE	2022	5,077	7,934	2,780,082	7,460	1,324,578	547.584	1.5627	350.4	260.898	1.4694	166.9
SEVLE	2023	5,010	12,537	19,102,322	7,431	1,096,954	3812.839	2.5024	1523.7	218.953	1.4832	87.5
SEVLE	2024	4,985	7,819	774,652	7,744	740,772	155.397	1.5685	99.1	148.600	1.5535	94.7

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.173b

Respondent: J. Robinson

Page: 1 of 1

Question: 173. Refer to pages 94-108 of Mr. Robinson's direct testimony on Substation Risk Projects. For each project, please: b. For each year 2019-2024, provide the SAIDI, SAIFI and CAIDI minutes contribution by each substation and the total company numbers for each reliability index for all-weather and excluding MED in Excel.

Answer: Please see AGDE-6.173a.

Attachment: *None*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.173c

Respondent: J. Robinson

Page: 1 of 1

Question: 173. Refer to pages 94-108 of Mr. Robinson's direct testimony on Substation Risk Projects. For each project, please: c. Provide the expected reduction in the SAIDI, SAIFI, and CAIDI indices (all-weather and excluding MED) in each of the first three years after completion of the project in Excel.

Answer: The Company has not performed this analysis.

Attachment: *None*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.173f

Respondent: J. Robinson

Page: 1 of 1

Question: 173. Refer to pages 94-108 of Mr. Robinson's direct testimony on Substation Risk Projects. For each project, please: f. Provide the cost/benefit analysis with calculations in Excel with formulas intact and all assumptions and supporting data explained and identified to a source.

Answer: The Company has not performed a formal cost-benefit analysis for Substation Risk projects. These projects are selected by the Company's engineers after assessing substation risks. These projects are created to rebuild substations after catastrophic failures occur and/or are designed to prevent failure events which could lead to the complete loss of a substation. The reasons for project selection can be found in Exhibit A-23 Schedule M5 which explains the purpose and necessity of Substation Risk projects.

Attachment: *None*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.174a

Respondent: J. Robinson

Page: 1 of 1

Question: 174. Refer to pages 108-111 of Mr. Robinson's direct testimony on the Mobile Fleet program. Please: a. Provide the amount spent on each component of the program for each year 2019-2024 and forecasted for 2025 and 2026, along with the number of units, quantities, or projects. Provide this information in Excel.

Answer: Assuming 'components' means portable generators, portable switchgear, portable substations, portable ISO equipment, portable poles, energy storage trailers and the controls as described on page JER-108 lines 18-20, see attachment. Note, the 'other' category are investments that could not be clearly identified with a prior project or are smaller projects as discussed on pages JER-110 to 111 of my testimony.

In 2024, \$795,000 of the mobile fleet investment was for the NWA: Battery Trailer project as identified in Exhibit A-12 Schedule B5.4.2.

Attachment: U-21860 AGDE-6.174a Mobile Fleet 2019-2026

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

Case No: U-21860
Exhibit: AG-6
August 22, 2025
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Discovery Response AGDE-6.174a

Michigan Public Service Commission									MPSC Case No.: U-21860	
DTE Electric Company									Requestor: Staff	
Distribution Plant - Capital Expenditures									Question No.: AGDE-6.174a	
Mobile Fleet									Respondent: J. Robinson	
Component	Project	Unit	2019	2020	2021	2022	2023	2024	2025	2026
Control Systems	Engineering and Control System Upgrades	N/A							283,000	500,000
Control Systems	ESOC Gen Control	N/A					4,339			
Control Systems	Fuel Control	PDG3, PDG4 and PDG5				4,275	9,786	31,555		
Control Systems	Motor Rebuild on PDG1 and Control Upgrades on PDG1 and PDG3	PDG1 and PDG3					321,706	80,934		
Energy Storage Trailers	CES battery	CES Units						0		
Energy Storage Trailers	CES battery Removal	CES Units	8,326	-6,166						
Other	NWA: Battery Trailer	Battery Trailer		1,254,322	1,018,192			795,017		
Other	Other	N/A			62,762	132,527	10,404	142,401		
Portable Generators	Breaker Upgrade	PDG3	338,734	-169,367						
Portable Generators	Breaker Upgrade	PDG4			41,382	-2,889				
Portable Generators	Fuel System Work	PDG4s and PDG5s			11,304	4,303				
Portable Generators	Generator yard distribution center	N/A				140,400	37,870			
Portable Generators	Load Bank Upgrade	PDG3, PDG4 and PDG5						2,428		
Portable Generators	Load Banks	Load Banks	-4,250			122,335	12,936			
Portable Generators	McGraw DG	McGraw Units				11,527,068	292,474	0		
Portable Generators	Modular Disaster Cable	Modular Disaster Cable	7,957		141,316					
Portable Generators	New Transformer	ISO 5-1 and 5-2						95,088		
Portable Generators	PDG 4 Generators	PDG4	39,485	-4,116						
Portable Generators	PDG1 Repackaging	PDG1						677,165	617,000	
Portable Generators	Program Engineering and Design	N/A	-934,073	665,961	446,038	250,449	77,036	60,737		
Portable Generators	Program Engineering and Design	PDG2		4,815						
Portable Generators	Program Engineering and Design	PDG4		15,964						
Portable Generators	Quail	QUAIL DG		16,183	1,564		12,577	268,071		
Portable Generators	Radiator and Cooling System Upgrade	PDG 3-1		87,949						
Portable Generators	Radiator and Cooling System Upgrade	PDG 5-1		479,329						
Portable Generators	Radiator and Cooling System Upgrade	PDG3-1		33,288	61,752					
Portable Generators	Radiator and Cooling System Upgrade	PDG3-4						136,160		
Portable Generators	Rebuilt Cooling Systems	N/A	457,188	-95,858	-8,586	182				
Portable Generators	Replace unit motor	PDG5-2	1,348,254	1,426						
Portable Generators	Small Switch Trailer	Small Switching Trailers				398,355	56,042	30,905		
Portable Generators	Switching trailers	Transformer Trailers	0	0	103	-20,094				
Portable ISO Equipment	ISO Trailers	PDG3	214							
Portable ISO Equipment	PISO Trailers	PISO Trailers						468	600,000	700,000
Portable Poles	Portable Pole	Portable Pole	90,825	50,590	57,565	28,673	33,963	11,191		
Portable Substations	Fencing for Portables	N/A				129,326		96,234		
Portable Substations	Howell Portable Substation	N/A						1,557,811		
Portable Substations	Portable Storage Site	N/A				156,767	639,217	11,237		5,500,000
Portable Substations	Portable Substation Units	Portable Sub 17			1,475,554	51,524	12,281	27,359		
Portable Substations	Portable Substation Units	Portable Sub 18			1,621,806	35,140	29,296	3,108		
Portable Substations	Portable Substation Units	Portable Sub 19			497,725	1,213,914	123,800	4,216		
Portable Substations	Portable Substation Units	Portable Sub 20			526,378	1,057,436	282,771	26,414		
Portable Substations	Portable Substation Units	Portable Sub 21					1,739,434	270,285		
Portable Substations	Step Up transformer Trailers	N/A								300,000
Portable Switchgear	Portable Switchgear	Switch Gear Trailer	762,727	51,700	28,900	3,917	6,655	59,354		
Grand Total			2,115,387	2,386,020	5,983,757	15,233,610	3,702,586	4,388,140	1,500,000	7,000,000

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.174b

Respondent: J. Robinson

Page: 1 of 1

Question: 174. Refer to pages 108-111 of Mr. Robinson's direct testimony on the Mobile Fleet program. Please: b. Provide the utilization of each component of the fleet in terms of number of occurrences and number of hours used during each year 2019-2024 in Excel.

Answer: As stated in Testimony on page JER-108, the Mobile Fleet program gives the Company a short-to-medium term solution to major outage events and allows the Company to perform planned work. The Company does not track utilization data for Mobile Fleet components used for emergency restoration, support during planned work, and grid flexibility. While the Company does not track component utilization, from 2022 through 2024, DTE Electric has experienced 109 major events, not including storm events, on the system, causing loss of power for a few hundred to over 10,000 customers. Page JER-108 of my direct testimony gives an example of Mobile Fleet asset deployment that prevented a prolonged outage for 1,100 customers at Snover Substation.

Attachment: *None*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.174c

Respondent: J. Robinson

Page: 1 of 1

Question: 174. Refer to pages 108-111 of Mr. Robinson's direct testimony on the Mobile Fleet program. Please: c. Provide the justification for the increase in spending and a cost/benefit analysis for each purchase of \$3 million or greater.

Answer: The Company has not completed a benefit cost analysis for the Mobile Fleet program. However, the Mobile Fleet program provides DTE Electric customers with faster power restoration during major outages and planned maintenance by deploying portable generators, substations, and switchgear. These mobile assets allow the company to restore service even before permanent repairs begin, minimizing downtime and improving reliability.

Attachment: *None*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.108a

Respondent: M. Guillaumin

Page: 1 of 1

Question: 108. Refer to Exhibit A-12, Schedule B5.1, page 2. Please: a. For lines 4, 5, 6, 18, and 19, provide the amount spent each year for these line items from inception through 2024 in Excel. Explain what these dollars were spent on and what was accomplished over that timeframe.

Answer: Please see attachment "U-21860 AGDE-3.108a Monroe Environmental Project Actual Spend".

Attachment: U-21860 AGDE-3.108a Monroe Environmental Project Actual Spend

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

Case No: U-21860
Exhibit: AG-7
August 22, 2025
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Discovery Response AGDE-6.174a

Michigan Public Service Commission								Case No.: U-21860
DTE Electric Company								Response: AGDE-3.108a
Monroe Environmental Project Actual Spend								Respondent: M. Guillaumin
(\$000)								Page 1 of 1
<u>Ex. A-12 Sch.</u>		Actual Spend Amount (\$000)						
<u>B5.1 pg 2 Line No.</u>	<u>Project</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	Work Performed
4	MN Dry Fly Ash (ELG)		17,554	66,735	19,998	20,751	2,644	Engineering, material procurement, construction of pneumatic system and local/final common storage silos, tie-in of new fly ash handling systems on each of the four units, final site work, performance testing, demobilization, and project closeout.
5	MN Bottom Ash (ELG)		3,363	4,859	4,191	11,661	32,123	Engineering, material procurement, installation of ash storage bunkers and conveyors, and tie-in of new ash handling systems on Units 1 and 2.
6	MN FGD Wastewater (ELG)		686	1,116	339	423	211	Compliance technology evaluations, initial site engineering
18	MN Bottom Ash (CCR)	1	2,901	19,652	15,393	14,390	9,423	Removal of approximately 1 million cubic yards of bottom ash from basin and transportation to Sibley Quarry via truck
19	MN Fly Ash (CCR)			72	528	3,798	4,813	Initial studies for conceptual regulatory compliance, engineering and design, issuance of RFP for closure construction

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.108b

Respondent: M. Guillaumin

Page: 1 of 1

Question: 108. Refer to Exhibit A-12, Schedule B5.1, page 2. Please: b. Explain why Bottom Ash and Fly Ash costs on lines 44–46 are being charged to a regulatory asset beginning with 2025. Provide also the total cost by year from 2025 to completion of the project or projects.

Answer: As stated in my direct testimony, in accordance with the Commission’s Order in the Company’s 2022 IRP Case, and as discussed in further detail in lines 12-24 on page 43 of Company Witness Uzenski’s direct testimony, recovery of Monroe Power Plant capital investments on these projects made after January 1, 2025 will be processed through a regulatory asset. These costs are detailed on lines 44-46 of Exhibit A-12, Schedule B5.1, page 2.

For total costs by year, please see attachment labelled “U-21860 AGDE-3.108b Reg Asset Costs by Year”.

Attachment: U-21860 AGDE-3.108b Reg Asset Costs by Year

Michigan Public Service Commission					Case No.:	U-21860
DTE Electric Company					Request No.:	AGDE-108b
Monroe Regulatory Asset effective January 2025					Respondent:	M. Guillaumin
(\$000)					Page:	1 of 1
		Forecast	Forecast	Forecast	Forecast	Forecast
		Jan-Dec	Jan-Dec	Jan-Dec	Jan-Dec	Jan-Dec
		<u>2025</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>	<u>2029</u>
	Monroe Bottom Ash Conversion (ELG)	10,950	50	-	-	-
	Monroe Bottom Ash Basin Closure (CCR)	720	-	-	-	-
	Monroe Fly Ash Basin Closure (CCR)	13,899	107,759	92,121	92,081	7,914
	Total	25,569	107,809	92,121	92,081	7,914

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.88a-b

Respondent: M. Guillaumin

Page: 1 of 1

Question: 88. Refer to lines 21–25 on page 36 and page 37 of Ms. Guillaumin’s direct testimony on capital expenditures for Monroe Fly Ash Basin Closure. Please:

- a. Show how the costs on lines 19 and 46 of page 2 of Exhibit A-12, Schedule B5.1, were determined.
- b. Provide a copy of the plan to close the Basin by year, with the related cost broken down by component.

Answer: Please see attachment labelled “U-21860 AGDE-3.88a, b MONPP FA Basin Closure Costs”.

The Monroe Fly Ash Basin closure plan can be found on the web at:
https://www.dteenergy.com/content/dam/dteenergy/deg/website/common/dte-impact-and-news/environment/coal-combustion-residual/2023/MPPFlyAshImpoundmentCP_2023.pdf. This October 2023 version of the plan is currently being updated.

Attachment: U-21860 AGDE-3.88a, b MONPP FA Basin Closure Costs

Michigan Public Service Commission				Case No.:	U-21860
DTE Electric Company				Request No.:	AGDE-3.88a-b
Monroe Fly Ash Basin Closure Cost Breakdown				Respondent:	M. Guillaumin
(\$000)				Page:	1 of 1
		2023	2024	2025	2026
	DTE Labor (Direct)	287	519	576	584
	Contract Labor (Direct)	2,993	3,913	12,359	102,000
	Owners Engineer	1,270	1,074	850	426
	Site Prep	1,505	2,564	-	-
	Dewatering	-	-	9,175	58,000
	Earth Moving	-	-	-	43,574
	Minor Contract Labor	218	275	2,334	-
	Material (Direct)	199	-	-	-
	Indirects	319	380	964	5,175
	Total	3,798	4,812	13,899	107,759

October 2023

Fly Ash Basin Closure Plan

Revision 1

Table 2-1: Closure Schedule

Activity	Schedule
Anticipated date of last known receipt of CCR or non-CCR wastestream	Q4 2023
Begin closure construction	Q2 2024
Pond unwatering / dewatering (bulk removal, water handling activities will continue throughout construction)	Q2 2024 - Q3 2026
Grading of CCR material (will occur in phases across the 410-acre footprint)	Q3 2024 - Q4 2028
Installation of final cover system (will occur in phases following grading activities and removal of separable pore water)	Q3 2024 - Q2 2029
Target to complete closure	Q2 2029

2.2.3.1 Closure Completion

The federal CCR rule requires that closure of the FAB be completed within five years of commencing closure activities. The rule also allows the timeframe for completing closure of the CCR unit to be extended by multiple two-year extensions if DTE can substantiate the factual circumstances demonstrating the need for the extension. If needed, a demonstration for an extension of the closure timeframe shall be completed pursuant to §257.102(f)(2).

The CCR Rule does not define “closure complete” for CCR units. For the purposes of this Closure Plan, closure of the FAB is considered complete when the final cover system is installed, and the applicable construction completion documentation is finalized.

Within 30 days of completion of closure of the FAB, DTE must prepare a notification of closure of the FAB and place it in the facility’s CCR Operating Record and on DTE’s CCR public website. This notification shall include certification by a qualified professional engineer in the State of Michigan verifying that closure has been completed in accordance with this Closure Plan and the requirements of §257.102. Additionally, DTE must record a notation on the deed to the property following completion of closure of the FAB in accordance with §257.102(i). The purpose of this notation is to inform any potential future owner of the property of the previous use of the land, and that the land is restricted by post-closure care requirements.

CONFIDENTIAL -SUBJECT TO PROTECTIVE ORDER IN CASE NO. U-21860

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.88c

Respondent: M. Guillaumin

Page: 1 of 1

Question: 88. Refer to lines 21–25 on page 36 and page 37 of Ms. Guillaumin’s direct testimony on capital expenditures for Monroe Fly Ash Basin Closure. Please:
c. Provide a copy of the request for proposal and bids received along with the analyses showing that the lowest cost service provider was chosen.

Answer: DTE Electric objects for the reasons that the request seeks confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm. Subject to this objection and without waiver thereof, the Company would answer as follows:

The RFP evaluation for the construction management firms to perform the basin closure is currently in progress and the final service provider has not been selected.

Please see attachment labelled NDA U-21860 AGDE-3.88c MONPP FA Basin Closure RFP”.

Attachment: NDA U-21860 AGDE-3.88c MONPP FA Basin Closure RFP

Discovery Response STDE-5.1.b

MPSC Case No: U-21860

Requester: Staff

Question No.: STDE-5.1.b.

Respondent: M. Guillaumin

Page: 1 of 1

Question: Referring to pages 2 and 4 through 7 of Exhibit A-12, Schedule B5.1, and 'Attachment 9.7' provided under Part III of the General Filing Requirements, please provide the following for each listed project: Have all projects identified received approval from the required level of DTE leadership? If not, identify any future internal budgetary approvals that are still required, and the expected date of these approvals.

Answer: All projects in Exhibit A-12 Schedule B5.1 page 2 and pages 4-7 have received internal approval by the Energy Supply business unit and have received appropriate further final approvals, as required, except as follows. Project authorizations exceeding \$10 million require additional corporate level approval. Projects in queue for corporate level authorizations currently include the following projects:

Exhibit A-12, Schedule B5.1, page 2

- Lines 19 and 46, Monroe Fly Ash Basin Closure (CCR) – full authorization expected in Fall 2025 by the Board of Directors.
- Line 25, Trenton Channel Sea Wall – full authorization expected in early 2026 by the Corporate Staff.

Exhibit A-12, Schedule B5.1, page 7

- Line 191, Monroe Unit 1 Waterwall Tubes – full authorization expected this summer (2025) by the Corporate Staff.

Attachment: None.

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.94a

Respondent: M. Guillaumin

Page: 1 of 1

Question: 94. Refer to page 50 of Ms. Guillaumin's direct testimony on capital expenditures for the Trenton Channel BESS installation. Please: a. Provide the capital expenditures for this project by year from inception to completion with major components and related dollars identified in Excel.

Answer: Please see attachment labelled "U-21860 AGDE-3.94a Trenton Channel BESS Forecast". The project forecast has been updated since the filing of the instant case. See also discovery responses STDE-13.2a-d.

Attachment: U-21860 AGDE-3.94a Trenton Channel BESS Forecast

Discovery Response AGDE-3.94a

Michigan Public Service Commission					Case No.:	U-21860	
DTE Electric Company					Request No.:	AGDE-3.94a	
Trenton Channel Energy Center					Respondent:	M. Guillaumin	
(\$000)					Page:	1 of 1	
		2023	2024	2025	2026	2027	Total
	DTE Labor (Direct)	128	370	866	1,256	283	
	Contract Labor (Direct)	1,816	95,124	60,448	166,466	172	
	Owners Engineer	69	546	549	660	110	
	EPC	500	41,253	20,341	27,561	-	
	Battery Supplier	1,100	49,154	35,503	136,591	-	
	Interconnect Costs	-	92	2,000	500	-	
	CCR Disposal cost	-	2,505	113	-	-	
	Minor Contract Labor	147	1,574	1,942	1,154	62	
	Material (Direct)	2,595	2,346	597	512	-	
	Other (Direct)	78	43	45	52	-	
	Indirects	639	5,069	12,355	26,889	303	
	Total	5,256	102,952	74,311	195,175	758	378,452
	AG Calculated Total						

Discovery Response STDE-5.4

MPSC Case No: U-21860

Requester: Staff

Question No.: STDE-5.4

Respondent: M. Guillaumin

Page: 1 of 1

Question: Please provide a breakout of the total estimated cost for the development of the Trenton Channel BESS on an annual basis, from project initiation through project closeout and commercial operations.

Answer: Please see attachment labelled "U-21860 STDE-5.4 Trenton Channel BESS Expenditures" for current cost projections. The Company is aware that the battery supplier for the project is currently working through financial issues. As more information becomes available, this response will be supplemented as necessary.

Attachment: U-21860 STDE-5.4 Trenton Channel BESS Expenditures

Michigan Public Service Commission				MPSC Case No.: U-21860		
DTE Electric Company				Requestor:	Staff	
Trenton Channel BESS Expenditures				Question No.:	STDE-5.4	
(\$000)				Respondent:	M. Guillaumin	
		Actual	Actual	Forecast	Forecast	Forecast
		Jan-Dec	Jan-Dec	Jan-Dec	Jan-Dec	Jan-Dec
		<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>	<u>2027</u>
1	DTE Labor	\$ 434	\$ 446	\$ 1,095	\$ 639	\$ -
2	Contract Labor	1,816	95,145	232,869	31,877	-
3	Material	2,595	2,346	1,070	-	-
4	Other	349	4,821	24,484	8,469	-
5	Indirect	61	194	571	365	-
6	Total	\$ 5,256	\$ 102,953	\$ 260,089	\$ 41,350	\$ -

Exhibit AG-9
(Trenton Channel Contracts)

CONFIDENTIAL

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.90a-d

Respondent: M. Guillaumin

Page: 1 of 1

Question: 90. Refer to lines 21–25 on page 43 and page 44 of Ms. Guillaumin's direct testimony on capital expenditures for the Trenton Channel Sea wall. Please:

- Provide the cost by year of designing and installing the greenway path.
- Explain whether such a path was already in place and how often it is used or would be used and why it is necessary.
- Provide an aerial view of the sea wall area with nearby facilities, pedestrian access, etc., along with a design rendering of the path as envisioned.
- Identify any remaining costs from the \$9.5 million forecasted for 2026 that will not be spent on the greenway path and explain what they will be spent on.

Answer: Please see table below for project forecast estimates related to designing and constructing the greenway path.

(\$000)	2026	2027
Description	Estimated Cost	Estimated Cost
Greenway Design	\$120	\$120
Greenway Construction	\$4,500	\$2,500
Total	\$4,620	\$2,620

The project is required by permit. There is no path currently, and DTE is unaware of how often the path would be used. The Company is in the process of designing the greenway pathway and has not generated aerial views of the proposed project area at this time. In addition to the greenway

MPSC Case No: U-21860

Requester: Staff

Question No.: STDE-5.1.d.

Respondent: M. Guillaumin

Page: 1 of 1

Question: Referring to pages 2 and 4 through 7 of Exhibit A-12, Schedule B5.1, and 'Attachment 9.7' provided under Part III of the General Filing Requirements, please provide the following for each listed project: Please explain any changes in the estimated costs for each project that appeared in Case No. U-21534 to the requested amounts for the bridge period and projected test year in the current case.

Answer: The current proceeding, Case No. U-21860, uses a projected test period that extends beyond the test period used in Case No. U-21534; therefore, comparison between the two cases using the Case No. U-21860 bridge period and projected test period is not possible. Please refer to the previously filed Part III, Attachment 9.8 supplemental data filing where I provide variance analysis relative to the U-21534 projections and periods.

Attachment: None.

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.93a

Respondent: M. Guillaumin

Page: 1 of 1

Question: 93. Refer to page 49 of Ms. Guillaumin's direct testimony on capital expenditures for the Slocum BESS installation. Please: a. Provide a comparison of the final cost of the project to the initial cost estimate used to receive internal approval to proceed with the project. Explain any variance of 10% or greater in the major components of the project.

Answer: Please see table below:

Description	Initial Cost Estimate	Current Project Forecast	Variance	Reason for Variance
Battery Materials	\$ 15.0	\$ 21.0	\$ 6.0	Raw lithium prices increased from the time a proposal was received to when the contract was fully executed
Demo & Installation Labor	5.4	8.1	2.7	Labor escalation based on actual competitive bids received
Electrical Infrastructure	8.5	7.9	(0.6)	
Engineering & Permits	1.0	1.9	0.9	Additional design revisions and permit reviews were required based on feedback from county and the city
Overheads (Indirects)	4.8	6.2	1.4	Adjustment based on cost increases for material and labor
Total	\$ 34.7	\$ 45.1	\$ 10.4	

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.93b

Respondent: M. Guillaumin

Page: 1 of 1

Question: 93. Refer to page 49 of Ms. Guillaumin's direct testimony on capital expenditures for the Slocum BESS installation. Please: b. Provide a copy of the cost/benefit analysis to justify this project as the most economical among other alternatives with calculations in Excel.

Answer: In its Integrated Resource Plan (IRP) approved by the Commission in Case No. U-21193, the Company conducted a comprehensive evaluation of multiple energy resources, including battery energy storage systems (BESS). As part of this evaluation, 1,810 MW of BESS were selected based on a wide range of factors, including capital cost, emissions, transmission, subtransmission and distribution system impacts, ancillary service values, flexibility value, energy value, O&M costs, tax credits, community impact, and capacity value. No cost/benefit analysis specific to the project was performed.

Attachment: None

Other Power Generation Routine Projects with Budget Estimates - Disallowed

171	Total 2025 Projects					161,649,542		
Michigan Public Service Commission					Case No.:	U-21860		
DTE Electric Company					Exhibit:	A-12		
Projected Capital Expenditures					Schedule:	B5.1		
Years 2023 to 2026					Witness:	M. E. Guillaumin		
Routine Maintenance Projects greater than \$1M					Page:	7 of 9		
	(a)	(b)	(c)	(d)	(e)	(f)		
Line		Calendar		High Level			Percent	Amount
No.	Facility	Year	Unit	Breakdown	Description	Amount	Disallowed	Disallowed
189	Monroe without Large Enviro.	2026	1	Minor Environmental	Unit 1 SCR Catalyst Layers 1, 2, & 4	6,903,508	100%	6,903,508
211	Blue Water Energy Center	2026	11	Reliability	CTG11 Hot Gas Path Overhaul	22,938,926	100%	22,938,926
213	Blue Water Energy Center	2026	12	Reliability	CTG12 Hot Gas Path Overhaul	23,793,977	100%	23,793,977
219	Blue Water Energy Center	2026	STG	Safety	Steam Turbine Valves	6,306,011	100%	6,306,011
228	Peakers	2026	Renaissance	Reliability	Renaissance Unit 3 Peaker Combustion Overhaul	3,759,887	100%	3,759,887
230	Total 2026 Projects					63,702,308		\$ 63,702,308

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.110a

Respondent: M. Guillaumin

Page: 1 of 1

Question: 110. Refer to Exhibit A-12, Schedule B5.1, pages 6 and 7. For 2025 and 2026 and for each project of \$3 million or greater, please: a. Provide the current phase of project development (i.e., Preliminary Assessment, Conceptual Design, Engineering Design, Construction, Completed, etc.) and the completion and in-service month and year.

Answer: Please see attachment labelled “U-21860 AGDE-3.110a Routine \$3M+”. The ‘Current Phase of Development’ was determined based on Table 1 of my direct testimony on page 19.

Attachment: U-21860 AGDE-3.110a Routine \$3M+

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

Case No: U-21860
Exhibit: AG-12
August 22, 2025
Page 3 of 3

Discovery Response AGDE-3.110a

Michigan Public Service Commission DTE Electric Company Projected Capital Expenditures Years 2025 and 2026 Routine Maintenance Projects greater than \$3M					Case No.: U-21860 Response: AGDE-3.110a Witness: M. E. Guillaumin Page: 1 of 2		
	(a)	(b)	(c)	(d)	(e)		
Line No.	Facility	Calendar Year	Unit	High Level Breakdown	Description	Current Phase of Development	Completion & In-Service (Month & Year)
125	Belle River/Range Road	2025	1	Reliability	Unit 1 Waterwall Tubes	Full Detail, Firm Price Estimate	December 2025
126	Belle River/Range Road	2025	1	Reliability	Unit 1 Secondary Air Heater Baskets	Full Detail, Firm Price Estimate	December 2025
127	Belle River/Range Road	2025	1	Safety	Unit 1 IP Turbine Valves	Full Detail, Firm Price Estimate	December 2025
138	Greenwood Energy Center	2025	1	Safety	Unit 1 LP Turbine Rotor & Blades	Completed	March 2025
139	Greenwood Energy Center	2025	1	Reliability	Unit 1 Waterwall Tubes	Completed	March 2025
144	Monroe without Large Enviro.	2025	1	Reliability	Unit 1 IP Turbine Rotor	Bid Estimate	December 2025
145	Monroe without Large Enviro.	2025	1	Minor Environmental	Unit 1 SCR Catalyst Layer 3	Full Detail, Firm Price Estimate	December 2025
147	Monroe without Large Enviro.	2025	2		Unit 2 LPA & LPB Turbine Rotor and Blades	Bid Estimate	June 2026
150	Monroe without Large Enviro.	2025	4		Unit 4 LPA & LPB Turbine Rotor and Blades	Completed	May 2025
151	Monroe without Large Enviro.	2025	4		Unit 4 Turbine Valves	Completed	May 2025
152	Monroe without Large Enviro.	2025	4	Safety	Unit 4 Coal Mill Primary Air Duct & Damper	Completed	May 2025
159	Trenton Channel	2025	Sibley	Minor Environmental	Sibley Quarry Chimney Drain Lift	Full Detail, Firm Price Estimate	October 2025
165	Peakers	2025	Renaissance	Reliability	Renaissance Unit 4 Modified Major Overhaul	Completed	June 2025
166	Peakers	2025	Renaissance	Reliability	Renaissance Unit 4 Peaker Exhaust Cylinder & Manifold	Completed	June 2025
170	Peakers	2025	DTE	Reliability	Blackstart Peaker Unit 1 Starting System	Full Detail, Firm Price Estimate	March 2026
Michigan Public Service Commission DTE Electric Company Projected Capital Expenditures Years 2025 and 2026 Routine Maintenance Projects greater than \$3M					Case No.: U-21860 Response: AGDE-3.110a Witness: M. E. Guillaumin Page: 2 of 2		
	(a)	(b)	(c)	(d)	(e)		
Line No.	Facility	Calendar Year	Unit	High Level Breakdown	Description	Current Phase of Development	Completion & In-Service (Month & Year)
172	Belle River/Range Road	2026	2	Reliability	Unit 2 Waterwall Tubes	Bid Estimate	December 2026
173	Belle River/Range Road	2026	2	Reliability	Unit 2 Secondary Air Heaters Baskets	Bid Estimate	December 2026
174	Belle River/Range Road	2026	2	Safety	Unit 2 HP Turbine Valves	Bid Estimate	December 2026
175	Belle River/Range Road	2026	2	Reliability	Unit 2 Generator Machine Breaker	Bid Estimate	December 2026
180	Belle River/Range Road	2026	Common	Minor Environmental	North Area Spare Transformer Containment Pad	Full Detail, Firm Price Estimate	December 2026
181	Belle River/Range Road	2026	Common	Safety	South Auxiliary Boiler	Bid Estimate	September 2026
182	Belle River/Range Road	2026	Common	Safety	North Auxiliary Boiler	Bid Estimate	September 2026
189	Monroe without Large Enviro.	2026	1	Minor Environmental	Unit 1 SCR Catalyst Layers 1, 2, & 4	Budget Estimate	May 2027
193	Monroe without Large Enviro.	2026	2	Reliability	Unit 2 Waterwall Tubes	Bid Estimate	May 2026
194	Monroe without Large Enviro.	2026	2	Safety	Unit 2 LPA & LPB Turbine Rotor and Blades	Bid Estimate	May 2026
195	Monroe without Large Enviro.	2026	2	Reliability	Unit 2 Coal Mill Classifiers	Bid Estimate	May 2026
196	Monroe without Large Enviro.	2026	2	Reliability	Unit 2 Expansion Joints	Full Detail, Firm Price Estimate	May 2026
197	Monroe without Large Enviro.	2026	2	Minor Environmental	Unit 2 SCR Catalyst Layers 1, 2, & 4	Bid Estimate	May 2026
198	Monroe without Large Enviro.	2026	2	Infrastructure	Unit 2 Precipitator SIFs	Bid Estimate	May 2026
199	Monroe without Large Enviro.	2026	2	Reliability	Unit 2 Economizer Tubes	Bid Estimate	May 2026
200	Monroe without Large Enviro.	2026	2	Safety	Unit 2 Turbine Valves	Bid Estimate	May 2026
201	Monroe without Large Enviro.	2026	2	Reliability	Unit 2 LPA & LPB Turbine Crossover Expansion Joints	Bid Estimate	May 2026
206	Monroe without Large Enviro.	2026	3	Minor Environmental	Unit 3 SCR Catalyst Layer 1	Bid Estimate	October 2026
207	Monroe without Large Enviro.	2026	Fuel Supply	Safety	Fuel Supply CV-09 to CR-02 Transfer Chute	Bid Estimate	June 2026
211	Blue Water Energy Center	2026	11	Reliability	CTG11 Hot Gas Path Overhaul	Budget Estimate	March 2026
213	Blue Water Energy Center	2026	12	Reliability	CTG12 Hot Gas Path Overhaul	Budget Estimate	March 2026
215	Blue Water Energy Center	2026	Common	Reliability	STG Transformer	Bid Estimate	April 2026
216	Blue Water Energy Center	2026	Common	Reliability	CT Transformer	Bid Estimate	December 2026
219	Blue Water Energy Center	2026	STG	Safety	Steam Turbine Valves	Budget Estimate	March 2026
224	Peakers	2026	Greenwood	Reliability	Greenwood 11-2 Peaker Major Overhaul	Bid Estimate	December 2026
225	Peakers	2026	Greenwood	Reliability	Greenwood 12-1 Peaker Major Overhaul	Bid Estimate	May 2026
228	Peakers	2026	Renaissance	Reliability	Renaissance Unit 3 Peaker Combustion Overhaul	Budget Estimate	November 2026

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-1.24a

Respondent: J. Davis

Page: 1 of 1

Question: 24. Refer to pages 23-27 of Mr. Davis' direct testimony on the Fermi 2 Security System Computer replacement project. Please: a. Provide a comparison of the initial cost estimate to complete the entire project to the final actual or estimated cost by major component and explain the reasons with related dollars for any variance of 10% or greater.

Answer: The Security System Computer replacement project was supported in Case No. U-21534 where the Commission found "that the record in the instant case provides a sufficient explanation for the increases in both budgets. For the security system computer project, the increase arises from nine security-related items with changed costs, and for the plant radio system project the increase is related to the wires powering the uninterruptible power supplies." (Case No. U-21534, Order dated January 23, 2025). The cost projection for Security System Computer replacement was approved at \$39.2 million as depicted in Attorney General's confidential Exhibit AG-9 of Witness Coppola's direct testimony in Case No. U-21534; the total project cost projection supported in this proceeding is \$41.6 million which is an approximate 6% change from Case No. U-21534 with the primary drivers being additional site acceptance testing, addition of new cameras and microwave zones, additional updates to cyber assessments and final system adjustments following the results of the site acceptance testing. Reference Company response to STDE-1.24b.

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-1.25a

Respondent: J. Davis

Page: 1 of 1

Question: 25. Refer to pages 27-30 of Mr. Davis' direct testimony on the Fermi 2 Plant Radio System replacement project. Please: a. Provide a comparison of the initial cost estimate to complete the entire project to the final actual or estimated cost by major component and explain the reasons with related dollars for any variance of 10% or greater.

Answer: The Plant Radio System replacement project was supported in Case No. U-21534 where the Commission found "that the record in the instant case provides a sufficient explanation for the increases in both budgets. For the security system computer project, the increase arises from nine security-related items with changed costs, and for the plant radio system project the increase is related to the wires powering the uninterruptible power supplies." (Case No. U-21534, Order dated January 23, 2025). The project estimate for Plant Radio System replacement was approved at \$19.4 million as depicted in Attorney General's confidential Exhibit AG-9 of Witness Coppola's direct testimony in Case No. U-21534; the total project cost projection supported in this proceeding is \$20.7 million which is an approximate 7% change from Case No. U-21534 with the primary drivers being additional system adjustments following onsite equipment initiation (i.e. real-world performance led to unanticipated radio signal dead spots which is unacceptable for this plant system. DTE Electric with supplier and other expertise tested the design and install to optimize equipment performance). Reference Company response to STDE-1.25b.

Exhibit AG-14

(Nuclear Underground Water Piping)

CONFIDENTIAL

Exhibit AG-15

(Nuclear Routine and Non-Routine
projects)

CONFIDENTIAL

Exhibit AG-16

(Engineering and Support Staff
Augment)

CONFIDENTIAL

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-8.222d

Respondent: J. Sobiechowski

Page: 1 of 1

Question: 222. Refer to lines 6–24 on page 62 of Ms. Uzenski’s direct testimony on facilities construction and upgrades. Please:
d. Explain what the problems are with the WCB building façade and why it requires \$3.3 million to complete. If this is a multi-year project, provide the cost by year from inception to completion of the project.

Answer: All buildings in the City of Detroit over 5 stories require an exterior inspection every 5 years by City of Detroit code. This project corrects all of the deficiencies found during the last inspection of the WCB. Current plan is \$1M in 2025, \$2M in 2026, and \$2M in 2027, for a total of \$5M over three years.

Attachment: *none*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-8.222e

Respondent: J. Sobiechowski

Page: 1 of 1

Question: 222. Refer to lines 6–24 on page 62 of Ms. Uzenski’s direct testimony on facilities construction and upgrades. Please:
e. Explain what the Company is doing to optimize the open space at the headquarters complex, why it is necessary, and what the \$7.8 million will be spent on by year. Explain why the plumbing needs to be renewed.

Answer: Refer to audit response ZSS-1.2a. The plumbing needs to be renewed because it is at end of life and continues to require repair causing water and bathroom outages.

Attachment: *none*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-8.222f

Respondent: J. Sobiechowski

Page: 1 of 1

Question: 222. Refer to lines 6–24 on page 62 of Ms. Uzenski’s direct testimony on facilities construction and upgrades. Please:

f. Explain why it is necessary to spend \$2.3 million to install furniture and structures in the courtyard and for what functions and events. Is this a courtyard at the headquarters building?

Answer: Please refer to audit responses ZSS-1.3a through c.

Attachment: *none*

MPSC Case No: U-21860

Requester: Staff

Question No.: ZSS-1.3a

Respondent: T. Uzenski

Page: 1 of 1

Question: 3. Per TMU-62, the company plans to spend \$2.3 million to install furniture, AV equipment and a structure in the courtyard for activities and events. (Reference Exhibit A-12, Schedule B5.8, Page 2, Line 13) a. Where is this courtyard located?

Answer: The courtyard is located at company headquarters in downtown Detroit.

Attachment: *none*

MPSC Case No: U-21860

Requester: Staff

Question No.: ZSS-1.3b

Respondent: T. Uzenski

Page: 1 of 1

Question: 3. Per TMU-62, the company plans to spend \$2.3 million to install furniture, AV equipment and a structure in the courtyard for activities and events. (Reference Exhibit A-12, Schedule B5.8, Page 2, Line 13) b. What specifically will this be used for?

Answer: The courtyard is currently an open-air space, and the improvements will allow it to be used for centralized team meetings and events.

Attachment: *none*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-8.225b

Respondent: J. Sobiechowski

Page: 1 of 1

Question: 225. Refer to lines 16–24 on page 64 of Ms. Uzenski’s direct testimony on the Trombly service center. Please:

b. Confirm that the renovation work was bid out to various contractors and vendors and the lowest cost option was chosen. If not confirming, explain why.

Answer: The renovation work will be competitively bid when the design is complete.

Attachment: *none*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-8.225c

Respondent: J. Sobiechowski

Page: 1 of 1

Question: 225. Refer to lines 16–24 on page 64 of Ms. Uzenski’s direct testimony on the Trombly service center. Please:

c. Identify how much of the spending pertains to the compliance standards versus land clearing for future use. Identify what future use the Company is planning and in which year.

Answer: The Trombly service center renovation is \$5.25M and sitework is \$2.5M. The sitework project is for demolition of buildings, land clearing, perimeter fencing and securing the property in preparation for a new six-bay vehicle repair facility replacing the existing two-bay vehicle repair facility at Trombly in 2028 and 2029.

Attachment: *none*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-8.234b

Respondent: T. Uzenski

Page: 1 of 1

Question: 234. Refer to Exhibit A-12, Schedule B5.8, page 2. Please:
b. For the amounts in Other on line 64, identify any projects of \$1 million or greater and describe those projects and why they are necessary.

Answer: Assuming the question meant to refer to line 54, this item is for emergent work. Specific projects have not been identified.

Attachment: *none*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-8.220a

Respondent: T. Uzenski

Page: 1 of 1

Question: 220. Refer to lines 1–10 on page 61 of Ms. Uzenski’s direct testimony on Fleet vehicles. Please:

a. Provide a copy of the model outcomes showing the recommendations for specific vehicles or equipment to be replaced for each year 2022–2026 within each type or class in Excel. Provide and describe the factors with related weights that the model uses to determine whether the vehicle should or should not be replaced.

Answer: See file attached for the model output. Fleet uses a proprietary model which develops a comprehensive asset life cycle that optimizes total cost of ownership. Historic ownership costs and operational data are used to develop a replacement strategy specific to DTE Electric. Assets with the greatest reduction to maintenance and ownership costs are chosen. The fleet mechanics also provide input on replacements based on their hands-on vehicle knowledge from the field.

In regard to the specific assumptions underlying the model, the company is unable to share this information. The company utilizes a vendor with a proprietary model who is unwilling to share their algorithm.

Attachment: *U-21860 AGDE-8.220a Vehicle Model Report DTE 9-10-24.xlsx*

<u>Even</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>	<u>2029</u>	<u>2030</u>	<u>2031</u>	<u>2032</u>	<u>2033</u>	<u>2034</u>	<u>2035</u>
Annual Capital	\$49,126,096	\$45,736,388	\$44,163,166	\$48,387,930	\$47,586,788	\$36,759,789	\$22,560,997	\$14,333,753	\$11,719,170	\$7,896,698
Units Replaced	359	333	328	345	329	249	173	114	85	69
Annual Maintenance	\$27,997,878	\$28,202,157	\$28,489,162	\$28,689,985	\$29,031,688	\$29,938,571	\$31,819,206	\$34,005,210	\$36,336,426	\$38,874,458
Annual Ownership	\$30,763,785	\$32,346,548	\$33,365,432	\$34,839,581	\$35,949,038	\$35,338,003	\$32,841,702	\$29,578,541	\$26,495,003	\$23,373,139
Total	\$58,761,664	\$60,548,705	\$61,854,594	\$63,529,565	\$64,980,726	\$65,276,575	\$64,660,909	\$63,583,751	\$62,831,429	\$62,247,597
Out of Life	1012	915	855	705	658	607	708	804	1062	1237
Avg Age	8.65	8.32	8.13	7.91	7.8	7.96	8.31	8.85	9.48	10.14

<u>OOL</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>	<u>2029</u>	<u>2030</u>	<u>2031</u>	<u>2032</u>	<u>2033</u>	<u>2034</u>	<u>2035</u>
Annual Capital	\$132,972,150	\$36,076,909	\$39,523,246	\$27,004,261	\$33,245,955	\$21,005,402	\$22,889,730	\$5,684,179	\$3,875,028	\$8,536,475
Units Replaced	1075	232	240	180	251	161	177	76	31	93
Annual Maintenance	\$25,044,107	\$25,683,190	\$26,358,554	\$27,652,922	\$28,937,582	\$30,802,678	\$32,869,957	\$35,230,625	\$37,674,323	\$40,288,051
Annual Ownership	\$42,414,768	\$40,302,087	\$39,056,364	\$36,370,517	\$35,043,290	\$32,247,859	\$30,232,197	\$26,125,439	\$22,417,918	\$20,079,418
Total	\$67,458,876	\$65,985,277	\$65,414,919	\$64,023,439	\$63,980,872	\$63,050,537	\$63,102,154	\$61,356,063	\$60,092,240	\$60,367,469
Out of Life	296	300	328	343	374	411	508	746	1114	1338
Avg Age	6.09	6.48	6.79	7.26	7.46	7.97	8.29	9	9.87	10.43

The even scenario takes the number of vehicles in the class and divides it by the length of the lifecycle to get the maximum number of replacements per year. For example, 100 half-ton pickups with a 10 year lifecycle would mean a maximum of 10 replacements per year. Then it would replace up to 10 vehicles that are out of lifecycle each year and repeat this process for every class. This helps avoid aging bubbles while keeping with the planned lifecycles or catching up to them if the fleet is behind.

The out of life scenario replaces everything that is out of lifecycle immediately and usually results in large expenditures initially to catch up on the lifecycles. This is not a realistic spending structure and it also creates aging bubbles that can cause issues if capital is reduced in future years.

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-8.220b

Respondent: T. Uzenski

Page: 1 of 1

Question: 220. Refer to lines 1–10 on page 61 of Ms. Uzenski’s direct testimony on Fleet vehicles. Please:

b. Provide the number of units within each vehicle or equipment type/class purchased each year 2021 through 2024 and forecasted to be purchased for 2025 and 2026 with the related cost in Excel. Explain any variance of 10% or greater in number of units and unit cost by type from 2024 to 2026.

Answer: Please see attached file.

Attachment: *U-21860 AGDE-8.220B 2021-2026 Fleet Vehicles*

Vehicle and equipment purchases for 2021

[illegible]

**Michigan Public Service Commission
DTE Electric Company
Case No. U-21860
AGDE-8.220b
Fleet Vehicle Purchases**

FORD	F250	31,081
FORD	RANGER	10,548
FORD	RANGER	10,548
FORD	RANGER	10,548
FORD	F250	31,065
FORD	F250	31,065
FORD	F250	31,065
FORD	F250	31,065
FORD	F250	31,065
FORD	F250	31,065
FORD	F250	31,065
FORD	F250	31,126
FORD	F250	31,126
FORD	F250	31,126
FORD	F250	31,126
FORD	F250	31,126
FORD	F250	31,126
FORD	F250	31,126
FORD	F250	31,126
FORD	F250	31,015
FORD	F250	31,015
FORD	F250	31,015
FORD	F250	31,015
FORD	F250	31,015
FORD	F250	31,015
FORD	F250	31,015
FORD	F250	31,015
FORD	F250	31,015
FORD	F250	31,008
FORD	F250	31,008
FORD	F250	31,008
FORD	F250	31,008
FORD	F250	31,008
FORD	F250	31,008
FORD	F150	39,344
FORD	F150	33,350
FORD	F150	33,350
FORD	F150	33,350
FORD	F150	33,350
FORD	F150	33,350
FORD	F150	39,338
FORD	F150	39,338
FORD	F150	39,338
FORD	F150	39,338
FORD	F150	39,338
FORD	F250	47,639
FORD	F250	47,639
FORD	F250	47,639
FORD	F250	47,639
FORD	F250	47,639
FORD	F250	46,915
FORD	F250	46,915
FORD	F250	46,915
FORD	F250	46,915
FORD	F250	46,915
FORD	F250	47,639
FORD	F250	47,639
FORD	F250	47,639
FORD	F250	47,639
FORD	F250	47,639

FORD	F250	50,730
FORD	F150	39,494
FORD	F150	39,494
FORD	F150	39,494
FORD	F150	39,494
FORD	F150	39,494
FORD	F150	39,494
FORD	F150	39,494
FORD	F150	39,494
FORD	F150	39,494
FORD	F150	39,394
FORD	F150	39,179
FORD	F150	39,413
FORD	F150	39,413
FORD	F150	39,413
FORD	F150	39,413
FORD	F150	40,652
FORD	F150	40,652
FORD	F150	40,652
FORD	F150	40,652
FORD	F150	40,652
FORD	F150	40,652
FORD	F150	40,652
FORD	F150	40,652
FORD	M2106	150,842
FREIGHTLINER	DM47	134,568
FREIGHTLINER	UNAVAILABL	103,385
BROOKS BROTHERS	UNAVAILABL	43,199
LOAD TRAIL	CUSTOM	64,220
LOAD TRAIL	F550	94,935
FORD	UNAVAILABL	184,673
INTERNATIONAL	M2106	144,413
FREIGHTLINER	CUSTOM	104,817
FORD	F350	87,674
FORD	F350	87,674
FORD	F350	87,674
FORD	F350	26,463
FORD	F250	12,684
FORD	F350	15,050
FORD	TRANSIT CARGO VAN	37,181
FORD	TRANSIT CARGO VAN	37,181
FORD	TRANSIT CARGO VAN	37,181
FORD	TRANSIT CARGO VAN	37,181
FORD	TRANSIT CARGO VAN	37,181
FORD	TRANSIT CARGO VAN	37,181
FORD	TRANSIT CARGO VAN	37,164
FORD	TRANSIT CARGO VAN	37,083
FORD	TRANSIT CARGO VAN	37,083
FORD	TRANSIT CARGO VAN	37,083
FORD	TRANSIT CARGO VAN	37,083
FORD	TRANSIT CARGO VAN	37,083
FORD	TRANSIT CARGO VAN	37,083
FORD	TRANSIT CARGO VAN	37,083
FORD	TRANSIT CARGO VAN	37,083
FORD	TRANSIT CARGO VAN	25,581
FORD	TRANSIT CARGO VAN	25,581
FORD	TRANSIT CARGO VAN	25,581
FORD	TRANSIT CARGO VAN	25,581

FORD	F550	302,589
FREIGHTLINER	M2106 JEMS	302,589
FREIGHTLINER	M2106	302,589
FREIGHTLINER	M2106 JEMS	302,589
FORD	F150	225,562
FORD	F150	225,562
PETERBILT	AC18-70	225,562
FREIGHTLINER	114SD	225,562
TRUCK TECH	CUSTOM	171,237
PETERBILT	AC18-70	25,754
BROOKS BROTHERS	PT122-8KE	82,362
TRUCK TECH	CUSTOM	42,809
BROOKS BROTHERS	PT122-8KE	27,454
BROOKS BROTHERS	UNAVAILABL	41,441
LOAD TRAIL	AT80	46,746
FELLING	MX70-2-DD	72,661
HASTINGS	UNAVAILABL	34,980
YALE	GDP300EF	200,412
JCB	950	144,902
CAT	TL1255	216,629
CAT	TL1255	216,629
YALE	ERP040VT	43,443
JCB	TLT77-52	122,488
JLG	UNAVAILABL	12,137
JLG	UNAVAILABL	12,137
JLG	UNAVAILABL	12,433
UNAVAILABLE	600AJ	114,989
JLG	600AJ	102,597
GENIE	GS-1930	12,248
BRODERSON	IC-80-3L	207,418
TAYLORDUNN	SS-546	8,823
YALE	GTP080	62,914
CAT	UNAVAILABL	441,035
CAT	938M	243,762
ALTEC	UNAVAILABL	161,702
ALTEC	DB37	161,702
ALTEC	UNAVAILABL	161,702
Training System		121,413
Capital Repairs/Tools		3,215,453
Capital Maintenance		945,356
Labor for capital maintenance/repairs, and purchase		1,207,224
278 Units		21,705,243

Vehicle and equipment purchases for 2022

<u>Make</u>	<u>Model</u>	<u>Cap Ex</u>
Stanley	32 LC	228,046
GREAT DANE	40 FT	50,170
GREAT DANE	40 FT	50,170
GREAT DANE	40 FT	50,170
GREAT DANE	40 FT	50,170
GREAT DANE	40 FT	50,170
GREAT DANE	40 FT	50,170
JLG	450AJSH	61,980
JCB	950	145,050
JCB	950	136,840
CAT	972M	436,375
ALTEC	AT48PEJEMS	69,217
CROWN	C5-1050-60	54,478
CROWN	C5-1050-60	54,478
LANDOLL	CUSTOM	147,137
UNAVAILABLE	CUSTOM	105,283
LOAD TRAIL	CUSTOM	42,515
JLG	E300AJP	43,965
Ford	E350 CUTAWAY	89,643
JLG	E400AJPN	52,900
FORD	E450	88,459
FORD	E450	77,012
FORD	E450	88,586
YALE	ERC065VG	55,036
YALE	ERC065VG	55,036
JLG	ES2632	18,175
PETERBILT	EV220	390,047
Ford	EXT LIGHTNING	67,512
FORD	F150	53,968
FORD	F150	47,300
FORD	F150	47,288
FORD	F150	47,269
FORD	F150	65,647
FORD	F150	65,647
FORD	F150	50,406
FORD	F150	53,047
FORD	F150	53,147
FORD	F150	49,937
FORD	F150	51,417
FORD	F150	54,708
FORD	F150	49,936
FORD	F150	49,962
FORD	F150	44,226
FORD	F150	38,855
FORD	F150	53,685
FORD	F150	47,288
FORD	F150	47,683
FORD	F150	47,266
FORD	F150	65,647
FORD	F150	65,647
FORD	F150	49,925
FORD	F150	49,928
FORD	F150	70,602
FORD	F150	49,942
Ford	F150	57,737

Michigan Public Service Commission
DTE Electric Company
Case No. U-21860
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Fleet Vehicle Purchases

FORD	F150	53,686
FORD	F150	47,268
FORD	F150	47,278
FORD	F150	47,266
FORD	F150	65,647
FORD	F150	65,647
FORD	F150	50,039
FORD	F150	50,014
FORD	F150	49,944
FORD	F150	44,711
Ford	F150	44,711
FORD	F150	37,855
FORD	F150	47,272
FORD	F150	47,266
FORD	F150	47,265
FORD	F150	65,647
FORD	F150	65,647
FORD	F150	49,948
FORD	F150	50,013
FORD	F150	49,946
Ford	F150	44,526
FORD	F150	38,855
FORD	F150	47,273
FORD	F150	47,295
FORD	F150	47,265
FORD	F150	65,647
FORD	F150	65,647
FORD	F150	47,107
FORD	F150	38,355
FORD	F150	38,355
FORD	F150	38,355
FORD	F150	38,355
FORD	F150	40,223
FORD	F150 HYBRID	59,595
FORD	F150 HYBRID	59,641
FORD	F150 HYBRID	59,608
FORD	F150 HYBRID	59,606
Ford	F150 HYBRID	53,644
FORD	F150 HYBRID	59,686
FORD	F150 HYBRID	59,579
FORD	F150 HYBRID	55,969
FORD	F150 HYBRID	59,757
Ford	F150 HYBRID	53,644
FORD	F150 HYBRID	59,646
Ford	F150 HYBRID	53,644
FORD	F150 HYBRID	63,010
FORD	F150 HYBRID	59,571
FORD	F150 HYBRID	56,057
Ford	F150 HYBRID	53,644
Ford	F150 HYBRID	53,659
Ford	F150 HYBRID	53,804
Ford	F150 HYBRID	57,754
Ford	F150 HYBRID	57,754
FORD	F250	68,312
FORD	F250	68,312
FORD	F250	68,324
FORD	F250	68,359
FORD	F250	48,484

FORD	F250	62,238
FORD	F250	59,658
FORD	F250	63,839
FORD	F250	63,335
Ford	F250	51,454
FORD	F250	68,312
FORD	F250	68,312
FORD	F250	68,324
FORD	F250	68,376
FORD	F250	48,038
FORD	F250	53,132
Ford	F250	51,454
FORD	F250	68,359
FORD	F250	68,324
FORD	F250	48,419
Ford	F250	51,454
FORD	F250	68,324
FORD	F250	68,312
Ford	F250	51,454
Ford	F250	51,454
Ford	F250	51,454
FORD	F350	63,640
FORD	F350	109,235
FORD	F350	101,364
FORD	F350	89,092
FORD	F350	88,716
FORD	F350	89,105
FORD	F350	88,398
FORD	F350	88,982
Ford	F350	85,141
Ford	F350	44,964
Ford	F350	44,964
Ford	F350	88,859
Ford	F350	44,047
Ford	F350	44,047
Ford	F350	44,047
FORD	F350	94,889
FORD	F350	93,673
Ford	F350	44,973
FORD	F350	68,854
FORD	F350	86,184
FORD	F350	97,479
FORD	F350	88,739
FORD	F350	89,111
FORD	F350	88,606
FORD	F350	89,856
Ford	F350	44,964
Ford	F350	44,964
Ford	F350	44,964
Ford	F350	88,859
Ford	F350	44,047
Ford	F350	44,047
Ford	F350	44,047
FORD	F350	93,667
Ford	F350	44,973
FORD	F350	88,629
FORD	F350	89,076
FORD	F350	88,433

Ford	F350	44,964
Ford	F350	44,964
Ford	F350	44,964
FORD	F350	94,794
FORD	F350	93,677
Ford	F350	44,973
FORD	F350	88,975
FORD	F350	89,174
FORD	F350	89,080
Ford	F350	44,964
Ford	F350	44,964
Ford	F350	44,964
FORD	F350	94,792
FORD	F350	90,927
Ford	F350	44,973
FORD	F350	89,074
FORD	F350	89,173
FORD	F350	89,076
FORD	F350	90,873
FORD	F350	91,056
Ford	F450	60,431
Ford	F450	60,347
FORD	F550	69,008
FORD	F550	269,991
FORD	F550	139,572
FORD	F550	69,217
FORD	F550	69,217
FORD	F550	69,217
FORD	F550	76,122
FORD	F550	163,108
Ford	F550	155,686
FORD	F550	69,620
FORD	F550	69,620
FORD	F550	409,800
FORD	F550	252,000
FORD	F550	269,991
FORD	F550	69,217
FORD	F550	69,217
FORD	F550	69,217
FORD	F550	255,976
FORD	F550	69,217
FORD	F550	69,217
FORD	F550	69,217
FORD	F550	269,991
FORD	F550	69,217
FORD	F550	69,217
FORD	F550	69,217
FORD	F550	237,010
FORD	F550	267,685
FORD	F550	69,217
FORD	F550	69,217
FORD	F550	237,010
FORD	F550	69,217
FORD / ALTEC	F550 / AT48 (JEMS)	69,217
FORD / ALTEC	F550 / AT48 (JEMS)	265,544
FORD	F600SD	110,622
FELLING	FT14-OT	28,250
FELLING	FT14-OT	32,879

FELLING	FT14-OT	28,250
FELLING	FT-14-OT	28,250
FELLING	FT-14-OT	28,250
FELLING	FT20-2	23,635
YALE	GDP210DF	188,352
YALE	GDP300EF	200,412
YALE	GP155VX	105,602
GENIE	GS-2032	14,555
FOREST RIVER	HAC8514TA3	26,550
GMC	HUMMER EV	122,232
BRODERSON	IC-80-3L	161,800
Ford	LIGHTNING	48,710
Ford	LIGHTNING	55,634
Ford	LIGHTNING	48,710
Ford	LIGHTNING	55,634
Ford	LIGHTNING	48,710
Ford	LIGHTNING	55,634
Ford	LIGHTNING	48,710
Ford	LIGHTNING	55,634
Ford	LIGHTNING	48,710
Ford	LIGHTNING	48,710
Ford	LIGHTNING	55,634
Ford	LIGHTNING	48,710
Ford	LIGHTNING	55,634
Ford	LIGHTNING	48,710
Ford	LIGHTNING	55,634
Ford	LIGHTNING	48,710
Ford	LIGHTNING	55,634
Ford	LIGHTNING	48,710
Ford	LIGHTNING	55,634
FORD	LIGHTNING EV	54,796
FORD	LIGHTNING EV	54,797
FORD	LIGHTNING EV	54,802
FORD	LIGHTNING EV	54,813
FORD	LIGHTNING EV	54,880
FORD	LIGHTNING EV	54,796
FORD	LIGHTNING EV	55,189
FORD	LIGHTNING EV	54,799
FORD	LIGHTNING EV	54,808
FORD	LIGHTNING EV	54,796
FORD	LIGHTNING EV	54,792
FORD	LIGHTNING EV	54,817
FORD	LIGHTNING EV	54,796
FORD	LIGHTNING EV	54,402
FORD	LIGHTNING EV	54,792
FORD	LIGHTNING EV	54,792
FORD	LIGHTNING EV	54,792
FORD	LIGHTNING EV	54,796
FORD	LIGHTNING EV	54,808
FORD	LIGHTNING EV	54,795
FORD	LIGHTNING EV	54,817
FORD	LIGHTNING EV	54,799
FORD	LIGHTNING EV	54,956
FORD	LIGHTNING EV	54,792
FORD	LIGHTNING EV	54,797
FORD	LIGHTNING EV	54,815

FORD	LIGHTNING EV	54,788
FORD	LIGHTNING EV	54,792
FREIGHTLINER	M2106	329,181
FREIGHTLINER	M2106	87,799
FREIGHTLINER	M2106	90,511
FREIGHTLINER	M2106	90,511
FREIGHTLINER	M2106	88,423
FREIGHTLINER	M2106	109,316
FREIGHTLINER	M2106	109,316
FREIGHTLINER	M2106	109,316
FREIGHTLINER	M2106	109,316
FREIGHTLINER	M2106	109,316
FREIGHTLINER	M2106	104,000
FREIGHTLINER	M2106	169,962
FREIGHTLINER	M2106	109,316
FREIGHTLINER	M2106	109,316
FREIGHTLINER/ALTEC	M2106 / AA55E	109,316
FREIGHTLINER/ALTEC	M2106 / AA55E (JEMS)	109,316
FREIGHTLINER/ALTEC	M2106 / AA55E (JEMS)	109,316
FREIGHTLINER/ALTEC	M2106 / AA55E (JEMS)	109,316
FREIGHTLINER/ALTEC	M2106 / AA55E (JEMS)	109,316
FREIGHTLINER	M2106 JEMS	335,072
FREIGHTLINER	M2106 JEMS	256,273
FREIGHTLINER	M2106 JEMS	335,072
FREIGHTLINER	M2106 JEMS	335,072
FREIGHTLINER	M2106 JEMS	86,312
FREIGHTLINER	M2106 JEMS	335,072
FORD	MAVERICK	33,775
FORD	MAVERICK	33,812
FORD	MAVERICK HYBRID	29,833
FORD	MAVERICK HYBRID	29,830
FORD	MAVERICK HYBRID	29,429
YALE	OPEN	52,480
BROOKS BROTHERS	PT122-8KE	28,674
KUBOTA	RTVX1140	31,816
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
GM	Silverado 1500 Double Cab	42,118
TENNANT	T300	7,124
Ford	T350	58,655
Ford	T350	58,655
Ford	T350	58,655

Ford	T350	58,655
Ford	T350	56,482
Ford	T350	56,482
Ford	T350	56,482
Ford	T350	56,548
Ford	T350	56,482
Ford	T350 130WB	59,220
TENNANT	T5	12,434
TENNANT	T600	13,797
Ford	TRANSIT 350	58,655
Ford	TRANSIT 350	58,655
Ford	TRANSIT 350	58,655
Ford	TRANSIT 350	58,655
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,816
FORD	TRANSIT CARGO VAN	87,004
FORD	TRANSIT CARGO VAN	85,075
FORD	TRANSIT CARGO VAN	85,057
FORD	TRANSIT CARGO VAN	61,201
FORD	TRANSIT CARGO VAN	91,741
FORD	TRANSIT CARGO VAN	69,244
FORD	TRANSIT CARGO VAN	91,761
FORD	TRANSIT CARGO VAN	91,750
FORD	TRANSIT CARGO VAN	91,715
FORD	TRANSIT CARGO VAN	91,884
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	85,069
FORD	TRANSIT CARGO VAN	85,088
FORD	TRANSIT CARGO VAN	85,053
FORD	TRANSIT CARGO VAN	91,790
FORD	TRANSIT CARGO VAN	69,244
FORD	TRANSIT CARGO VAN	91,904
FORD	TRANSIT CARGO VAN	55,463
FORD	TRANSIT CARGO VAN	91,677
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,791
FORD	TRANSIT CARGO VAN	85,093
FORD	TRANSIT CARGO VAN	85,027
FORD	TRANSIT CARGO VAN	91,737
FORD	TRANSIT CARGO VAN	91,781
FORD	TRANSIT CARGO VAN	91,672
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	85,087
FORD	TRANSIT CARGO VAN	85,063
FORD	TRANSIT CARGO VAN	91,703
FORD	TRANSIT CARGO VAN	91,740
FORD	TRANSIT CARGO VAN	66,406
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	91,905
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,788

FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	91,886
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,803
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	67,174
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	62,496
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	62,103
FORD	TRANSIT CARGO VAN	66,788
FORD	TRANSIT CARGO VAN	62,496
FORD	TRANSIT-350	63,365
FORD	TRANSIT-350	69,736
FORD	TRANSIT-350	68,462
FORD	TRANSIT-350	63,365
FORD	TRANSIT-350	68,462
FORD	TRANSIT-350	69,736
FORD	TRANSIT-350	68,462
FORD	TRANSIT-350	63,365
FORD	TRANSIT-350	69,736
FORD	TRANSIT-350	63,365
FORD	TRANSIT-350	68,462
FORD	TRANSIT-350	68,462
FORD	TRANSIT-350	63,365
FORD	TRANSIT-350	63,365
INTERNATIONAL	AA55E	523,200
INTERNATIONAL	DH48E Rear Mount	430,800
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	AA55E	523,200
INTERNATIONAL	DH48E Rear Mount	430,800
INTERNATIONAL	AA55E	523,200
INTERNATIONAL	DH48E Rear Mount	430,800
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	DH48E Rear Mount	430,800
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	DH48E Rear Mount	430,800
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	DH48E Rear Mount	430,800
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	DH48E Rear Mount	430,800
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	DH48E Rear Mount	430,800
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	AA55E	518,400
INTERNATIONAL	DH48E Rear Mount	506,400
CROWN	WAV60-118	22,737
2022 Tool Boxes	0000203306-IDSC HOLDIN	237,925
2022 Tool Boxes	0000203306-IDSC HOLDIN	548,262
2022 Electric Tools	0000251084-BRIGADE ELE	32,305
2022 Electric Tools	0000204715-TENNANT SAL	13,180

2022 Electric Tools	0000211216-HYTORC	221,986
2022 Electric Tools	0000200186-ALLIED INC	70,590
2022 Electric Tools	0000203306-IDSC HOLDIN	31,897
2022 Electric Tools	0000200186-ALLIED INC	114,806
2022 Electric Tools	0000203306-IDSC HOLDIN	31,897
457 units	\$	46,346,506

Vehicle and equipment purchases for 2023

**Michigan Public Service Commission
DTE Electric Company
Case No. U-21860
AGDE-8.220b
Fleet Vehicle Purchases**

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

Ford	T350	25,704.97
Ford	T350	27,281.56
Ford	T350	27,281.56
Ford	T350	27,281.56
Ford	T350	27,281.56
Ford	T350	21,753.51
Ford	T350	21,753.51
Ford	T350	21,753.51
Ford	T350	21,753.51
Ford	T350	21,753.51
Ford	T350	12,080.93
Ford	T350	12,080.93
Ford	T350	12,080.93
Ford	T350	12,080.93
Ford	T350	12,080.93
Ford	T350	12,080.93
Ford	T350	58,724.58
Ford	T350 (MILLWRIGHT)	59,208.67
Ford	T350 (MILLWRIGHT)	59,208.67
Ford	T350 (MILLWRIGHT)	59,208.67
Ford	T350 148WB	58,996.48
Tennant	T500 WALK BEHIND	14,062.80
ALTEC	Tandem Digger (AWD) (JEMS)	120,695.84
ALTEC	Tandem Digger (AWD) (JEMS)	120,695.84
ALTEC	Tandem Digger (AWD) (JEMS)	120,695.84
ALTEC	Tandem Digger (AWD) (JEMS)	120,695.84
ALTEC	Tandem Digger (AWD) (JEMS)	120,695.84
ALTEC	Tandem Digger (FWD) (JEMS)	120,695.84
ALTEC	Tandem Digger (FWD) (JEMS)	120,695.84
ALTEC	Tandem Digger (FWD) (JEMS)	120,695.84
ALTEC	Tandem Digger (FWD) (JEMS)	120,695.84
TOWMASTER	TC-12HD	20,587.00
NORAMP	U-14	16,207.00
POLARIS	XP 1000 NorthStar	37,317.29
2022 Electric Tools	0000204565-SHELVING INC	22,886.43
2023 Electric Tools	0000200186-ALLIED INC	85,116.00
2023 Electric Tools	0000201767-CDW DIRECT LLC	19,748.40
2023 Electric Tools	0000203306-IDSC HOLDINGS LLC	47,178.41
2023 Electric Tools	0000205352-EXPERT AUTO ACCENTS INC	11,850.00
2023 Electric Tools	0000211104-CUMMINS INC	25,264.52
2023 Electric Tools	0000230744-APH STORES INC	19,493.88
2023 Electric Tools	0000231898-AUTO WARES LLC	28,344.27
Labor, Labor Allocations, Capital Repair Labor, Payroll Tax, A&G and other OH's		3,051,022.34
Electrification, Investment Recovery, Vehicle Allocations, Capital Tooling, Capital Tooling		
Allocation, Capital Repairs, Capital Repair Allocation (not included in STDE 4.3A because it was		
outside the scope of the question, only equipment over \$10k was inlucded in STDE4.3A.)		1,202,083.73
Mcqueen Sweeper		344,500.00
Items under 10k		717,922.62
396 Units	\$	33,944,820.35

Vehicle and equipment purchases for 2024

	<u>Make</u>	<u>Model</u>	<u>Capex</u>
Labor and Allocations			2,118,287
INTERNATIONAL		UNAVAILABL	584,733
Caniff EV Chargers			528,621
HOGG DAVIS		HP-650	401,932
BRODERSON		UNAVAILABL	390,223
Western Wayne EV Chargers			382,719
FREIGHTLINER		M2106	382,649
FREIGHTLINER		M2106	382,649
FREIGHTLINER		M2106	382,649
Spend Under \$10k Total			374,431
FREIGHTLINER		M2106	348,507
FREIGHTLINER		MT55	307,852
FREIGHTLINER		MT55	307,851
FREIGHTLINER		MT55	307,851
FREIGHTLINER		MT55	307,851
FREIGHTLINER		MT55	307,851
FREIGHTLINER		MT55	307,851
FREIGHTLINER		MT55	307,851
FREIGHTLINER		MT55	307,851
FREIGHTLINER		MT55	307,851
FREIGHTLINER		MT55	307,851
FREIGHTLINER		MT55	307,851
FREIGHTLINER		MT55	307,851
FREIGHTLINER		M2106	291,380
FREIGHTLINER		M2106	285,675
FREIGHTLINER		M2106	285,675
KENWORTH		T480	285,675
ALTEC		DB41B	262,208
ALTEC		DB41B	262,208
FORD		F750	250,963
FORD		F750	250,963
FREIGHTLINER		M2106	250,963
FREIGHTLINER		M2106	250,963
FREIGHTLINER		M2106	250,963
FREIGHTLINER		M2106	250,963
FREIGHTLINER		M2106	250,963
FREIGHTLINER		M2106	250,963
FREIGHTLINER		M2106	250,963
Redford EV Chargers			216,000
BEHNKE		10T	211,827
FORD		F550	187,631
NAEC EV Chargers			185,545
KENWORTH		T480_6x4	182,098
KENWORTH		T480_6x4	182,098
KENWORTH		T480_6x4	182,058
Waterford Mobile Hoist			165,364
20241206-CR01 Engine replacement (855)			150,248
FORD		F550	147,546
FORD		F350	145,951
FORD		F350	145,951
FORD		F350	145,951
FORD		F350	145,951
FORD		F350	145,951
FORD		F350	145,951
FORD		F350	145,951
FORD		F350	145,951
FORD		F350	145,951
FORD		F350	145,951
FORD		F350	145,951
FORD		F350	145,951
BUCKET TRUCK_AA55E Pending new unit alias #			129,233
DIGGER / DERRICK Pending new unit alias #			129,233
BUCKET TRUCK_AN46E-OC Pending new unit alias #			129,233
BUCKET TRUCK_AA55E Pending new unit alias #			129,233
BUCKET TRUCK_AA55E Pending new unit alias #			129,233

Michigan Public Service Commission
DTE Electric Company
Case No. U-21860
AGDE-8.220b
Fleet Vehicle Purchases

BUCKET TRUCK_AA55E Pending new unit alias #		129,233
BUCKET TRUCK_AA55E Pending new unit alias #		129,233
DREXEL	1	122,128
FORD	F750	119,680
FORD	F750	119,680
FORD	F750	119,680
FORD	F750	119,680
FORD	F750	119,680
FREIGHTLINER	M2106	119,680
FREIGHTLINER	M2106	119,680
FREIGHTLINER	M2106	119,680
KENWORTH	T480	119,680
KENWORTH	T480	119,680
KENWORTH	T480	119,680
KENWORTH	T480	119,680
KENWORTH	T480	119,680
KENWORTH	T480	119,680
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KENWORTH	T480	119,680
KENWORTH	T480	119,680
KENWORTH	T480	119,680
KENWORTH	T480	119,680
KENWORTH	T480	119,680
KENWORTH	T480	119,680
KENWORTH	T480	119,680
KENWORTH	UNAVAILABL	119,680
Decal removal in preperation for auction sale or scrap		115,965
20240301-CR02 Under Carriage 2		114,269
20241220-CR01 Track replacement (722)		114,269
FORD	TRANSIT	113,750
GENIE	UNAVAILABL	111,300
FORD	TRANSIT CARGO VAN	110,331
JCB	505-20	107,993
GREAT DANE	UNAVAILABL	103,506
GREAT DANE	UNAVAILABL	103,506
GREAT DANE	UNAVAILABL	103,506
FORD	F450	100,760
FORD	F650	99,881
FORD	F750	99,881
FREIGHTLINER	M2106	99,881
BUCKET TRUCK_AA55E Pending new unit alias #		99,881
BUCKET TRUCK_AA55E Pending new unit alias #		99,881
BUCKET TRUCK_AA55E Pending new unit alias #		99,881
AN46E Pending New Unit Alias #		99,881
KENWORTH	AN46	99,252
FREIGHTLINER	M2106	99,252
KENWORTH	T380	99,252
KENWORTH	T380	99,252
KENWORTH	T380	99,252
BUCKET TRUCK_AN46E-OC Pending new unit alias #		99,252
BUCKET TRUCK_AN46E-OC Pending new unit alias #		99,252
DIGGER / DERRICK Pending new unit alias #		99,252
BUCKET TRUCK_AN46E-OC Pending new unit alias #		99,252
FORD	F450	97,518
FORD	TRANSIT CARGO VAN	97,216
FORD	TRANSIT CARGO VAN	97,216
FORD	TRANSIT CARGO VAN	97,216
FORD	TRANSIT CARGO VAN	97,216
FORD	TRANSIT CARGO VAN	97,216
FORD	TRANSIT CARGO VAN	91,988
FORD	TRANSIT CARGO VAN	91,988

FORD	E350	91,514
FORD	TRANSIT CARGO VAN	90,956
FORD	TRANSIT CARGO VAN	90,956
FORD	TRANSIT CARGO VAN	90,000
FORD	F350	88,279
FORD	F250	83,574
FORD	F250	83,574
FORD	F250	83,574
FORD	F250	83,574
FORD	F250	83,249
20240226-CR03 Waterford Shelving		82,592
FORD	F150	80,587
FORD	F150 HYBRID	80,587
FORD	F150 HYBRID	80,587
FORD	F150 HYBRID	80,587
FORD	F150 HYBRID	80,587
FORD	F150 HYBRID	80,587
FORD	F150 HYBRID	80,587
FORD	F150 HYBRID	80,587
FORD	F150 HYBRID	80,587
FORD	F150 HYBRID	80,587
FORD	F150 HYBRID	80,587
FORD	F150 HYBRID	80,587
CUSTOM	CUSTOM	79,720
CHEVROLET	2500	76,368
CHEVROLET	2500	76,368
CHEVROLET	2500	76,368
CHEVROLET	2500	76,368
CHEVROLET	2500	76,368
CHEVROLET	2500	76,368
CHEVROLET	2500	76,368
CHEVROLET	2500	76,368
FORD	F550	73,880
FORD	F550	73,880
FORD	F550	73,880
FORD	F550	73,880
FORD	F550	73,880
FORD	F550	73,880
20231017-CR01 Blade Replacement (799)		71,530
CROWN	C5	68,231
CROWN	C5	68,231
YALE	GP060VX	67,821
YALE	GP060VX	67,821
20240308-CR01 Oil Water Seperator		66,807
FORD	F150 HYBRID	66,279
FORD	F150 HYBRID	66,279
FORD	F150 HYBRID	65,989
CHEVROLET	SILVERADO EV	65,678
CHEVROLET	SILVERADO EV	65,678
YALE	ERC065VG	65,487
YALE	ERC065VG	65,487
YALE	GP70N	65,061
YALE	GP70N	65,061
YALE	GP70N	65,061
Caniff, soil removal associated with install of chargers		63,517
FORD	F550	61,702
FORD	F550	61,702
20240813-CR04 Undercarriage Replacement		61,557
FORD	F350	60,032
FORD	F550	60,032
FORD	F550	60,032
FORD	F150	57,259
FORD	F150	57,259
FORD	F150	57,259
FORD	F150	57,259
FORD	F150	57,200

FORD	F150	56,057
FORD	F150	56,057
FORD	F150	56,057
FORD	F150	56,057
FORD	F150	56,057
FORD	F150	56,057
FORD	F150	56,057
FORD	F150	56,057
FORD	F150	56,057
Capital Repair - 6 Brad Torque Tools		55,968
FORD	F350	55,729
FORD	F150	55,452
FORD	F150	55,452
FORD	F150	55,452
FORD	F150	55,452
FORD	F150	55,288
FORD	F150	55,238
FORD	F150	55,238
FORD	F150	55,238
FREIGHTLINER	M2106	54,136
20240920-CR08 DO shelving		53,570
FORD	F350	53,239
FORD	F350	53,239
FORD	F350	53,239
FORD	F350	53,239
FORD	F350	53,239
FORD	F350	53,239
ALLMAND	NIGHT-LITE PRO	53,000
FORD	TRANSIT CARGO VAN	51,084
FORD	F350	51,039
BROOKS BROTHERS	PT122-8KE	50,168
UNAVAILABLE	UNAVAILABL	50,168
UNAVAILABLE	UNAVAILABL	50,168
UNAVAILABLE	UNAVAILABL	50,168
UNAVAILABLE	UNAVAILABL	50,168
CHEVROLET	3500	49,893
CHEVROLET	3500	49,893
CHEVROLET	3500	49,893
CHEVROLET	3500	49,893
CHEVROLET	3500	49,893
CHEVROLET	3500	49,893
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CHEVROLET	3500	49,893
CHEVROLET	3500	49,893
CHEVROLET	3500	49,893
CHEVROLET	3500	49,893
CHEVROLET	3500	49,893
20240305-CR03 Transmission replacement (796)		49,408
KUBOTA	RTVX1100CWL-H	48,666
KUBOTA	RTVX1100CWL-H	48,666

JLG	UNAVAILABL	44,870
FORD	MAVERICK	41,011
FORD	MAVERICK	41,011
FORD	MAVERICK	41,011
FORD	MAVERICK	41,011
20231011-CR03 Bulk Oil Newport Service Center		35,490
20231207-CR01 Caniff Portable Lifts		35,235
20231121-CR01 B-Rad		34,980
KUBOTA	RTVX1100CWL-H	34,731
KUBOTA	RTVX1100CWL-H	34,731
KUBOTA	RTVX1100CWL-H	34,731
FORD	TRANSIT CARGO VAN	34,700
FORD	F250	31,558
FORD	F250	31,558
FORD	F250	31,558
FORD	F250	31,558
FORD	F250	31,558
FORD	F250	31,558
FORD	F250	31,558
FORD	F250	31,558
CROWN	WAV60-118	28,402
FORD	F150 HYBRID	28,115
FORD	F250	27,706
FORD	F250	27,706
FORD	F250	27,706
FORD	F250	27,706
FORD	F250	27,706
FORD	F250	27,706
FORD	F250	27,706
FORD	F250	27,706
FORD	F250	27,706
MOTREC	UNAVAILABL	27,479
FORD	TRANSIT CARGO VAN	27,467
FORD	TRANSIT CARGO VAN	26,871
FORD	E350	26,572
FORD	TRANSIT	26,572
FORD	TRANSIT-350	26,572
FORD	TRANSIT-350	26,572
Engineering costs for Ann Arbor		26,556
KARCHER	BR 75	26,405
FORD	TRANSIT CARGO VAN	26,215
JLG	1	26,182
FORD	TRANSIT CARGO VAN	25,346
FORD	TRANSIT CARGO VAN	25,346
FORD	TRANSIT CARGO VAN	25,346
20231109-CR02 Engine Replacement (891530)		25,241
20240216-CR05 Engine Replacement (891510)		25,161
20240822-CR03 Engine Replacement (891628)		25,004
20241022-CR06 Engine Replacement (897631)		23,368
FORD	F150	22,535
20240820-CR04 Engine Replacement (897641)		22,385
20240920-CR02 Engine Repair (891501)		21,647
Engineering costs for NAEC install		21,510
20240920-CR07 DO & PP shelving		21,507
VERMEER	D10X15 S3	21,500
202331103-CR02 B-Rad Torque Tools		21,412
TENNANT	T600	21,135
TENNANT	T600	21,135
FORD	F150	21,125
FORD	F150	21,125
FORD	F150	21,125
FORD	LIGHTNING EV	21,125
FORD	LIGHTNING EV	21,125
FORD	LIGHTNING EV	21,125
FORD	LIGHTNING EV	21,125
FORD	LIGHTNING EV	21,125

FORD	LIGHTNING EV	21,125
FORD	LIGHTNING EV	21,125
FORD	LIGHTNING EV	21,125
FORD	LIGHTNING EV	21,125
UNAVAILABLE	T12	20,885
2nd PO for above refrence #		20,815
20231024-CR04 Engine Replacment (897720)		20,408
FORD	TRANSIT CARGO VAN	19,987
FORD	TRANSIT CARGO VAN	19,987
20231214-CR01 Redford Hydraulic Press		19,539
20240805-CR10 AC Machine newport		19,132
20231017-CR02 Dual AC Machine		19,100
Capital Repair - Dual AC Machine		19,100
20240126-CR01 Lower Boom Replacement (418719)		18,354
JLG	1	17,500
JLG	1	17,500
JLG	1	17,500
JLG	1	17,500
CROWN	UNAVAILABLE	17,421
20231122-CR03 Redford Tire Machine		17,393
Engineering costs for NAEC install		17,000
20240205-CR01 Dual A/C Waterford SC		16,773
20231220-CR03 Newport Myers Tires		16,714
20231009-CR04 CTM Tool Kit		16,522
20240716-CR01 Service tools		16,447
JAXON FAB WERKS	7X14TA	16,437
TENNANT	T300	15914.03
20231104-CR01 Welder Warren and Caniff		15206.76
20240118-CR01 Generator (849505)		13282.21
20241022-CR04 Engine Replacement (897811)		13247.03
20241112-CR02 Syncrowave Welder		13239.93
20231220-CR02 Lapeer Tool Kit		13166.1
20231016-CR04 Caniff Hydraulic Crimper		12853.41
20240307-CR02 AC Machine		12669.65
20240826-CR05 Engine Replacement (835901)		12506.37
JCB	UNAVAILABLE	12456
20240118-CR08 Engine Replacement (891222)		12407.32
FELLING	FT14	12057.5
FELLING	FT14	12057.5
FELLING	FT14-OT	12057.5
FELLING	FT14-OT	12057.5
FELLING	FT14-OT	12057.5
Felling FT14OT Upfit		12057.5
20240209-CR04 Generator (841800)		11944.41
20240528-CR06 Generator Replacement (841810)		11944.41
20240424-CR02 Engine Replacement (835880)		11765.98
TENNANT	T300	11755.19
FORD	EXPLORER	11458.68
FORD	EXPLORER	11458.68
20240226-CR02 Waterford Shop Cabinets		11193.12
20231208-CR01 NAEC Tool Kit		10541.74
20240206-CR01 Wireless Controller Upgrade Kit		10186.2
379 Units		36,016,008

Vehicle and equipment purchases projected for the remainder of 2025

<u>Make</u>	<u>Model</u>	<u>Capex</u>
Emergent Work (Capital Repairs current run rate)		958,000
Labor and Allocations		900,000
KENWORTH	T380_4x2	301,000
FREIGHTLINER	M2106_4x2	300,494
FREIGHTLINER	M2106_4x2	300,494
FREIGHTLINER	M2106_4x2	300,494
KENWORTH	T480_6x4	272,000
KENWORTH	T480_6x4	272,000
KENWORTH	T480_6x4	271,486
KENWORTH	T480_6x4	271,486
KENWORTH	T480_6x4	271,486
KENWORTH	T480_6x4	271,486
KENWORTH	T480_6x4	271,486
KENWORTH	T480_6x4	271,486
KENWORTH	T480_6x4	271,486
KENWORTH	T480_6x4	271,486
KENWORTH	T480_6x4	271,486
KENWORTH	T380_4x2	258,000
KENWORTH	T380_4x2	258,000
Ford	F550_4x4	255,249
KENWORTH	T480_6x4	249,600
KENWORTH	T480_6x4	249,600
KENWORTH	T480_6x4	249,600
KENWORTH	T480_6x4	249,600
KENWORTH	T480_6x4	249,600
KENWORTH	T480_6x4	249,600
KENWORTH	T480_6x4	233,000
FREIGHTLINER	M2106_6x4	217,000
FREIGHTLINER	M2106_6x4	217,000
Ford	F550_4x4	213,000
FREIGHTLINER	M2106_6x4	200,000
FREIGHTLINER	M2106_6x4	200,000
Ford	F550_4x4	130,000
Ford	F550_4x4	130,000
Ford	F350	65,000
Ford	F350	65,000
Ford	F350	65,000
Ford	F350	65,000
Ford	F350	60,000
Ford	F350	55,000
Ford	F350	55,000
Ford	F350	55,000
Ford	F350	55,000
Ford	F350	55,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
Ford	F350	50,000
CHEVROLET	SILVERADO 3500	50,000

Michigan Public Service Commission
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AGDE-8.220b
Fleet Vehicle Purchases

CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
CHEVROLET	SILVERADO 3500	50,000
Ford	F350	45,000
Ford	F350	45,000
Ford	F350	45,000
Ford	F350	45,000
Ford	F350	45,000
Ford	F350	45,000
Ford	F350	45,000
Ford	F350	30,000
Ford	F350	30,000
Ford	F350	30,000
Ford	F350	30,000
Ford	F350	30,000
Ford	F350	30,000
Ford	F350	30,000
Ford	F350	30,000
86 units		12,262,105

Vehicle and equipment purchases projected for 2026

[illegible]

**Michigan Public Service Commission
DTE Electric Company
Case No. U-21860
AGDE-8.220b
Fleet Vehicle Purchases**

TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TRUCK TECH	DO-7 TON	52,156
TALBERT	T3D60HRG	22,156
FORD	1530	20,000
KUBOTA	RTV1140CPX	17,330
KUBOTA	RTV900	17,330
TAYLORDUNN	B2-48	17,330
KUBOTA	RTV900	17,330
KUBOTA	RTV900	17,330
CUSHMAN		17,330
MOTREC	E240	17,330
KUBOTA	RTV900	17,330
TAYLORDUNN	B2-48	17,330
CUSHMAN		17,330
299 units		66,631,426

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.61b

Respondent: M. Leuker

Page: 1 of 1

Question: 61. Refer to pages 7 and 8 of Mr. Foley's direct testimony on EVs. Please: b. Provide the forecasts by year similar to Figures 1 and 2 made in each of the prior three rate cases compared to the forecasts in this rate case in Excel.

Answer: See attachment "U-21860 AGDE-3.61b EV Forecast Comparison"

Attachment: U-21860 AGDE-3.61b EV Forecast Comparison

Discovery Response AGDE-3.61b

Michigan Public Service Commission
DTE Electric Company
Electric Vehicle Forecast Comparison

Case No: U-21860
Attachment: U-21860 AGDE-3.61b EV Forecast Comparison
Respondent: M.B. Leuker
Page 1 of 1

Annual New Registrations				
	U-21860	U-21534	U-21297	U-20836
2025	28,787	34,528	36,934	68,325
2026	37,525	57,425	46,621	75,963
2027	50,334	80,321	57,512	83,252
2028	66,608	95,504	72,210	93,014
2029	86,334	112,683	90,230	103,725

Cumulative EV Adoption				
	U-21860	U-21534	U-21297	U-20836
2025	98,833	98,167	115,680	219,530
2026	134,547	153,854	160,563	295,493
2027	183,905	232,201	216,102	376,771
2028	248,895	325,134	285,741	467,214
2029	333,255	435,938	374,093	570,939

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.66a

Respondent: N. Foley

Page: 1 of 1

Question: 66. Refer to lines 13–25 on page 15 of Mr. Foley’s direct testimony on the utility EV Make-Ready program. Please: a. Provide the basis, assumptions, and calculations in Excel showing how the Company determined the \$9.2 million for 2025, \$18.6 million for 2026, and the \$98 million for 2025–2028. Provide also the number of forecasted installations for each year.

Answer: See attachment “U-21860 AGDE-3.66a-01 UMR” for the requested data.

Attachment: U-21860 AGDE-3.66a-01 UMR

Discovery Response AGDE-3.66a

Forecasted Number of Charger installations (based on prevailing EV adoption forecast presented in Company Witness Foley's testimony)									
Line		a	b	c	d	e	f	g	
		2022	2023	2024	2025	2026	2027	2028	
1	Residential - Individual	10,382	12,780	19,952	23,937	29,149	36,520	45,134	
2	Residential - MUD	385	473	784	990	1,261	1,642	2,099	
3	Workplace	1,569	1,749	2,453	3,373	5,025	6,324	6,790	
4	Depot charging	177	238	371	617	917	1,184	1,334	
5	Public On-route charging	114	139	192	258	366	443	468	
6	Public charging	331	376	533	765	1,235	1,696	2,017	
7	Total	12,957	15,756	24,285	29,941	37,954	47,810	57,843	
Average UMR Investment per Charger (based on Market Model)									
Line		a	b	c	d	e	f	g	
		2022	2023	2024	2025	2026	2027	2028	
8	Residential - Individual	\$ 23	\$ 37	\$ 58	\$ 91	\$ 143	\$ 224	\$ 352	
9	Residential - MUD	\$ 1,200	\$ 1,260	\$ 1,285	\$ 1,311	\$ 1,337	\$ 1,364	\$ 1,391	
10	Workplace	\$ 298	\$ 313	\$ 318	\$ 324	\$ 329	\$ 334	\$ 390	
11	Depot charging	\$ 4,739	\$ 5,421	\$ 5,585	\$ 6,696	\$ 6,121	\$ 5,917	\$ 5,870	
12	Public On-route charging	\$ 19,800	\$ 20,790	\$ 20,799	\$ 20,623	\$ 20,712	\$ 20,797	\$ 20,415	
13	Public charging	\$ 10,002	\$ 9,915	\$ 9,623	\$ 9,434	\$ 9,387	\$ 9,420	\$ 9,609	
Utility Make Ready Spend (\$M)									
Line		a	b	c	d	e	f	g	
		2022	2023	2024	2025	2026	2027	2028	
14	Residential - Individual	\$ 0.24	\$ 0.47	\$ 1.16	\$ 2.18	\$ 4.17	\$ 8.20	\$ 15.89	a1:g1 x a8:g8
15	Residential - MUD	\$ 0.46	\$ 0.60	\$ 1.01	\$ 1.30	\$ 1.69	\$ 2.24	\$ 2.92	a2:g2 x a9:g9
16	Workplace	\$ 0.47	\$ 0.55	\$ 0.78	\$ 1.09	\$ 1.65	\$ 2.11	\$ 2.65	a3:g3 x a10:g10
17	Depot charging	\$ 0.84	\$ 1.29	\$ 2.07	\$ 4.13	\$ 5.61	\$ 7.01	\$ 7.83	a4:g4 x a11:g11
18	Public On-route charging	\$ 2.25	\$ 2.89	\$ 4.00	\$ 5.32	\$ 7.59	\$ 9.21	\$ 9.55	a5:g5 x a12:g12
19	Public charging	\$ 3.31	\$ 3.73	\$ 5.13	\$ 7.22	\$ 11.59	\$ 15.98	\$ 19.38	a6:g6 x a13:g13
20	Total	\$ 7.57	\$ 9.53	\$ 14.15	\$ 21.25	\$ 32.30	\$ 44.75	\$ 58.22	
21	2022-2024 Average UMR Spend (\$M)	\$ 10.42	Average of a20, b20, c20						
22	DTE Contribution to UMR Spend (%)	85%	Assumption: 100%-15% CIAC						
23	DTE Contribution to 2022-2023 Average UMR Spend (\$M)	\$ 8.86	a21 x a22						
Projected Incremental Infrastructure for EV (\$M)									
		a							
24	2025	\$ 9.20	d20 x a22-a23						
25	2026	\$ 18.60	e20 x a22-a23						
26	2027	\$ 29.18	f20 x a22-a23						
27	2028	\$ 40.63	g20 x a22-a23						
28	Total 2025-2028	\$ 97.61	sum a24:a27						

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.66b

Respondent: N. Foley

Page: 1 of 1

Question: 66. Refer to lines 13–25 on page 15 of Mr. Foley’s direct testimony on the utility EV Make-Ready program. Please: b. Provide the amount of make-ready capital expenditures that the Company forecasted in the last two rate cases by year and compare them to the actual amount incurred for those years or the most recent forecast in this rate case. Provide also the related number of forecasted and actual installations for the same years and from the same rate cases.

Answer: The Company does not specifically identify and track Utility Make Ready (UMR) costs for EV charger deployments and therefore cannot provide the requested information.

As shown in Attachment “U-21860 AGDE-3.66a-01 UMR” referenced in response AGDE-3.66a, the Company forecasts the amount of UMR capital it expects to invest. Actual historical UMR costs are captured and incorporated into Exhibit A-12, Schedule B5.4, Lines 9 (Connections and New Loads).

Attachment: None

Adjustments to Capital Expenditures, Rate Base and Depreciation Expense

(\$000)

Line	Description (a)	Capital Expenditure Reductions ¹				Rate Base Reduction (f)	Depreciation Rate ² (g)	Reduction in Depreciation Expense (h)	Property Tax	
		2024 & Prior (b)	2025 (c)	2026 (d)	Total (e)				Millage Rate (i)	Adjustment ⁴ (j)
1	Distribution Operations:									
2	Emergent Replacements		48,795	69,181	117,976	83,386	4.10%	3,419	0.05650	\$ 1,323
3	Customer Connections & Load Growth		(1,745)	8,806	7,061	2,658	4.10%	109	0.05650	\$ (47)
4	Relocations		12,250	11,785	24,035	18,143	4.10%	744	0.05650	\$ 332
5	Electric System Equipment		(1,370)	-1,322	(2,692)	(2,031)	4.10%	(83)	0.05650	\$ (37)
6	Meters		(2,981)	-2,935	(5,916)	(4,449)	4.10%	(182)	0.05650	\$ (81)
7	NRUC & Improvement Blankets		1,276	1,499	2,775	2,026	4.10%	83	0.05650	\$ 35
8	General Plant, Tools, Equipment & Miscellaneous		617	682	1,299	958	4.10%	39	0.05650	\$ 17
9	Substation Risk Projects		27,104	5,625	32,729	29,917	4.10%	1,227	0.05650	\$ 735
10	Mobile Fleet			5,500	5,500	2,750	4.10%	113	0.05650	\$ -
11	Strategic Capital Programs and Other ³									
12	System Loading			45,300	45,300	22,650	4.10%	929	0.05650	\$ -
13	Pole and Poletop Maintenance & Modernization			200,000	200,000	100,000	4.10%	4,100	0.05650	\$ -
14	Strategic Undergrounding			14,000	14,000	7,000	4.10%	287	0.05650	\$ -
15	Circuit Conversions			20,700	20,700	10,350	4.10%	424	0.05650	\$ -
16	Distribution Automation			112,000	112,000	56,000	4.10%	2,296	0.05650	\$ -
17	Grid Automation Telecommunications			15,000	15,000	7,500	4.10%	308	0.05650	\$ -
18	Power Generation:									
19	Trenton Channel BESS Project		185,778	(120,345)	65,433	125,606	3.24%	4,070	0.05650	\$ 5,038
20	Trenton Channel Seawall & Green Path			9,456	9,456	4,728	3.24%	153	0.05650	\$ -
21	Sclocum BESS Project	4,345	655		5,000	5,000	3.24%	162	0.05650	\$ 136
22	Kiewit BWEC Payment		6,000		6,000	6,000	3.24%	194	0.05650	\$ 163
23	Preliminary and Premature Projects			63,703	63,703	31,852	3.24%	1,032	0.05650	\$ -
24	Nuclear									
25	Security System Computer		2,400		2,400	2,400	4.26%	102	0.05650	\$ 65
26	Plant Radio System		1,300		1,300	1,300	4.26%	55	0.05650	\$ 35
27	Underground Service Water Piping Replacement	12,600			12,600	12,600	4.26%	537	0.05650	\$ 342
28	Preliminary and Premature Projects - Routine			24,331	24,331	12,166	4.26%	518	0.05650	\$ -
29	Preliminary and Premature Projects - Non-Routine		8,742	28,298	37,040	22,891	4.26%	975	0.05650	\$ 237
30	Engineering and Support Services		16,888	5,630	22,518	19,703	4.10%	808	0.05650	\$ 458
31	Corporate									
32	WCB Façade Repairs		1,000	2,254	3,254	2,127	7.70%	164	0.05650	\$ 27
33	HQ Complex Space Optimization		4,001	3,754	7,755	5,878	7.70%	453	0.05650	\$ 109
34	HQ Courtyard			2,254	2,254	1,127	7.70%	87	0.05650	\$ -
35	Trombly Service Center Renovations			5,254	5,254	2,627	7.70%	202	0.05650	\$ -
36	Other - Emergent Projects		4,388	4,567	8,955	6,672	7.70%	514	0.05650	\$ 119
37	Transportation Fleet			22,566	22,566	11,283	7.70%	869	0.05650	\$ -
38	Total	\$ 16,945	\$ 315,098	\$ 557,543	\$ 889,586	\$ 610,815		\$ 24,706		\$ 9,005
39										
40	Working Capital - Exhibit AG-21					(58,860)				
41										
42	Total Rate Base Deduction					\$ 551,955				

Source: (1) See AG witness Coppola Direct Testimony.
(2) Depreciation rates from Exhibit A-13, Schedule C6, page 2.
(3) See AG-MNS witness Paul Alvarez and Dennis Stephens Direct Testimony.
(4) Property tax adjustment for 2025 and prior years disallowances x 96% factor x 50% x millage rate. No property taxes on IT software.

**MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case**

**Exhibit AG-21
Case No: U-21860
August 22, 2025
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Working Capital Adjustments (\$000)

<u>Line</u>		<u>Working Capital Inc. (Dec.)</u>	<u>Notes</u> (e)
1	Interest payable	\$ (4,700)	Coppola Testimony
2	Taxes Payable	(9,500)	Coppola Testimony
3	Monroe Fly Ash Basin Closure	(26,940)	Coppola Testimony ¹
4	PTMM Regulatory Asset	<u>100,000</u>	Stephens/Alvarez Testimony ²
5	Total Increase in Working Capital	<u>\$ 58,860</u>	

(1) Total proposed disallowance for 2026 of \$53,880,000 averages to \$26,940,000 for the year.

(2) Total proposed shift of capex for PTMM of \$200 million to regulatory asset averages to \$100 million for 2026.

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-7.208a

Respondent: S. Wisniewski

Page: 1 of 1

Question: 208. Refer to Working Capital item "Taxes Payable" on line 62 of Exhibit A-12, Schedule B4, and discovery response AGDE 2.59. Please:

a. Part (a) of the discovery response states that the Company is forecasting to generate a taxable loss in 2026. Provide a copy of the calculation of the taxable loss in Excel with supporting data and assumptions clearly explained.

Answer: Refer to Witness Wisniewski's Exhibit A-13, Schedule C8 for the Projected Federal Income Tax calculation. This calculation results in a net operating loss for the test period of \$13.9 million as shown on Lines 38 and 39.

Refer to Witness Wisniewski's Exhibit A-13, Schedule C9 for the Projected State Income Tax calculation. This calculation results in a net operating loss for the test period of \$119.8 million as shown on Lines 6 and 7.

Refer to Witness Wisniewski's Exhibit A-13, Schedule C10 for the Projected Local Income Tax calculation. This calculation results in a net operating loss for the test period of \$13.9 million as shown on Lines 3 and 4.

Attachment: None

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-7.208b

Respondent: S. Wisniewski

Page: 1 of 1

Question: 208. Refer to Working Capital item "Taxes Payable" on line 62 of Exhibit A-12, Schedule B4, and discovery response AGDE 2.59. Please:
b. Identify what portion of the rate relief requested in this case the Company included in its calculation of the taxable loss in question.

Answer: Refer to Witness Wisniewski's Exhibit A-13, Schedule C8 for the Projected Federal Income Tax calculation, which results in a net operating loss for the test period. Line 1 of the calculation starts with Net Operating Income, which does not reflect the rate relief being requested in this filing.

Attachment: None

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-7.211a

Respondent: T. Uzenski

Page: 1 of 1

Question: 211. Exhibit A-4, Schedule D1, shows the historical long-term debt and short-term debt of \$8.109 billion and \$188 million, respectively, for a total of \$8.297 billion. Exhibit A-14, Schedule D1 shows the projected period balances for these items at \$9.076 million and \$563 million, respectively, for a total of \$9.639 million, which is a 16% increase over the historical period. In this regard, address the following:

a. Explain why the Working Capital item Interest Payable on Exhibit A12, Schedule B4 falls by \$2.5 million for the projected period versus the historical period when overall debt levels are increasing by 16%.

Answer: Exhibit A-4, Schedule D1 shows historical long-term debt of \$8.642 billion not \$8.109 billion.

In responding to this question, the Company found an error in the interest payable ending balance of \$20.351 million. The corrected change in the 13-month average is an increase in interest payable of \$2.17 million (versus a \$2.5 million reduction). The Company is retiring approximately \$800 million of debt associated with the Monroe power plant during the bridge period. The Company eliminated the associated annual interest expense of \$40.702 million but the related payments in 2025 were reduced by only \$20.351 million (one payment instead of two). The corrected balance for interest payable is \$116.941 million as of December 2026 and \$117.799 million for the 13-month average.

Attachment: *none.*

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-21860
Exhibit AG-23
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Recommended Capital Structure & Cost Rates for Test
Year Ending December 31, 2026

(Millions of Dollars)

<u>Line</u>	<u>Description</u> (a)	<u>Capital Structure</u>			<u>Cost</u> <u>Rate**</u> (e)	<u>Total</u> <u>Cost</u> (d) x (e) (f)	<u>Conversion</u> <u>Factors***</u> (g)	<u>Pre-Tax</u> <u>Wtd. Cost</u> (f) x (g) (h)
		<u>Capital</u> <u>Balances*</u> (b)	<u>% Permanent</u> <u>Capital</u> (c)	<u>% Total</u> <u>Capital</u> (d)				
1	Long Term Debt	\$ 9,214.0	50.0%	39.11%	4.24%	1.66%	1.0000	1.66%
2	Preferred Stock	-	0.0%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Equity	<u>9,214.0</u>	<u>50.0%</u>	<u>39.11%</u>	9.85%	<u>3.85%</u>	1.3496	<u>5.20%</u>
4	Total Permanent Capital	18,428.0	<u>100.0%</u>	78.22%		5.51%		6.86%
5	Short Term Debt	562.9		2.39%	3.91%	0.09%	1.0000	0.09%
6	Deferred Income Taxes	4,535.0		19.25%	0.00%	0.00%	1.0000	0.00%
7	JDITC							
8	Long Term Debt	17.1		0.07%	4.24%	0.00%	1.0000	0.00%
9	Preferred Stock	-		0.00%	0.00%	0.00%	1.3496	0.00%
10	Common Equity	<u>17.1</u>		<u>0.07%</u>	9.85%	<u>0.01%</u>	1.3496	<u>0.01%</u>
11	Total Capitalization & Cost Rates	<u>\$ 23,560.1</u>		<u>100.00%</u>		5.61%		6.96%

Notes

* All capital balances per Company Exhibit A-14, Schedule D1 except that Long-Term Debt and Common Equity set at 50%/50%

** All cost rates per Company Exhibit A-14, Schedule D1 except for Common Equity which is set forth on Exhibit AG-24

*** Conversion factors per Company Exhibit A-14, Schedule D1.

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

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August 22, 2025
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Summary of Cost of Common Equity Capital Analysis
Year Ending December 31, 2026

<u>Line</u>	<u>Description</u> (a)	<u>Relative Weighting</u> (b)	<u>Peer Group</u> (c)	<u>Note</u> (d)
1	Discounted Cash Flow (DCF) Approach	50.00%	9.80%	1
2	Capital Asset Pricing Model (CAPM) Approach	25.00%	9.97%	2
3	Equity Risk Premium Approach	25.00%	<u>9.86%</u>	3
4	Calculated Cost of Common Equity (Sum of Col. (b) x (c) for each line)		<u>9.86%</u>	4
5	Cost of Common Equity Rounded Down for Rate Case Purposes		<u>9.85%</u>	

Note 1 See Exhibit AG-25
Note 2 See Exhibit AG-26
Note 3 See Exhibit AG-X27

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

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Exhibit AG-25
August 22, 2025
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Discounted Cash Flow (DCF) Application
(See Equation Below)

Year Ending December 31, 2026

Line	Company	Ticker	Stock Price*	EPS Growth Rate***		Value Line Long Term Growth	Analysts 2 Yr Growth p/Yahoo	Average of Col. (f) & (g)	DCF ROE for Proxy Co. Col. (e) + (h)
				Projected 2025-26 Avg. Dividend**	Dividend Yield Col. (d)/(c)				
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Alliant Energy	LNT	62.43	\$ 2.10	3.36%	6.00%	6.18%	6.09%	9.45%
2	Ameren	AEE	96.99	2.94	3.03%	6.50%	7.20%	6.85%	9.88%
3	American Electric Power	AEP	105.57	3.89	3.68%	6.50%	5.82%	6.16%	9.84%
4	CenterPoint Energy	CNP	36.69	0.92	2.51%	6.50%	N/A	6.50%	9.01%
5	CMS Energy	CMS	70.59	2.23	3.16%	5.50%	7.42%	6.46%	9.62%
6	Consolidated Edison	ED	100.77	3.50	3.47%	6.00%	5.48%	5.74%	9.21%
7	Evergy	EVRG	68.78	2.78	4.04%	N/A	6.04%	6.04%	10.08%
8	IDACORP	IDA	118.00	3.59	3.04%	6.00%	7.64%	6.82%	9.86%
9	NorthWestern Energy Grp	NWE	52.03	2.60	5.00%	4.50%	6.09%	5.30%	10.29%
10	OGE Energy	OGE	44.25	1.72	3.89%	6.50%	5.34%	5.92%	9.81%
11	Portland General Electric	PGE	40.71	2.14	5.26%	6.50%	4.00%	5.25%	10.51%
12	WEFC Energy	WEC	105.81	3.69	3.49%	6.00%	7.01%	6.51%	9.99%
13	Average				<u>3.66%</u>	<u>6.05%</u>	<u>6.20%</u>	<u>6.14%</u>	<u>9.80%</u>

Notes

* High-Low Average Prices for the 30 days June 18 to July 31, 2025 per Yahoo

** From the Value Line Investment Survey Publications of May 9, June 6 and July 18, 2025

*** Columns (f) and (g) are from AG workpapers

N/M Result eliminated if at 7.5% or higher

Equation

$R = D/P + g$ Where

R = the required return on the equity security

P = the current price of the equity security

D = the next dividend on the security

g = the expected growth rate of earnings

Capital Asset Pricing Model Application
(See Equation Below)

Year Ending December 31, 2026

Line	Company (a)	Ticker (b)	Common Equity to Capital % (c)	Current Beta (B) (d)	Risk Premium (Rp) (e)	Beta x Risk Premium Col. (d) x (e) (f)	Projected 2026 Risk Free Rate (Rf) (g)	Ke or 2026 CAPM ROE for Proxy Co. Col. (e) + (f) (h)
1	Alliant Energy	LNT	41.2%	0.80	7.35%	5.88%	4.46%	10.34%
2	Ameren	AEE	40.4%	0.80	7.35%	5.88%	4.46%	10.34%
3	American Electric Power	AEP	38.6%	0.70	7.35%	5.15%	4.46%	9.61%
4	CenterPoint Energy	CNP	34.4%	0.85	7.35%	6.25%	4.46%	10.71%
5	CMS Energy	CMS	31.8%	0.70	7.35%	5.15%	4.46%	9.61%
6	Consolidated Edison	ED	48.0%	0.65	7.35%	4.78%	4.46%	9.24%
7	Evergy	EVRG	44.0%	0.75	7.35%	5.51%	4.46%	9.97%
8	IDACORP	IDA	51.3%	0.70	7.35%	5.15%	4.46%	9.61%
9	Northwestern	NWE	48.5%	0.75	7.35%	5.51%	4.46%	9.97%
10	OGE Energy	OGE	47.7%	0.85	7.35%	6.25%	4.46%	10.71%
11	Portland General Electric	PGE	44.9%	0.75	7.35%	5.51%	4.46%	9.97%
12	WEFC Energy	WEC	39.4%	0.70	7.35%	5.15%	4.46%	9.61%
13	Average		42.5%	0.75	7.35%	5.51%	4.46%	9.97%

Sources	Column (c)	From Data included in SEC filings. See WP-AG-26A
	Column (d)	From the Value Line Investment Survey Publications of May 9, June 6 and July 18, 2025
	Column (e)	From AG Workpapers WP-AG26B
	Column (g)	See Nelson workpaper WP-2 for Blue Chip Forecast used.

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

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Electric Utility Equity Risk Premium Approach
Year Ending December 31, 2026

<u>Line</u>	<u>Description</u> (a)	<u>Projected Test Period</u> (c)	<u>Note</u> (d)
<u>Build-up of Common Equity Rate of Return</u>			
1	Long Term US Treasury Rate Projection	4.46%	1
2	"A" rated Corporate Spread Over Treasury Bond Rate	<u>1.15%</u>	2
3	Sub Total (Line 1 + Line 2)	5.61%	
4	Historical Spread - Utility Common Stocks over Bonds	<u>4.25%</u>	3
5	Cost of Common Equity (Line 3 + Line 4)	<u>9.86%</u>	

Notes

- 1 Nelson workpaper WP-2 for Blue Chip Forecast used.
- 2 2024 Spread over 30 Year U.S. Treasuries per AG workpaper AG-27-1
- 3 Historical average per AG workpapers AG-27-2

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Electric Rate Case Return on Equity (ROE) Rates (12 Mo. Ended June 2024 and 2025)*

ROEs Under 9.9%					ROE Awarded-12 M.E. June		Pub Finan'ls	Long Term Debt Issued
Line	Electric Company	Jurisdiction & Order Date			2024	2025		
						Parent Company	Avail.	Since Date of Rate Order
1	Consolidated Edison of NY	NY	Jul. 20	2023	9.25%	Consolidated Edison	Yes	Nov 2023 \$600M (10 Yr.) at 5.5%
2	Northern Indiana P. S.	IN	Aug. 2	2023	9.80%	NIPSCO	Yes	Jun 2024 \$600M (5 Yr) at 5.2%
3	Entergy Texas	TX	Aug. 3	2023	9.57%	Entergy	Yes	May 2024 \$1.2B (30 Yr.) at 7.125%
4	Duke Energy Progress	NC	Aug. 18	2023	9.80%	Duke Energy	Yes	Sep. 2023 \$600M (10 Yr), \$750M (30 Yr.) at 5.75% & 6.10%
5	Green Mountain Power	VT	Aug. 23	2023	9.58%	Eniger	Private	
6	United Illuminating Group	CT	Aug. 25	2023	8.63%	Avangrid	Yes	Oct. 2023 \$65M 10 Yr. 4.5% (Remarketed)
7	Tucson Electric Power	AZ	Aug. 25	2023	9.55%	Fortis	Canada	Feb 2025 \$300M (30 Yr.) at 5.9%
8	Avista	ID	Aug. 31	2023	9.40%	Avista	Yes	
9	Public Service of Colorado	CO	Sep. 6	2023	9.30%	Xcel Energy	Yes	Feb 2024 \$800M (10 Yr.) at 5.5%
10	MDU Resources	MT	Sep. 21	2023	9.65%	MDU Resources	Yes	
11	Duke Energy KY	KY	Oct. 12	2023	9.75%	Duke Energy	Yes	Jun 2024 \$1.5B (10 Yr & 30 Yr) at 5.45 & 5.80
12	New York State Elec. & Gas	NY	Oct. 12	2023	9.20%	Avangrid	Yes	
13	Rochester Gas & Electric	NY	Oct. 12	2023	9.20%	Avangrid	Yes	
14	Potomac Edison	MD	Oct. 18	2023	9.50%	Exelon	Yes	Feb 2024 \$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
15	Southwestern Public Service	NM	Oct. 19	2023	9.50%	Xcel Energy	Yes	Feb 2024 \$800M (10 Yr.) at 5.5%
16	NorthWestern Energy Group	MT	Oct. 25	2023	9.65%	NorthWestern Energy Group	Yes	Mar 2025 \$400M (5 Yr) 5.07%
17	Madison Gas & Electric	WI	Nov. 3	2023	9.70%	MGE Energy	Yes	Oct 2024 \$50M (10 & 30 Yr.) at 5.3% and 5.59%
18	Public Service of Oklahoma	OK	Nov. 3	2023	9.30%	American Electric Power	Yes	Jun 2024 \$1.0B (30 Yr.) 7%
19	Northern States Power	WI	Nov. 9	2023	9.80%	Xcel Energy	Yes	Feb 2024 \$800M (10 Yr.) at 5.5%
20	Wisconsin Power & Light	WI	Nov. 9	2023	9.80%	Alliant Energy	Yes	Mar 2024 \$300M (10 Yr) Variable
21	Atlantic City Electric	NJ	Nov. 17	2023	9.60%	Exelon	Yes	Feb 2024 \$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
22	PacifiCorp	WY	Nov. 28	2023	9.35%	Berkshire Hathaway	Yes	Mar 2025 \$850M (30 Yr.) 7.375%
23	Empire District Electric	AR	Dec. 7	2023	9.70%	Algonquin Power & Utilities	Canada	
24	Ameren Illinois	IL	Dec. 14	2023	8.72%	Ameren	Yes	
25	Baltimore Gas & Electric	MD	Dec. 14	2023	9.50%	Exelon	Yes	Feb 2024 \$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
26	Commonwealth Edison	IL	Dec. 14	2023	8.91%	Exelon	Yes	Feb 2024 \$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
27	Portland General Electric	OR	Dec. 18	2023	9.50%	Portland General Electric	Yes	Mar 2025 \$310M (5, 20, 30 Yr) 5.36%, 5.72% & 5.84%
28	Nevada Power	NV	Dec. 26	2023	9.52%	Berkshire Hathaway	Yes	Mar 2025 \$850M (30 Yr.) 7.375%
29	Idaho Power	ID	Dec. 28	2023	9.60%	IDACORP	Yes	Mar 2025 \$400M (30 Yr) 5.75%
30	Public Service of New Mexico	NM	Jan. 3	2024	9.26%	TXNM Energy	Yes	
31	Kentucky Power	KY	Jan. 19	2024	9.75%	Amer. Elec. Power	Yes	Jun 2024 \$1.0B (30 Yr.) 7%
32	UNS Electric	AZ	Jan. 30	2024	9.75%	Fortis	Canada	
33	Jersey Central P & L	NJ	Feb. 14	2024	9.60%	First Energy	Yes	Dec 2024 \$700M (10 Yr) at 5.1%
34	Virginia Electric	VA	Feb. 28	2024	9.70%	Dominion Energy	Yes	
35	Arizona Public Service	AZ	Mar. 5	2024	9.55%	Pinnacle West	Yes	
36	Monongahela Power	WV	Mar. 26	2024	9.80%	First Energy	Yes	Dec 2024 \$700M (10 Yr) at 5.1%
37	Delmarva Power	DE	Apr. 18	2024	9.60%	Dominion Energy	Yes	
38	Indiana Michigan Power	IN	May. 8	2024	9.85%	Amer. Elec. Power	Yes	
39	Potomac Electric	MD	Jun. 10	2024	9.50%	Exelon	Yes	May 2025 \$200M (15 Yr) at 5.48%
40	Fitchburg G & E	MA	Jun. 28	2024	9.40%	Utilicorp	Yes	Aug 2024 \$72M (10, 30 Year) 5.54% and 5.69%
41	Average ROE				9.50%			

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Electric Rate Case Return on Equity (ROE) Rates (12 Mo. Ended June 2024 and 2025)*

ROEs Under 9.9%					ROE Awarded-12 M.E. June		Pub Finan'ls	Long Term Debt Issued	
Line	Electric Company	Jurisdiction & Order Date			2024	2025	Parent Company	Avail.	Since Date of Rate Order
1	Indiana Michigan Power	IN	Jul. 2	2024		9.86%	Amer. Elec. Power	Yes	
2	Central Hudson G & E	NY	Jul. 18	2024		9.50%	Fortis	Canadian	
3	Interstate Power & Light	IA	Sep. 17	2024		9.87%	Alliant Energy	Yes	May 2025 \$600M (10 Yr.) 5.6%
4	Sierra Pacific	NV	Sep. 18	2024		9.74%	Berkshire Hathaway	Yes	Mar 2025 \$850M (30 Yr.)7.375%
5	Idaho Power	OR	Sep. 23	2024		9.50%	IDA Corp.	Yes	Mar 2025 \$400M (30 Yr) 5.75%
6	Upper Peninsula Power	MI	Sep. 26	2024		9.86%	Private	No	
7	Massachusetts Electric	MA	Sep. 30	2024		9.35%	National Grid	No	
8	AEP Texas	TX	Oct. 3	2024		9.76%	Amer. Elec. Power	Yes	
9	Public Service	NJ	Oct. 10	2024		9.60%	Public Service Enterp. Grp.	Yes	
10	Upper Michigan Energy Res	MI	Oct. 16	2024		9.86%	WEC Energy	Yes	Jun 2025 \$900M (3 Yr CNV) 3.375
11	Minnesota Power	MN	Oct. 24	2024		9.78%	Allete	Yes	July 2025 \$250M (Var. to 30 Yr) Various
12	Appalachian Power	VA	Nov. 20	2024		9.75%	Amer. Elec. Power	Yes	
13	Potomac Electric	DC	Nov. 25	2024		9.50%	Exelon	Yes	
14	Oklahoma Gas & Electric	OK	Nov. 26	2024		9.50%	OGE Energy	Yes	Apr 2025 \$350M (30 Yr.) 5.8%
15	PacifiCorp	OR	Dec. 19	2024		9.50%	Berkshire Hathaway	Yes	Mar 2025 \$850M (30 Yr.)7.375%
16	Wisconsin Electric Pwr	WI	Dec. 19	2024		9.80%	WEC Energy	Yes	Jun 2025 \$900M (3 Yr CNV) 3.375
17	Wisconsin Public Service	WI	Dec. 19	2024		9.80%	WEC Energy	Yes	Jun 2025 \$900M (3 Yr CNV) 3.375
18	Avista Washington	WA	Dec. 20	2024		9.80%	Avista	Yes	
19	Portland General Electric	OR	Dec. 20	2024		9.34%	Portland General Elec Hldg	Yes	
20	Public Service	OK	Jan. 15	2025		9.50%	Amer. Elec. Power	Yes	
21	Duke Energy	IN	Jan. 29	2025		9.75%	Duke	Yes	
22	Southern Indiana G & E	IN	Feb. 3	2025		9.80%	CenterPoint	Yes	
23	Black Hills Colorado	CO	Mar. 12	2025		9.40%	Black Hills	Yes	
24	CenterPoint Texas	TX	Mar. 13	2025		9.65%	CenterPoint	Yes	
25	Versant Power	ME	Mar. 13	2025		9.35%	EnMax of Alberta	No	
26	Orange and Rockland	NY	Mar. 20	2025		9.75%	Consolidated Edison	Yes	
27	Liberty Utilities	NH	Mar. 25	2025		9.10%	Algonquin	Canadian	
28	PacifiCorp	UT	Apr. 25	2025		9.38%	Berkshire Hathaway	Yes	
29	Public Service of New Mexico	NM	May. 15	2025		9.45%	TXNM Energy	Yes	
30	PacifiCorp	WY	Jun. 2	2025		9.50%	Berkshire Hathaway	Yes	
31	Wind Energy	TX	Jun. 20	2025		9.60%	Private	No	
32	Northern Indiana P.S.	IN	Jun. 26	2025		9.75%	NiSource	Yes	
33	Average ROE					9.61%			

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Electric Rate Case Return on Equity (ROE) Rates (2022 and 2023)

Summary of All Cases (incl. ROEs at 9.9% and Above)*

				Number of Companies		ROEs Awarded				
				12 Mo; Ended June of		12 Mo; Ended June of		Explanations & Commentary **		
				2024	2025	2024	2025			
State	Company /Description									
1		Average ROEs - Companies Under 9.9%			40	32	9.50%	9.61%		
2		ROEs Awarded - at 9.9% and Above								
3	California	Pacific Gas & Electric			1	1	10.70%	10.28%	Wildfire Risk	
4		Southern California Edison			1	1	10.75%	10.33%	Wildfire Risk	
5		San Diego Gas & Electric			1	1	10.65%	10.23%		
6		PacifiCorp			1		10.00%		Wildfire Risk	
		Bear Valley Electric Service				1		10.00%	Small Utility - 25k customers	
7	Florida	Florida Public Service				1		10.20%	Hurricane Risk	
8		Duke Energy Florida				1		10.30%	Hurricane Risk	
9		Tampa Electric				1		10.50%	Hurricane Risk	
10	Michigan	DTE Electric			1	1	9.90%	9.90%		
11		Consumers Energy			1	1	9.90%	9.90%		
12	Alaska	Alaska Electric Light & Power			1		11.45%		Small Isolated Utility - 13K Customers	
13	Other Jurisd.	Duke Energy Carolinas	NC	1			10.10%			
14		Duke Energy South Carolina	SC	1			9.94%			
15		AES Indiana	IN	1			9.90%		Small Utility - 531K customers	
		Otter Tail Power	ND		1		9.94%		Small Utility - 134k customers	
16		Dominion Energy - S. Carolina	SC		1		10.10%			
17		Green Mountain Power	VT		1		9.97%		Small Utility - 275K customers	
18		Virginia Electric	VA		1		9.95%			
19		Puget Sound	WA	-	1		9.90%			
18	Cases at 9.9% + with ROEs Stated (Excl. Lmted. Issue Riders)				10	14	10.33%	10.11%		
19	Average of All ROEs Awarded				50	46	9.67%	9.76%		

* All ROE data from Regulatory Research Associates & excludes Limited Issue Rider cases

** Customer size information is from SEC documents and Company web site:

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2024-25 Midwest ROE Decisions Outside Michigan*

<u>Line</u>	<u>Company</u> (a)	<u>State</u> <u>Jurisdiction</u> (b)	<u>Month</u> (c)	<u>Year</u> (d)	2023 <u>Authorized</u> <u>ROE Decision</u> (e)
1	Kentucky Power	Kentucky	January	2024	9.75%
2	AES Indiana	Indiana	April	2024	9.90%
3	Indiana Michigan Power	Indiana	May	2024	9.85%
4	Interstate Power & Light	Iowa	September	2024	9.87%
5	Minnesota Power Enterprises	Minnesota	October	2024	9.78%
6	Wisconsin Electric Power	Wisconsin	December	2024	9.80%
7	Wisconsin Public Service	Wisconsin	December	2024	9.80%
8	Duke Energy	Indiana	January	2025	9.75%
9	Southern Indiana G & E	Indiana	February	2025	9.80%
10	Northern Indiana Public Service	Indiana	June	2025	<u>9.80%</u>
10	Average of 2024-2025 Decisions				9.81%

* As published by Regulatory Research Associates

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Comparison of AG and DTEE Peer Groups

Elimination Factors													
Line	Value Line Electric Utilities	2024	Revs. Over Under		No Div. Grth	Foreign	Reorg. M & A	No/Low	OS Wind & Wildfr.	Large Gas, NU Ops & DTE	Total	Peer Group per	
		Revs. (\$M)	20 B +	1 B				Hist. EPS Growth		Factors	AG	DTEE	
1	Consolidated Edison	15,256										x	
2	Dominion Energy	14,459			Yes				Yes		2		
3	Duke Energy	30,357	Yes								1		x
4	Eversource Energy	11,901					Yes				1		
5	Exelon	23,028	Yes								1		
6	FirstEnergy	13,472						Yes			1		x
7	Hydro One Limited	5,873				Yes					1		
8	NextEra Energy	24,753	Yes							Yes	2		x
9	PPL Corp.	8,462						Yes			1		x
10	Public Service Enterp. Group	10,290						Yes			1		
11	Southern Co.	26,724	Yes								1		x
12	ALLETE	1,530					Yes				1		
13	Alliant Energy	3,981										x	x
14	Ameren	7,623										x	x
15	American Electric Power	19,721										x	x
16	CMS Energy	7,515										x	x
17	CenterPoint Energy	8,643										x	
18	DTE Energy	12,457								Yes	1		
19	Entergy	11,880					Yes	Yes			2		x
20	Fortis	11,508				Yes					1		
21	Evergy	5,847										x	x
22	MGE Energy	677		Yes							1		
23	OGE Energy	2,985										x	x
24	Otter Tail	1,330								Yes	1		
25	WEC Energy	8,600										x	
26	Avista	1,938							Yes		1		x
27	Black Hills	2,128								Yes	1		
28	Edison International	17,599							Yes		1		
29	Hawaiian Electric	3,220			Yes			Yes			2		
30	IDACORP	1,827										X	x
31	Northwestern	1,514										x	x
32	Pacific Gas & Electric	24,419	Yes						Yes		2		
33	Pinnacle West Capital	5,125						Yes			1		x
34	Portland General Electric	3,440										x	x
35	Sempra Energy	13,185				Yes					1		
36	TXNM Energy	1,971					Yes				1		x
37	Xcel Energy	13,441							Yes		1		x
38	Unitil	495		Yes							1		
	Totals		5	2	2	3	4	6	5	4	31	12	19

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Companies Eliminated from Peer Group Consideration
(due to M & A, Reorg. and EPS Growth Disruptions)

Line Company involved in M & A, Reorg.

- 1 Eversource
- 2 Allete
- 3 Entergy*
- 4 TXNM Energy*

Anticipated Actions to be Taken per Value Line

Selling Water Utility business for \$2.4 billion
 Going Private in \$6.2 billion deal with Global Infrastructure Partners
 Selling Louisiana Gas Distribution business
 Being acquired by Blackstone Infrastructure for \$11.5 billion

Company with
Earnings Disruption

EPS Per Value Line Investment Survey

	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025 Est.</u>
5 First Energy*	\$ 2.39	\$ 2.60	\$ 2.41	\$ 2.56	\$ 2.63	\$ 2.55
6 Entergy*	3.45	3.44	2.69	5.55	2.45	3.35
7 Hawaiian Electric	1.80	2.25	2.20	1.81	(10.42)	0.95
8 Pinnacle West*	4.87	5.47	4.26	4.41	5.24	4.80
9 PPL Corp.*	2.04	0.53	1.41	1.60	1.68	1.85
10 P. S. Enterprise Group	3.43	3.65	3.47	3.48	3.68	4.00

Comments based on Value Line and Company Documents

Non core operations negatively affecting overall results in 2025
 Special Items in 2023; progress from 2024 EPS to 2025 unclear
 Legal & Other expenses due to 2023 Wildfires
 Hot 2024 weather; plant overhaul costs in 2025; growth unclear.
 Sale of Assets and Reorganization; future growth is unclear
 Company Financials show 2023 and 2024 EPS at \$5.13 per share
 and \$3.54 per share (special items). Overall results
 for 2020 to 2024 per Value Line are "flat".

* These companies have been included in the DTEE peer group

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Peer Group Market to Book Equity Ratios-Mar. 31, 2025

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Line	Company (a)	Ticker (b)	Mkt. Val. p/Sh. Of Com. Equity Mar.. 31, 2025* (c)	Millions		Book Value per Share (d) / (e) (f)	Market to Book Ratio (c) / (f) (g)
				Book Value of Com. Equity** (d)	Common Shares** (e)		
1	Alliant Energy	LNT	\$ 64.35	\$ 7,093	256.9	\$ 27.61	2.33
2	Ameren	AEE	100.40	12,219	270.30	45.21	2.22
3	American Electric Power	AEP	109.27	27,321	535.20	51.05	2.14
4	CenterPoint Energy	CNP	36.23	10,955	652.70	16.78	2.16
5	CMS Energy	CMS	75.11	8,335	299.10	27.87	2.70
6	Consolidated Edison	ED	110.56	23,783	366.00	64.98	1.70
7	Evergy	EVRG	68.95	9,931	230.10	43.16	1.60
8	IDACORP	IDA	116.22	3,346	54.00	61.96	1.88
9	NorthWestern Energy Grp.	NWE	57.87	2,896	64.90	44.62	1.30
10	OGE Energy	OGE	45.96	4,616	201.30	22.93	2.00
11	Portland General Electric	POR	44.60	3,844	109.50	35.11	1.27
12	WEFC Energy Group	WEC	108.98	12,976	319.10	40.66	2.68

13 Average

2.00

* Per Yahoo

** Per SEC Filings on Form 10-Q for quarter ended March 2025

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-21860
Exhibit AG-32
August 22, 2025
Page 1 of 1

Rating Agency Cash Flow Ratios
(With ROE at 9.85% and a 50% Common Equity Ratio)

		<u>12 M.E. March 2023 Adjusted Moody's Cash Flow Ratio (\$ Mil.)</u>			<u>Note</u>
<u>Line</u>	<u>Caption</u>	<u>Cash From Operations</u>	<u>Debt</u>	<u>Ratio</u>	
	(a)	<u>Pre-Wkg. Cap.</u> (b)	(c)	<u>(e) / (f)</u> (d)	
1	12 M.E. March 2023 Actual Ratio Results	\$ 2,290	\$ 11,322	20.2%	1
2	Increase Common Equity (to 50% vs 47.1%)	21	(559)		2
3	Increase ROE (to 9.85% vs 9.13%)	121			3
4	Pro Forma w/50% Common Equity, 9.85% ROE	<u>\$ 2,432</u>	<u>\$ 10,763</u>	22.6%	L 1 + L 2 + L 3
5	Ratings Downgrade Risk			Below 21%	4

Notes

- From case U-21534 page 1 of Moody's July 6, 2023 report on DTE Electric (see AGDE-1.11 Attachment 1)
- Amount from "Rebalancing Adjustments" determined under the footnotes on this page
Higher Net Income of \$21M = \$559M lower debt x 5.25% debt cost x after tax rate of 74.1%
- Net Income if a 9.85% ROE was earned: Common Equity of \$9.779 below x 9.85% equals \$ 963 M
DTE Electric 12 M.E. March net income (from Company SEC filings) 842 M
Net Income Under 9.85% **\$ 121 M**
- From page 2 of Moody's July 6, 2023 report on DTE Electric under "Factors that could lead to a downgrade"

<u>Avg. Capital (\$Mil.) 12 M.E. March 2023</u> <u>(Per SEC Filings of Company)</u>	<u>March</u> <u>2022</u>	<u>March</u> <u>2023</u>	<u>Two Point</u> <u>Average</u>	<u>Rebalancing</u> <u>Adjustmts.</u>	<u>12 Mo. Ended March 2023 Rebalanced</u>	
					<u>Amount</u>	<u>% Capital</u>
Long-Term Debt	\$ 9,787	\$ 10,889	\$ 10,338	\$ (559)	\$ 9,779	50.0%
Preferred Stock	-	-	-		-	0.0%
Common Equity	8,827	9,613	9,220	559	9,779	50.0%
Total	<u>\$ 18,614</u>	<u>\$ 20,502</u>	<u>\$ 19,558</u>		<u>\$ 19,558</u>	<u>100.0%</u>
Common Equity %			47.1%			

MPSC Case No: U-21860**Requester:** AG**Question No.:** AGDE-2.43**Respondent:** T. Lepczyk**Page:** 1 of 1

Question: 43. Provide a copy of all rating agency reports from Moody's, S&P, and Fitch issued in 2024 and 2025 for DTE Energy and DTE Electric.

Answer: See attachments labeled "U-21860 AGDE-2.43-01 Moody's 2025 Combined", "U-21860 AGDE-2.43-02 S&P 2025 DTE Electric", "U-21860 AGDE-2.43-03 Fitch 2025 DTE Electric", "U-21860 AGDE-2.43-04 Fitch 2025 DTE Energy", "U-21860 AGDE-2.43-05 Moody's 2024 DTE Energy", "U-21860 AGDE-2.43-06 Moody's 2024 Combined", "U-21860 AGDE-2.43-07 S&P DTE Energy Apr 2024", "U-21860 AGDE-2.43-08 S&P DTE Energy Oct 2024", "U-21860 AGDE-2.43-09 S&P DTE Electric 2024" and "U-21860 AGDE-2.43-10 Fitch 2024 Combined".

Attachment: U-21860 AGDE-2.43-01 Moody's 2025 Combined
U-21860 AGDE-2.43-02 S&P 2025 DTE Electric
U-21860 AGDE-2.43-03 Fitch 2025 DTE Electric
U-21860 AGDE-2.43-04 Fitch 2025 DTE Energy
U-21860 AGDE-2.43-05 Moody's 2024 DTE Energy
U-21860 AGDE-2.43-06 Moody's 2024 Combined
U-21860 AGDE-2.43-07 S&P DTE Energy Apr 2024
U-21860 AGDE-2.43-08 S&P DTE Energy Oct 2024
U-21860 AGDE-2.43-09 S&P DTE Electric 2024
U-21860 AGDE-2.43-10 Fitch 2024 Combined

Tear Sheet:

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

January 31, 2025

What's new: The Michigan Public Service Commission (MPSC) recently approved a \$217 million revenue increase for DTE Electric Co. (DTEE) effective Feb. 6, 2025. The rate case decision maintains the company's authorized return on equity (ROE) at 9.9%, maintains the previously approved equity capitalization structure at 50%, and rejects DTEE's request to raise its authorized ROE to 10.5%. Additionally, the commission also extended the company's investment recovery mechanism (IRM) feature through 2026.

DTE Electric Co.

Michigan

	Rate change (mil. \$)	ROE (%)	Rate base (mil. \$)
Current Case			
Company request	441.0	10.50	22,063
Authorized	217.4	9.90	21,787
Previous Case			
Company request	583.1	10.25	22,344
Authorized	368.1	9.90	22,151

Source: S&P Capital IQ Pro

Why it matters: Although the approved revenue increase is materially lower than DTEE's original rate request of approximately \$456 million (later revised to \$441 million), it is only modestly below S&P Global Ratings' base case expectation for DTEE's financial performance. The key difference between the company's rate request and the final MPSC decision primarily reflects lower forecasted operating expenses capital spend for forecasted years and lower-than-requested approved ROE, collectively accounting for close to half of DTEE's revised rate request. The commission also approved DTEE's request to extend its IRM through Dec. 31, 2026. The IRM is a cost recovery rider that permits for a timelier recovery of DTEE's electric distribution system investments aimed at improving reliability.

Overall, while the rate case outcome modestly weakens DTEE's funds from operations (FFO) to debt by about 30 basis points beginning in 2025, we expect the company's forecasted FFO to

Primary contact

Obioma Ugboaja, CFA
New York
1-212-438-7406
obie.ugboaja
@spglobal.com

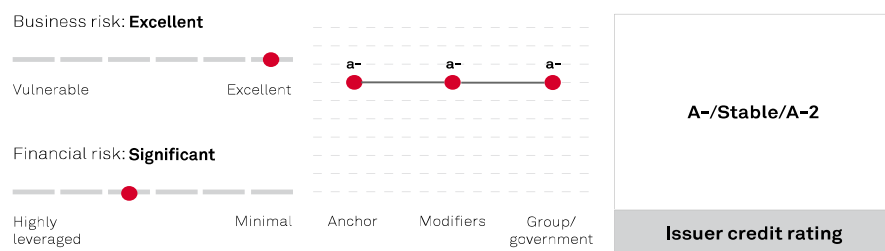
Secondary contact

Ruchi Agrawal
Toronto
14372252983
ruchi.agrawal
@spglobal.com

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

debt to remain within its financial risk profile category, averaging about 19%-20% over the next two years. Key assumptions to our forecast include capital spending of about \$3.8 billion over the next two years, dividends of \$800-\$900 million, negative cash flow deficit of approximately \$1.8 billion in 2025, and steady costs recovery for its investments.

Ratings Score Snapshot



Recent Research

- DTE Energy Co., April 2, 2024

Company Description

DTEE generates and distributes electricity to about 2.3 million residential, commercial, and industrial customers in southeastern Michigan. The electric utility has around 12,000 megawatts of generation capacity.

Outlook

Our stable outlook on DTEE reflects our base-case assumption that the company will generate sufficient cash flow to maintain financial measures that support S&P Global Ratings-adjusted FFO to debt of 19%-20%. The stable outlook also reflects our expectation that parent DTE will focus growth on its lower-risk, regulated utility strategy. We expect the utility businesses will account for about 90% of the consolidated company. We expect DTE's financial measures will generally remain in line with expectations, including FFO to debt of 14%-16%.

Downside scenario

We could lower our rating on DTEE within the next 24 months if we lower our rating on DTE or if DTEE's stand-alone financial measures weaken such that its FFO to debt remains consistently below 15%.

Upside scenario

We could raise our rating on DTEE within the next 24 months if we raise our rating on DTE and DTEE's stand-alone FFO to debt consistently exceeds 21%.

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

Financial Summary

DTE Electric Co.--Financial Summary

Period ending	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	\$	\$	\$	\$	\$	\$
Revenues	5,298	5,224	5,506	5,809	6,353	5,729
EBITDA	2,157	2,297	2,507	2,596	2,715	2,715
Funds from operations (FFO)	1,858	1,943	2,165	2,256	2,389	2,282
Interest expense	428	465	490	504	551	623
Cash interest paid	299	309	329	335	359	418
Operating cash flow (OCF)	1,725	1,740	1,909	1,273	1,654	1,534
Capital expenditure	1,982	2,192	2,666	3,008	2,617	3,076
Free operating cash flow (FOCF)	(257)	(453)	(757)	(1,735)	(964)	(1,542)
Discretionary cash flow (DCF)	(718)	(947)	(1,296)	(2,323)	(1,727)	(2,544)
Cash and short-term investments	18	12	16	9	15	15
Gross available cash	18	12	16	9	15	15
Debt	8,219	9,087	9,490	10,115	11,528	12,009
Common equity	6,793	7,195	8,070	8,903	9,695	10,224
Adjusted ratios						
EBITDA margin (%)	40.7	44.0	45.5	44.7	42.7	47.4
Return on capital (%)	8.7	8.2	8.1	8.0	7.6	6.8
EBITDA interest coverage (x)	5.0	4.9	5.1	5.1	4.9	4.4
FFO cash interest coverage (x)	7.2	7.3	7.6	7.7	7.6	6.5
Debt/EBITDA (x)	3.8	4.0	3.8	3.9	4.2	4.4
FFO/debt (%)	22.6	21.4	22.8	22.3	20.7	19.0
OCF/debt (%)	21.0	19.1	20.1	12.6	14.3	12.8
FOCF/debt (%)	(3.1)	(5.0)	(8.0)	(17.2)	(8.4)	(12.8)
DCF/debt (%)	(8.7)	(10.4)	(13.7)	(23.0)	(15.0)	(21.2)

Peer Comparison

DTE Electric Co.--Peer Comparisons

	DTE Electric Co.	CenterPoint Energy Inc.	CMS Energy Corp.	NiSource Inc.	Southwestern Public Service Co.
Foreign currency issuer credit rating	A-/Stable/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB/Negative/A-2
Local currency issuer credit rating	A-/Stable/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB/Negative/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2023-12-31	2023-12-31	2023-12-31	2023-12-31	2023-12-31
Mil.	\$	\$	\$	\$	\$

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

DTE Electric Co.--Peer Comparisons

Revenue	5,729	8,523	7,425	5,505	2,152
EBITDA	2,715	3,077	2,498	2,262	902
Funds from operations (FFO)	2,282	2,103	1,854	1,753	670
Interest	623	769	644	576	167
Cash interest paid	418	760	629	499	152
Operating cash flow (OCF)	1,534	3,614	2,309	1,881	842
Capital expenditure	3,076	4,369	2,439	2,590	707
Free operating cash flow (FOCF)	(1,542)	(755)	(130)	(708)	135
Discretionary cash flow (DCF)	(2,544)	(2,065)	(755)	(1,572)	(174)
Cash and short-term investments	15	541	227	2,245	3
Gross available cash	15	541	227	2,245	3
Debt	12,009	18,802	14,610	12,494	3,934
Equity	10,224	9,667	9,018	9,893	3,986
EBITDA margin (%)	47.4	36.1	33.6	41.1	41.9
Return on capital (%)	6.8	6.5	5.8	6.5	6.4
EBITDA interest coverage (x)	4.4	4.0	3.9	3.9	5.4
FFO cash interest coverage (x)	6.5	3.8	3.9	4.5	5.4
Debt/EBITDA (x)	4.4	6.1	5.8	5.5	4.4
FFO/debt (%)	19.0	11.2	12.7	14.0	17.0
OCF/debt (%)	12.8	19.2	15.8	15.1	21.4
FOCF/debt (%)	(12.8)	(4.0)	(0.9)	(5.7)	3.4
DCF/debt (%)	(21.2)	(11.0)	(5.2)	(12.6)	(4.4)

Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of DTEE. The company has exposure to environmental risks compared with peers given its dependence on coal-fired generation and exposure to nuclear generation. Coal-fired generation contributed over 30% of DTEE's net generation portfolio in 2023, a significant carbon footprint relative to its peers. The company is working to reduce its carbon footprint by retiring its coal-fired generation and replacing that capacity with clean energy sources, and the recently approved IRP in Michigan signals a manageable path for the company to address energy-transition risk. Additionally, the company's nuclear generation (approximately 10% of net generation capacity) entail operating and nuclear waste risks and exposes it to potential health and safety risks.

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

Rating Component Scores

Foreign currency issuer credit rating	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2
Business risk	Excellent
Country risk	Very Low
Industry risk	Very Low
Competitive position	Excellent
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	a-
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	a-
Group credit profile	bbb+
Entity status within group	Core (no impact on SACP)

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024,
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

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MOODY'S

RATINGS

Announcement of Periodic Review: Moody's Ratings announces completion of a periodic review of ratings of DTE Energy Company, DTE Electric Company and DTE Gas Company

11 Mar 2025

New York, March 11, 2025 -- Moody's Ratings (Moody's) has completed a periodic review of the ratings of DTE Energy Company (DTE Energy), DTE Electric Company (DTE Electric), DTE Gas Company (DTE Gas) and other ratings that are associated with these issuers.

The review was conducted through a rating committee held on 7 March 2025 in which we reassessed the appropriateness of the ratings in the context of the relevant principal methodology(ies), and recent developments.

This publication does not announce a credit rating action and is not an indication of whether or not a credit rating action is likely in the near future. Please see the Issuer page on <https://ratings.moody.com> for the most updated credit rating action information and rating history.

Key Rating considerations and rationale are summarized below.

DTE Energy Company's credit quality reflects the relatively strong credit profiles of its two primary regulated utilities, DTE Electric Company (DTE Electric, A2 stable) and DTE Gas Company (DTE Gas, A3 stable), and the supportive regulatory framework in Michigan, where both utilities operate. We view DTE as a stable regulated utility holding company with good growth potential, and expect the regulatory environment to remain credit supportive. In 2023 and 2024, DTE's credit metrics sustained an improvement back to historical levels following the weakness exhibited in 2022 primarily driven by a less supportive rate case outcome and delays in the recovery in commodity cost. As a result, its cash flow from operations before changes in working capital (CFO pre-WC) to debt was 17.1% in 2024, excluding securitization debt and the underfunded portion the nuclear decommission trust. We anticipate that the company's credit metrics be lower as a result of elevated capital expenditures and the potential for higher debt. We expect DTE to produce CFO pre-WC to debt around 14% over the next 2-3 years.

DTE Electric Company's credit quality reflects its operating profile as a vertically integrated utility that generates steady and predictable cash flow in a credit supportive Michigan regulatory environment. This is offset by capital investments that will remain elevated in order to maintain operational reliability, and to transform DTE Electric's majority coal-fired generation fleet into a predominantly renewable technologies fleet with some continued use of natural gas fuel and nuclear. Over the next couple of years, we expect DTE Electric to produce CFO pre-WC to debt of between 21% and 23% compared to 20.5% and 21.8% in 2023 and 2024, respectively. We anticipate that DTE Electric's leverage will be sustained at an elevated level to fund its capital investment program. However, the company should maintain a relatively steady credit profile supported by the regulatory mechanisms for cost recovery available in Michigan.

DTE Gas Company's credit assessment incorporates its low business risk profile as a regulated natural gas local distribution company (LDC) and a credit supportive regulatory environment in Michigan. Despite this regulatory environment and frequent rate case filings, the credit profile of DTE Gas declined in 2024 as it continues to undergo a large capital investment program. We expect DTE Gas's cash flow from operations before changes in working capital (CFO pre-WC) to

debt ratio to decline from historical levels driven by these sustained higher capital expenditures and potential delays in the timing of commodity cost recovery. In 2024, DTE Gas's cash flow from operations before changes in working capital (CFO pre-WC) to debt was 18.7%, down from 22.1% in 2022 and 24.1% in 2023. Over the next 2-3 years, the company's leverage is likely to increase in order to partially fund its capital expenditures and to maintain a 50% equity capital structure. However, we expect DTE Gas to also steadily increase its cash flow generation under the constructive Michigan regulatory framework, maintaining an adequate financial profile for its rating.

This document summarizes our view as of the publication date and will not be updated until the next periodic review announcement, which will incorporate material changes in credit circumstances (if any) during the intervening period.

The principal methodology used for this review was Regulated Electric and Gas Utilities published in August 2024. Please see the Rating Methodologies page on <https://ratings.moodys.com> for a copy of this methodology.

This announcement applies only to EU rated, UK rated, EU endorsed and UK endorsed ratings. Non-EU rated, non-UK rated, non-EU endorsed and non-UK endorsed ratings may be referenced herein to the extent necessary, if they are part of the same organization list.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on <https://ratings.moodys.com> for the most updated credit rating action information and rating history.

Knox Gainer
Analyst

Michael G. Haggarty
Associate Managing Director

Releasing Office:
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

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MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-2.46b

Respondent: T. Lepczyk

Page: 1 of 1

Question: 46. Refer to Mr. Lepczyk's direct testimony on the forecasted equity ratio. Please: b. State whether any of the rating agencies have notified the Company that a higher equity ratio is required to maintain existing credit ratings. If yes, provide a copy of the written notifications or a detailed, summary of any conversations on this point with rating agency personnel, including the date that they took place.

Answer: None of the rating agencies have notified us at this time that a higher equity ratio is required to maintain existing credit ratings. However, they are not required to notify us that a credit rating action will occur ahead of reporting the change. Ratings for DTE Electric are highly dependent on regulatory outcomes, and all of the agencies will do a thorough review of our credit rating after the forthcoming order is received.

Attachment: None

MPSC Case No: U-21534

Requester: AG

Question No.: AGDE-1.11

Respondent: T. Lepczyk

Page: 1 of 1

Question: 11. Provide a copy of the rating agency reports on DTE Energy and DTE Electric issued in 2023 and 2024.

Answer: See attachments.

Attachment: U-21534 AGDE-1.11-01 Moody's 2023 DTE Electric Report
U-21534 AGDE-1.11-02 Moody's 2023 DTE Energy Report
U-21534 AGDE-1.11-03 Fitch 2023 DTE Electric Report
U-21534 AGDE-1.11-04 Fitch 2023 DTE Energy Report
U-21534 AGDE-1.11-05 S&P 2023 DTE Electric Report
U-21534 AGDE-1.11-06 S&P 2023 DTE Energy Report
U-21534 AGDE-1.11-07 S&P 2023 DTE Energy IRP Tear Sheet
U-21534 AGDE-1.11-08 S&P 2023 DTE Energy Tear Sheet
U-21534 AGDE-1.11-09 S&P 2023 Results DTE Energy Tear Sheet
U-21534 AGDE-1.11-10 Fitch 2024 DTE Energy, DTE Electric, DTE Gas Combined Report
U-21534 AGDE-1.11-11 Moody's 2024 DTE Energy, DTE Electric, DTE Gas Combined Report
U-21534 AGDE-1.11-12 S&P 2024 DTE Energy Report

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CREDIT OPINION

6 July 2023

Update

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RATINGS

DTE Electric Company

Domicile	Detroit, Michigan, United States
Long Term Rating	A2
Type	LT Issuer Rating
Outlook	Stable

Please see the [ratings section](#) at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

Contacts

Jairo Chung +1.212.553.5123
VP-Sr Credit Officer
jairo.chung@moodys.com

Tang Zheng +1.212.553.0300
Associate Analyst
tang.zheng@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
MD - Global Infrastructure & Cyber Risk
james.hempstead@moodys.com

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Americas 1-212-553-1653
Asia Pacific 852-3551-3077
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DTE Electric Company

Update to credit analysis

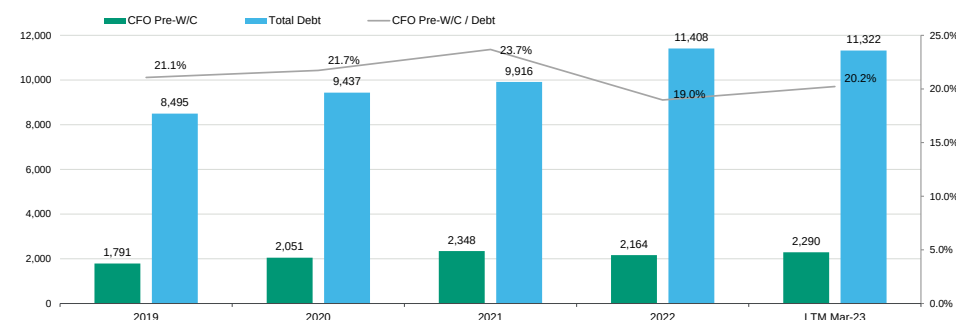
Summary

DTE Electric Company's (DTE Electric) credit quality reflects its operating profile as a vertically integrated utility in a credit supportive regulatory environment in Michigan that provides steady and predictable cash flow. This is offset by capital investments that will remain elevated in order to maintain operational reliability, and to transform DTE Electric's predominantly coal-fired generation fleet into a more balanced portfolio with natural gas fuel and renewable technologies.

Over the next couple of years, we expect DTE Electric to produce cash flow from operations before changes in working capital (CFO pre-WC) to debt between 21% and 23% compared to 23.7% and 19% in 2021 and 2022, respectively. The decline in 2022 was primarily due to the company's robust capital investment program, the mismatched timing of the commodity cost recovery and the outcome of its last electric rate case. We anticipate that DTE Electric's leverage will be maintained at an elevated level to fund its capital investment program. However, the company should maintain a relatively steady credit profile supported by regulatory mechanisms for cost recovery available in Michigan.

Exhibit 1

Historical CFO pre-WC, Total Debt and CFO pre-WC to Debt \$MM



For analytical purpose, we exclude securitization bonds and the underfunded portion of NDT in the credit metric calculations. DTE Electric's CFO pre-WC to debt ratio in 2021, 2022 and LTM 1Q23 would be 24.5%, 20.6% and 21.9%, respectively, when we make these adjustments.

Source: Moody's Financial Metrics

Credit strengths

- » Stable financial profile with predictable cash flow
- » Supportive regulatory environment
- » Timely cost recovery mechanisms

Credit challenges

- » Maintaining regulatory support for significant capital expenditure program
- » Elevated leverage and slightly lower metrics compared to historical levels
- » High, albeit moderating, exposure to coal-fired generation

Rating outlook

DTE Electric's stable outlook reflects our expectation that the Michigan legislative and regulatory environments will remain credit supportive and enable the utility to recover the cost of, and earn a reasonable return on, prudently incurred capital investments and maintain a consistent financial profile.

Factors that could lead to an upgrade

A rating upgrade could be considered if the ratio of CFO pre-WC to debt is consistently above 24%. Also, if the Michigan regulatory environment became even more formulaic, transparent or timely with its suite of recovery mechanisms, an upgrade could be considered.

Factors that could lead to a downgrade

DTE Electric's rating could be downgraded if there is an adverse change in Michigan's regulatory environment, leading to an increase in recovery lag, less transparency, more contentiousness or insufficient cost recovery and returns. Also, if capital investments are higher than expected or there are uncertain recovery prospects, or if its credit metrics deteriorate such that the ratio of CFO pre-WC to debt remains below 21% for a sustained period of time, a downgrade could be possible.

Key indicators [1] [2]

Exhibit 2

DTE Electric Company

	Dec-19	Dec-20	Dec-21	Dec-22	LTM Mar-23
CFO Pre-W/C + Interest / Interest	6.3x	6.8x	7.5x	6.5x	6.6x
CFO Pre-W/C / Debt	21.1%	21.7%	23.7%	19.0%	20.2%
CFO Pre-W/C – Dividends / Debt	15.3%	16.0%	17.8%	12.3%	14.3%
Debt / Capitalization	47.2%	47.1%	46.0%	47.4%	47.3%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

[2] For our analytical purposes, we exclude securitization bonds and the underfunded portion of NDT in the credit metric calculations. DTE Electric's CFO pre-WC to debt ratio in 2021, 2022 and LTM 1Q23 were 24.5%, 20.6% and 21.9%, respectively, excluding these factors.

Source: Moody's Financial Metrics

Profile

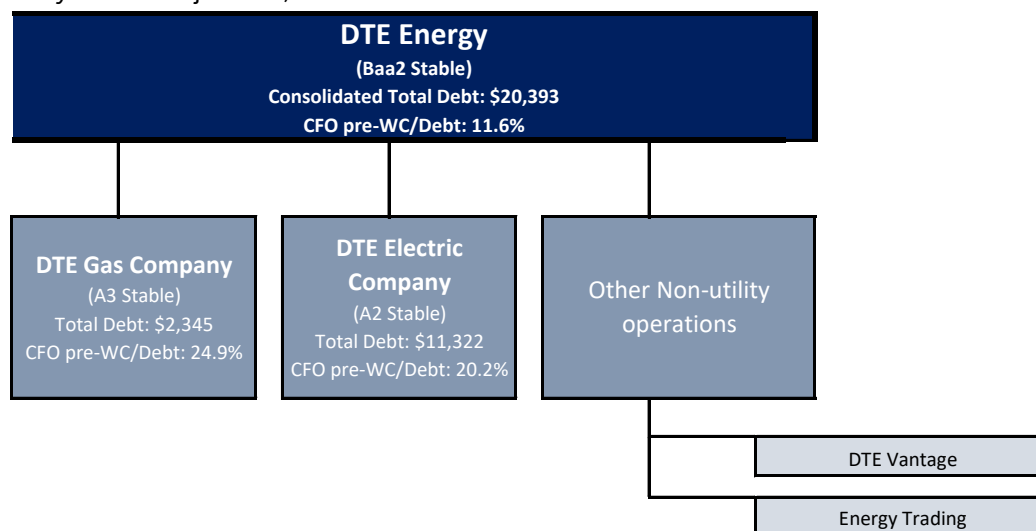
DTE Electric is a vertically integrated electric utility regulated by the Michigan Public Service Commission (MPSC) and is the largest subsidiary of DTE Energy Company (DTE, Baa2 stable). The company serves approximately 2.3 million customers in southeastern Michigan, with approximately \$22 billion in rate base.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on <https://ratings.moody.com> for the most updated credit rating action information and rating history.

Exhibit 3

Organizational Chart

Amounts including Moody's Standard Adjustments, as of 3/31/2023



Source: Moody's Financial Metrics, company presentation

Detailed credit considerations**Generally credit supportive Michigan regulatory environment**

DTE Electric benefits from a credit supportive regulatory environment in Michigan, which helps sustain the utility's long-term credit quality. As a result of energy legislation passed in both 2008 and 2016, the regulatory framework and rate case process have been streamlined and the timeliness of cost recovery has improved. Also, Michigan continues to provide credit positive financial support for utility investments. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which already included pre-construction approval for large generating resources, into an integrated resource planning (IRP) process. The IRP process considers a wide range of factors including fuel cost, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options, before constructing major projects.

In November 2022, DTE Electric filed its request for approval of its latest IRP. In its proposed plan, DTE Electric is seeking to accelerate the retirements of its two coal-fired power plants: Belle River to 2026 from 2028 and Monroe to 2028 and 2035 from 2040. Also, the proposal included converting Belle River to natural gas generation, and the addition of 15 GW of solar and wind generation sources along with 1,800 MW of storage. Based on the proposed IRP, DTE is targeting to achieve carbon reduction of 85% in 2035, 90% by 2040 and net zero by 2050.

Prescriptive suite of cost recovery mechanisms

Michigan utilities benefit from several formulaic rate adjustment mechanisms that provide a high degree of cash flow stability and assurance of cost recovery and have allowed DTE Electric to consistently earn its allowed return. For example, DTE Electric has a forward-looking power supply cost recovery (PSCR) mechanism intended to ensure that it can recover prudently incurred power supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. DTE Electric also has a forward-looking 20-year levelized renewable energy plan surcharge (RPS), structured to recover the cost of complying with the utility's renewable energy requirements. We view these automatic adjustment mechanisms as positive for credit quality.

In February 2023, DTE Electric filed its latest rate case, requesting a \$622 million base rate increase. The requested increase was based on a forward looking test year ending 30 November 2024 and an allowed return on equity (ROE) of 10.25%. The Staff of the MPSC filed its recommendation for a \$383.2 million revenue increase based on a 9.8% ROE in June 2023. Although the staff's recommendation was below the company's request, we expect a constructive outcome of the rate case. A final order from the MPSC is expected in December 2023.

DTE Electric's prior rate case was not consistent with its rate case outcome historical trends and our expectation. In its case filed in January 2022, a discrepancy regarding its sales forecast resulted in a significant difference in the company's requested rate increase of \$388 million and the \$31 million increase authorized by the MPSC. Given that the primary reason for the difference was the sales forecast, which is addressed in the current rate case as actual sales, we view that the outcome of the prior rate case was not an indication of any material change in Michigan's regulatory environment.

Overall stable financial profile through elevated capital investment cycle

Over the last three years, DTE Electric has averaged CFO pre-WC to debt of around 21% with its metric as of latest twelve month (LTM) period ending 31 March 2023 at 20.2%, including new securitization debt and the underfunded portion of its nuclear decommissioning obligations. Excluding these items, we estimate the ratio to be 21.9% at the same period. We expect the utility's CFO pre-WC to debt, excluding securitization debt and underfunded NDT, to be in the 21%-23% range over the next two years. Capital expenditures will continue to be relatively robust as a result of increased investment in distribution infrastructure and renewable generation. However, DTE Electric should continue to benefit from the credit supportive regulatory framework, recovering its investment costs on a timely basis.

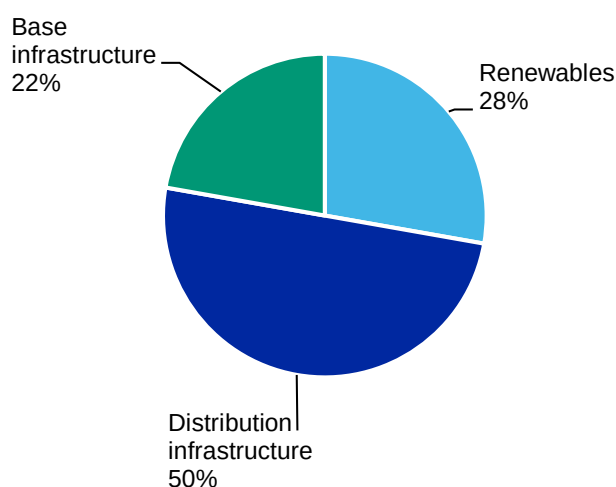
DTE Electric's investment plan through 2027 is approximately \$18 billion. Approximately \$9 billion of these investments will be related to improving its distribution infrastructure. About \$4 billion is earmarked for base infrastructure improvements and \$5 billion is for cleaner generation sources including renewables. DTE Electric has retired eleven coal-fired generation units. In its latest proposed IRP, the company described its plan to accelerate the retirement of the Monroe and Belle River plants. DTE Electric has been authorized to issue securitization bonds to recover the remaining book value of its retired coal power plants thus far and we expect the utility to receive constructive regulatory treatment for the remaining planned retirements.

On 3 April 2023, DTE Electric filed an application with the MPSC seeking approval for the securitization of \$496 million related to the net book value of the St. Clair and Trenton Channel power plants. On 22 June 2023, the company received a MPSC order authorizing a securitization of \$602 million related to the net book value of the St. Clair and Trenton Channel power plants. A securitization financing is expected by the fourth quarter of 2023.

Exhibit 4

DTE Electric's capex guidance through 2027 aggregates around \$18 billion

2023-2027 Forecast Capex: \$18 billion



Source: Company presentation

ESG considerations

DTE Electric's ESG Credit Impact Score is CIS-3

Exhibit 5

ESG Credit Impact Score

CIS-3**Moderately Negative**

For an issuer scored CIS-3 (Moderately Negative), its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The negative influence of the overall ESG attributes on the rating is more pronounced compared to an issuer scored CIS-2.



Source: Moody's Investors Service

DTE Electric's ESG Credit Impact Score **of CIS-3** reflects the company's current high exposure to coal-fired generation that is reducing over time; and inherent social risk for regulated utilities tied to demographic and societal trends; and governance attributes that pose no particular risk to the company.

Exhibit 6

ESG Issuer Profile Scores

ENVIRONMENTAL

E-3**Moderately Negative**

SOCIAL

S-3**Moderately Negative**

GOVERNANCE

G-2**Neutral-to-Low**

Source: Moody's Investors Service

Environmental

DTE Electric's environmental risks (**E-3** issuer profile score) reflect its current high exposure to coal-fired generation that is reducing over the medium term, decreasing its overall carbon transition risk. The company is currently undergoing a transition plan to phase out coal-fired generation. Its carbon transition efforts are supported by Michigan legislation and regulatory framework, which allow DTE Electric to phase out coal while providing timely cost recovery, and is articulated in its integrated resource planning.

Social

Social risk for DTE Electric (**S-3** issuer profile score) is primarily related to the utility's customer and regulatory relations as well as demographic and societal trends that could increase public concerns over affordability and the utility's reputation. These pressures could turn into an adverse political intervention or regulatory response.

Governance

DTE Electric's governance does not pose a particular risk (**G-2** issuer profile score) as its financing strategy and risk management, as well as management credibility and track record, are considered to be neutral to low risk.

Liquidity analysis

We expect DTE Electric's liquidity to be adequate over the next 12-18 months.

DTE Electric has access to an \$800 million revolving credit facility expiring in October 2027 and, as of 31 March 2023, there were no borrowings outstanding. The credit facility has one financial covenant that requires a maximum debt to capital ratio of 65%; as of 31 March 2023, the ratio was reported to be 53%.

Given its large capital investment program, DTE Electric is reliant on external capital sources in addition to internally generated cash flow. For the LTM ended 31 March 2023, DTE Electric generated \$1.9 billion of cash from operations, invested \$2.8 billion in capital investments and upstreamed \$668 million in dividend payments to DTE, resulting in negative free cash flow of \$1.6 billion.

We note that DTE Electric has received equity contributions from the parent every year, albeit in varying amounts. In 2021 and 2022, capital contributions from the parent were \$555 million and \$600 million, respectively. We expect parent equity contributions to continue over the next 2-3 years.

In addition, cash shortfalls were partly funded by incremental long-term debt at the DTE Electric level. Given DTE Electric's significant capital plans, we anticipate a continued need for external financing and regulatory support. Through 31 March 2023, DTE Electric issued \$1.2 billion of First Mortgage Bonds (FMB). In June, the company issued \$100 million of tax-exempt bonds related to conversion and disposal to dry ask at St. Clair and Monroe power plants.

As of 31 March 2023, DTE has a \$1.5 billion revolving credit facility expiring in October 2027, a \$150 million letter of credit facility expiring in February 2025, and an unsecured letter of credit facility of \$50 million. DTE retired the \$81 million revolving credit facility which expired in May 2023 with commercial paper issuance and extended and decreased the \$375 million letter of credit facility matured in June 2023 for \$275 million to June 2024. In addition in June 2023, DTE increased the above unsecured letter of credit from \$50 million to \$100 million, and added another \$100 million unsecured letter of credit facility for \$100 million which can be utilized by DTE Energy or DTE Electric.

As of 31 March 2023, DTE had \$80 million of revolver borrowings, \$315 million of letters of credit and \$50 million of commercial paper issuances outstanding, leaving \$1.7 billion of net availability. None of the DTE credit facilities have a MAC clause for new borrowings and all maintain a single financial covenant test requiring DTE to maintain a total funded debt to capitalization ratio of no more than 70% and DTE was in compliance with 63%.

Rating methodology and scorecard factors

As a vertically integrated utility that has generation, DTE Electric is scored under the standard risk Regulated Electric and Gas Utilities methodology financial metric grid.

Exhibit 7

Methodology Scorecard Factors

DTE Electric Company

Regulated Electric and Gas Utilities Industry [1][2]			Current LTM 3/31/2023		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)			Measure	Score	Measure	Score
a) Legislative and Judicial Underpinnings of the Regulatory Framework			A	A	A	A
b) Consistency and Predictability of Regulation			Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)						
a) Timeliness of Recovery of Operating and Capital Costs			Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns			A	A	A	A
Factor 3 : Diversification (10%)						
a) Market Position			Ba	Ba	Ba	Ba
b) Generation and Fuel Diversity			Ba	Ba	Ba	Ba
Factor 4 : Financial Strength (40%)						
a) CFO pre-WC + Interest / Interest (3 Year Avg)			6.9x	Aa	6.5x - 6.7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)			20.9%	Baa	21% - 23%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)			14.8%	Baa	13% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)			47.6%	Baa	45% - 48%	Baa
Rating:						
Scorecard-Indicated Outcome Before Notching Adjustment				A2		A2
HoldCo Structural Subordination Notching					0	0
a) Scorecard-Indicated Outcome				A2		A2
b) Actual Rating Assigned						A2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

[2] A of 3/31/2023.

[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures

Source: Moody's Investors Service

Appendix

Exhibit 8

Stable Cash Flow and Credit Metrics [1]

CF Metrics	Dec-19	Dec-20	Dec-21	Dec-22	LTM Mar-23
As Adjusted					
FFO	1,819	1,972	2,138	2,213	2,165
+/- Other	-29	79	210	-49	125
CFO Pre-WC	1,791	2,051	2,348	2,164	2,290
+/- ΔWC	-57	-134	-20	-464	-398
CFO	1,734	1,917	2,328	1,700	1,892
- Div	494	539	588	763	668
- Capex	2,218	2,690	3,035	2,642	2,776
FCF	-979	-1,312	-1,295	-1,705	-1,552
(CFO Pre-W/C) / Debt	21.1%	21.7%	23.7%	19.0%	20.2%
(CFO Pre-W/C - Dividends) / Debt	15.3%	16.0%	17.8%	12.3%	14.3%
FFO / Debt	21.4%	20.9%	21.6%	19.4%	19.1%
RCF / Debt	15.6%	15.2%	15.6%	12.7%	13.2%
Revenue	5,224	5,506	5,809	6,397	6,286
Interest Expense	338	355	359	390	406
Net Income	533	708	751	857	755
Total Assets	24,588	26,513	28,405	30,236	30,755
Total Liabilities	17,453	18,443	19,502	20,541	21,142
Total Equity	7,135	8,070	8,903	9,695	9,613

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months

Source: Moody's Financial Metrics

Exhibit 9

Peer Comparison [1]

(In US millions)	DTE Electric Company			Consumers Energy Company			Wisconsin Power and Light Company			Arizona Public Service Company			Northern States Power Company (Minnesota)		
	A2 (Stable)			(P)A3 (Stable)			A3 (Negative)			A3 (Negative)			A2 (Stable)		
	FYE Dec-21	FYE Dec-22	LTM Mar-23	FYE Dec-21	FYE Dec-22	LTM Mar-23	FYE Dec-21	FYE Dec-22	LTM Mar-23	FYE Dec-22	FYE Dec-22	LTM Mar-23	FYE Dec-21	FYE Dec-22	LTM Mar-23
Revenue	5,809	6,397	6,286	7,021	8,151	8,078	1,523	1,856	1,866	3,909	4,462	4,623	5,756	6,684	6,652
CFO Pre-W/C	2,348	2,164	2,290	2,041	2,114	2,045	377	339	341	1,170	1,365	1,426	1,054	2,034	2,091
Total Debt	9,916	11,408	11,322	9,018	10,472	10,487	2,819	3,323	3,390	7,455	7,901	8,639	6,832	7,292	7,505
CFO Pre-W/C + Interest / Interest	7.5x	6.5x	6.6x	7.5x	7.2x	6.6x	4.9x	4.8x	4.7x	5.4x	5.8x	5.9x	5.0x	8.2x	8.2x
CFO Pre-W/C / Debt	23.7%	19.0%	20.2%	22.6%	20.2%	19.5%	13.4%	10.2%	10.1%	15.7%	17.3%	16.5%	15.4%	27.9%	27.9%
CFO Pre-W/C - Dividends / Debt	17.8%	12.3%	14.3%	14.6%	12.8%	12.0%	7.4%	4.9%	4.8%	10.4%	12.1%	11.8%	9.1%	20.2%	20.7%
Debt / Capitalization	46.0%	47.4%	47.3%	43.7%	45.1%	45.0%	44.1%	43.8%	43.0%	45.1%	45.6%	47.4%	41.8%	43.4%	43.8%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade

Source: Moody's Financial Metrics

Ratings

Exhibit 10

Category	Moody's Rating
DTE ELECTRIC COMPANY	
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Senior Secured	Aa3
Commercial Paper	P-1
PARENT: DTE ENERGY COMPANY	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Commercial Paper	P-2

Source: Moody's Investors Service

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REPORT NUMBER

1374467

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

CONFIDENTIAL- SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21860

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-2.52a

Respondent: J. Nelson

Page: 1 of 1

Question: 52. Refer to Exhibit A-14, Schedule D5.4, pages 1 and 2, regarding the CAPM analysis in the lower half of each page, which shows a 4.46% 30-year projected U.S. Treasury bond rate. Please: a. Provide a copy of the source document from which the 4.46% rate was sourced.

Answer: Please see Ms. Nelson's confidential workpaper "NDA U-21860 Nelson WP 2_Blue Chip Financial Forecasts.pdf" for the source documents.

Please see Ms. Nelson's confidential workpaper "NDA U-21860 Nelson WP (WP 3-17)" tab "WP-9 BCFF Proj. 30yr Yield" for the derivation of the projected 30-year Treasury bond yield.

Attachment: None.

VLFAAlert



ValueLinefunds

4th Quarter 2018

Volume VII, Issue IV

00207257



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 VLFAAlert 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)

Value Line Article on Volatility vs. Risk

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, taxable 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 Electric - Electric Rate Case

Case No. U-21534
Exhibit AG-39
Date: August 22, 2025
Page 1 of 1

O & M Summary-Thousands of Dollars

<u>Line</u>	<u>Caption or Description of Item</u> (a)	<u>Amount</u> (b)	<u>Reference</u> (c)
<u>AG Case Adjustments</u>			
1	Distribution Operations	\$ (54,251)	Testimony
2	Engineering & Support Staff	(8,328)	Testimony
3	Steam Power Generation	(25,531)	Testimony
4	Other Power Generation	(8,741)	Testimony
5	Nuclear Power	(5,845)	Testimony
6	Regulated Marketing	(8,085)	Testimony
7	Credit Card Merchant Fees	(7,013)	Testimony
8	Uncollectible Accounts Expense	(1,586)	Exhibit AG-54
9	Administrative & General	(30,798)	Exhibit AG-55
10	VEBA Plan	(1,808)	Exhibit AG-56
11	Health Care Plan	(513)	Exhibit AG-57
12	WCB Façade Repairs	2,254	Testimony
13	Rate Case Expenses	(7,100)	Testimony
14	Incentive Compensation Plan	(46,227)	Exhibit AG-60
15	Total Adjustments	<u>\$ (203,572)</u>	

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-5.167

Respondent: J. Kryscynski

Page: 1 of 1

Question: 167. Refer to Exhibit A-13, Schedule C5.6, page 1. Please provide the same information in columns (a) through (f) for actual 2024 in Excel.

Answer: Please refer to the response for MNSCDE-3.16.

Attachment: *None.*

Discovery Response AGDE-5.167

Michigan Public Service Commission DTE Electric Company Projected Operation and Maintenance Expenses Distribution Expenses (\$000)											Case No.: U-21860 Discovery MNSC-3.16	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
								Projected Adjustments				
			1/1/24 - 12/31/24 Historical Test Period	Eliminate TRM N/A	Normalization Adjustments 4/	Adjusted Historical Test Period		1/1/25 - 12/31/25 Inflation Adj 5/	1/1/26 - 12/31/26 Inflation Adj 5/	Other Adjustments 6/	Total Projected Adjustments	Projected Test Period
Line No.	Description	Account										
						sum (c) thru (e)					sum (g) thru (j)	(f) + (k)
1	Distribution Expenses											
2	Miscellaneous Transmission Expenses	566	-	-	-	-	-	-	-	-	-	-
3	Operation Supervision and Engineering	580	56,302	-	4,944	61,247	-	1,837	1,956	11,823	15,616	76,863
4	Load Dispatching	581	1,324	-	-	1,324	-	40	42	-	82	1,406
5	Station Expenses	582	4,843	-	-	4,843	-	145	155	-	300	5,143
6	Overhead Line Expenses	583	7,643	-	-	7,643	-	229	244	-	473	8,116
7	Underground Line Expenses	584	781	-	-	781	-	23	25	-	48	830
8	Street Lighting and Signal System Exp	1/ 585	-	-	-	-	-	-	-	-	-	-
9	Meter Expenses	586	8,710	-	-	8,710	-	261	278	-	539	9,249
10	Customer Installations Expenses	587	426	-	-	426	-	13	14	-	26	453
11	Miscellaneous Expenses	588	25,756	-	1,071	26,827	-	805	857	5,175	6,836	33,663
12	Amortization of Deferred ADMS Costs	588	1,174	-	-	1,174	-	-	-	-	-	1,174
13	Rents	589	-	-	-	-	-	-	-	-	-	-
14	Total Operation Expense		106,959	-	6,015	112,974	-	3,354	3,570	16,998	23,922	136,896
15	Maintenance											
16	Maintenance Supervision and Engineering	590	7,307	-	-	7,307	-	219	233	-	453	7,760
17	Maintenance of Structures	591	2,668	-	-	2,668	-	80	85	-	165	2,834
18	Maintenance of Station Equipment	592	15,547	-	-	15,547	-	466	496	1,548	2,511	18,058
19	Maintenance of Overhead Lines-Tree Trim	2/ 593	104,811	-	-	104,811	-	-	-	75,189	75,189	180,000
20	Maintenance of Overhead Lines-Other	593	73,806	-	35,828	109,634	-	3,289	3,501	12,489	19,279	128,912
21	Maintenance of Underground Lines	594	9,486	-	182	9,668	-	290	309	7,293	7,892	17,561
22	Maintenance of Line Transformers	595	-	-	-	-	-	-	-	-	-	-
23	Maintenance of Street Lighting and Signal Systems	1/ 596	5,091	-	-	5,091	-	153	163	-	315	5,406
24	Maintenance of Meters	597	-	-	-	-	-	-	-	-	-	-
25	Maintenance of Misc Distribution Plant	598	-	-	-	-	-	-	-	-	-	-
26	Total Maintenance Expense		218,716	-	36,010	254,726	-	4,497	4,787	96,520	105,804	360,530
27	Total Distribution Expenses		325,675	-	42,025	367,700	-	7,851	8,357	113,518	129,726	497,426

Discovery Response AGDE-5.167

										Page: 2 of 4	
<u>Other Sponsoring Witnesses</u>					<u>Projection Adjustments</u>						
1/ Street Lighting and Signal Systems (accounts 585 and 596) are sponsored by Witness Hartley											
2/ Tree Trim Expenses (account 593) are sponsored by Witness Steudle (Exh. A-13 C5.6.1)											
<u>Historical Adjustments</u>											
3/ Eliminate expenses recovered through Transitional Reconciliation Mechanism (TRM)											
4/ Normalization Adjustments:											
		<u>Account</u>	<u>Amount</u>				<u>1/1/25 -</u>	<u>1/1/26 -</u>			
							<u>12/31/25</u>	<u>12/31/26</u>			
Restoration (Exh. A-13 C5.6 p.2, Line 18, col. (j))		593	35,828		5/ Inflation Adjustment:						
Hiring pause		580			Annual Rate		3.00%	3.10%			
		588			No. of Months in Period		12	12			
Temporary pause in purchases of non-critical safety materials and advertising		580	1,758		Pro-rated Inflation Rate		0.00%	3.00%	3.10%		
Temporary reduction in consulting spend		580			(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)						
			2,128		6/ Other Projected Adjustments:					<u>Account</u>	<u>Amount</u>
Apprentice Classes		588	576		Community Lighting Normalized Outage Repair Volume					596	-
					Tree Trim					593	75,189
					ADMS Regulatory Asset Amortization sponsored by Witness Uzenski Exh. A-13 C5.6.2, Line 11, Col. (i)					588	-
					Surge tree trim savings sponsored by Witness Steudle Exh. A-22, Schedule L1, p. 1					593	(1,300)
					Staking Rate Increase sponsored by Witness Hill Exh. A-13, Sch. C5.6, p. 3, Line 2 and 3, Col. (i) (The adjustment differs from the amount in U-21860 Exhibit A-13, Schedule C5.6, page 2 because a portion is reflected in 2024 actuals)					580	1,618
					Preventative Maintenance Backlog sponsored by Witness Robinson					580, 590, 591, 592, 593, 594	7,300
Total Normalization Adjustments			42,025		PTMM - Pole Top Inspections sponsored by Witness Robinson					593	2,400
					PTMM - Pole Inspections sponsored by Witness Robinson					593	6,200
					PTMM - Infrared Thermography sponsored by Witness Robinson					593	1,900
					Corrective Maintenance sponsored by Witness Robinson					580, 593	7,300
					System Cable Testing Program sponsored by Witness Robinson					594	2,000
					Workforce Augmentation					580, 592, 593, 594	8,300
					Peaker Study					588	500
					NMS/ESRI Data Quality Controls sponsored by Witness Rademacher					588	500
					Cloud Storage					588	1,000
					NERC Compliance					588	700
					VSIP Savings sponsored by Witness Leslie					593	(89)
					Total Projection Adjustments						113,518

Discovery Response AGDE-5.167

				Page: 2 of 4			
<u>Other Sponsoring Witnesses</u>				<u>Projection Adjustments</u>			
1/ Street Lighting and Signal Systems (accounts 585 and 596) are sponsored by Witness Hartley				1/1/25 - 1/1/26 -			
2/ Tree Trim Expenses (account 593) are sponsored by Witness Steudle (Exh. A-13 C5.6.1)				12/31/25 12/31/26			
				Annual Rate 3.00% 3.10%			
<u>Historical Adjustments</u>				No. of Months in Period 12 12			
3/ Eliminate expenses recovered through Transitional Reconciliation Mechanism (TRM)				Pro-rated Inflation Rate 0.00% 3.00% 3.10%			
				(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)			
4/ Normalization Adjustments:						<u>Account</u> <u>Amount</u>	
Restoration (Exh. A-13 C5.6 p.2, Line 18, col. (j))		593	35,828	6/ Other Projected Adjustments:			
Hiring pause		580		Community Lighting Normalized Outage Repair Volume		596	-
		588					
		594	1,758	Tree Trim		593	75,189
Temporary pause in purchases of non-critical safety materials and advertising		580	1,735	ADMS Regulatory Asset Amortization sponsored by Witness Uzenski Exh. A-13 C5.6.2, Line 11, Col. (i)		588	-
Temporary reduction in consulting spend		580	2,128	Surge tree trim savings sponsored by Witness Steudle Exh. A-22, Schedule L1, p.1		593	(1,300)
Apprentice Classes		588	576	Staking Rate Increase sponsored by Witness Hill Exh. A-13, Sch. C5.6, p. 3, Line 2 and 3, Col. (i) (The adjustment differs from the amount in U-21860 Exhibit A-13, Schedule C5.6, page 2 because a portion is reflected in 2024 actuals)		580	1,618
				Preventative Maintenance Backlog sponsored by Witness Robinson		580, 590, 591, 592, 593, 594	7,300
Total Normalization Adjustments			42,025	PTMM - Pole Top Inspections sponsored by Witness Robinson		593	2,400
				PTMM - Pole Inspections sponsored by Witness Robinson		593	6,200
				PTMM - Infrared Thermography sponsored by Witness Robinson		593	1,900
				Corrective Maintenance sponsored by Witness Robinson		580, 593	7,300
				System Cable Testing Program sponsored by Witness Robinson		594	2,000
				Workforce Augmentation		580, 592, 593, 594	8,300
				Peaker Study		588	500
				NMS/ESRI Data Quality Controls sponsored by Witness Rademacher		588	500
				Cloud Storage		588	1,000
				NERC Compliance		588	700
				VSIP Savings sponsored by Witness Leslie		593	(89)
				Total Projection Adjustments			113,518

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Distribution Expenses
(\$000)

Exhibit AG-41
Case No.: U-21860
August 22, 2025
Page 1 of 2

Line No.	(a) Description	(b) Account	(c) 1/1/24 - 12/31/24 Historical Test Period	(d) Eliminate TRM N/A	(e) Normalization Adjustments 4/	(f) Adjusted Historical Test Period	(g)	Projected Adjustments			(k) Total Projected Adjustments	(l) Projected Test Period
								1/1/25 - 12/31/25 Inflation Adj 5/	1/1/26 - 12/31/26 Inflation Adj 5/	Other Adjustments 6/		
						sum (c) thru (e)					sum (g) thru (j)	(f) + (k)
1	Distribution Expenses											
2	Miscellaneous Transmission Expenses	566	-	-	-	-	-	-	-	-	-	-
3	Operation Supervision and Engineering	580	56,302	-	-	56,302	-	1,576	1,389	11,823	14,789	71,091
4	Load Dispatching	581	1,324	-	-	1,324	-	37	33	-	70	1,394
5	Station Expenses	582	4,843	-	-	4,843	-	136	119	-	255	5,098
6	Overhead Line Expenses	583	7,643	-	-	7,643	-	214	189	-	403	8,045
7	Underground Line Expenses	584	781	-	-	781	-	22	19	-	41	822
8	Street Lighting and Signal System Exp	1/ 585	-	-	-	-	-	-	-	-	-	-
9	Meter Expenses	586	8,710	-	-	8,710	-	244	215	-	459	9,169
10	Customer Installations Expenses	587	426	-	-	426	-	12	11	-	22	449
11	Miscellaneous Expenses	588	25,756	-	-	25,756	-	721	635	5,175	6,531	32,287
12	Amortization of Deferred ADMS Costs	588	1,174	-	-	1,174	-	-	-	-	-	1,174
13	Rents	589	-	-	-	-	-	-	-	-	-	-
14	Total Operation Expense		106,959	-	-	106,959	-	2,962	2,610	16,998	22,570	129,529
15	Maintenance											
16	Maintenance Supervision and Engineering	590	7,307	-	-	7,307	-	205	180	-	385	7,692
17	Maintenance of Structures	591	2,668	-	-	2,668	-	75	66	-	141	2,809
18	Maintenance of Station Equipment	592	15,547	-	-	15,547	-	435	384	1,548	2,367	17,914
19	Maintenance of Overhead Lines-Tree Trim	2/ 593	104,811	-	-	104,811	-	-	-	75,189	75,189	180,000
20	Maintenance of Overhead Lines-Other	593	73,806	-	23,784	97,590	-	2,733	2,408	12,489	17,629	115,219
21	Maintenance of Underground Lines	594	9,486	-	-	9,486	-	266	234	7,293	7,793	17,279
22	Maintenance of Line Transformers	595	-	-	-	-	-	-	-	-	-	-
23	Maintenance of Street Lighting and Signal Systems	1/ 596	5,091	-	-	5,091	-	143	126	-	268	5,359
24	Maintenance of Meters	597	-	-	-	-	-	-	-	-	-	-
25	Maintenance of Misc Distribution Plant	598	-	-	-	-	-	-	-	-	-	-
26	Total Maintenance Expense		218,716	-	23,784	242,500	-	3,855	3,397	96,520	103,772	346,272
27	Total Distribution Expenses		325,675	-	23,784	349,459	-	6,817	6,007	113,518	126,342	475,802
28	Company Forecasted O&M expense for 2026											505,513
29	Reduction in Expense											\$ (29,711)

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Distribution Expenses
(\$000)

Exhibit AG-41
Case No.: U-21860
August 22, 2025
Page 2 of 2

Historical Adjustments

	Account	Company Amount	Company Amount	
4/ Normalization Adjustments:				
Restoration (Exh. A-13 C5.6 p.2, Line 18, col. (j))	593	35,828	23,784	(a)
	580			
Hiring pause	588			
	594	1,758	-	
Temporary pause in purchases of non-critical safety materials and advertising	580	1,735	-	
Temporary reduction in consulting spend	580			
		2,128	-	
Apprentice Classes	588	576	-	
Total Normalization Adjustments		42,025		

(a) Storm Restoration Expense Adjustment:

2,024	59,672
2,023	183,671
2,022	60,850
2,021	73,429
2,020	39,657
Average	83,456
2024 expense	59,672
Normalization Adjustment	23,784

5/ Inflation Adjustment:	1/1/25 - 12/31/25	1/1/26 - 12/31/26
Annual Rate	2.80%	2.40%
No. of Months in Period	12	12
Pro-rated Inflation Rate	0.00%	2.80%
		2.40%

6/ Other Projected Adjustments:

	Account	Amount
Community Lighting Normalized Outage Repair Volume	596	-
Tree Trim	593	75,189
ADMS Regulatory Asset Amortization sponsored by Witness Uzenski Exh. A-13 C5.6.2, Line 11, Col. (i)	588	-
Surge tree trim savings sponsored by Witness Steudle Exh. A-22, Schedule L1, p.1	593	(1,300)
Staking Rate Increase sponsored by Witness Hill Exh. A-13, Sch. C5.6, p. 3, Line 2 and 3, Col. (i)	580	1,618
(The adjustment differs from the amount in U-21860 Exhibit A-13, Schedule C5.6, page 2 because a portion is reflected in 2024 actuals)		
	580, 590, 591, 592, 593, 594	7,300
Preventative Maintenance Backlog sponsored by Witness Robinson		
PTMM - Pole Top Inspections sponsored by Witness Robinson	593	2,400
PTMM - Pole Inspections sponsored by Witness Robinson	593	6,200
PTMM - Infrared Thermography sponsored by Witness Robinson	593	1,900
Corrective Maintenance sponsored by Witness Robinson	580, 593	7,300
System Cable Testing Program sponsored by Witness Robinson	594	2,000
Workforce Augmentation	580, 592, 593, 594	8,300
Peaker Study	588	500
NMS/ESRI Data Quality Controls sponsored by Witness Rademacher	588	500
Cloud Storage	588	1,000
NERC Compliance	588	700
VSIP Savings sponsored by Witness Leslie	593	(89)
Total Projection Adjustments		113,518

Source: DR MNSC-DE-3.16

Discovery Response AGDE-6.201a

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.201a

Respondent: R. Steudle

Page: 1 of 1

Question: 201. Refer to page 32 of Ms. Steudle's direct testimony on tree trimming O&M expense for the projected test year. Please: a. Show in Excel how the \$145 million and \$35 million were developed, the basis for those amounts, and the underlying number of miles and cost per mile.

Answer: Please see attached file.

Attachment: U-21860 AGDE-6.201a - 2026 Tree Trim Budget

	U-21860 AGDE-6.201a - 2026 Tree Trim Budget Breakdown			
Base Budget (\$145)				
	Maint.			Cycle (years)
		Dist Miles	28500	5.8
		STMiles	2500	3
		Dist Miles addressed on capital	350	
		Annual Dist Miles Trimmed	4564	
		Annual STMiles Trimmed	833	
		Dist Cost per Mile	\$ 24,570.00	
		STCost per Mile	\$ 16,300.00	
		Dist Cost	\$ 112,132,397	
		STCost	\$ 13,583,333	
		Maintenance Subtotal	\$ 125,715,730	
	Non-Maint			
		Trouble	\$ 10,000,000.00	
		Herbicide	\$ 1,000,000.00	
		Staff, Program Costs	\$ 8,500,000.00	
	Base Total		\$ 145,215,729.89	
Specification Changes (\$35)				
	Overhang Removal			
		Estimated total trees of target species	1,450,000	
		Portion of Dist Z2/Z3	82%	
		Trees that require overhang removed	1189000	
		Incremental cost per tree	\$ 90.00	
		Total	\$ 107,010,000.00	
		Annualized	\$ 18,450,000.00	
	Target ~1/3 of 2026 plan		\$ 6,150,000.00	
	Increased Removals			
	Brush	Brush Not Removed	179,912,268	
		Relative Days to Remove (assume 6,000 ft^2 per Day)	29,985.38	
		Cost	\$ 63,718,928	
		Annualized - Brush (incremental cost of 75%)	\$ 7,964,866	
	Target all brush on 2026 plan		\$ 7,964,866	

	Trees	B1/B2's that were trimmed		
		B1		1,052,122
		B2		103,555
		Incremental Cost to Remove		
		B1		25%
		B2		45%
		Cost		
		B1	\$	39,454,575.00
		B2	\$	6,989,962.50
		Annualized - Trees (assuming 90% removals)	\$	6,966,680.63
	Target ~1/3 of 2026 plan		\$	2,322,226.88
	OROW Trees			
		Pirority Trees identified as GRCS but not removed		63,000
		Additional GRCS Due to Expanded Spec and Mid-Cycle Inspec		18,900
		Annualized on 6-year Cycle		13650
		Cost to remove	\$	11,602,500
		Inspections/Planning	\$	3,500,000
		Total	\$	15,102,500
	Target all OROW trees identified		\$	15,102,500
	Supporting Costs			
		Cust Outreach / Call Center Support	\$	2,500,000
		Wood Haul (overhang and tree removal)	\$	1,000,000
		Total	\$	3,500,000
	Supoorting Costs for 2026		\$	3,500,000
	Specification Change Summary			
		Overhang Removal	\$	6,150,000
		Increased Tree/Brush Removals	\$	10,287,093
		OROW Trees	\$	15,102,500
		Supporting Costs	\$	3,500,000
	Specification Change Total		\$	35,039,592.91

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.201b

Respondent: R. Steudle

Page: 1 of 1

Question: 201. Refer to page 32 of Ms. Steudle's direct testimony on tree trimming O&M expense for the projected test year. Please: b. Provide the amount spent on the three areas outlined on page 22 for each year 2018–2024 and forecasted for 2025.

Answer: The proposed expansion areas have not been implemented by the Company and therefore there are no historical / forecasted costs for 2018-2025.

Attachment: None.

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.170a

Respondent: J. Robinson

Page: 1 of 1

Question: 170. Refer to Table 6 on page 40 of Mr. Robinson's direct testimony. Please identify the as of date of the Population and explain whether the inspection cycles are current or historical inspection cycles, or whether they are new proposed cycles. If new cycles, provide the previous inspection cycles in Excel.

Answer: The equipment populations shown in Table 6 are based on 2025 data. The inspection cycles reflected in the table represent both current and historical inspection practices. They are not newly proposed cycles. Therefore, there are no prior inspection cycles to provide in Excel, as no changes to the cycles are being proposed in this context.

Attachment: *None*

Discovery Response AGDE-6.171a

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.171a

Respondent: J. Robinson

Page: 1 of 1

Question: 171. Refer to Tables 7 and 8 on page 41 of Mr. Robinson's direct testimony. Please:

a. Explain what time periods the tables reflect and whether these are historical or newly proposed activities.

Answer: Tables 7 and 8 reflect activities based on current and historical inspection and maintenance cycles. These are not newly proposed activities. Please see AGDE-6.170a.

Attachment: *None*

Discovery Response AGDE-6.172

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.172

Respondent: J. Robinson

Page: 1 of 1

Question: 172. Refer to lines 1-12 on page 45 of Mr. Robinson's direct testimony. Please explain what the \$5.0 million will be spent on versus the \$7.3 million and provide the calculations in Excel showing how these amounts were developed.

Answer: Please see the attachment

Attachment: *U-21860 AGDE-6.172-01 PM O&M.xlsx*

Discovery Response AGDE-6.172

U-21860 AGDE-6.172-01 PMO&M							
Maintenance Policy Area	Activity performed on this Asset Type	Target based on whats Due in '25	33% of backlog units	Total Units	Incremental Cost to Backlog on Cycle	Incremental Cost for Backlog	Total Incremental Cost
Substation	120kV Breakers	2	0	2	\$ 1,427,732	\$ 917,870	\$ 2,345,602
	120kV Disconnects	26	10	36			
	24/40kV Breaker (see Note 1)	66	0	66			
	Distribution Breaker	413	67	480			
	Busses (subtrans)	26	9	35			
	Regulators	21	3	24			
	Single Taps	11	10	21			
	Portables	13	2	15			
	AC Netbanks	86	43	129			
	13.2kV Enclosed Cap Banks	231	0	231			
	Batteries	651	0	651			
	Voltage Control Periodics	841	318	1159			
	Relay Periodics	182	0	182			
	Relay Calibrations (RCAL)	160		160			
	Pole Inspections within Substations (# of Substations)	10	0	10			
Overhead	DGA	3354	0	3354	\$ 634,980	\$ 2,185,495	\$ 2,820,474
	SPdM	410	0	410			
	40kV Pole Top Switches	80	46	126			
	Dist Remote Devices	222	321	543			
	Towers	45	5	50			
	OH Cap & Reg Controls	4765	765	5530			
Underground	OH Dist Device Battery Replacement	325	92	417	\$ 254,735	\$ 1,879,189	\$ 2,133,923
	DECO Equipment in High Rise Stations	11	2	13			
	Primary Switch Cabinets	153	52	205			
	Manholes	715	592	1307			
	URD Padmounted Transformers	14561	34113	48674			
					\$ 2,317,447	\$ 4,982,553	\$ 7,300,000

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.176bi

Respondent: J. Robinson

Page: 1 of 1

Question: 176. Refer to Footnote 6 to Exhibit A-13, Schedule C5.6, pertaining to items sponsored by Mr. Robinson. Please: b. For Corrective Maintenance and System Cable Testing: i. Explain what these projects or programs entail, why they are necessary going forward, and how they are justified.

Answer: As stated in Witness Robinson's direct testimony on page JER-42, lines 4–12, the Corrective Maintenance ("CM") backlog includes damaged or defective electrical or structural system equipment that requires repair or replacement. The associated cost to address the CM backlog is also provided in that section.

For the System Cable Testing program, please refer to page JER-67, lines 2–22, of Witness Robinson's direct testimony, which outlines the program's scope, anticipated benefits, and forecasted costs.

Attachment: *None*

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-6.176bii

Respondent: J. Robinson

Page: 1 of 1

Question: 176. Refer to Footnote 6 to Exhibit A-13, Schedule C5.6, pertaining to items sponsored by Mr. Robinson. Please: b. For Corrective Maintenance and System Cable Testing: ii. Provide the amount spent on each item for each year 2021–2024 and forecasted for 2025 and 2026, along with the number of units, quantities, projects, or other metrics.

Answer: The line-item Corrective Maintenance, sponsored by Witness Robinson, reflects a proposed adjustment intended to address the existing backlog of corrective maintenance work. This adjustment is entirely forward-looking and does not represent any actual historical O&M expenditures. Consequently, there are no recorded O&M amounts for this item for the years 2021 through 2024, as the adjustment did not exist during those periods. Details of this proposal are provided in Witness Robinson’s direct testimony on page JER-42.

Similarly, the System Cable Testing program is a new initiative introduced in this case and does not include any historical O&M expenditures. Accordingly, there are no amounts reported for the years 2021 through 2024. There are also no expenditures planned for 2025. Forecasted expenditures and the number of circuits to be tested for 2026 through 2029 are outlined in Witness Robinson’s direct testimony on page JER-67.

Attachment: None

Exhibit AG-44

(Staking and Locating Expenses)

CONFIDENTIAL

MPSC Case No: U-21860

Requester: Staff

Question No.: STDE-4.1

Respondent: M. Guillaumin

Page: 1 of 1

Question: 1. Referring to Exhibit A-13 Schedules C5.1, C5.2, C5.3, C5.4, and C5.5, please provide information using 2024 as the historical test period incorporating historical and projected adjustments. Please provide in native format with formulas intact, such as in Excel.

Answer: Please see attachment labelled "U-21860 STDE-4.1 2024 O&M A-13 C5.1-C5.5".

Attachment: U-21860 STDE-4.1 2024 O&M A-13 C5.1-C5.5

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

Case No: U-21860
Exhibit: AG-45
August 22, 2025
Page 2 of 3

Discovery Response STDE-4.1

Michigan Public Service Commission DTE Electric Company Projected Operation and Maintenance Expenses Steam Power Generation (\$000)													Case No.: U-21860 Discovery Request STDE-4.1 Schedule: C5.1 Witness: M. E. Guillaumin	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
				Rate Case Adjustments					Projected Adjustments					
			1/1/24 - 12/31/24 Historical	Reclass Fuel Handling to O&M 2/	Reclass MERC Fuel Handling Non-O&M Expense 3/	Other Adjustments 4/	Historical	Adjusted Historical	1/1/24 - 12/31/24 Inflation Adj	1/1/25 - 12/31/25 Inflation Adj	1/1/26 - 12/31/26 Inflation Adj	Other	Total Projected	Projected
Line No.	Description	Account	Test Period				Normalizations 5/	Test Period	6/	6/	6/	Adjustments 7/	Adjustments	Test Period
1	Steam Power Generation							sum (c) thru (g)					sum (i) thru (l)	(h) + (m)
2	Operation													
3	Operation Supervision and Engineering	500	6,846	-	-		73	6,918	-	208	221	(409)	19	6,938
4	Fuel Handling	501	-	26,444	(5,868)		389	20,965	-	629	669	3,100	4,398	25,364
5	Steam Expenses	502	13,550	-	-		138	13,688	-	411	437	(775)	73	13,760
6	Steam from Other Sources	503	-	-	-		-	-	-	-	-	-	-	-
7	(Less) Steam Transferred-Cr.	504	-	-	-		-	-	-	-	-	-	-	-
8	Electric Expenses	505	2,105	-	-		92	2,197	-	66	70	(517)	(381)	1,816
9	Misc Steam Power Expenses	506	27,962	-	-	(159)	3,057	30,861	-	926	985	52	1,963	32,823
10	Rents	507	-	-	-		-	-	-	-	-	-	-	-
11	Total Operation Expense		50,463	26,444	(5,868)	(159)	3,748	74,629	-	2,239	2,383	1,451	6,072	80,701
12	Maintenance													
13	Maintenance Supervision and Engineering	510	87	-	-		51	138	-	4	4	-	9	147
14	Maintenance of Structures	511	6,056	-	-		2,073	8,128	-	244	260	676	1,179	9,308
15	Maintenance of Boilers	512	45,171	-	-		53	45,224	-	1,357	1,444	4,407	7,208	52,432
16	Maintenance of Electric Plant	513	7,938	-	-		(610)	7,327	-	220	234	625	1,079	8,407
17	Maintenance of Misc Steam Plant	514	35,301	-	-		7,982	43,283	-	1,299	1,382	8,218	10,899	54,182
18	Total Maintenance Expense		94,553	-	-	-	9,548	104,102	-	3,123	3,324	13,927	20,374	124,475
19	Total Steam Power Generation		145,017	26,444	(5,868)	(159)	13,296	178,730	-	5,362	5,707	15,377	26,446	205,176
20	Less Fuel Supply & MERC Fuel Handling	1/	2,171	11,295	(5,868)	-	-	7,598	-	228	243	(1,824)	(1,353)	6,244
21	Total Steam excluding Fuel Supply & MERC		142,846	15,149	-	(159)	13,296	171,133	-	5,134	5,464	17,201	27,799	198,932

Discovery Response STDE-4.1

Page 3 of 3

[illegible]

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Steam Power Generation
(\$000)

Exhibit AG-46
Case No.: U-21860
August 22, 2025
Page 1 of 1

Line No.	(a) Description	(b) Account	(c) 1/1/24 - 12/31/24 Historical Test Period	(d) Rate Case Adjustments			(g) Historical Normalizations 5/	(h) Adjusted Historical Test Period	(i) Projected Adjustments				(m) Total Projected Adjustments	(n) Projected Test Period
				(d) Reclass Fuel Handling to O&M 2/	(e) Reclass MERC Fuel Handling Non-O&M Expense 3/	(f) Other Adjustments 4/			(i) 1/1/24 - 12/31/24 Inflation Adj 6/	(j) 1/1/25 - 12/31/25 Inflation Adj 6/	(k) 1/1/26 - 12/31/26 Inflation Adj 6/	(l) Other Adjustments 7/		
1	Steam Power Generation							sum (c) thru (g)					sum (i) thru (l)	(h) + (m)
2	Operation													
3	Operation Supervision and Engineering	500	6,846	-	-	-		6,846	-	192	169	(409)	(48)	6,797
4	Fuel Handling	501	-	26,444	(5,868)	-		20,576	-	576	508	3,100	4,184	24,760
5	Steam Expenses	502	13,550	-	-	-		13,550	-	379	334	(775)	(61)	13,489
6	Steam from Other Sources	503	-	-	-	-		-	-	-	-	-	-	-
7	(Less) Steam Transferred-Cr.	504	-	-	-	-		-	-	-	-	-	-	-
8	Electric Expenses	505	2,105	-	-	-		2,105	-	59	52	(517)	(406)	1,699
9	Misc Steam Power Expenses	506	27,962	-	-	(159)		27,804	-	779	686	52	1,516	29,320
10	Rents	507	-	-	-	-	-	-	-	-	-	-	-	-
11	Total Operation Expense		50,463	26,444	(5,868)	(159)	-	70,880	-	1,985	1,749	1,451	5,184	76,064
12	Maintenance													
13	Maintenance Supervision and Engineering	510	87	-	-	-		87	-	2	2	-	5	92
14	Maintenance of Structures	511	6,056	-	-	-		6,056	-	170	149	676	995	7,051
15	Maintenance of Boilers	512	45,171	-	-	-		45,171	-	1,265	1,114	4,407	6,787	51,958
16	Maintenance of Electric Plant	513	7,938	-	-	-		7,938	-	222	196	625	1,043	8,981
17	Maintenance of Misc Steam Plant	514	35,301	-	-	-		35,301	-	988	871	8,218	10,077	45,379
18	Total Maintenance Expense		94,553	-	-	-	-	94,553	-	2,647	2,333	13,927	18,907	113,460
19	Total Steam Power Generation		145,017	26,444	(5,868)	(159)	-	165,434	-	4,632	4,082	15,377	24,091	189,524
20	Less Fuel Supply & MERC Fuel Handling	1/	2,171	11,295	(5,868)	-	-	7,598	-	228	243	(1,824)	(1,353)	6,244
21	Total Steam excluding Fuel Supply & MERC		142,846	15,149	-	(159)	-	157,836	-	4,404	3,839	17,201	25,444	183,280
22	Company Forecasted O&M Expense - Exhibit A-12, Schedule C5.1													197,831
23	Reduction in O&M Expense before Changes to Other Adjustments													(14,551)

1/ Reclassify Fuel Supply and MERC Fuel Handling sponsored by Witness Milo on Exh A-13, C5.2

2/ Reclassify Fuel Handling O&M charged to Fuel Account 501

3/ Portion of MERC Fuel Handling Charge that is reallocated to other line item classifications within net operating income (see Witness Milo's Exh A-13, C5.2)

4/ Historical Adjustments:

Account	Amount
Corporate Membership Adjustment	506
Total Historical Adjustments	(159)

5/ Normalization Adjustments:

	500,501,502,505,506,511,512,513,514,510, 511, 512,513,514	2,412	-
Economic Reserve			
Forced Outage Normalization	512,513,514	1,605	-
Excess and Obsolete adj	514	1,904	-
	510, 511, 512,513,514		
Periodic Outage Normalization		4,871	-
Sibley Tipping Fees for BESS projects	506		
		2,504	-
Total Normalization Adjustments		13,296	-

	1/1/24 - 12/31/24	1/1/25 - 12/31/25	1/1/26 - 12/31/26
6/ Annual Inflation Rate		2.80%	2.40%
No. of Months in Period	12	12	12
Pro-rated Inflation Rate	0.00%	2.80%	2.40%
(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)			

7/ Projected Adjustments

Account	Amount
VSIP Savings (sponsored by Witness Leslie)	501
VSIP Savings (sponsored by Witness Leslie)	506
SCPP and RRPP Environmental	506
Legacy CCR Environmental	506
BRPP Gas Conversion of Unit 1	500,501,502,505,506,511,512,513,514
BRPP U2 Turbine Support	
Structure Restoration	514
BRPP U1 Operational	511,512,513,514
MNPP Reliability Maintenance	511,512,513,514
MNPP Fuel Supply	
Maintenance for Post MERC	501

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.101a

Respondent: M. Guillaumin

Page: 1 of 1

Question: 101. Refer to lines 6–14 on page 122 of Ms. Guillaumin's direct testimony on the higher maintenance expense of the coal unloading system after MERC closes its operations in mid-2026. Please: a. Explain what the higher maintenance cost is for and why with MERC the higher maintenance was not necessary.

Answer: Please see discovery response STDE-4.9a attachment "U-21860 STDE-4.9a Exh A-13 Sched C5.1 Note 7 Support" tab labelled "MNPP FS Maint for Post MERC" and discovery response STDE-14.1b.

Attachment: None.

Discovery Response STDE-4.9a

Michigan Public Service Commission		Case No.:	U-21860
DTE Electric Company		Request No.:	STDE-4.9a
Operation and Maintenance Expenses		Respondent:	M. Guillaumin
Exhibit A-13 Sch. C5.1 Note 7 Adjustments -- MNPP Fuel Supply Maintenance for Post MERC		Page:	1 of 1
Equipment	Amount (\$M)	Description	
Monroe Coal Dumper Outage	3.294	Positioner, trunyon, gear rack overhaul during 2026 rail car dumper outage. Dumper reliability is critical after MERC retirement when all coal deliveries are by rail	

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-4.128c.ii

Respondent: M. Guillaumin

Page: 1 of 1

Question: 128. Refer to Exhibit A-13, Schedule 5.1, on O&M expenses for Steam Power Generation sponsored by Ms. Guillaumin. Please: c. Regarding Footnote 7: ii. Regarding the \$7,686,000 for Monroe Reliability Maintenance, please explain why these are incremental expenses for the projected test year and not routine maintenance items performed annually and in prior years. Provide the year when each of this type of maintenance was last performed and the amount spent.

Answer: Please see discovery responses STDE-4.9a, STDE-4.9b and STDE-14.1b.

Attachment: None.

Discovery Response STDE-4.9a

Michigan Public Service Commission			Case No.:	U-21860
DTE Electric Company			Request No.:	STDE-4.9a
Operation and Maintenance Expenses			Respondent:	M. Guillaumin
Exhibit A-13 Sch. C5.1 Note 7 Adjustments -- MNPP Reliability Maintenance			Page:	1 of 1
Equipment	Amount (\$M)	Description		
Monroe Sootblower PMs	2.196	Compliance to recommended schedule for sootblower preventative maintenance on all 4 units. Requires contracting and / or overtime to complete.		
Monroe Coal Mill Maintenance	1.208	Compliance to recommended schedule for coal mill 4K inspections on all 4 units. Required contracting all work.		
Monroe Polisher Resin Replacement	0.933	Replace polisher resin on 3/4 side.		
Monroe ID Fan Blade Restoration	1.373	Performing metal spray restoration on ID fans on all 4 units to maintain current reliability. Work performed during scheduled cleaning outages		
Monroe Equipment Cleanings	1.976	Backpass, transformer, air heater cleanings on all 4 units.		
Total	7.686			

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.103a

Respondent: M. Guillaumin

Page: 1 of 1

Question: 103. Refer to lines 11–21 on page 124 of Ms. Guillaumin’s direct testimony on the higher O&M expense for BVEC. Please: a. Provide the calculation in Excel and the basis and assumption used to determine the \$3.6 million in higher expense due to the periodic outage.

Answer: Please see discovery response STDE-4.12 attachment “U-21860 STDE-4.12 Exh A-13 Sched C5.5 Note 4 Support” tab labelled “BVEC Periodic”.

Attachment: None.

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.103b

Respondent: M. Guillaumin

Page: 1 of 1

Question: 103. Refer to lines 11–21 on page 124 of Ms. Guillaumin’s direct testimony on the higher O&M expense for BWEC. Please: b. Provide the number of days that the outage will last in 2026 and the amount of normal O&M expense that will not be incurred in 2026 due to the outage.

Answer: The outage is scheduled to be 44 days in 2026.

The Company does not project avoided O&M cost that result from a unit being in a periodic outage. O&M costs are expected to be higher during any periodic outage driven by work being performed on the unit while in an outage.

Attachment: None.

Discovery Response STDE-4.01

Page 3 of 7

Michigan Public Service Commission DTE Electric Company												Case No.: U-21860
Projected Operation and Maintenance Expenses											Discovery Request	STDE-4.1
Other Power Generation											Schedule:	C5.5
(\$000)											Witness:	M. E. Guillaumin
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
							Projected Adjustments					
			1/1/24 - 12/31/24 Historical Test Period	Rate Case Adjustments 1/	Historical Adjustments 2/	Adjusted Historical Test Period	1/1/24 - 12/31/24 Inflation Adj 3/	1/1/25 - 12/31/25 Inflation Adj 3/	1/1/26 - 12/31/26 Inflation Adj 3/	Other Adjustments 4/	Total Projected Adjustments	Projected Test Period
Line No.	Description	Account										
1	Other Power Generation					sum (c) thru (e)					sum (g) thru (j)	(f) + (k)
2	Operation											
3	Operation Supervision and Engineering	546	-	-	-	-	-	-	-	-	-	-
4	Generation Expenses	548	4,165	-	36	4,201	-	126	134	287	547	4,748
5	Misc Other Power Expenses	549	17,031	(14,438)	-	2,593	-	78	83	24	185	2,777
6	Rents	550	-	-	-	-	-	-	-	-	-	-
7	Total Operation Expense		21,196	(14,438)	36	6,793	-	204	217	311	732	7,525
8	Maintenance											
9	Maintenance Supervision and Engineering	551	-	-	-	-	-	-	-	-	-	-
10	Maintenance of Structures	552	-	-	-	-	-	-	-	-	-	-
11	Maintenance of Generating & Electric Plant	553	41,284	(26,668)	228	14,845	-	445	474	12,121	13,040	27,885
12	Maintenance of Misc Other Power Plant	554	2,051	-	92	2,143	-	64	68	794	927	3,070
13	Total Maintenance Expense		43,335	(26,668)	320	16,988	-	510	542	12,915	13,967	30,955
14	Power Supply Related Expenses											
15	Operation Supervision and Engineering	556	3,039	-	-	3,039	-	91	97	-	188	3,227
16	Generation Expenses	557	-	-	12	12	-	0	0	4	5	17
17	Total Expense		3,039	-	12	3,051	-	92	97	4	193	3,244
18	Total Other Power Generation Expenses		67,569	(41,106)	368	26,832	-	805	857	13,230	14,892	41,724
									1/1/24 - 12/31/24	1/1/25 - 12/31/25	1/1/26 - 12/31/26	
	1/ Rate Case Adjustments		Account	Amount			3/ Annual Inflation Rate			3.00%	3.10%	
	Eliminate Renewable Energy Program		549, 553	(41,106)			No. of Months in Period		12	12	12	
							Pro-rated Inflation Rate		0.00%	3.00%	3.10%	
	2/ Historical Adjustments:		Account	Amount			(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)					
	BWEC Routine Maintenance		548, 553, 554,557	368								
							4/ Other Adjustments				Account	Amount
							BWEC Normalization of Periodic Spend				548,553,554,557	3,562
							BESS Operation				553	1,226
							Peaker Increased Maintenance				553	8,605
							Retired Peakers				553	(163)
											13,233	

MPSC Case No: U-21860

Requester: Staff

Question No.: STDE-4.12

Respondent: M. Guillaumin

Page: 1 of 1

Question: 12. Referring to Exhibit A-13 Schedule C5.5, please provide a detailed explanation with supporting documentation and references for how the “Historical Adjustments” listed under footnote number 2 and the “Other Adjustments” listed under footnote number 4 were developed.

Answer: Please see attachments labelled “U-21860 STDE-4.12 Exh A-13 Sched C5.5 Note 2 Support” and “U-21860 STDE-4.12 Exh A-13 Sched C5.5 Note 4 Support”.

Attachment: U-21860 STDE-4.12 Exh A-13 Sched C5.5 Note 2 Support
U-21860 STDE-4.12 Exh A-13 Sched C5.5 Note 4 Support

Discovery Response STDE-4.12

Michigan Public Service Commission				Case No.:	U-21860
DTE Electric Company				Request No.:	STDE-4.12
Operation and Maintenance Expenses				Respondent:	M. Guillaumin
Exhibit A-13 Sch. C5.5 Note 2 Adjustments -- BWEC Routine Maintenance				Page:	1 of 1
Description	Amount				
2023 Warranty Claims (\$000)	\$565				
Estimated increase for future claims	30%				
Increase (\$000)	\$170				
Total (\$000)	\$735				
<u>FERC Account</u>	<u>548</u>	<u>553</u>	<u>554</u>	<u>557</u>	
% Allocated	10%	62%	25%	3%	
Amount (\$000)	\$70	\$456	\$185	\$24	

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

Case No: U-21860
Exhibit: AG-48
August 22, 2025
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Discovery Response STDE-4.12

Michigan Public Service Commission			Case No.:	U-21860
DTE Electric Company			Request No.:	STDE-4.12
Operation and Maintenance Expenses			Respondent:	M. Guillaumin
Exhibit A-13 Sch. C5.5 Note 4 Adjustments -- BWEC Normalization of Periodic Spend			Page:	1 of 1
Equipment	Category	Amount (\$000s)	Description	
Common	Common-Electrical	\$ 150	bus/breaker cleanings, PRC-005 relays	
	Common-Misc	\$ 200	PMs and minor correctives	
	Common-Shared Costs	\$ 766	CSG support, security, warehouse, Ops/Maint	
	Common-Water	\$ 195	CTWR screen and basin cleaning, CCW heat exchanger cleaning	
	<u>Common-Water Treatment</u>	\$ 100	RWS strainer cleaning	
Common Total		\$ 1,411		
CTG11	CTG 11-Electrical	\$ 150	bus/breaker cleanings, PRC-005 relays	
	CTG 11-Fuel	\$ 10	duct burner inspections	
	CTG 11-HRSG	\$ 209	Hot spots, inspections, I&C PMs	
	CTG 11-Misc	\$ 54	I&C PMs	
	CTG 11-Turbine	\$ 4,231	CSA cost, I&C PMs, equip operator, scaffold, insulation, electrician	
	CTG 11-Water	\$ 10	BFP motor testing and hydraulic coupling maint	
	CTG 11-Generator	\$ 215	Electrician, scaffold	
	<u>CTG 11-HEP</u>	\$ 478	HEP inspections, scaffold/insulation/trades for valves	
CTG11 Total		\$ 5,358		
CTG12	CTG 12-Electrical	\$ 150	bus/breaker cleanings, PRC-005 relays	
	CTG 12-Fuel	\$ 10	duct burner inspections	
	CTG 12-HRSG	\$ 209	Hot spots, inspections, I&C PMs	
	CTG 12-Misc	\$ 54	I&C PMs	
	CTG 12-Turbine	\$ 4,231	CSA cost, I&C PMs, equip operator, scaffold, insulation, electrician	
	CTG 12-Water	\$ 10	BFP motor testing and hydraulic coupling maint	
	CTG 12-Generator	\$ 215	Electrician, scaffold	
	<u>CTG 12-HEP</u>	\$ 478	HEP inspections, scaffold/insulation/trades for valves	
CTG12 Total		\$ 5,358		
STG1	STG1-Electrical	\$ 150	bus/breaker cleanings, PRC-005 relays	
	STG1-Generator	\$ 500	Generator inspection, scaffold and trade	
	STG1-HP/IP Turbine	\$ 100	vacuum leaks, oil leaks	
	STG1-LP Turbine	\$ 100	vacuum leaks, oil leaks	
	STG1-Turbine Valves	\$ 920	turbine valves	
	STG1-Water	\$ 50	Condenser inspection and cleaning	
	<u>STG1-HEP</u>	\$ 300	HEP inspections, scaffold/insulation/trades for valves	
STG1 Total		\$ 2,120		
Total Forecasted O&M for 2026 outage		\$ 14,247		
Outage Cadence			4 years	
Normalization periodic spend for BWEC		\$ 3,562		

Discovery Response STDE-4.12

Michigan Public Service Commission		Case No.:	U-21860
DTE Electric Company		Request No.:	STDE-4.12
Operation and Maintenance Expenses		Respondent:	M. Guillaumin
Exhibit A-13 Sch. C5.5 Note 4 Adjustments -- Peaker Increased		Page:	1 of 1
Equipment Description	Amount (\$000)	Work Description	
Renaissance Unit 2 Compressor	\$2,196	Blending compressor blade due to cracking / rolling of blade tip identified during borescope inspections. Cannot access without pulling the casing. Moderate reliability risk for blade tip liberation with continued operation.	
Dean Peakers Flex Seal Replacement	\$1,867	Turbine seal replacements. Leakage is occurring.	
Diesel Engine Rebuilds	\$1,373	Rebuild 8 diesel engines at high priority sites.	
Frame 7 Electrical	\$1,427	Transformer & bus maintenance to be performed on Frame 7 units.	
Tier 2 Unit Maintenance	\$1,098	Critical maintenance work on higher use Tier 2 peaking units.	
<u>Tier 1 Unit Maintenance</u>	<u>\$644</u>	Critical maintenance work on Tier 1 peaking units.	
Total	\$8,605		

Exhibit AG-49
U-21860
August 22, 2025
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		1/1/24 - 12/31/24	1/1/25 - 12/31/25	1/1/26 - 12/31/26
1/ Rate Case Adjustments	Account	Amount		
Eliminate Renewable Energy Program	549, 553	(41,106)		
			2.80%	2.40%
			12	12
			Pro-rated Inflation Rate	0.00%
				2.80%
				2.40%
2/ Historical Adjustments:	Account	Company Amount	AG Amount	
BWEC Routine Maintenance	548, 553, 554,557	368	-	
4/ Other Adjustments				Account
				Amount
				548,553,554,557
BWEC Normalization of Periodic Spend				3,562
BESS Operation				1,226
Peaker Increased Maintenance				553
Retired Peakers				553
				(163)
				13,230

Discovery Response STDE-4.1

MPSC Case No: U-21860

Requester: Staff

Question No.: STDE-4.1

Respondent: M. Guillaumin

Page: 1 of 1

Question: 1. Referring to Exhibit A-13 Schedules C5.1, C5.2, C5.3, C5.4, and C5.5, please provide information using 2024 as the historical test period incorporating historical and projected adjustments. Please provide in native format with formulas intact, such as in Excel.

Answer: Please see attachment labelled "U-21860 STDE-4.1 2024 O&M A-13 C5.1-C5.5".

Attachment: U-21860 STDE-4.1 2024 O&M A-13 C5.1-C5.5

Discovery Response STDE-4.1

Case No.:	U-21860
Discovery Request	STDE-4.1
Schedule:	C5.3
Witness:	J. C. Davis

Michigan Public Service Commission										Case No.: U-21860				
DTE Electric Company										Discovery Request STDE-4.1				
Projected Operation and Maintenance Expenses										Schedule: C5.3				
Nuclear Power Generation										Witness: J. C. Davis				
(\$000)														

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-1.36diii

Respondent: J. Davis

Page: 1 of 1

Question: 36. Refer to Exhibit A-13, Schedule C5.3, page 1, sponsored by Mr. Davis. Please: d. For the \$4,070,000 in footnote 3: iii. Provide the staffing levels by function or area at year end 2022, 2023, 2024, May 2025, and forecasted at year end 2025 and 2026 in Excel.

Answer: DTE Electric's Nuclear Generation staffing details for year-end 2022, 2023, 2024 is provided. DTE Electric projects Nuclear Generation staffing at 716 for year-end 2025. DTE Electric 2026 projected attrition is at the Business Unit level (i.e. Nuclear Generation); therefore, the year-end 2026 targeted staffing of 720 by organization is provided in the attachment.

Attachment: U-21860 AGDE-1.36d(iii)-01 NG Staffing 2022 – 2026.xlsx

Discovery Response AGDE-1.36diii

DTE Electric Company					Case No.: U-21860
Nuclear Generation					Response: AGDE-1.36d(iii)
Headcount Reconciliation					Witness: J.C. Davis
(a)	(b)	(c)	(d)	(e)	(f) (g)
	Actual Staffing				Projected Staffing
	2022	2023	2024	2025	2025 2026
	(as of 12/31)	(as of 12/31)	(as of 12/31)	(as of 5/31)	(as of 12/31) (as of 12/31)
Nuclear Generation Department					
Chemistry	19	17	19	20	20 21
Design Engineering	32	42	38	36	40 36
Engineering Staff	26	2	2	2	2 3
Information Management	10	7	7	7	7 7
Licensing	7	8	8	6	8 8
Maintenance	152	146	150	153	154 155
Nuclear Projects	18	11	12	12	11 12
Nuclear Support Staff	3	3	3	3	3 3
Operations	123	116	125	121	135 115
Outage & Work Management	23	24	23	22	23 26
Oversight	18	19	17	18	19 21
Performance Engineering	4	27	27	25	25 26
Performance Improvement	8	7	6	5	5 5
Production Staff	3	5	3	3	4 5
Radiation Protection	37	39	37	36	36 40
RERP	5	5	6	6	5 6
Security	155	148	141	144	137 145
Strategic Engineering	48	38	38	38	35 35
Strategic Planning	2	2	1	2	4 3
Training	45	40	42	42	40 45
Vice President Staff	3	3	3	2	3 3
Total Nuclear Generation staffing (DTE Electric employees)	741	709	708	703	716 720

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Nuclear Power Generation
(\$000)

Exhibit AG-51
U-21860
August 22, 2025
Page 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
				Rate Case Adjustments					Projected Adjustments						
Line No.	Description	Account	1/1/24 - 12/31/24 Historical Test Period	Nuclear Surcharge 1/	Reclassify PERC	Other Adjustments 2/	Normalization Adjustments 3/	Adjusted Historical Test Period	1/1/24 - 12/31/24 Inflation Adj 4/	1/1/25 - 12/31/25 Inflation Adj 4/	1/1/26 - 12/31/26 Inflation Adj 4/	Outage Accrual 5/	PERC Amortization 6/	Total Projected Adjustments	Projected Test Period
1	Nuclear Power Generation							sum (c) thru (g)						sum (i) thru (m)	(h) + (n)
2	Operation														
3	Operation Supervision and Engineering	517	12,086	(40)	(512)		-	11,535	-	323	285	-	-	608	12,143
4	Coolants and Water	519	4,399	-	-		-	4,399	-	123	109	-	-	232	4,631
5	Steam Expenses	520	3,252	(5,902)	543		-	(2,107)	-	(59)	(52)	(424)	-	(535)	(2,642)
6	Steam from Other Sources	521	-	-	-		-	-	-	-	-	-	-	-	-
7	(Less) Steam Transferred-Cr.	522	-	-	-		-	-	-	-	-	-	-	-	-
8	Electric Expenses	523	8,937	-	-		-	8,937	-	250	220	-	-	471	9,408
9	Misc Nuclear Power Expenses	524	67,797	(23,089)	(124)	(24)	-	44,559	-	1,248	1,099	-	-	2,347	46,906
10	Rents	525	-	-	-		-	-	-	-	-	-	-	-	-
11	Station Expense	562	166	-	-	-	-	166	-	5	4	-	-	9	175
12	Total Operation Expense		<u>96,637</u>	<u>(29,031)</u>	<u>(93)</u>	<u>(24)</u>	<u>-</u>	<u>67,490</u>	<u>-</u>	<u>1,890</u>	<u>1,665</u>	<u>(424)</u>	<u>-</u>	<u>3,131</u>	<u>70,620</u>
13	Maintenance														
14	Maintenance Supervision and Engineering	528	20,700	-	-		-	20,700	-	580	511	-	-	1,090	21,791
15	Maintenance of Structures	529	20,401	-	-		-	20,401	-	571	503	-	-	1,075	21,476
16	Maintenance of Reactor Plant Equipment	530	8,371	(0)	(10,028)		-	(1,657)	-	(46)	(41)	(1,271)	-	(1,358)	(3,015)
17	Maintenance of Electric Plant	531	20,737	(2)	(6,296)		-	14,440	-	404	356	-	-	761	15,200
18	Maintenance of Misc Nuclear Plant	532	15,350	-	(4,466)		-	10,884	-	305	269	-	-	573	11,457
19	Maintenance of station equipment	570	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Total Maintenance Expense		<u>85,560</u>	<u>(2)</u>	<u>(20,790)</u>	<u>-</u>	<u>-</u>	<u>64,768</u>	<u>-</u>	<u>1,814</u>	<u>1,598</u>	<u>(1,271)</u>	<u>-</u>	<u>2,140</u>	<u>66,909</u>
	PERC Regulatory Asset														
21	PERC Base Expense		-	-	15,000		-	15,000	-	-	-	-	-	-	15,000
22	Reg Asset Amortization-PERC		-	-	5,882	-	-	5,882	-	-	-	-	(4,258)	(4,258)	1,624
23	Total PERC Expense		<u>-</u>	<u>-</u>	<u>20,882</u>	<u>-</u>	<u>-</u>	<u>20,882</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>(4,258)</u>	<u>(4,258)</u>	<u>16,624</u>
24	Total Nuclear Power Generation		<u>182,197</u>	<u>(29,033)</u>	<u>-</u>	<u>(24)</u>	<u>-</u>	<u>153,140</u>	<u>-</u>	<u>3,703</u>	<u>3,263</u>	<u>(1,695)</u>	<u>(4,258)</u>	<u>1,013</u>	<u>154,153</u>
25	Company Forecasted 2026 Expense														159,998
26	Reduction in Expense														<u>(5,845)</u>

1/ Eliminate O&M expenses recovered separately in Nuclear Surcharge:			4/ Annual Inflation Rate			1/1/24 - 12/31/24	1/1/25 - 12/31/25	1/1/26 - 12/31/26
	Amount	Account	No. of Months in Period					
Site Security	(16,272)	524	Pro-rated Inflation Rate			12	12	12
						0.00%	2.80%	2.40%
Radiation Protection	(12,761)	517-520, 524, 530, 531						
	<u>(29,033)</u>							
2/ Excluded membership dues			5/ Outage Accrual Projection Adjustment:			Amount	Account	
	(24)	524	Outage Accrual Steam Expense			(424)	520	
			Outage Accrual Reactor Plant Maint.			(1,271)	530	
			Total Outage Accrual			<u>(1,695)</u>		
3/ Normalization Adjustments:								
	Amount	Account						
Staffing temporarily below long-term sustainable threshold	4,861	531						
	<u>4,861</u>							

6/ PERC (Performance Evaluation Review Committee) regulatory asset amortization sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.17

MPSC Case No: U-21860

Requester: Staff

Question No.: TMS-2.1 (S1)

Respondent: N. Foley

Page: 1 of 1

Question: Please provide exhibit A-13, schedule C5.9 updated with 2024 actual numbers.

Answer: Please see attachment “21860 TMS-2.1-01 Regulated Marketing 2024 O&M Actuals (Revised)” for requested information. The attachment included in the original response to this request contained an error that did not properly account for inflation.

Attachment: *U-21860 TMS-2.1-01 Regulated Marketing 2024 O&M Actuals (Revised)*

Discovery Response TMS-2.1

Page 2 of 4

Michigan Public Service Commission DTE Electric Company 2024 Operation and Maintenance Expenses Regulated Marketing (\$000)											MPSC Case No.: U-21860 Requester: Staff Question No: TMS-2.1 Respondent.: N. Foley Page: 1 of 1		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
							Projected Adjustments						
							1/1/25 - 12/31/25	1/1/26 - 12/31/26		Other			
Line No.	Description	Account	1/1/24 - 12/31/24	Other Adjustments 2/	Rate Case Normalizations 3/	Adjusted 2024	4/	4/	4/	5/	Total Projected Adjustments	Projected Test Period	
1	Customer Service and Informational Expenses					sum (c) thru (e)					sum (g) thru (j)	(f) + (k)	
2	Operation												
3	Supervision	907	412		264	677		20	22	-	42	719	
4	Customer Assistance Expenses	908	5,399	(105)	1,149	6,443	-	193	206	(616)	(217)	6,226	
5	Total Customer Service (Major Account Services)		5,812	(105)	1,413	7,119	-	214	227	(616)	(175)	6,944	
6	Sales Expenses												
7	Operation												
8	Supervision	911	2,821		(67)	2,754		83	88	-	171	2,925	
9	Demonstrating and Selling Expenses-DR 1/	912	4,465		-	4,465		134	143	3,801	4,077	8,542	
10	Demonstrating and Selling Expenses-Other	912	5,141		3,563	8,704		261	278	1,340	1,879	10,583	
11	Miscellaneous Sales-Charging Forward Amort	912	2,279		-	2,279	-	-	-	3,466	3,466	5,745	
12	Advertising Expenses	913	-		-	-	-	-	-	-	-	-	
13	Miscellaneous Sales-Other	916	-	-	-	-	-	-	-	-	-	-	
14	Total Sales Expenses		14,706	-	3,496	18,203	-	478	508	8,606	9,592	27,795	
15	Total Marketing Expense		20,518	(105)	4,909	25,322	-	691	736	7,990	9,417	34,740	
	1/ Demand Response is sponsored by Markus Leuker								1/1/25 - 12/31/25	1/1/26 - 12/31/26			
						4/ Annual Inflation Rate			3.00%	3.10%			
	2/ Excluded membership dues	908	(105)			No. of Months in Period			12	12			
						Pro-rated Inflation Rate			3.00%	3.10%			
	3/ Normalization Adjustments												
	Temporary 2024 Items						5/ Projection Adjustments (adjusted for amounts incurred in 2024):				Account	Amount	
	Clean Energy - Temporarily reduced customer outreach to promote clean energy adoption	912	3,563				Smart Savers (sponsored by Witness Leuker)				912	1,262	
	Temporarily deferred backfilling employees that left the company, which impacted the ability to fully meet customer expectations	907,908,911	1,346				SmartCharge (sponsored by Witness Leuker)				912	428	
							Cool Currents (sponsored by Witness Leuker)				912	840	
			4,909				Pilots and other projects (sponsored by Witness Leuker)				912	1,535	
							Subtotal Demand Response					4,066	
							Charging Forward Expansion (Sponsored by Witness Foley Exh. A-12 B5)				912	1,340	
							Charging Forward Reg Asset Amort (sponsored by Witness Uzenski Exh. A-12 B5)				912	3,466	
												8,871	
							VSIP Savings (sponsored by Witness Leslie)				908	(616)	
											912	(265)	
							Total Other Projection Adjustments					7,990	

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-3.81a

Respondent: N. Foley

Page: 1 of 1

Question: 81. Refer to page 41 of Mr. Foley's direct testimony on Regulated Marketing O&M expense. Please: a. Provide the number of employees and O&M expense pertaining to each bulleted item for each year 2021 to 2024 actual and forecasted for 2025 and 2026 in Excel.

Answer: See attachment "U-21860 AGDE-3.81a-01 Regulated Marketing O&M" for requested O&M expense data.

The Company does not capture the historical number of employees, nor does it forecast future number of employees, for the specific groups referenced in the request. As such it cannot provide the requested information. Please refer to Part 3 Att 6, page 3 for total historical and projected marketing headcount.

Attachment: *U-21860 AGDE-3.81a-01 Regulated Marketing O&M*

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric Company

Case No: U-21860
Exhibit: AG-52
August 22, 2025
Page 4 of 4

Discovery Response AGDE-3.81a

Michigan Public Service Commission							MPSC Case No.: U-21860
DTE Electric Company							Requestor: AG
Selected O&M Summary: 2021-2026							Question No.: AGDE-3.81a
(\$ in Thousands)							Respondent: N. Foley
	Actual				Forecast		
	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>	
Major Account Services	\$ 6,974	\$ 7,039	5,746	5,559	\$ 6,196	\$ 6,388	
Customer Marketing	2,803	2,173	2,514	4,865	5,011	5,167	
Demand Response	2,572	2,572	2,395	4,465	5,913	6,165	
Economic Development	454	601	341	253	445	497	
TEP/Charging Forward (O&M Only)	485	500	986	1,964	3,252	3,305	
Total	\$ 13,288	\$ 12,884	\$ 11,982	\$ 17,106	\$ 20,817	\$ 21,522	

Michigan Public Service Commission
DTE Electric Company
2024 Operation and Maintenance Expenses
Regulated Marketing
(\$000)

Exhibit AG-53
U-21860
August 22, 2025
Page 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
Line No.	Description	Account	1/1/24 - 12/31/24	Other Adjustments 2/	Rate Case Normalizations 3/	Adjusted 2024	Projected Adjustments				Total Projected Adjustments	Projected Test Period	
							1/1/25 - 12/31/25 Inflation 4/	1/1/26 - 12/31/26 Inflation 4/	Other Adjustments 5/				
1	Customer Service and Informational Expenses					sum (c) thru (e)					sum (g) thru (j)	(f) + (k)	
2	Operation												
3	Supervision	907	412			412		12	10	-	22	434	
4	Customer Assistance Expenses	908	5,399	(105)		5,294	-	148	131	(616)	(337)	4,957	
5	Total Customer Service (Major Account Services)		5,812	(105)	-	5,706	-	160	141	(616)	(315)	5,391	
6	Sales Expenses												
7	Operation												
8	Supervision	911	2,821			2,821		79	70	-	149	2,970	
9	Demonstrating and Selling Expenses-DR 1/	912	4,465			4,465		125	110	3,801	4,036	8,501	
10	Demonstrating and Selling Expenses-Other	912	5,141			5,141		144	127	1,340	1,610	6,752	
11	Miscellaneous Sales-Charging Forward Amort	912	2,279		-	2,279	-	-	-	3,466	3,466	5,745	
12	Advertising Expenses	913	-		-	-	-	-	-	-	-	-	
13	Miscellaneous Sales-Other	916	-	-	-	-	-	-	-	-	-	-	
14	Total Sales Expenses		14,706	-	-	14,706	-	348	307	8,606	9,261	23,967	
15	Total Marketing Expense		20,518	(105)	-	20,413	-	508	447	7,990	8,945	29,358	
Company Forecasted Expense for the projected test year												32,097	
Reduction in Expense for the projected test year												\$ (2,739)	
1/ Demand Response is sponsored by Markus Leuker													
							1/1/25 - 12/31/25		1/1/26 - 12/31/26				
							2.80%		2.40%				
2/ Excluded membership dues							12		12				
							2.80%		2.40%				
3/ Normalization Adjustments													
Temporary 2024 Items			Company Amount	AG Amount	5/ Projection Adjustments (adjusted for amounts incurred in 2024):							Account	Amount
Clean Energy - Temporarily reduced customer outreach to promote clean energy adoption			912	3,563	-	Smart Savers (sponsored by Witness Leuker)					912	1,262	
Temporarily deferred backfilling employees that left the company, which impacted the ability to fully meet customer expectations			907,908,911	-	-	SmartCharge (sponsored by Witness Leuker)					912	428	
						Cool Currents (sponsored by Witness Leuker)					912	840	
						Pilots and other projects (sponsored by Witness Leuker)					912	1,535	
						Subtotal Demand Response						4,066	
						Charging Forward Expansion (Sponsored by Witness Foley Exh. A-12 B5.9)					912	1,340	
						Charging Forward Reg Asset Amort (sponsored by Witness Uzenski Exh. A-					912	3,466	
												8,871	
						VSIP Savings (sponsored by Witness Leslie)					908	(616)	
											912	(265)	
						Total Other Projection Adjustments						7,990	

Uncollectible Accounts Expense
(Thousands of Dollars)

<u>Line</u>	<u>Caption or Description</u>	<u>Net Write- Off Amounts</u>	<u>Net Sales</u>	<u>% Charged Off & AG Projection (b) / (c)</u>	<u>Reference</u>
	(a)	(b)	(c)	(d)	
1	Total Year 2022	37,658	5,614,043	0.671%	See AGDE 4.117a Attchmt.
2	Total Year 2023	44,144	5,847,903	0.755%	See AGDE 4.117a Attchmt.
3	Total Year 2024	43,799	6,216,303	<u>0.705%</u>	See AGDE 4.117a Attchmt.
4	Avg. Percentage			0.710%	Avg. of Lines 1,2 & 3
5	Projected Test Year Revenues			<u>\$ 6,398,301</u>	See AGDE 4.117a Attchmt.
6	Total Uncollectible per AG (Excl. Amortization)			<u>\$ 45,433</u>	Line 4 x Line 5
7	Amortization of Low Income Pilot Bad Debts			<u>1,011</u>	See AGDE 4.117a Attchmt.
8	AG Uncollectible Estimate			<u>46,444</u>	Line 6 + 7
9	Uncollectible per DTE Electric in 2026			<u>48,030</u>	Ex. A-13, Sch. C5.8, line 15
10	<i>Increase in O&M Expense for Uncollectible Accounts Expense</i>			<u><u>\$ (1,586)</u></u>	Line 8 less Line 9

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Case No. U-21860
Exhibit AG-55
Date: August 22, 2025
Page 1 of 2

Administrative & General Expenses (\$000)

Administrative & General Expenses in O&M Determined for 2026							
Line	O&M Category or Description (a)	2024 Expense	Inflation (Co. Factors)		Other	Total	Notes / Commentary
		Normalized (b)	2025 (c)	2026 (d)	Changes (e)	2026 (f)	
1	<u>AG Projection of O&M Expenses</u>						
2	Admin. And General Salaries	\$ 112,721 *	\$ 3,156	\$ 2,781	\$ (2,390)	\$ 116,268	
3	Amort. Incentive Tracker (see page 2, Line 7)	-	-	-	(1,084)	(1,084)	
4	Office Supplies & Expense	59,345	1,662	1,464	7,230	69,701	
5	(Less) Administrative Trans. (Cr.)	(60,989)	(1,708)	(1,505)	-	(64,201)	
6	Outside Services Employed	25,027	701	617	-	26,345	
7	Property Insurance	5,296	148	131	-	5,575	
8	Injuries & Damages	16,338	-	-	-	16,338	
9	General Advertising Expenses	3,748	105	92	-	3,945	
10	Misc.. General Expenses	7,854	220	194	-	8,268	
11	Environmental Remediation	3,492	-	-	-	3,492	
12	Rents	3,977	111	98	-	4,186	
13	Total Operation Expense	176,809	4,395	3,873	3,756	188,833	Sum of lines 2 through 12
14	Maintenance	4,207	118	104	-	4,429	
15	Total Admin. & General O&M	\$ 181,016	\$ 4,513	\$ 3,977	\$ 3,756	\$ 193,262	Sub of lines 13 and 14
16	<u>Company Projection</u>					224,060	From Exhibit A-13, Sched. C5.10
17	<u>Reduced O&M Expenses for Admin. & General Expenses</u>					\$ (30,798)	Line 15 less Line 16

Col (b) From AGDE-4.127(a): 2024 Results in column (f)

Col (c) Amount for 2024 multiplied by inflation rate of 2.8%

Col (d) Combined result of columns (b) and (c) multiplied by Inflation of 2.4%

Col (e) From Exhibit A-13, Schedule C5.10 footnote 4 as follows

	(\$000)	
Federal Funds Compliance Adjustment		
VSIP Savings (25% of \$9.55M Company Estimate)	(2,390)	Per DR AGDE 1,5a headcount data, substantially all of the VSIP reductions were in March 2024
Incentive Tracker Amortization Amount	(1,084)	See page 2 of this exhibit
Maximo Software-shift from capital to O&M	7,230	
CTA Project	-	
Total	\$ 3,756	

* Column (b) for this item incorporates \$31.5M of "VSIP Costs to Achieve" (per footnote 2 of 2024 presentation in AGDE-4.127(a))

DTE Electric - Electric Rate Case

Exhibit AG-55
Date: August 22, 2025
Page 2 of 2

Administrative & General Expenses (\$000)
Incentive Compensation Tracker

<u>Line</u>	<u>Caption or Description</u> (a)	<u>AG Case</u> (b)	<u>Company Case</u> (c)	<u>Notes or Comments</u> (d)
1	2024 Incentive Compensation Dollar Potential	\$ 19,504	\$ 19,504	U-21297 Order page 233
2	Amount Related to 2024 Performance	11,507	14,633	See AG Payout Analysis below
3	Amount used to set customer rates	10,142	10,142	52% of Line1
4	Amount Exceeding Customer Rates	1,365	4,491	L2 less L3
5	Amortization per Year Over 5 Years	\$ 273	\$ 898	Line 4 / 5 years
6	Amortization of Amounts (pre 2024 layers)	(1,357)	(1,357)	See Exhibit A-13, Sched. C5.10.1, lines 4, 5 and 6
7	Amount to Admin. & General Expense	\$ (1,084)	\$ (459)	Line 5 less Line 6

AG's Payout Analysis

		<u>Payout %</u>	<u>Avg. Wtd % and Outcome</u>
AIP			
Metrics at Target or Better (Per Exh. AG-59)	14 of 23	100.0%	60.9%
REP			
Metrics at Target or Better (Per Exh. AG-59)	12 of 21	100.0%	57.1%
Average of Two Plans			59.0%
2024 Non Financial Metric Potential			\$ 19,504
Total Amount to Line 2			\$ 11,507

Note: The data supporting the Company's payout percentages was provided in ADGE-8.288

New Hire VEBA Expense

Thousands of Dollars

<u>Line</u>	<u>Caption or Description</u>	<u>2026 Estimate</u>	<u>Notes</u>
	(a)	(b)	(c)
1	Actual 2024 New Hire VEBA Expense	\$ 5,605	A
2	Annualized Historic Cost Growth (1.5% per year for 2025 & 2026) plus 1.0	<u>1.030</u>	B
3	Sub Total (L1 x L2)	5,773	
4	Projected Growth in Employee Population (1.7% per year for 2025 & 2026) plus 1.0	<u>1.034</u>	C
5	AG Estimate for New Hire VEBA (L3 x L4)	\$ 5,969	
6	Company Projection of New Hire VEBA	<u>7,777</u>	D
7	Reduction in New Hire VEBA Expense	<u>\$ (1,808)</u>	

A Per AGDE-4.115 a, Line 21

B Per AGDE 4.115 a far right column (under Total Costs) which increase 1.5% on average annually from 2020 to 2024

C Per AGDE 4.112 c showing employee population growth as shown below

D Per Company Exhibit A-13, Schedule C5.11

Employee Population Per Company

	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>	
DTE Electric	4,439	4,296	4,424	4,523	
DTE Corporate Services	<u>2,049</u>	<u>1,871</u>	<u>1,958</u>	<u>1,951</u>	
Total	<u>6,488</u>	<u>6,167</u>	<u>6,382</u>	<u>6,474</u>	
Average		<u>6,328</u>	<u>6,275</u>	<u>6,428</u>	<u>Shows 1.7% Annual Growth</u>

Active Healthcare
Thousands of Dollars

<u>Line</u>	<u>Caption or Description</u>	<u>2026 Estimate</u>	<u>Notes</u>
	(a)	(b)	(c)
1	Actual 2024 Active Healthcare	\$ 45,437	A
2	CPI Growth for 2025 (\$45.4M x 2.8%)	<u>1,272</u>	B
3	Sub Total (L1 + L2)	46,709	
4	CPI Growth for 2026 (\$46.7M x 2.4%)	<u>1,121</u>	B
5	Sub Total (L3 + L4)	47,830	
6	Projected Growth in Employee Population (1.7% per year or 3.4% x L 5))	<u>1,626</u>	C
7	AG Estimate for Active Healthcare (L5 + L6)	49,456	
8	Company Projection of Active Healthcare	<u>49,969</u>	D
9	Reduction in Active Healthcare Expense (L8 less L7)	\$ (513)	

- A Per AGDE-4.115 a, Line 21
B Per AGDE 4.115 a far right column (under Total Costs) which increase 1.5% on average annually from 2020 to 2024
C Per AGDE 4.112 c showing employee population growth as shown below
D Per Company Exhibit A-13, Schedule C5.11

Employee Population Per Company

	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>	
DTE Electric	4,439	4,296	4,424	4,523	
DTE Corporate Services	<u>2,049</u>	<u>1,871</u>	<u>1,958</u>	<u>1,951</u>	
Total	<u>6,488</u>	<u>6,167</u>	<u>6,382</u>	<u>6,474</u>	
Average		<u>6,328</u>	<u>6,275</u>	<u>6,428</u>	Shows 1.7% Annual Growth

MPSC Case No: U-21860

Requester: AG

Question No.: AGDE-8.255

Respondent: M. Fix

Page: 1 of 1

Question: 255. Refer to the response to AGDE-4.126 where the request was to expand Exhibit A-21, Schedule K7, to include 2024 results. The response references the attachment to response to AGDE-4.123a, which is not in the same format as Schedule K7.

Please provide an expanded Schedule K7 for pages 1 to 4 as requested in Excel.

Answer: Please see attachment entitled "U-21860 AGDE-8.255 AIPREP 2019 to 2024 Weighted Operating Results".

Attachment: U-21860 AGDE-8.255 AIPREP 2019 to 2024 Weighted Operating Results

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)
		AIP							AIP Executives							REP							
Line No	Description	2019	2020	2021	2022	2023	2024	Average	2019	2020	2021	2022	2023	2024	Average	2019	2020	2021	2022	2023	2024	Average	Combined Average
1	DTE Electric																						
2	Less than Threshold	4	3	4	2	6	2		4	3	4	2	6	2		4	3	4	2	6	2		
3	Between Threshold and Target	3	0	2	2	1	1		3	0	2	2	1	1		3	0	2	2	1	1		
4	Target	0	1	0	1	0	1		0	1	0	1	0	1		0	1	0	1	0	1		
5	Between Target and Maximum	4	6	3	3	1	3		4	6	3	3	1	3		2	5	2	2	0	2		
6	Maximum	2	4	0	1	1	1		2	4	0	1	1	1		2	4	0	1	1	1		
7		13	14	9	9	9	8		13	14	9	9	9	8		11	13	8	8	8	7		
8																							
9	Sum of Performance for all measures	1,124%	1,544%	483%	790%	389%	747%		1,124%	1,544%	483%	790%	425%	805%		774%	1,273%	366%	637%	238%	595%		
10																							
11	Average Performance	86.5%	110.3%	53.6%	87.8%	43.2%	93.4%	79.1%	86.5%	110.3%	53.6%	87.8%	47.2%	100.6%	81.0%	70.3%	97.9%	45.7%	79.6%	29.8%	85.0%	68.1%	
12																							
13	Nuclear Generation																						
14	Less than Threshold	3	1	2	4	4	3		3	1	2	4	4	3		3	1	2	3	4	3		
15	Between Threshold and Target	0	1	3	2	0	0		0	1	3	2	0	0		0	0	2	1	0	0		
16	Target	0	1	0	0	0	3		0	1	0	0	0	3		0	1	0	0	0	2		
17	Between Target and Maximum	3	1	1	0	2	2		3	1	1	0	2	2		3	1	1	0	1	2		
18	Maximum	2	3	1	2	2	0		2	3	1	2	2	0		0	3	1	3	2	0		
19		8	7	7	8	8	8		8	7	7	8	8	8		6	6	6	7	7	7		
20																							
21	Sum of Performance for all measures	803%	786%	550%	411%	593%	573%		8.025	7.864	5.499	4.107	657%	597%		433%	660%	432%	521%	413%	449%		
22																							
23	Average Performance	100.3%	112.3%	78.6%	51.3%	74.1%	71.6%	81.4%	100.3%	112.3%	78.6%	51.3%	82.1%	74.6%	83.2%	72.2%	110.0%	72.0%	74.5%	58.9%	64.1%	75.3%	
24																							
25	DTE LLC																						
26	Less than Threshold	5	5	3	1	6	2		5	5	3	1	6	2		5	5	3	1	6	2		
27	Between Threshold and Target	3	0	1	1	1	1		3	0	1	1	1	1		3	0	1	1	1	1		
28	Target	0	1	0	2	0	1		0	1	0	2	0	1		0	1	0	2	0	1		
29	Between Target and Maximum	4	6	4	3	1	3		4	6	4	3	1	3		3	5	3	2	0	2		
30	Maximum	5	5	0	1	0	0		5	5	0	1	0	0		4	5	0	1	0	0		
31		17	17	8	8	8	7		17	17	8	8	8	7		15	16	7	7	7	6		
32																							
33	Sum of Performance for all measures	1,631%	1,732%	533%	864%	222%	597%		16.313	17.323	5.331	8.635	235%	638%		1,207%	1,439%	404%	678%	88%	445%		
34																							
35	Average Performance	96.0%	101.9%	66.6%	107.9%	27.8%	85.3%	80.9%	96.0%	101.9%	66.6%	107.9%	29.4%	91.1%	82.2%	80.5%	90.0%	57.7%	96.9%	12.6%	74.1%	68.6%	
36																							
37	Total																						
38	Less than Threshold	12	9	9	7	16	7		12	9	9	7	16	7		12	9	9	6	16	7		
39	Between Threshold and Target	6	1	6	5	2	2		6	1	6	5	2	2		6	0	5	4	2	2		
40	Target	0	3	0	3	0	5		0	3	0	3	0	5		0	3	0	3	0	4		
41	Between Target and Maximum	11	13	8	6	4	8		11	13	8	6	4	8		8	11	6	4	1	6		
42	Maximum	9	12	1	4	3	1		9	12	1	4	3	1		6	12	1	5	3	1		
43		38	38	24	25	25	23		38	38	24	25	25	23		32	35	21	22	22	20		
44																							
45	Sum of Performance for all measures	3,558%	4,063%	1,566%	2,064%	1,204%	1,917%		3,558%	4,063%	1,566%	2,064%	1,316%	2,039%		2,414%	3,373%	1,202%	1,837%	0,739%	1488%		
46																							
47	Average Performance	93.6%	106.9%	65.2%	82.6%	48.1%	83.4%	80.0%	93.6%	106.9%	65.2%	82.6%	52.7%	88.7%	81.6%	75.4%	96.4%	57.2%	83.5%	33.6%	74.4%	70.1%	77.2%

		Performance Results														
Line No.	Measure	AIP						AIP Exec			REP					
		2019	2020	2021	2022	2023	2024	2022	2023	2024	2019	2020	2021	2022	2023	2024
1	Customer Satisfaction															
2	Net Promoter Score			0.0%	100.0%	0.0%	75.0%	100.0%	0.0%	75.0%			0.0%	100.0%	0.0%	83.3%
3																
4	Customer Satisfaction Index	80.1%	0.0%								86.8%	0.0%				
5																
6	Customer Satisfaction Improvement Program	96.9%	175.0%								97.9%	150.0%				
7																
8	Customer Satisfaction Improvement Program (+1PMO)	0.0%	0.0%								0.0%	0.0%				
9																
10	MPSC Customer Complaints	36.5%	175.0%	0.0%	81.8%	0.0%		81.8%	0.0%		57.7%	150.0%	0.0%	87.9%	0.0%	
11																
12	Employee Engagement															
13	DTE Electric Employee Engagement-Gallup	157.7%	134.6%	134.1%	134.6%	131.6%	105.0%	146.2%	142.1%	106.7%						
14																
15	DTE Electric OSHA Recordable Incident Rate	0.0%	175.0%	95.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	150.0%	97.1%	0.0%	0.0%	0.0%
16																
17	DTE Electric OSHA DART Rate	0.0%	129.4%	0.0%							0.0%	119.6%	0.0%			
18																
19	DTE Energy High Energy Serious Injury or Fatality				125.0%	0.0%	100.0%	133.3%	0.0%	100.0%				116.7%	0.0%	100.0%
20																
21	DTE Electric National Safety Council Barometer Survey	156.3%														
22																
23	Operating Excellence															
24	Customers experiencing multiple interruptions (CEMI)		0.0%		135.5%	0.0%	162.1%	147.3%	0.0%	182.8%		0.0%		123.6%	0.0%	141.4%
25																
26	SAIDI Excluding MEDs	0.0%	135.0%	105.4%	0.0%	82.5%		0.0%	82.5%		0.0%	123.3%	103.6%	0.0%	88.3%	
27																
28	Blue Sky CAIDI	125.0%	113.6%	25.0%							116.7%	109.1%	50.0%			
29																
30	Storm Customers Restored in 48 Hours	175.0%					130.0%			140.0%	150.0%					120.0%
31																
32	Tree Trimming Mileage	121.6%	116.7%								114.4%	111.1%				
33																
34	Generation Availability				38.2%	175.0%	175.0%	38.2%	200.0%	200.0%				58.8%	150.0%	150.0%
35																
36	Fossil Random Outage Factor	175.0%	175.0%	122.5%							150.0%	150.0%	115.0%			
37																
38	Wind Time-Based Availability		100.0%									100.0%				
39																
40	Nuclear Unit Capability Factor/ORLF (UCF)		115.0%	0.0%	175.0%	0.0%	0.0%	200.0%	0.0%	0.0%		110.0%	0.0%	150.0%	0.0%	0.0%
41																

DTE Electric Company
Case No. U-21860
AGDE-8.255 'AIP and REP Operating Measure Results: 2019-2024
Nuclear Generation

Line No.	Measure	Performance Results														
		AIP						AIP Exec			REP					
		2019	2020	2021	2022	2023	2024	2022	2023	2024	2019	2020	2021	2022	2023	2024
1	Employee Engagement															
2	DTE Electric Employee Engagement-Gallup	146.2%	46.4%	89.3%	35.7%	123.7%	100.0%	35.7%	131.6%	100.0%						
3																
4	Nuclear Total Industrial Safety Accident Rate	0.0%	175.0%	75.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	150.0%	75.0%	0.0%	0.0%	0.0%
5																
6	DTE Electric OSHA Recordable Incident Rate	0.0%	175.0%	95.6%	0.0%	0.0%		0.0%	0.0%		0.0%	150.0%	97.1%	0.0%	0.0%	
7																
8	DTE Energy High Energy Serious Injury or Fatality (HSIF)						100.0%			100.0%						100.0%
9																
10	DTE Electric National Safety Council Barometer Survey	156.3%														
11																
12	Nuclear On-Line Radiation Exposure					0.0%	135.4%		0.0%	147.1%					0.0%	123.6%
13																
14	Operating Excellence															
15	Nuclear Power Plant Unit Capability Factor/ORLF	175.0%	115.0%	0.0%	175.0%	0.0%	0.0%	200.0%	0.0%	0.0%	150.0%	110.0%	0.0%	150.0%	0.0%	0.0%
16																
17	Nuclear Annualized Work Management Index			0.0%	175.0%	175.0%		200.0%	200.0%				0.0%	150.0%	150.0%	
18																
19	Nuclear Radiation Protection Index			115.0%	25.0%			25.0%					110.0%	150.0%		
20																
21	Nuclear Equipment and Human Error Consequential Events	0.0%					100.0%			100.0%	0.0%					100.0%
22																
23	Nuclear Power Plant Performance Improvement Matrix	150.0%	100.0%								133.3%	100.0%				
24																
25	Nuclear Power Plant Reliability Matrix	175.0%									150.0%					
26																
27	Nuclear Power Plant Refuel Outage Matrix		0.0%		0.0%		137.5%	0.0%		150.0%		0.0%		0.0%		125.0%
28																
29	Nuclear Power Plant Safety Culture Matrix		175.0%									150.0%				
30																
31	Nuclear Power Plant Operational Focus Performance			175.0%	0.0%	118.8%	0.0%	0.0%	125.0%	0.0%			150.0%	71.3%	112.5%	0.0%
32																
33	Nuclear Refuel Outage Milestone Completion					175.0%			200.0%						150.0%	
34																
35	Sum of Performance	8.025	7.864	5.499	4.107	5.925	5.729	4.607	6.566	5.971	4.333	6.6	4.321	5.213	4.125	4.486
36																
37	Number of Measures	8	7	7	8	8	8	8	8	8	6	6	6	7	7	7
38																
39	Average	100.3%	112.3%	78.6%	51.3%	74.1%	71.6%	57.6%	82.1%	74.6%	72.2%	110.0%	72.0%	74.5%	58.9%	64.1%
35																
36																
37																
38																
39	Less than Threshold	3	1	2	4	4	3	4	4	3	3	1	2	3	4	3
40	Between Threshold and Target	0	1	3	2	0	0	2	0	0	0	0	2	1	0	0
41	Target	0	1	0	0	0	3	0	0	3	0	1	0	0	0	2
42	Between Target and Maximum	3	1	1	0	2	2	0	2	2	3	1	1	0	1	2
43	Maximum	2	3	1	2	2	0	2	2	0	0	3	1	3	2	0
44		8	7	7	8	8	8	8	8	8	6	6	6	7	7	7
45																
46	Sum	8.025	7.864	5.499	4.107	5.925	5.729	4.607	6.566	5.971	4.333	6.6	4.321	5.213	4.125	4.486
47																
48	Number of Measures	8	7	7	8	8	8	8	8	8	6	6	6	7	7	7
49																
50	Average	100.3%	112.3%	78.6%	51.3%	74.1%	71.6%	57.6%	82.1%	74.6%	72.2%	110.0%	72.0%	74.5%	58.9%	64.1%

DTE Electric Company
Case No. U-21860
AGDE-8.255 'AIP and REP Operating Measure Results: 2019-2024
LLC

Line No.	Measure	Performance Results														
		AIP						AIP Exec			REP					
		2019	2020	2021	2022	2023	2024	2022	2023	2024	2019	2020	2021	2022	2023	2024
1	Customer Satisfaction															
2	Net Promoter Score			0.0%	100.0%	0.0%	75.0%	100.0%	0.0%	75.0%			0.0%	100.0%	0.0%	83.3%
3																
4	Customer Satisfaction Index	80.1%	0.0%								86.8%	0.0%				
5																
6	Customer Satisfaction Improvement Program	96.9%	175.0%								97.9%	150.0%				
7																
8	Customer Satisfaction Improvement Program (+1PMO)	0.0%	0.0%								0.0%	0.0%				
9																
10	MPSC Customer Complaints	36.5%	175.0%	0.0%	81.8%	0.0%		81.8%	0.0%		57.7%	150.0%	0.0%	87.9%	0.0%	
11																
12	Employee Engagement															
13	DTE Energy Employee Engagement-Gallup	146.2%	123.1%	127.3%	146.2%	139.5%	130.0%	161.5%	152.6%	140.0%						
14																
15	DTE Energy OSHA Recordable Incident Rate	0.0%	175.0%	120.8%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	150.0%	113.9%	100.0%	0.0%	0.0%
16																
17	DTE Energy OSHA DART Rate	0.0%	153.9%	57.1%							0.0%	135.9%	71.4%			
18																
19	DTE Energy High Energy Serious Injury or Fatality				125.0%	0.0%	100.0%	133.3%	0.0%	100.0%			116.7%	0.0%	100.0%	
20																
21	National Safety Council Barometer Survey	175.0%														
22																
23	Operating Excellence															
24	Customers experiencing multiple interruptions (CEMI)		0.0%		135.5%	0.0%	162.1%	147.3%	0.0%	182.8%		0.0%		123.6%	0.0%	141.4%
25																
26	SAIDI Excluding MEDs	0.0%	135.0%	105.4%	0.0%	82.5%		0.0%	82.5%		0.0%	123.3%	103.6%	0.0%	88.3%	
27																
28	Blue Sky CAIDI	125.0%	113.6%								116.7%	109.1%				
29																
30	Storm Customers Restored in 48 Hours	175.0%					130.0%			140.0%	150.0%					120.0%
31																
32	Tree Trimming Mileage	121.6%	116.7%								114.4%	111.1%				
33																
34	Fossil Random Outage	175.0%	175.0%	122.5%							150.0%	150.0%	115.0%			
35																
36	Wind Time-Based Availability		100.0%									100.0%				
37																
38	Nuclear Unit Capability Factor/ORLF	175.0%	115.0%	0.0%	175.0%	0.0%	0.0%	200.0%	0.0%	0.0%	150.0%	110.0%	0.0%	150.0%	0.0%	0.0%
39																
40	Nuclear RFO Unplanned Risk Color Change		175.0%									150.0%				
41																
42	Nuclear RFO Dose		0.0%									0.0%				
43																
44	Nuclear RFO Duration		0.0%									0.0%				
45																
46	Nuclear Power Plant Performance	0.0%										0.0%				
47																
48	Nuclear Power Plant Performance Improvement Matrix	150.0%										133.3%				
49																
50	Nuclear Power Plant Reliability Matrix	175.0%										150.0%				
51																
52	Sum of Performance	1,631%	1,732%	533%	864%	222%	597%	924%	235%	638%	1,207%	1,439%	404%	678%	88%	445%
53																
54	Number of Measures	17	17	8	8	8	7	8	8	7	15	16	7	7	7	6
55																
56	Average	96.0%	101.9%	66.6%	107.9%	27.8%	85.3%	115.5%	29.4%	91.1%	80.5%	90.0%	57.7%	96.9%	12.6%	74.1%
57																
58																
59																
60																
61																
	Less than Threshold	5	5	3	1	6	2	1	6	2	5	5	3	1	6	2
	Between Threshold and Target	3	0	1	1	1	1	1	1	1	3	0	1	1	1	1
	Target	0	1	0	2	0	1	2	0	1	0	1	0	2	0	1
	Between Target and Maximum	4	6	4	3	1	3	3	1	3	3	5	3	2	0	2
	Maximum	5	5	0	1	0	0	1	0	0	4	5	0	1	0	0
		17	17	8	8	8	7	8	8	7	15	16	7	7	7	6
	Sum	16.31	17.32	5.33	8.64	2.22	5.97	9.24	2.35	6.38	12.07	14.39	4.04	6.78	0.88	4.45
	Number of Measures	17	17	8	8	8	7	8	8	7	15	16	7	7	7	6
	Average	96.0%	101.9%	66.6%	107.9%	27.8%	85.3%	115.5%	29.4%	91.1%	80.5%	90.0%	57.7%	96.9%	12.6%	74.1%

MICHIGAN PUBLIC SERVICE COMMISSION
DTE Electric - Electric Rate Case

Exhibit AG-59
Case No. U-21860
Date: August 22, 2025
Page 1 of 1

O & M Summary - 2020 to 2024 Incentive Compensation Metrics

Line No.		AIP					AIP Executives						REP					Combined Average		
		2020	2021	2022	2023	2024	AVG	2020	2021	2022	2023	2024	AVG	2020	2021	2022	2023	2024	AVG	
1	DTE Electric*																			
2	Less Than Threshold	3	4	2	6	2		3	4	2	6	2		3	4	2	6	2		
3	Btw. Threshold & Target	0	2	2	1	1		0	2	2	1	1		0	2	2	1	1		
4	Target	1	0	1	0	1		1	0	1	0	1		1	0	1	0	1		
5	Btw. Target & Maximum	6	3	3	1	3		6	3	3	1	3		5	2	2	0	2		
6	Maximum	4	0	1	1	1		4	0	1	1	1		4	0	1	1	1		
7		14	9	9	9	8		14	9	9	9	8		13	8	8	8	7		
8	Nuclear Generation*																			
9	Less Than Threshold	1	2	4	4	3		1	2	4	4	3		1	2	3	4	3		
10	Btw. Threshold & Target	1	3	2	0	0		1	3	2	0	0		0	2	1	0	0		
11	Target	1	0	0	0	3		1	0	0	0	3		1	0	0	0	2		
12	Btw. Target & Maximum	1	1	0	2	2		1	1	0	2	2		4	2	3	3	2		
13	Maximum	3	1	2	2	0		3	1	2	2	0		0	0	0	0	0		
14		7	7	8	8	8		7	7	8	8	8		6	6	7	7	7		
15	DTE LLC*																			
16	Less Than Threshold	5	3	1	6	2		5	3	1	6	2		5	3	1	6	2		
17	Btw. Threshold & Target	0	1	1	1	1		0	1	1	1	1		0	1	1	1	1		
18	Target	1	0	2	0	1		1	0	2	0	1		1	0	2	0	1		
19	Btw. Target & Maximum	6	4	3	1	3		6	4	3	1	3		5	3	2	0	3		
20	Maximum	5	0	1	0	0		5	0	1	0	0		5	0	1	0	0		
21		17	8	8	8	7		17	8	8	8	7		16	7	7	7	7		
22	Total*																			
23	Less Than Threshold	9	9	7	16	7		9	9	7	16	7		9	9	6	16	7		
24	Btw. Threshold & Target	1	6	5	2	2		1	6	5	2	2		0	5	4	2	2		
25	Target	3	0	3	0	5		3	0	3	0	5		3	0	3	0	4		
26	Btw. Target & Maximum	13	8	6	4	8		13	8	6	4	8		14	7	7	3	7		
27	Maximum	12	1	4	3	1		12	1	4	3	1		9	0	2	1	1		
28		38	24	25	25	23		38	24	25	25	23		35	21	22	22	21		
29																				
30	Measures at Target and Above																			
31	Target	3	0	3	0	5		3	0	3	0	5		3	0	3	0	4		
32	Btw. Target & Maximum	13	8	6	4	8		13	8	6	4	8		14	7	7	3	7		
33	Maximum	12	1	4	3	1		12	1	4	3	1		9	0	2	1	1		
34	Total at Target & Above	28	9	13	7	14		28	9	13	7	14		26	7	12	4	12		
35																				
36																				
37	Total Measures	38	24	25	25	23		38	24	25	25	23		35	21	22	22	21		
38																				
39	% at Target & Above	73.7%	37.5%	52.0%	28.0%	60.9%	50.4%	73.7%	37.5%	52.0%	28.0%	60.9%	50.4%	74.3%	33.3%	54.5%	18.2%	57.1%	47.5%	49.4%

* Information source is Exhibit A-21, Schedule K7, page 1

Incentive Compensation Exclusion from O&M expense
(\$000)

<u>Line</u>	<u>Caption or Description of Item</u> (a)	<u>\$Thousands</u> <u>Amount</u> (b)	<u>Reference</u> (c)
1	Financial Metric Related Incentive Compensation - Disallowed	\$ 35,838	Note 1
2	Operational Metrics Compensation - Disallowed	<u>10,389</u>	Note 2
3	Total O&M Reduction	<u>\$ 46,227</u>	
1	See page 39 of witness Fix's testimony		
2	Determined as follows		
	Operational Metric Incentive Compensation (p. 39 of Fix testimony)	\$ 20,531	
	Portion to Defer for later recovery (100% less 49.4% per Exhibit AG-59).	<u>50.60%</u>	
	Amount to Defer (\$20,531 x 52.6%)	<u>\$ 10,389</u>	
3	Over-recovery of 2023 Incentive Compensation of \$6.792K x 20% per Exhibit AG-WC1		

Computation of Revenue Deficiency for Projected Test Year 2026

(\$000)

Line	Description (a)	Company Filed Amount (b)	AG Recommended Adjustments (c)	Revised Amount (d)
1	Rate Base ⁽¹⁾	\$ 23,560,071	\$ (551,955)	\$ 23,008,117
2	Rate of Return	6.03%	-0.42%	5.61%
3	Income Required	\$ 1,419,871	\$ (129,116)	\$ 1,290,755
4	Adjusted Net Operating Income ⁽²⁾	1,107,875	173,659	1,281,534
5	Income Deficiency (Sufficiency)	\$ 311,996	\$ (302,775)	\$ 9,221
6	Revenue Multiplier	1.3496	1.3496	1.3496
7	Revenue Deficiency (Sufficiency)	421,081	\$ (408,636)	12,445
8	Return On - Tree Trim Surge Program	11,916	(6,988)	4,928
9	Return On - Monroe Regulatory Asset	141,070	-	141,070
10	Revenue Deficiency (Sufficiency) - Total	\$ 574,067	\$ (415,624)	\$ 158,443

⁽¹⁾ Rate Base Adjustments Exhibit AG-20

⁽²⁾ AG adjustments to Operating Income - Increase (Decrease):

		Source
O&M Expenses	203,572	Exhibit AG-39
Property Tax	9,005	Exhibit AG-20
Depreciation Expense	24,706	Exhibit AG-20
Total	\$ 237,283	
Effective Tax Rate (1-1/1.3496)	25.91%	
Taxes	(61,470)	
Interest Synchronization on Capital Adjustments	(2,153)	RevDef-WP1
Adjusted Net Operating Income	\$ 173,659	

Michigan Public Service Commission
DTE Electric Company
Tree Trim Regulatory Asset - Return On
Projected 12 Month Period Ending December 31 , 2026
(\$000)

Case No.: U-21860
Exhibit: AG-62
August 22, 2025
Page: 1 of 1

AG Revised Return for Short-Term Debt

Line No.	(a) Description	(b) Test Period Amount	(c) Reference
1	<u>Return on Tree Trim Regulatory Asset</u>		
2	Average Balance Regulatory Asset	170,100	Line 16
3	Deferred Tax Liability	<u>(44,056)</u>	- Line 2 x 25.9% Composite Tax Rate
4	Average Net Rate Base	126,044	
5	Authorized Rate of Return on Permanent Capital (pretax)	3.91%	Exhibit A-14, Schedule D1
6	Return on Tree Trim	<u>4,928</u>	

PROOF OF SERVICE - U-21860

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 22nd day of August 2025

Joel King
Joel B. King

DTE Electric Company:

Jon Christinidis
John Janiszewski
Carlton Watson
Breanne Reitzel
Andrea Hayden
Jon.christinidis@dteenergy.com
John.janiszewski@dteenergy.com
Carlton.watson@dteenergy.com
Breanne.reitzel@dteenergy.com
Andrea.hayden@dteenergy.com
Mpscfilings_account@dteenergy.com

Attorney General of Michigan:

Joel King
Lucas Wollenzien
Kingj38@michigan.gov
wollenzienl@michigan.gov
ag-enra-spec-lit@michigan.gov

Sebastian Coppola
Paul Alvarez
Dennis Stephens
sebcoppola@corplytics.com
palvarez@wiredgroup.net
dennis.stephens@hotmail.com

Rick Bunch
Julielyn Gibbons
Douglas Jester
rbunch@5lakesenergy.com
jgibbons@5lakesenergy.com
djester@5lakesenergy.com

ALJ:

Hon. Sally Wallace
Wallaces2@michigan.gov

ELPC/EC/UCC/VS (CEO):

Daniel Abrams
Katie Toolan
Alondra Estrada
Brad Klein
Curt Volkmann
Katie Duckworth
dabrams@elpc.org
ktoolan@elpc.org
aestrada@elpc.org
bklein@elpc.org
curt@newenergy-advisors.com
Kduckworth@elpc.org
MPSCDocket@elpc.org

Boroatha Tan
James Gignac
Lee Shaver
William Kenworthy
btan@votesolar.org
jgignac@ucsusa.org
lshaver@ucsusa.org
will@votesolar.org

MEC/NRDC/SC/CUB (MNSC):

Tracy Jane Andrews
Christopher Bzdok
Holly Hillyer
Natasha Fowles
tjandrews@tropospherelegal.com
chris@tropospherelegal.com
holly@tropospherelegal.com
natasha@tropospherelegal.com
service@5lakesenergy.com

MPSC Staff:

Lori Mayabb
Heather Durian
Monica Stephens
Anna Stirling
Adam Cozort
mayabbl@michigan.gov
durianh@michigan.gov
stephensm11@michigan.gov
stirlinga1@michigan.gov
cozort1@michigan.gov
BoutetR@michigan.gov
DuellJ@michigan.gov
DurfeeA1@michigan.gov
EvansN@michigan.gov
ShiJ@michigan.gov

City of Ann Arbor:

Valerie Jackson
vjackson@a2gov.org

Electrify America:

Krystal Hermiz
Stephen Bright
Jigar Shah
Jeremy Wiley
khermiz@grsm.com
steve.bright@electrifyamerica.com
jigar.shah@electrifyamerica.com
extern.jeremy.wiley@electrifyamerica.com

MI-MAUI/PROTEC:

Michael Watza
Nathan Inks
Tonya Voakes
Mike@bloomsluggett.com
nathan@bloomsluggett.com
tonya@bloomsluggett.com

MCTA:

Sean Gallagher
Jon Austin
sgallagher@fraserlawfirm.com
jaustin@fraserlawfirm.com

FA/EM/MEIBC/IEI/AEU (MEIU):

Laura Chappelle
Timothy Lundgren
Justin Ooms
Lydia Lubbers
lachappelle@varnumlaw.com
tjlundgren@varnumlaw.com
jkooms@varnumlaw.com
lydiamlubbers@varnumlaw.com

GLREA:

Don Keskey
donkeskey@publiclawresourcecenter.com

UWUA Local 223

Richard Mack, Jr.
Jacob Porcarelli
Susan Brohman
Adrienne Mack
richardmack@millercohen.com
jporcarelli@millercohen.com
sbrohman@millercohen.com
amack@millercohen.com

Walmart, Inc.:

Melissa Horne
mhorne@hcc-law.com

Soulardarity:

Jacob Schuhardt
Amanda Urban
Mark Templeton
Madison Wilson
jschuhardt@uchicago.edu
aurbanlaw@gmail.com
templeton@uchicago.edu
aelc_mpsc@lawclinic.uchicago.edu
madisonswilson@uchicago.edu

The Kroger Co.

Kurt Boehm
Jody Kyler Cohn
Michael Kurtz
Justin Bieber
Rebecca Forbes
Jason Kiengsiri
Jared Robertson
kboehm@bkllawfirm.com
jkyleercohn@bkllawfirm.com
mkurtz@bkllawfirm.com
jbieber@energystrat.com
rforbes@energystrat.com
jkiengsiri@energystrat.com
jrobertson@energystrat.com

Gerdau MacSteel, Inc.

Jennifer Utter Heston
jheston@fraserlawfirm.com

ITC:

Richard Aaron
Courtney Kissel
Olivia Flower
Hannah Buzolits
raaron@dykema.com
ckissel@dykema.com
oflower@dykema.com
hbuzolits@dykema.com
MPSCFilings@dykema.com

ABATE:

Michael Pattwell
Stephen Campbell
Benjamin Holwerda
James Dauphinais
Jessica York
Christina Hildebrandt
mpattwell@clarkhill.com
scampbell@clarkhill.com
bholwerda@clarkhill.com
jdauphinais@consultbai.com
jyork@consultbai.com
childebrandt@consultbai.com