STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21981

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for the)
distribution of natural gas and other relief)

PUBLIC

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of
Attorney General Dana Nessel

April 15, 2026

TABLE OF CONTENTS

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 located at 5928 Southgate Rd., Rochester, Michigan 48306.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

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

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

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

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2024-2025 GCR reconciliation in case No. U-21440.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2025 gas rate case U-21973 on several issues, including revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric (DTEE) 2024 PSCR reconciliation in Case N-U-21426.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) proposed sale of hydroelectric power generating assets in Case No. U-21985.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2024-2025 GCR plan reconciliation in Case No. U-21446.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2024 PSCR reconciliation in Case N-U-21424.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2025 electric rate case U-21870 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 2025 electric rate case U-21860 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 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 DTEE 2023 PSCR Plan Case No. U-21594.
- Filed testimony on behalf of the Michigan Attorney General in 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.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 PSCR reconciliation in case No. U-21260.

- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR reconciliation in case No. U-21270.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan reconciliation in case No. U-21278.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21258.
- Filed testimony on behalf of the Michigan Attorney General in CECo 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 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.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Michigan Department of Attorney General to perform an independent analysis of Consumers Energy Company's (CECo or the Company) gas rate case filing in Case No. U-21981. This testimony presents a report of that analysis with related recommendations.

Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?

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

1. The level of proposed rate base and capital expenditures
2. The amount of working capital
3. The Company's cost of capital
4. The level of operations and maintenance expenses
5. Depreciation and property tax adjustments
6. Revenue Decoupling Mechanism
7. Deferral of Staking and Locating Costs
8. Rate design issues

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

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

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

1. Exhibit AG-1 CMS Energy Investor Presentations
2. Exhibit AG-2 CPI Inflation Factors
3. Exhibit AG-3 New Large Business Connections
4. Exhibit AG-4 Asset Relocations
5. Exhibit AG-5 Meters Subprogram
6. Exhibit AG-6 Smart Gas Meters Pilot
7. Exhibit AG-7 Distribution MAOP Projects
8. Exhibit AG-8 Distribution MAOP Disallowances
9. Exhibit AG-9 Distribution Capacity and Deliverability Projects
10. Exhibit AG-10 EIRP Miles Retired and Installed

11. Exhibit AG-11 EIRP Premature Projects
12. Exhibit AG-12 Material Condition 2025 Capex
13. Exhibit AG-13 EIRP Extended Completion Date
14. Exhibit AG-14 EIRP No Engineering Studies
15. Exhibit AG-15 Material Condition Non-Modeled Projects
16. Exhibit AG-16 Material Condition Non-Modeled Renewal Projects
17. Exhibit AG-17 VSR Program
18. Exhibit AG-18 Distribution Tools and New Technology
19. Exhibit AG-19 Distribution Plant Actual 2025 Capex
20. Exhibit AG-20 Transmission Asset Relocations
21. Exhibit AG-21 Transmission Pipeline Integrity Capex
22. Exhibit AG-22 TOD Pipeline Integrity
23. Exhibit AG-23 TED Capex Projects
24. Exhibit AG-24 Field Measurement Projects
25. Exhibit AG-25 Transmission Pipeline Projects
26. Exhibit AG-26 Transmission City Gates Projects
27. Exhibit AG-27 Transmission 2025 Underspent
28. Exhibit AG-28 Storage and Compression Projects
29. Exhibit AG-29 Storage New Wells
30. Exhibit AG-30 Gas Compression Projects
31. Exhibit AG-31 Storage Pipeline Projects
32. Exhibit AG-32 Gas Compression Projects 2025 Underspent
33. Exhibit AG-33 IT Tracking and Traceability Project
34. Exhibit AG-34 IT Web Proxy Service Project.
35. Exhibit AG-35 OT Data Center Migration Project
36. Exhibit AG-36 Facilities Emergent Projects
37. Exhibit AG-37 Capex, Rate Base, Depreciation and Property Taxes Adj.
38. Exhibit AG-38 Working Capital Adjustments and Accrued Taxes
39. Exhibit AG-39 CONF Working Capital SAP S4 HANA Deferred Costs
40. Exhibit AG-40 Overall Cost of Capital
41. Exhibit AG-41 Cost of Common Equity

42. Exhibit AG-42 Cost of Common Equity-DCF
43. Exhibit AG-43 Cost of Common Equity-CAPM
44. Exhibit AG-44 Cost of Common Equity-Risk Premium
45. Exhibit AG-45 Peer Group Utility and Non-Utility Business Mix
46. Exhibit AG-46 Market to Book Ratios of Peer Group
47. Exhibit AG-47 ROE Decisions by Regulatory Commissions
48. Exhibit AG-48 Cash Flow to Debt Coverage Ratio Recalculation
49. Exhibit AG-49 Peer Group ROEs
50. Exhibit AG-50 S&P September 15, 2025 Rating Report
51. Exhibit AG-51 Moody's May 29, 2025 Rating Report
52. Exhibit AG-52 Moody's March 23, 2026 Rating Report
53. Exhibit AG-53 Blue Chip Report
54. Exhibit AG-54 Value Line Market Volatility Not Risk
55. Exhibit AG-55 O&M Summary Adjustments
56. Exhibit AG-56 Distribution Pipeline Operations Expense
57. Exhibit AG-57 Leak Repair and Survey Expense
58. Exhibit AG-58 Meter Tech and Management Expense
59. Exhibit AG-59 EIRP Training
60. Exhibit AG-60 Distribution Filed Operations
61. Exhibit AG-61 Compression Gas Expense
62. Exhibit AG-62 Transmission Pipeline Integrity Expense
63. Exhibit AG-63 Customer Service Contact Center Calls
64. Exhibit AG-64 Customer Service Analytics and Outreach
65. Exhibit AG-65 Customer Service Economic Development Staff
66. Exhibit AG-66 IT Security Expense
67. Exhibit AG-67 Corporate Services Expense
68. Exhibit AG-68 Health Care Savings
69. Exhibit AG-69 Rate Cases Expense
70. Exhibit AG-70 Incentive Compensation Operating Measures Results
71. Exhibit AG-71 AG Revised Revenue Requirement

II. SUMMARY CONCLUSIONS & RECOMMENDATIONS

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

A. The Company filed for a rate increase of $240 million. The rate increase represents an overall increase in base rates of 14% and an increase in residential base rates of 11.8%. Including the cost of gas, the average residential gas bill would increase by approximately 8%. I have identified several cost disallowances to the Company's proposed cost levels and capital projects, that I recommend the Commission approve. As a result of these adjustments, I have determined that the Company has a revenue deficiency of $93.8 million. It should be noted that the Company reported a revenue sufficiency (surplus) of $46.1 million in 2024. The Company also achieved a Return on Common Equity of 10.7% in 2024.[1] My conclusions and related adjustments are summarized below:

1. I recommend a reduction in capital expenditures of $662.6 million and a reduction of $525 million to rate base for the test year, including a $93 million adjustment to working capital. This reduces the Company's revenue deficiency by $43 million.
2. I recommend that the Commission adopt a lower cost of capital rate of 6.12%, a capital structure with 50% equity capital and a return on common equity of 9.70%. These recommendations reduce the Company's revenue deficiency by $47.4 million.

---

[1] Exhibit A-1, Schedule A1 and Schedule A-2.

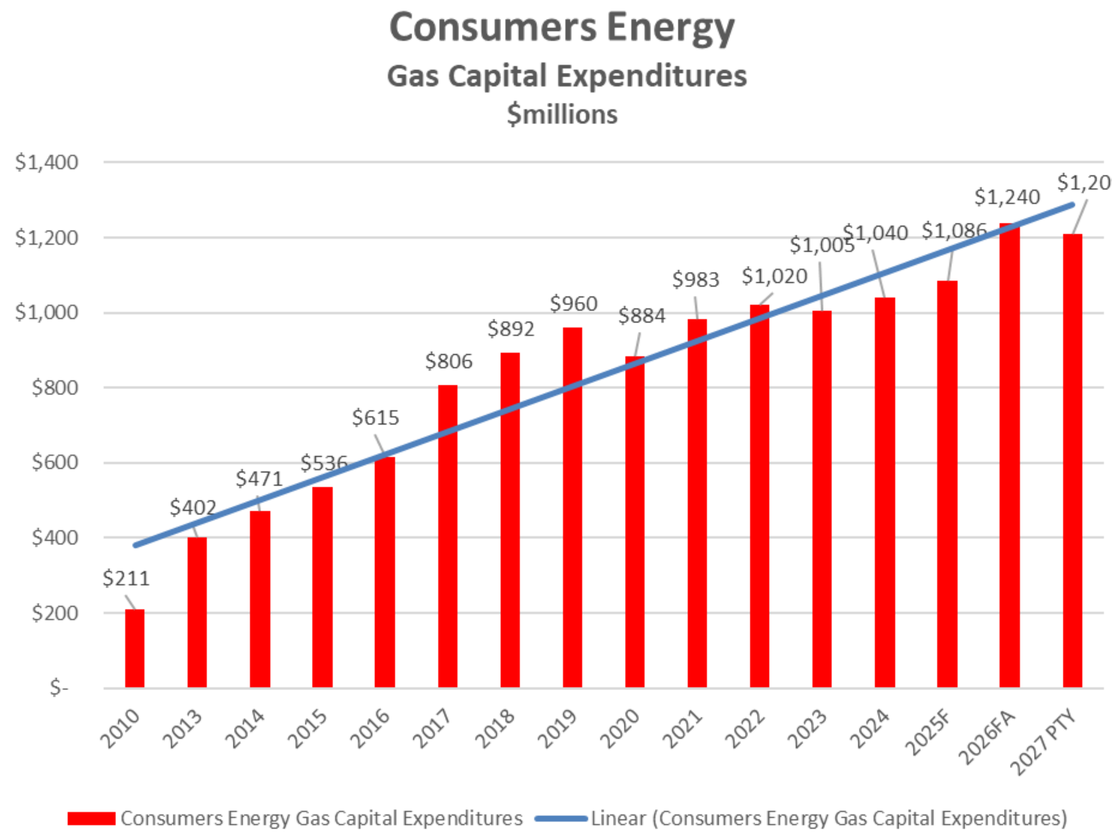
3. I recommend a lower level of Operations and Maintenance expenses for the test year. This reduces the Company's revenue deficiency by $42.4 million.
4. I recommend a lower depreciation expense of $12.2 million and lower property tax expense of $4.6 million pertaining to the lower capital expenditures and additions to plant discussed above. These adjustments reduce the revenue deficiency by the same amount.
5. I recommend that the Commission retain the residential monthly customer charge at $17.00.
6. I recommend that the Commission retain the General Service GS-1 monthly customer charge at $21.00.
7. I recommend that the Commission reject the Company's proposed RDM.
8. I recommend that the Commission reject the accounting cost deferral for Staking and Locating.

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

III. LARGE INCREASE IN RATE BASE AND CAPITAL EXPENDITURES

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

A. In this general rate case, CECo has proposed capital expenditures of $1.0 billion for 2024, $1.1 billion for 2025, $1.0 billion for the 10 months ending October 2026 ($1.2 billion annualized), and an additional $1.2 billion for the 12 months ending October 2027. These increases are in addition to capital expenditures of $2.9 billion made during the prior three years from 2020 to 2023.[2] The following chart in Table 1 shows the dramatic increase in capital expenditures over recent years in comparison to more moderate amounts in prior years.



Until 2014, the Company was able to keep capital expenditures below $500 million annually. Beginning in 2015, the level of capital expenditures started to increase dramatically, more than doubling by 2025 to $1.1 billion and maintaining an annual spending level of over $1.0 billion from 2022 through 2027.

---

[2] Exhibit A-12, Schedule B-5 in MPSC Case Nos. U-21308, U-21490, U-21806. U-21981.

The capital expenditures have fueled an alarming increase in rate base. As shown below in Table 2, rate base has been growing at double digit rates in recent years, and the Company is proposing to increase rate base again in this rate case by 31% to $12.5 billion over the 2024 historical rate base.

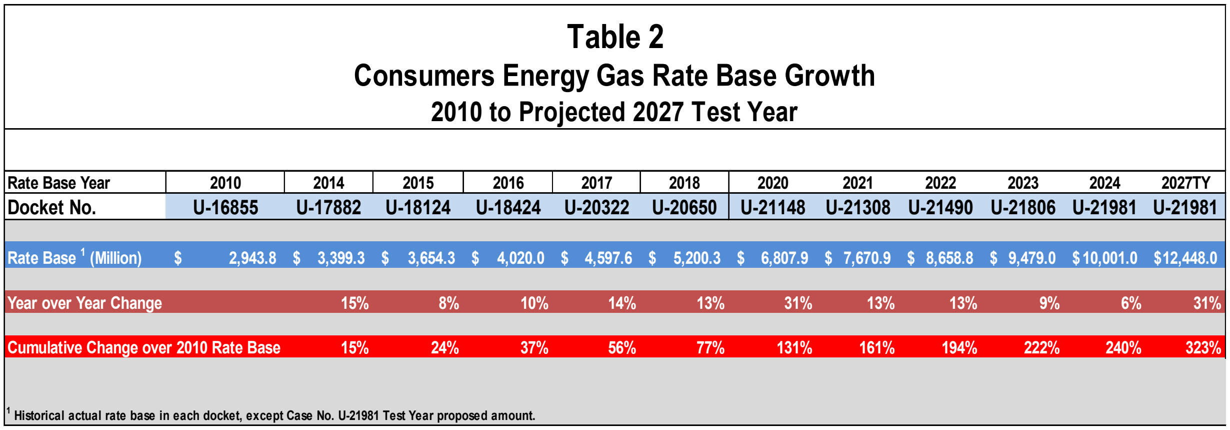


Table 2
Consumers Energy Gas Rate Base Growth
2010 to Projected 2027 Test Year

Rate Base Year	2010	2014	2015	2016	2017	2018	2020	2021	2022	2023	2024	2027TY
Docket No.	U-16855	U-17882	U-18124	U-18424	U-20322	U-20650	U-21148	U-21308	U-21490	U-21806	U-21981	U-21981
Rate Base [1] (Million)	$ 2,943.8	$ 3,399.3	$ 3,654.3	$ 4,020.0	$ 4,597.6	$ 5,200.3	$ 6,807.9	$ 7,670.9	$ 8,658.8	$ 9,479.0	$ 10,001.0	$12,448.0
Year over Year Change		15%	8%	10%	14%	13%	31%	13%	13%	9%	6%	31%
Cumulative Change over 2010 Rate Base		15%	24%	37%	56%	77%	131%	161%	194%	222%	240%	323%

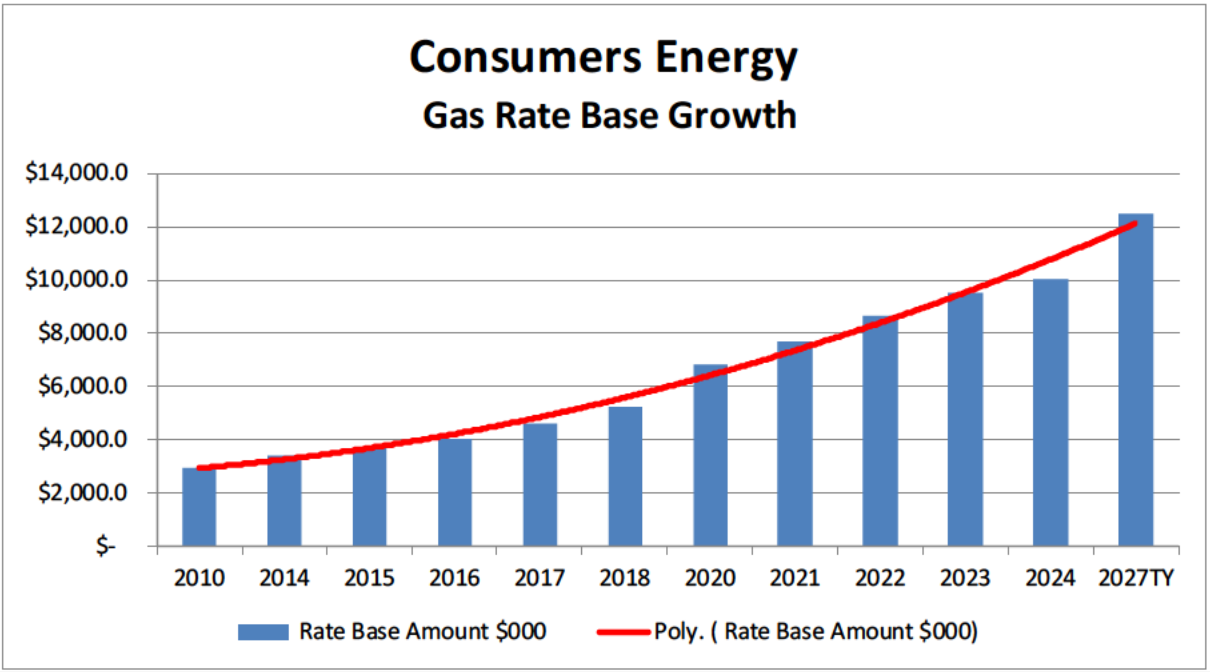
[1] Historical actual rate base in each docket, except Case No. U-21981 Test Year proposed amount.

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

---

[3] Table 3 shows a Polynomial trend line (Poly.) to show the latest trend in rate base growth.

Table 3



Q. WHAT DO YOU BELIEVE IS DRIVING THIS DRAMATIC INCREASE IN CAPITAL EXPENDITURES AND RATE BASE SINCE 2010?

A. I believe there are two main drivers. First, replacement of aging infrastructure and new capital spending to address market growth have required an increase in capital expenditures, which may have accelerated investment to some degree. The Company continues to propose ever-increasing capital expenditures to replace cast iron mains, steel mains and related service lines with few limits. It is unclear what significant changes in the conditions of the pipes and related infrastructure have occurred since 2010 to justify the dramatic escalation in capital expenditures. In fact, the Company has provided no in-depth engineering studies and very limited evidence that there has been a major change in the integrity of its distribution system in the past decade.

The Company also has experienced moderate customer growth in its market area. However, moderate customer growth existed in prior years. Prior to 2010, CECo was able to manage replacement of aging infrastructure and invest in new facilities to meet market growth with more reasonable increases in rate base. Therefore, customer growth and replacement of aging infrastructure by themselves do not fully explain the significant increase in capital expenditures and rate base since 2010.

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

The Company's executive management team, which is largely the same for Consumers Energy and for CMS Energy, has been quite clear and aggressive in communicating to investors and securities analysts its goal of increasing earnings per share at an average annual rate of 6% to 8%. For a utility such as CECo with limited gas sales and revenue growth, the increase in earnings per share comes almost entirely from the increase in capital expenditures and rate base. Exhibit AG-1 includes pertinent sections of a CMS Energy's presentation to investors and securities analysts in March 2026 where Company management communicated its earnings per share, capital expenditures growth goals and achievements. Other recent presentations tell the same story. The presentations point to only gas sales or revenue growth of 1-3%, which does not get anywhere close to propelling earnings per share growth of 6% to 8% without higher rate base growth.

Even more troubling is management's recent pronouncement forecasting $25 billion in capital spending over the next 5 years with a large portion of that amount coming from the gas utility. Management has also communicated that capital spending opportunities exist in excess of $50 billion in the coming years. Exhibit AG-1 shows this forecast along with other supporting information.

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

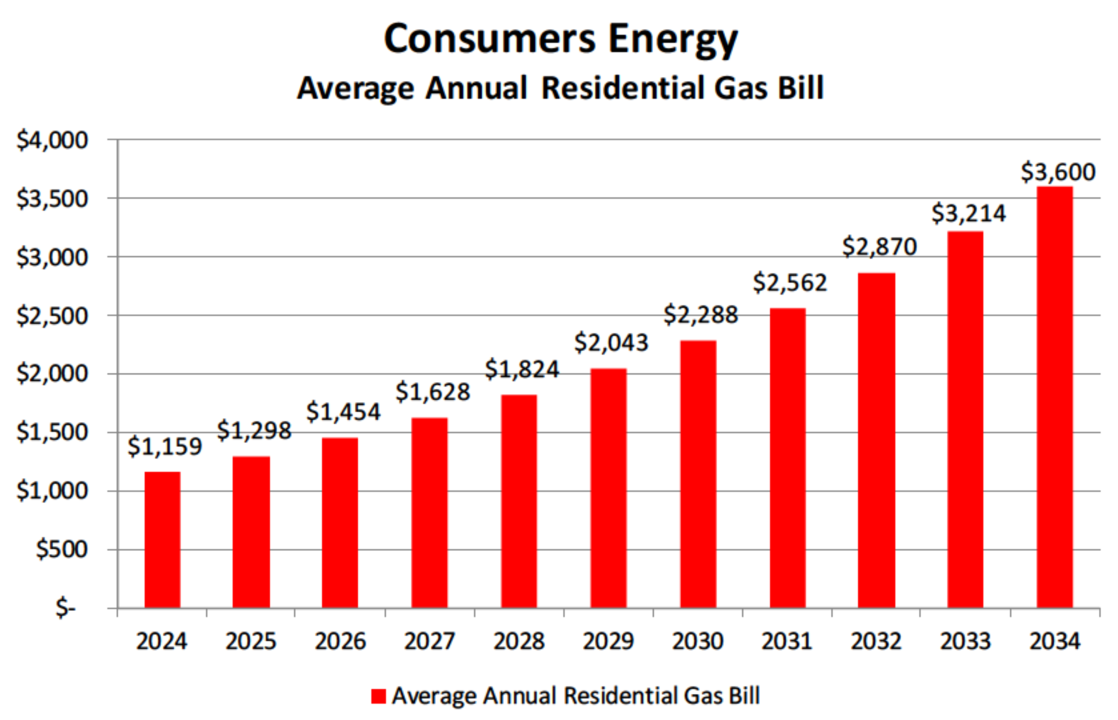
A. Yes. Based on the 2024 sales revenue filed by the Company in this rate case, the average annual gas bill for residential customers was $1,159.[4] As shown in Table 2 above, the Company's rate base has been growing in double digits and for the past 10 years from 2016 through the end of the 2027 projected test year at an average annual rate of 12%. If we assume that the Company will continue the current pace of capital expenditures and annual rate base growth of 12% annually, this growth rate accompanied by increases in operating expenses will more than triple the actual 2024 annual gas bill of $1,159 in 10 years to $3,600 by 2034. Table 4 below shows the potential increase in the average residential gas bill if

---

[4] Exhibit A-16, Schedule F2, shows residential revenue of $1,816,409,000 for 2024. The Company had 1,567,016 residential customers for the year (Exh. A-5, Schedule E-2}, which calculates to the actual average residential gas bill of $1,159 for the year.

the current trend in rate base growth continues, and the price of natural supply remains the same as in 2024. Although gas prices have abated since 2022, with increased demand for natural gas and limited gas supply, they could reach or surpass those prices in future years.

Table 4



This potential escalation in annual customer bills is likely to pose a significant burden on residential customers and businesses. In addition, this potential increase in residential gas bills does not take into consideration further escalations in capital expenditures, which the Company seems to be contemplating as discussed above.

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

IV. Review of Capital Expenditures

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

A. Yes. I have analyzed the Company's forecasted capital expenditures by major department or area, and I have identified reasonable expenditure levels that the Commission should adopt. In projecting adjusted capital expenditures for 2026 and the projected test year where applicable I applied an inflation factor to the historical cost base to reflect inflationary cost pressure that the Company may face in those years. The inflation factors are 2.8% for 2025, 2.4% for 2026, and 2.3% for 2027. These rates reflect the increase in the forecasted Consumer Price Index during the 2025-2027 periods as shown in the S&P Global Market Intelligence Forecast provided by the Company.[5]

A. Distribution Plant

In Exhibit A-12 (LDW-1), Schedule B-5.8, the Company shows forecasted capital expenditures for Distribution Plant capital programs of $251.6 million for 2025, $289.2 million for the 10 months ending October 2026, and $301.9 million for the 12 months ending October 2027. In comparison, the Company spent $187.3 million in 2024. In my

---

[5] Exhibit AG-2 includes DR AG-CE-0249 with the S&P Global Market Intelligence forecast report.

testimony below, I will discuss certain programs where adjustments to the proposed capital expenditures should be made.

1. Large New Business Projects

As shown in Exhibit A-127 (LDW-2), within the Distribution New Business Program, the Company forecasted capital expenditures for Large New Business Projects of $2.3 million for 2025, $7.5 million for the 10 months ending October 2026, and zero dollars for the 12 months ending October 2027. Company witness Lincoln Warriner discusses the 2025 and 2026 projects beginning on page 21 of his direct testimony. On page 23 of his testimony, Mr. Warriner shows a table with the major components of the capital expenditures by year.

Regarding the Agricultural Processing Complex projects of $12.0 million forecasted for 2026 within this subprogram, in discovery, the Attorney General asked the Company to provide the date the Company signed a contract with the customer to undertake this project and to provide other relevant information. In response, the Company reported that it is still engaged in discussions with the customer and a contract may be signed later in 2026 with project construction possibly to be rescheduled for mid-2027.[6]

With no contract signed and construction being postponed, it is still uncertain if this project will occur before the end of the projected test year. Given the uncertainty, it is premature

---

[6] Exhibit AG-3 includes DR AG-CE-0272.

to include the $12.0 million in rate base in this rate case. Therefore, I recommend that the Commission remove this amount from the Company's forecasted capital expenditures.

2. Asset Relocation

As shown on page 1 of Exhibit A-128 (LDW-3), the Company has two Asset Relocation subprograms: Civic Improvements and Reimbursable. For the Asset Relocation-Civic Improvement subprogram the Company reported $48.3 million in actual capital expenditures for 2024 and forecasted $63.9 million for 2025, $63.5 million for the 10 months ending October 2026, and $76.2 million for the 12 months ending October 2027. For the Asset Relocation-Reimbursable subprogram, the Company reported actual capital expenditures of $23.2 million for 2024 and forecasted $17.7 million for 2025, $12.0 million for the 10 months ending October 2026, and $15.0 million for the 12 months ending October 2027. Company witness Lincoln Warriner discusses these subprograms beginning on page 24 of his direct testimony.

In discovery, the Attorney General asked the Company to provide the actual expenditures for 2025 along with the number of projects, feet of main installed for historical and projected periods and known projects for 2026 and 2027. The information provided by the Company shows that asset relocations for civic improvements have been on a declining trend since 2022 with capital expenditures falling from $103 million in 2022 to $49.6 million in 2025. The number of feet of main installed and the number of projects also have declined over this same period with main installations falling from 297,246 feet in 2022 to 141,896 feet in 2025. The number of projects has also declined from 170 to 134.

Reimbursable Asset Relocations have been more stable with capital expenditures ranging from $13.4 million to $23 million over the 2022-2025 period.[7]

In addition to the information discussed above, the Company provided a list of known Civic Improvements projects for the 10 months ending October 2026 and the 12 months ending October 2027. This additional information shows that the Company has identified sufficient projects to fully support the capital spending for the 10 months ending October 2026. However, for the 12 months ending October 2027, the Company has known projects totaling $12.9 million against the $76.2 million forecasted for that period.[8] The Company could not provide a similar list of projects to support forecasted capital expenditures for 2026 and 2027 for Reimbursable Asset relocations.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR ASSET RELOCATIONS?

A. Based on the information received, I find the Company's forecasted capital expenditures for Asset Relocations for both Civic Improvements and Reimbursable projects to be significantly overstated for the projected test year. Given the emergent nature of most of the projects within the two subprograms and with a large portion of the forecasted capital spending still unknown, a reasonable basis to forecast future expenditures for the projected test year is to rely on historical expenditures adjusted for future inflation. For the most recent three years, 2023-2025, the Company's total Asset Relocation capital expenditures

---

[7] Exhibit AG-4 includes DR AG-CE-0273 and 0274 with related attachments.
[8] Id. includes DR AG-CE-0273 Attachment 3.

averaged $79,242,000. Adjusting this amount for 2026 and 2027 inflation results in forecasted capital expenditures for the projected test year of $82,699,000.[9] This amount is $8,661,000 lower than the $91,260,000 forecasted by the Company. I recommend that the Commission remove the $8,661,000 from the Company's forecasted capital expenditures.

3. Regulatory Compliance Program

As shown in Exhibit A-129 (LDW-4), the Company incurred capital expenditures of $47.8 million for the Regulatory Compliance Program for 2024 and forecasted $109.8 million for 2025, $159.5 million for the 10 months ending October 2026, and $144.0 million for the 12 months ending October 2027. Included in those amounts are capital expenditures for the Meter subprogram and for MAOP projects for large distribution pipelines and related facilities.[10] I will address each of the two subprograms separately.

3a. Meter Subprogram

For 2024, the Company incurred capital spending of $24.6 million for the Meters subprogram. The Company forecasted capital expenditures of $26.4 million for 2025, $26.8 million for the 10 months ending October 2026, and $31.4 million for the projected test year. Mr. Warriner discusses this program beginning on page 41 of his direct testimony. There are two areas of concern with this program. The first concern is with the excessive number of meters forecasted by the Company for 2026 and 2027. The

---

[9] $79,242,000 x 1.024 (2026) = $81,144,000 x 1.023 (2027) = $83,010,000; $81,144,000 x 2/12 + $83,010,000 x 10/12 = $82,699,000.

[10] MAOP = Maximum Allowable Operating Pressure for a pipeline or related facilities.

second concern is with the Company's proposal to begin a pilot program for "smart gas meters."

Regarding the number of meters, in response to discovery, the Company provided the number of meters purchased annually from 2022 to 2025 and forecasted for 2026, 2027 and the projected test year. For New Business customer connections, the data shows that during the four years from 2022 to 2025, the number of meters purchased ranged from 9,730 to 21,871 and averaged 19,365 meters during the most recent three years. The Company forecasted 25,965 meter purchases for New Business for 2026 and 2027 and included 22,874 meters in the projected test year.[11]

Purchases for other (mostly replacement) Meters have ranged from 11,422 to 26,343 meters during 2022-2025 with the highest number occurring in 2025. For 2026, the Company forecasted purchases of 30,480 meters in this area with a similar quantity for 2027 and a scaled down quantity of 26,852 meters for the projected test year.[12]

Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES THAT THE COMPANY SEEKS TO INCLUDE IN RATE BASE FOR METER PURCHASES, EXCLUDING THE SMART METER PILOT?

A. I find the number of meters forecasted to be purchased for 2026 and the projected test year to be excessive and not adequately supported. Regarding the meters to be purchased for

---

[11] Exhibit AG-5 include DR AG-CE-0279 with Attachment 1.
[12] Id.

New Business, on pages 14 through 19 of his direct testimony and in Table 7, Mr. Warriner discusses and shows that new customer connections are forecasted to be lower for 2026 and 2027 than in recent historical years and on par with 2024 levels. Therefore, the higher forecasted meter purchases for 2026 and 2027 do not accurately reflect the lower forecasted customer additions. Therefore, I determined that the 19,463 meters purchased in 2024 is a reasonable proxy to forecast the number of New Business meters for 2026, 2027, and the projected test year.

For Other Meters, purchases have grown over the four years 2022 to 2025, reaching a peak of 26,343 in 2025. I find this quantity to be a reasonable basis to forecast future year purchases for 2026, 2027, and the project test year.[13] Combining the New Business meter quantity of 19,463 to the Other Meter purchases of 26,343, I forecast total meter purchases of 45,806 for 2026 and the projected test year.

For 2026, the Company forecasted a unit cost per meter of $541.[14] Using this unit cost and applying it to 45,806 meters, I calculated a cost for 2026 meter purchases of $24,781,000 or $20,651,000 for the 10 months ending October 2026.[15] This amount is $6,259,000 lower than the Company's forecast of $26,820,000. I recommend that the Commission remove the $6,259,000 from the Company's forecast capital expenditures for the bridge period.

---

[13] As discussed later in my testimony, I will propose that the EIRP and VSR programs be moderated, thus reducing the need for additional meter replacements from these programs in future years.
[14] Exhibit AG-5 include DR AG-CE-0279 with Attachment 1.
[15] 45,806 x 541 = $24,781,000 x 10/12 = $20,651,000.

For 2027, I increased the unit cost of $541 from 2026 by the inflation rate of 2.3% to arrive at the adjusted unit cost of $553. I find the Company's forecasted unit cost of $571 for 2027 to be excessive and unsupported given that the mix of forecasted meter purchases did not change from 2026 to 2027. Therefore, I applied the inflation adjusted unit cost of $553 to the 45,806 forecasted meter purchases to arrive at forecasted capital expenditures of $25,331,000 for 2027.[16] The result is projected test year capital expenditures of $25,239,000.[17] This amount is $4,194,000 lower than the $29,433,000 amount forecasted by the Company, excluding the costs for the "smart meter" pilot program. I recommend that the Commission remove the $4,194,000 from the Company's forecasted capital expenditures for the projected test year.

Q. PLEASE DISCUSS YOUR ASSESSMENT OF THE NEW SMART METER PILOT PROGRAM PROPOSED BY THE COMPANY.

A. Beginning on page 46 of his direct testimony, Mr. Warriner discusses the initiation of a new pilot program in 2027 to replace existing diaphragm and rotary meters with ultrasonic meters containing new technology and new features. The Company refers to the new meters as "smart" meters because of the additional features that they provide. According to Mr. Warriner, the additional features include automatic and remote shutoff of the meter, pressure monitoring sensors, and hourly gas usage data. The new meters would replace the

---

[16] 45,806 x $553 = $25,331,000.

[17] $24,781,000 x 2/12 + $25,331,000 x 10/12 = $25,239,000.

existing meters equipped with AMR and AMI modules, which provide remote meter reading.

Interestingly, when introduced in 2015, the Company also referred to the AMI meter module, as "smart" meters for their ability to provide time of day gas usage and other features. The Company installed the AMR and AMI module on its 1.8 million gas meters between 2015 and 2019[18]. Therefore, the oldest modules have been in place amount 10 years with the most recent installations occurring about 6 years ago. Replacement of those modules and meters at this time seems premature. Although the batteries on some of the modules may be failing and may fail in larger numbers after those modules reach their expected 20-year life, they are being replaced and can continue to be replaced with new AMR and AMI modules as those failures occur.

In discovery, the Attorney General asked the Company to identify certain aspects of the pilot program, including:

1. Number of meters to be installed and the timeframe
2. Cost per meter
3. Vendor selected
4. Use of the smart meters by other gas utilities
5. Implementation plan
6. Cost/Benefit analysis for the new meter program
7. Actual benefits to be derived from the new meter features

---

[18] Exhibit AG-6 include DR AG-CE-0281.

In response, the Company reported that the pilot would entail two phases with the installation of 1,000 new smart meters in the projected test year at a cost of $1,977,000, including communication software, and 100,000 meters in phase 2 in 2028. No cost was disclosed for 2028, but assuming the same cost of $1,000 per meter and meter stand as in 2027, the total cost in 2028 would be $100 million.[19] At this point, phase 2 is no longer a pilot project but the start of a full-fledged implementation. At a cost of $1,000 per meter, the full replacement of 1.8 million meters would cost $1.8 billion in today's dollars.

In his testimony, Mr. Warriner states that the industry is moving away from diaphragm meters and into the new smart meters, but in response to discovery the Company could not identify any other gas utilities and stated generally that several utilities were in various stages of implementation.[20] In his testimony, Mr. Warriner also raises concerns with potential communication problems from not replacing the current gas meters with the new smart meters if the Company were to proceed with the replacement of existing electric meters with new smarter meters. However, in response to discovery, the Company could not provide any more information on this issue.[21] The Company has not yet proposed and the Commission has not approved a new meter replacement program for electric meters.

In response to discovery, the Company stated that it had not yet selected a vendor for the new smart meter and was still considering four potential vendors.[22] Regarding the additional features of automatic remote shutoff of the meter and customers being able to

---

[19] Exhibit AG-6 include DR AG-CE-0280 and 0283.
[20] Id. DR AG-CE-0283b.
[21] Id. include DR AG-CE- 0282c.
[22] Id. includes DR SA-CE-302.

access their gas usage daily or hourly, the Company reported that it envisions using the shutoff feature on 112,000 occasions during the year for bill collection activities and customer move-in/move outs. This number represents about 6% of the customer base.[23]

Although the Company touts the safety aspects of shutting off the meter in gas leak situations, it would still require a visit by a Company employee to investigate and identify the source of the leak. It is also not clear how this process of remotely shutting off the meter would work or how frequently it would be used for safety reasons. As to the ability of the new meter to provide daily or hourly consumption of natural gas, the Company could not provide any information on the number of customers who had requested this information or would find it useful.[24] The likelihood is that the use of this feature would be very limited and would not justify the higher meter cost by itself.

In discovery, the Company was also asked why it had not prepared a cost/benefit study before planning to undertake the large pilot program. In response, the Company stated that it is currently working with a consultant to develop a cost/benefit analysis to be completed before the start of the pilot.[25] However, none was provided in this rate case either with filed testimony or in response to discovery. The Company claims that it needs the pilot to gather accurate costs and benefits and assess technical challenges during the implementation phase. This claim is faulty. The Company knows the cost of the meter and the meter stand. It also knows what it costs to replace a meter and meter stand having

---

[23] Id. DR AG-CE-0283g.
[24] Id. DR AG-CE-0283h and i.
[25] Id. DR AG-CE-0283a.

done that procedure thousands of times already with other meters or can reasonably estimate that cost. Assuming, it has done sufficient research with other utilities that have implemented new smart meters, it should be able to anticipate technical and field implementation problems and should be able to take those into consideration in preparing a relatively accurate cost/benefit analysis without waiting for implementation of the first or second phase of the proposed pilot. In fact, if the cost/benefit analysis does not provide a clear indication that undertaking the smart meter program is justified, both economically and otherwise, the pilot program may not be needed at all.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION FOR THE SMART METER PILOT?

A. The Company has not done sufficient analysis of installations at other gas utilities, has not confirmed that the expected benefits from the additional features would materialize to reasonable levels, has not presented a cost/benefit analysis to show the economic benefits of the program versus the total implementation costs, has not presented a complete long-term implementation plan, and has not provided conclusive evidence the existing meters and related modules cannot be replaced for many more years to come.

My conclusion is that the proposed pilot program has not been adequately justified and it is premature to begin the pilot program during the projected test year. Therefore, I recommend that the Commission remove the forecasted capital expenditures of $1,977,000 from this rate case.

Q. WHAT ARE THE TOTAL CAPITAL EXPENDITURES DISALLOWANCES THAT YOU RECOMMEND FOR THE METERS SUBPROGRAM FOR THE BRIDGE AND PROJECTED TEST YEAR PERIODS?

A. As discussed above, I recommend that in total for the meters subprogram the Commission disallow $6,259,000 for the 10 months ending October 2026 and $6,171,000 for the projected test year.[26]

3b. Distribution MAOP Projects

For 2024, the Company incurred capital spending of $10.4 million for Distribution MAOP Pipeline Replacements projects. For future years, the Company forecasted capital expenditures of $66.4 million for 2025, $124.7 million for the 10 months ending October 2026, and $102.7 million for the projected test year. Mr. Warriner discusses this program beginning on page 48 of his direct testimony. The proposed projects entail replacement of segments of large diameter distribution pipelines where the Company has concluded that it cannot confirm the MAOP.

Although the MAOP projects fall within recently issued regulations issued by the Pipeline Hazardous Materials Safety Administration (PHMSA), the genesis of the problem requiring the replacement or remediation of pipelines to re-establish the MAOP is the lack of traceable, verifiable, and complete (TVC) records that should have been maintained by the Company. In response to discovery, the Company acknowledged the missing records

---

[26] $4,194,000 meter number forecast + $1,977,000 for the smart meter pilot.

that prevent it from confirming the appropriate MAOP at which the pipeline should be currently operating.[27] Although the PHMSA rules provide for procedures and alternative steps that the Company can undertake short of replacing the pipeline to develop TVC records and to re-establish the MAOP, the Company claims that it needs to replace 22 distribution pipeline segments, as identified in Table 19 on page 50 of Mr. Warriner's direct testimony.

In discovery, the Attorney General asked the Company to provide the current phase of development for MAOP projects with capital expenditures of $1.0 million or greater. In response, the Company identified the current phase of development and when the design phase and construction will be completed.[28] The discovery response also reported that four of the projects had been reevaluated, canceled, and removed from the bridge period and projected test year.

Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES THAT THE COMPANY SEEKS TO INCLUDE IN RATE BASE FOR MAOP PROJECTS?

A. Based on the information provided in response to discovery, the Company has cancelled or significantly changed the scope on project Nos. 22861, 22781, 21676, and 22738. The capital expenditures for these projects for the 10 months ending October 2026 and the

---

[27] Exhibit AG-7 includes DR AG-CE-0284.

[28] Id. includes DR AG-CE-0285 with Attachments 1 and 2.

projected test year are $44,156,000 and $40,855,000, respectively, based on monthly proration calculations of the capital spending that would fall in each period.[29]

In response to DR AG-CE-0285c (Exhibit AG-7), the Company reported the total amount of adjustment for capital adjustment for the bridge period of $34,389,000 and $32,781,000 for projected test year. The summary form of this information makes it impossible to determine what amount is attributable to the cancelled projects or the projects with changes in scope, or to determine what the change in scope entails.

Attachment 2 to DR AG-CE-0285 shows that two of the projects that had not been cancelled and the scope of the projects had changed were still in the early stage of design. These projects are still preliminary and have a great degree of uncertainty to be included in rate base in this rate case. Therefore, removal of the entire capital expenditures for the two projects for the bridge period and projected test year is appropriate. If the Company proceeds with the two projects, it can request cost recovery in the next rate case.

The information on the current phase of project development shows that there are six other projects that have not entered the design phase or are still in the early stage of project design. Exhibit AG-8 shows those projects on line 3 and lines 5 through 9. The project on line 5 had not yet been assigned a project number, which reflects its preliminary phase

---

[29] Exhibit AG-8 shows the calculation and proration for 10 months ending October 2026 and the project test year for each project based on 2026 and 2027 capital expenditures provided by the Company in response to DR AG-CE-0285.

of development. Exhibit AG-8 shows the projects highlighted with the phase of development and other pertinent information.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE MAOP PROJECTS?

A. The 10 projects shown in Exhibit AG-8 have either been cancelled or are in the very early phase of project development. There is significant uncertainty about how quickly the projects will develop and when, or whether the capital expenditures will occur as forecasted by the Company. These projects are too premature to include in rate base in this rate case.

Therefore, I recommend that the Commission remove $44,106,000 for the 10 months ending October 2026 and $90,705,000 for the projected test year from the Company's forecasted capital expenditures.

4. Distribution Capacity/Deliverability

As shown in Exhibit A-130 (LDW-5), the Company incurred capital expenditures of $7.0 million for the Capacity/Deliverability Program, or Augmentation program, for 2024 and forecasted $6.5 million for 2025, $4.9 million for the 10 months ending October 2026, and $14.3 million for the 12 months ending October 2027. Mr. Warriner discusses this subprogram beginning on page 72 of his direct testimony.

In discovery, the Attorney General asked the Company to provide the actual amount spent on this subprogram for 2025, the number of feet of main installed for historical and projected periods, the current phase of development, and the start of the next phase for each project planned for 2026 and 2027. The information provided by the Company shows that for 2025 it only spent $0.9 million instead of the forecasted capital expenditures of $6.5 million. For 2026, the Company identified 8 projects. Except for two projects, the other projects are in advanced stages of design or construction. The two projects, Front & Western Ave and Sheldon Rd. Augment, have not yet been sufficiently developed. For the Front & Western Ave project, the Company stated that design is in progress, indicating that design may have begun but has not progressed much. For the Sheldon Rd. project, the Company reported that design had not yet started.[30]

For the two projects, the Company forecasted total capital expenditures of $868,000 for 2026.[31] The two projects are still in the preliminary phase of development and too premature to include in rate base in this case. I recommend that this amount be removed from the Company's forecasted capital expenditures. The amount for the 10 months ending October 2026 is $723,000 with the remaining amount of $145,000 applicable to the projected test year.[32]

For 2027, the Company identified four projects totaling $13,543,000 in capital expenditures with $2,480,000 for other undefined projects. None of the four projects have

---

[30] Exhibit AG-9 includes DR AG-CE-0290 and 0291 with attachments.

[31] Id. DR AG-CE-0291 Attachment 1.

[32] $868,000 x 10/12 = $723,000 – $868,000 = $145,000.

entered the design phase and with one of the projects having just completed the field survey phase. The four projects are still very preliminary and not sufficiently developed to be included in rate base in this rate base. In this area and other areas, the Company continues to propose capital expenditures for projects that have not been sufficiently developed. In prior rate cases, the Commission has made it clear that projects need to be sufficiently developed to ensure there is high degree of certainty that the capital expenditures will occur as forecasted to be included in rate base.

Therefore, I recommend that $11,286,000 ($13,543,000 for 2027 x 10/12) pertaining to the projected test year for the four projects be removed from the Company's forecasted capital expenditures. Adding the residual amount of $145,000 from 2026 discussed above to the $11,286,000 results in a total disallowance of $11,431,000 for the projected test year.

5. Material Condition Program

As shown on page 1 of Exhibit A-112 (KAP-4), the Company incurred $291.1 million for the Material Condition Program in 2024 and forecasted capital expenditures of $358.3 million for 2025, $324.9 million for the 10 months ending October 2026, and $415.8 million for the 12 months ending October 2027. This program consists of five subprograms. I will address four of those subprograms: EIRP, Material Condition Non-Modeled, Renewals, and Vintage Service Replacements. Company witness Kristine Pascarello discusses each of these programs beginning on 31 of her direct testimony.

5a. EIRP

As shown on page 1 of Exhibit A-112 (KAP-4), the Company incurred $193 million for the Enhanced Infrastructure Replacement Program (EIRP) in 2024 and forecasted capital expenditures of $234.4 million for 2025, $196.4 million for the 10 months ending October 2026, and $234.2 million for the 12 months ending October 2027. Ms. Pascarello discusses the EIRP beginning on page 33 of her direct testimony.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE EIRP.

A. In Case No. U-16855 filed in September 2011, the Company proposed a comprehensive main replacement program that would achieve the following objectives:

1. Replacement of all cast iron mains over the course of the 25-year program.
2. Replacement of all bare, oxyacetylene welded, threaded & coupled and cathodically-unprotected steel mains over the course of the 25-year program.
3. Replacement of 100 miles of transmission gas mains located in high consequence areas (HCA) over the 25-year program.
4. Replacement of approximately 70 miles of ERW piping located in gas storage fields and install launcher/receivers, as necessary, to permit future inspection by in-line inspection (ILI) technology.[33]

According to the direct testimony of Steven Beachum in that rate case, the Company would be able to achieve the 25-year replacement target with an annual capital spending level of $70 million. If that plan had been successful, full replacement of targeted mains would

---

[33] MPSC Case No. U-16855, Steven Beachum direct testimony at page 33.

have been achieved by the year 2036, or 10 years from now. However, the Company's plan has not materialized at anything close to what was proposed in 2011.

At the beginning of the main replacement program, the Company had targeted replacement of 2,869 miles of mains, which over the 25-year plan period would have resulted in an annual replacement rate of 115 miles at an average annual capital spending level of $70 million, or $609,000 per mile. During the 14 years from 2012 to 2025, the Company retired approximately 1007 miles of the targeted old mains plus other at-risk mains for a total of 1,265 miles of retired mains.[34] The Company replaced those mains by installing 1,258 miles of new mains at an average cost per mile of $1,196,343.[35] The retirement rate per year on the old targeted mains has been 74 miles of main instead of the planned 115 miles per year.[36]

What is most concerning is the fact that the Company projected it would cost $609,000 to replace a mile of main when it announced the program in 2011.[37] Instead, the actual average cost over the past 14 years has been $1.2 million per mile, or nearly two times the original estimate. In response to discovery, the Company reported that the cost per mile for plastic pipe replacement reached $1.6 million in 2023 and $1.4 million in 2024 and with the Company attempting to lower it to $1.3 million during 2025 to 2027.[38]

---

[34] Exhibit AG-10 includes DR AG-CE-0362 with Attachment 1.

[35] Id. includes DR AG-CE-0363 with Attachment 1 showing the miles installed. The $1.505 billion cost is update from Case U-21806 of $1.277 billion from 2012 through 2024 plus $228 million spent in 2025.

[36] 1007 miles plus 33 miles of coated and wrapped = 1,040 miles / 14 years = 74 miles per year.

[37] $70 million per year divided by 115 miles of main targeted for replacement annually over a 25-year period equals to an average cost per mile of $609,000.

[38] Exhibit AG-10 includes DR AG-CE-0365. See also page 45 of Kristine Pascarello's direct testimony.

In addition to the base distribution system pipe replacement program, the Company also includes in the EIRP the replacement of steel pipe for Transmission lines Operated by the Distribution department. These are referenced or identified as TOD projects. During the 13 years from 2012 to 2024, the Company retired approximately 38.8 miles of TOD mains and replaced them with 74.4 miles of new main.[39]

Q. IN YOUR REVIEW OF THE LARGER EIRP PROJECTS, DID YOU IDENTIFY CERTAIN COSTS THAT SHOULD BE REMOVED FROM THE COMPANY'S FORECASTED CAPITAL EXPENDITURES?

A. Yes. After reviewing the list of EIRP projects with a cost of $5 million or greater included on page 3 of Exhibit A-112 (KAP-4), the Attorney General asked the Company to identify the current phase of project development. In response, the Company identified projects that were in different phases of development from Conceptual Design to Engineering and with construction start dates spanning from December 2026 to October 2027.[40] Four of these projects included in the projected test year are still in the early stages of project development.

One of the four projects, ROK29, is still in the Conceptual Design phase with engineering design not starting until April 2026. The forecasted capital expenditures for this project is $13,218,000. The other three projects (LIV8, LIV9, and KAL9) are still in the early engineering design phase with construction not starting until August to October 2027. The

---

[39] Exhibit AG-10 DR AG-CE-0362 and 0363 with related attachments.

[40] Exhibit AG-11 includes DR AG-CE-0384 with Attachment 1.

total capital expenditures for the three projects are $32,058,000 and $45,276,000 for all four projects, which have been highlighted in the attachment in Exhibit AG-11.[41]

Clearly, all four projects are still in the preliminary phase of development and premature to include in rate base in this rate case. With no engineering design yet started, it is highly uncertain whether construction will begin early enough in the projected test year and questionable that the projects will be completed before October 2027. Therefore, I recommend that the Commission remove the $45,276,000 from the Company's forecasted capital expenditures.

Q. DO YOU HAVE OTHER OBSERVATIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S FORECASTED EIRP CAPITAL EXPENDITURES FOR THE PROJECTED TEST YEAR AND FUTURE YEARS?

A. Yes. As stated earlier, the Company expects to reach a new peak level of capital spending on the EIRP program in the projected test year at $234.2 million. In contrast, the Company spent $193 million in 2024. The projected test year spending level is an increase of 21% in less than 3 years. The Company also is not meeting its commitment to restrain spending. In the settlement agreement for Case No. U-21490, the Company stated that it would keep the EIRP spending level for the 12 months ending September 2025 at $215.3 million.

---

[41] Id.

However, the Company exceeded that spending level by reaching in excess of $231 million in capital expenditures in 2025.[42]

This increasing spending trend for the EIRP is not sustainable from a customer affordability viewpoint and must be reversed. The Commission should set a firm spending budget for the EIRP to avoid the program's current runaway cost.

Most homeowners must live within their own budgets and do not have unlimited resources to be able to afford ever increasing household costs. They make hard choices every day as to where to spend their money within the available resources. Similarly, the Company needs to set an annual budget to replace and install the number of miles of main that can be completed within a set budget cap. The current practice of unlimited and increasing capital spending on the EIRP program needs to be restrained.

Based on the actual spending of $193 million in 2024 and adjusting that amount for forecasted inflation of 2.8% in 2025, 2.4% in 2026, and 2.3% in 2027, I propose a spending budget of $207 million for the projected test year ending October 2027. That spending level would be adjusted for the CPI rate of inflation in future years. In Case No. U-21291 for the DTE Gas IRM, the Commission established a similar limit for the calculation of the IRM surcharge, which resulted in DTE Gas limiting its spending within the Commission approved amount. The budget limit for Consumers Energy that I propose here would accomplish the same result.

---

[42] Exhibit AG-12 includes DR AG-CE-0383 with Attachment 1.

Although the lower spending level that I propose may reduce somewhat the number of miles that the Company planned to retire and install in the projected test year and future years, the completion of the program would not be affected significantly. In discovery in Case No. U-21806, the Attorney General asked the Company to provide the end year of the EIRP if the Company pursued a pace of pipe replacement equivalent to the year 2023.

In response, the Company stated that under that assumption, the end date of the EIRP program would be extended from the current expected date of 2035 to the year 2038. The completion date would extend to 2040 if retirement of additional TOD steel pipe and wrapped steel pipe is added to the EIRP.[43] This three-to-five-year extension of the program seems reasonable if it helps moderate the rate of increase in spending to a level equivalent to 2024 adjusted for inflation.

The lower capital spending level will also give the Company added incentive to reduce the cost per mile of main installed and reduce pressure on scarce resources. The Company is competing for limited resources, whether through the direct hire of employees or through subcontractors, and also for materials and equipment, with other utilities around the country, as those utilities also have undertaken large pipe replacement programs. This competition for limited resources has contributed to the higher cost of pipe replacement under the Company EIRP program during recent high inflationary periods. A more

---

[43] Exhibit AG-13 includes DR U-21806 AG-CE-0391 and 0781.

moderate pace of pipe replacement will help take the pressure off the competition for those resources.

It should also be pointed out that through the risk-based approach to pipe replacement that the Company has employed over the past 13 years, most of the high-risk mains and services should already have been replaced. In fact, the Company admits that gas leak data shows a downward trend for below grade leaks. The Company stated in response to discovery that as the pipe continues to age the number of gas leaks will increase.[44]

However, this is a conclusion without any engineering analysis. The Company has not provided any compelling evidence that a three-to-five-year extension of the program will result in a material increase in gas leaks or larger infiltration of water in gas pipes above recent historical levels. Also, there is no evidence that the planned increase in spending in recent years and for the projected test year is tied to any increased safety risks.

The Company has revealed that it has not undertaken any recent engineering studies to show that there is increased deterioration of the vintage pipelines and that all vintage pipe must be removed by 2035. The Company describes its pipe replacement methodology as being focused on material type, age of pipe, and pipe operating pressure level and not on the probability of risk of failure.[45] In other words, if the pipe is old and of a certain material type, it gets replaced.

---

[44] Id. includes DR AG-CE-0389 and 0780.

[45] Exhibit AG-14 includes DR AG-CE-0361 and MEC-CE-0101.

Therefore, if the completion of the EIRP program is extended a few more years past the current 2035 date, it does not pose an unacceptable risk and it is a reasonable trade-off to balance against customer bill affordability from uncontrolled capital spending on the program.

I recommend that the Commission approve establishing a budget of $207 million for the EIRP and remove $27,183,000 from the Company's forecasted capital expenditures for the projected test year in addition to removing the $45,276,000 for premature projects discussed above. Therefore, in total, I recommend that the Commission reduce the projected test year capital expenditures by $72,459,000.

5b. Material Condition Non-Modeled Program

As shown on page 1 of Exhibit A-112 (KAP-4), the Company incurred capital expenditures for the Material Condition Non-Modeled Program of $39.4 million in 2024 and forecasted $52.8 million for 2025, $45.6 million for the 10 months ending October 2026, and $47.2 million for the 12 months ending October 2027. Ms. Pascarello discusses this program beginning on page 50 of her direct testimony.

In contrast to the EIRP, which is a planned replacement of vintage pipelines and services, the Material Condition Non-Modeled program addresses emergent needs for pipeline replacement and other work that arise during the course of the year. Beginning in 2024, the Company expanded this capital program to undertake the replacement of wrought iron mains, replacement of high-pressure mains at water crossings, leak mitigation activities, and replacing obsolete meters. In my testimony below, I will address the replacement of wrought iron mains, the additional leak mitigation activities, and replacement of obsolete meters.

Q. PLEASE DISCUSS YOUR ASSESSMENT OF THE REPLACEMENT OF WROUGHT IRON MAINS WITHIN THE MATERIAL CONDITION NON-MODELED SUBPROGRAM.

A. Beginning in 2024, the Company expanded the non-modeled program to include the replacement of wrought iron mains. Ms. Pascarello discusses this spending category beginning on page 53 of her direct testimony. In 2024, the Company spent approximately $617,000 on wrought iron replacement with additional $2.19 million spent in 2025. For 2026, it proposed to spend $8,842,000 to complete full retirement and replacement of remaining wrought iron mains within the Non-Modeled subprogram.[46]

However, in response to discovery, the Company stated that its current plans are to replace the remaining wrought iron mains through civic asset relocation and the EIRP in addition to the Non-Modeled subprogram.[47] This intermingled replacement plan is unnecessary. Wrought iron mains are similar to cast iron mains that the Company has been replacing within the EIRP. Replacement of the wrought iron mains should be included in the EIRP and prioritized against other projects for risk and replacement. Replacement can also be

---

[46] Exhibit AG-15 includes DR AG-CE-0383.

[47] Id. includes DR MEC-CE-0107.

done through civic asset relocations, as those situations arise. There is no need to include the replacement of wrought iron mains within the Non-Modeled subprogram.

Therefore, I recommend that the forecasted capital expenditures of $8,842,000 for 2026 be removed from the Non-Modeled subprogram. The amount to be removed for the 10 months ending October 2026 is $7,368,000 ($8,842,00 x 10/12) with the remaining amount of $1,474,00 to be removed from the projected test year.

Q. PLEASE DISCUSS YOUR ASSESSMENT OF THE REPLACEMENT OF OBSOLETE METERS WITHIN THE MATERIAL CONDITION NON-MODELED SUBPROGRAM.

A. On page 51 of her direct testimony, Ms. Pascarello briefly mentions the Company's plans to replace 5,500 obsolete residential meters at cost of $6.6 million in the projected test year. On page 65 of her testimony, she discusses the replacement of meter stands that seem related to the replacement of the 5,500 residential meters. Additionally, in response to DR AG-CE-0383, the Company identified $3.7 million of capital expenditures for obsolete meter replacements in 2026, which Ms. Pascarello did not address in her testimony.[48]

In response to discovery, the Company elaborated further and stated that the meters being replaced are diaphragm meters that cannot be repaired when they fail and need to be pre-

---

[48] Id.

engineered before replacement.[49] This explanation is not persuasive. Residential meters are replaced routinely when they fail without the need to be pre-engineered. The Company also has two other programs for meter replacements, one within the Meters program discussed above and the other through the Service Renewal subprogram discussed below. The replacement of the 5,500 obsolete meters should be done within those other programs as the meters fail. There is no need for an additional special program at a total cost of $10.3 million between 2026 and 2027.

Therefore, I recommend that the Commission remove $3,083,000 for the 10 months ending October 2026 ($3,700,000 x 10/12), and $6,117,000 for the 12 months ending October 2027.[50]

Q. PLEASE DISCUSS YOUR ASSESSMENT OF THE REPLACEMENT OF OBSOLETE METERS WITHIN THE MATERIAL CONDITION NON-MODELED SUBPROGRAM.

A. On page 51 of her direct testimony, Ms. Pascarello briefly mentions the Company's plans to mitigate 400 gas leaks at a cost of $2.0 million in the projected test year. In response to DR AG-CE-0383, the Company identified an additional $4.0 million of capital expenditures to mitigate 800 leaks in 2026, which Ms. Pascarello did not address in her testimony.[51] Additionally, on page 62 of her testimony, she discusses leak repairs within

---

[49] Id. DR AG-CE-0368a.
[50] $6,600,000 x 10/12 + $3,700,000 x 2/12 = $6,117,000.
[51] Exhibit AG-15 includes DR AG-CE-0383.

the Material Condition Renewals subprogram that seem related to the mitigation of the 400 leak repairs.

In response to discovery, the Company elaborated further on her testimony and stated that the targeted leak mitigations do not require immediate emergency replacement, but the Company prefers to address them in a planned matter through the Non-Modeled subprogram.[52] This explanation is befuddling. The Company has a separate gas leak repair program to address gas leaks that require both immediate attention and those that can be postponed and repaired later. In addition, the Company has the Material Condition Renewals subprogram to address the replacement of vintage mains, services, and meter stands that are prone to leaks or need to be replaced.[53] There is no reason to have a third spending category to address repairs or mitigation of gas leaks within the Non-Modeled subprogram and increase overall capital spending even further. There is no need for this additional special spending category at a total cost of $6.0 million between 2026 and 2027.

Therefore, I recommend that the Commission remove $3,333,000 for the 10 months ending October 2026 ($4,000,000 x 10/12), and $2,333,000 for the 12 months ending October 2027.[54]

---

[52] Id. DR AG-CE-0368c.

[53] Kristine Pascarello direct testimony at page 62.

[54] $2,000,000 x 10/12 + $4,000,000 x 2/12 = $2,333,000.

Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE MATERIAL CONDITION NON-MODELED PROGRAM?

A. As discussed above, I recommend that the Commission remove $13,784,000 for the 10 months ending October 2026, and $9,924,000 for the projected test year from the Company's forecasted capital expenditures.

5c. Material Condition - Renewal Program

As shown on page 1 of Exhibit A-112 (KAP-4), the Company incurred capital expenditures for the Material Condition-Renewal Program of $38.6 million for 2024 and forecasted spending of $41.7 million for 2025, $37.4 million for the 10 months ending October 2026, and $66.3 million for the 12 months ending October 2027. In comparison the Company spent $31.8 million in 2023. Ms. Pascarello discusses this subprogram beginning on page 60 of her direct testimony.

In her testimony, Ms. Pascarello states that renewals are done by field personnel on an immediate and emergent basis, meaning that there are no specific planned activities. During the most recent three years, 2023-2025, the Company averaged capital expenditures of $40,263,000 in this subprogram, with 2025 expenditures reaching $60.3 million with the increase driven primarily by repairs to facilities from damages likely caused by third parties.[55]

---

[55] Exhibit AG-16 includes DR AG-CE-0373 with Attachment 1 and AG-CE-0375.

For 2026, the Company forecasted capital expenditures of $40.9 million in line with the three-year historical average. However, for the projected test year, the Company forecasted a significant increase in spending to $66,330,000. In her testimony, Ms. Pascarello explains that higher spending is necessary to address potentially additional renewals that could occur from the Company's use of Advanced Methane Detection (AMD) technology, which discovers additional gas leaks. The Company has used AMD technology since at least 2022[56] and there was not a significant impact on Non-Modeled Renewals in 2024 and 2025. As stated earlier, the Company forecasted spending for 2026 is in line with historical levels.

Furthermore, leak survey data provided by the Company shows that Grade 1 hazardous leaks were lower in 2024 and 2025 in comparison with 2023. Grade 1 leaks are the gas leaks that would be addressed quickly under the emergent Renewal subprogram. The AMD technology seems to identify more Grade 2 and 3 Non-Hazardous gas leaks.[57] Therefore, the large increase in spending for the projected test year tied to ADM technology is not supported by historical evidence.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION FOR NON-MODELED RENEWALS?

A. My conclusion is that given the emergent and uncertain nature of future capital expenditures in this subprogram, the most reasonable approach to forecast capital

---

[56] Kristine Pascarello's direct testimony at page 74.

[57] Exhibit AG-16 includes DR AG-CE-0337 with Attachment 1.

expenditures for the projected that year would be to rely on the most recent three-year average capital expenditures of $40,263,000. However, the Company's 2026 forecast capital expenditures are only slightly higher at $40,864,000, which in this situation is a reasonable base to forecast the projected test spending. The higher 2025 expense was largely driven by damage repairs, which are not likely to repeat in the projected test year at the same level,

Using the 2026 forecast, as a more normal level of expense, and adjusting it for 2027 inflation, results in forecasted capital expenditures for the projected test year of $41,637,000.[58] This amount is $24,693,000 lower than the Company's forecast of $66,330,000.

Therefore, I recommend that the Commission remove the $24,693,000 from the Company's forecasted capital expenditures.

5d. Vintage Services Replacement Program

As shown on page 1 of Exhibit A-112 (KAP-4), the Company incurred capital expenditures for the Vintage Service Replacement Program of $19.4 million in 2024 and forecasted $30.1 million for 2025, $43.7 million for the 10 months ending October 2026, and $65.8 million for the 12 months ending October 2027. Ms. Pascarello discusses this subprogram program beginning on page 66 of her direct testimony.

---

[58] $40,854,000 x 1.023 x 10/12 + $40,854,000 x 2/12 = $41,637,000.

The program replaces deteriorating service lines outside of the EIRP. Beginning in 2022, the Company began to align replacement of vintage services with the replacement of mains under the EIRP to avoid duplicating work by replacing services before the associated mains were replaced. From Table 11 on page 69 of Ms. Pascarello's testimony, it appears that this effort resulted in fewer non-EIRP services replacements in 2022, 2023, and 2024. In the three years prior to 2022, the Company replaced more than 5,000 service under the VSR program annually, in 2022 the forecasted number declined to 2,176, and in 2023 it declined further to 1,228 services with a slight reversal in 2024 to 2,569.

In response to discovery, the Company reported that the actual number of services replaced in 2025 was 4,392. For 2026 and 2027, the Company forecasts further increases to 5,913 and 7,683, respectively.[59] Additionally, the Company forecasted a 17% increase in the unit cost from $7,342 in 2025 to $8,559 in 2027, claiming more complex replacements, physical barriers, more commercial customer locations, and higher restoration costs. It is not clear how the Company knew in late 2025 when it prepared its rate case filing what additional obstacles and higher costs it would encounter in 2027. It is also unclear why current and future locations are much different and more complex now than they were historically.

The increase in activity with more units forecasted to be addressed in 2026 and 2027 is also questionable given that the Company has forecasted the number of service replacements to be completed under the EIRP and other programs will decline in 2027 to

---

[59] Exhibit AG-17 includes DR AG-CE-0379 with Attachment 1.

2,617 units from 3,227 units in 2025.[60] The Company is supposedly coordinating replacements of vintage services between the EIRP and the VSR. The Company is not forecasting any let up in spending on the EIRP in 2027. In fact, as discussed above in my testimony, capital spending on the EIRP is increasing in 2027 from prior years.

From the discussion in Ms. Pascarello's testimony, it is not clear why an increase in the number of service replacements for 2026 and 2027 is necessary other than meeting an arbitrary program completion date of 2035. For example, the gas leak data provided on page 66 of her testimony shows a decline in the number of below grade gas leaks after a slight uptick in the number of gas leaks in 2024 from 2023 but overall, there is a declining trend in gas leaks for all types of gas services since 2021. The higher number of service replacements is not adequately supported and should be scaled back.

While I would normally recommend the use of the average number of services replaced in the most recent three-years from 2023 through 2025, which would be 2,730 services with average capital expenditures of $20,983,000, to facilitate a more expeditious replacement of the remaining vintage services, I propose that the actual capital expenditures for 2025 of $32,244,000 with 4,392 units be used to forecast capital expenditures for this subprogram.

---

[60] Id.

The $32,244,000 adjusted for inflation results in 2026 capital expenditures of $33,018,000 or $27,515,000 for the 10 months ending October 2026. This amount is $16,174,000 lower than the $43,689,000 forecasted by the Company.[61]

For the 12 months ending October 2027, I forecasted capital expenditures of $33,651,000 after also adjusting for forecasted inflation for 2027.[62] This amount is $32,110,000 lower than the Company's forecasted amount of $65,761,000.

Based on those calculations, I recommend that the Commission remove the excessive capital expenditures of $16,174,000 for the 10 months ending October 2026 and $32,110,000 for the 12 months ending October 2027 from the Company's forecasted capital expenditures.

6. Tools

On page 1 of Exhibit A-113 (KAP-5), the Company included forecasted capital expenditures for Tools of $4.5 million for 2025, $3.7 million for the 10 months ending October 2026, and $8.1 million for the 12 months ending October 2027. On page 70 of her direct testimony, Ms. Pascarello identifies incremental spending in the projected test year of $3.6 million to support the Work Innovation and Transformation department. She states that this effort is to modernize field operations through the deployment of advanced

---

[61] $32,244,000 x 1.024 = $33,018,000 x 10/12 = $27,515,000.

[62] $32,244,000 x 1.024 x 1.023 = $33,777,000 x 10/12 + $33,018,000 x 2/12 = 33,651,000.

technologies and pilot programs, such as GPS asset tracking, air tagging systems, and an array of other reasons.

In discovery, the Attorney General asked the Company why this additional spending is necessary and to identify cost savings or financial benefits that would be derived from the new technologies. In response, the Company states that the $3.6 million is to replace outdated equipment and improve operational efficiency with the typical standard byline that the additional spending will support the Company's safety, reliability, and affordability commitments. No cost savings were identified or provided. The rest of the discovery response consists of vague statements and concepts about field efficiencies. There is also a reference to funding for enhanced methane detection tools, which is a separate cost category in Ms. Pascarello's testimony with its own funding requirements.[63] The inclusion here of additional funding for methane detection tools seems redundant.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?

A. The incremental spending of $3.6 million for the projected test year for Tools has not been adequately supported or justified. Therefore, I recommend that the Commission remove this amount from the Company's forecasted capital expenditures.

---

[63] Exhibit AG-18 includes DR AG-CE-0380.

7. Compliance & Controls Projects

On page 1 of Exhibit A-113 (KAP-5), the Company included forecasted capital expenditures for Compliance and Controls Projects of $119,000 for 2025, $3.8 million for the 10 months ending October 2026, and $4.9 million for the 12 months ending October 2027. Included in these amounts are capital expenditures for the Advanced Methane Detection (AMD) system. The Company included capital expenditures for this spending category of $3,280,000 for 2026 and $4,773,000 for the projected test year.[64] Ms. Pascarello discusses this item beginning on page 71 of her direct testimony.

As shown in Table 13 on page 74 of Ms. Pascarello's direct testimony, the Company began phase 1 implementation of the AMD system in 2021 and followed with additional phases in later years with cumulative capital spending of $11.67 million through 2024. Additional O&M expenses from 2021 through 2025 have been $1.4 million. This program was initially launched on the expectation that the Pipeline and Hazardous Materials Safety Administration (PHMSA) was ready to issue a new and final rule requiring broader leak detection practices as early as 2023. However, a final rule was never issued, and the current Federal Administration has placed an indefinite hold on the issuance of new regulations including the AMD rule. It is unlikely that in the foreseeable future the rule will be finalized and issued.

---

[64] Table 12 on page 71 of Ms. Pascarello's direct testimony.

Nevertheless, the Company proceeded with the acquisition of expensive equipment in 2021 and with implementation of a program similar to the one contained in the preliminary rule issued by PHMSA. According to Ms. Pascarello's testimony, the Company now states that the new AMD technology has a five-year life cycle and needs to be replaced or upgraded beginning in 2026.[65]

Q. WHAT IS YOUR ASSESSMENT OF THE AMD FORECASTED CAPITAL SPENDING FOR 2026 AND 2027?

A. It is disconcerting that so soon after spending more than $11 million on AMD technology and before any evaluations have been presented on the effectives and incremental benefits of this new technology that the Company now finds it needs to spend an additional $8.0 million over the 2026-2027 timeframe with perhaps even more additional amounts past the year 2027.

Beginning with my testimony in Case No. 21148 and in subsequent Company gas rate cases, I recommended against beginning this program at the time proposed given the still unproven track record of the technology and the preliminary nature of the PHMSA rule. That concern has been proven valid. It is premature now for the Company to request additional large spending on this technology for 2026 and 2027 without a clear understanding of what it has actually achieved to date based on the historical spending and whether it is advisable to continue to spend millions of dollars more going forward at a

---

[65] Kristine Pascarello's direct testimony beginning on page 75.

time when there is no regulatory mandate from PHMSA and customers are facing increasing gas bills each month and bill affordability has become a major issue for customers.

Therefore, I recommend that the Commission reject the Company's proposed spending for 2026 and 2027 and remove $3,280,000 for the 10 months ending October 2026 and $4,773,000 for the projected test year from the Company's forecasted capital expenditures.[66]

10. Distribution Plant – 2025 Underspent Amount

Q. ARE THERE OTHER ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL EXPENDITURES FOR DISTRIBUTION PLANT?

A. Yes. In response to discovery, the Company provided the actual capital expenditures incurred for 2025 Distribution Plant. The report shows that the Company underspent the forecasted capital expenditures for 2025 included in rate base in this case. The Company had forecasted it would spend $251,580,000 on page 1 of Exhibit A-12, Schedule B-5.8 but only spent $247,025,000.[67] The underspent amount was $4,561,000.

The underspent amount cannot remain in rate base. The Company would be earning a return and recovering depreciation expense on costs that it did not incur because that

---

[66] Exhibit A-113, page 3, line 8.
[67] Exhibit AG-19 includes DR AG-CE-0293 and Attachment 1.

amount was not actually spent. Therefore, I recommend that the Commission remove the $4,561,000 from rate base.

B. Transmission Plant - Capital Expenditures

In Exhibit A-12 (MPG-2), Schedule B-5.3, the Company shows actual capital expenditures for Transmission Plant of $317.5 for 2024 and forecasted amounts of $196.6 million for 2025, $185.7 million for the 10 months ending October 2026, and $227.1 million for the 12 months ending October 2027 The three programs within the Transmission area are Asset Relocation, Regulatory Compliance, and Capacity/Deliverability. In my testimony below, I propose adjustments to the capital expenditures in several areas within the three programs.

1. Asset Relocation

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED ASSET RELOCATION WORK AND THE RELATED CAPITAL EXPENDITURES.

A. In Exhibit A-73 (MPG-4), the Company shows forecasted capital expenditures for Asset Relocation projects of $24.9 million for 2025, $24.7 million for the 10 months ending October 2026, and $9.7 million for the projected test year. Beginning on page 5 of his direct testimony, Mr. Michael Griffin discusses the major projects within this program and points out the Company's plans to relocate or lower the depth of shallow pipelines where the depth of soil cover has been eroded.

Using the Company's workpaper WP-MPG-1, which lists the projects that the Company planned to undertake for each year 2025 through 2027,[68] the Attorney General asked the Company to provide additional information on certain projects, such as the current depth of cover, the required depth of the pipeline, the potential risk of damage to the pipeline as it is currently situated, and the current phase of project development.

The information provided by the Company shows that three projects (GL-00091, GL-003470, and B-GL-00617) are in the Conceptual Design phase of project design with no engineering design yet started. These three projects are not sufficiently developed, costs and timing of the projects are still preliminary, and they are too premature to include in rate base in this rate case.[69]

Regarding two other projects, Project GL 00990 is within agricultural farmland with some nearby wetlands. This project has a current depth of cover of 18 inches in comparison to the 36 inches depth that is now required at time of installation of a new pipeline. Project GL 02086 is also within agricultural farmland and has current depth of cover of 21 inches and would require an additional 15 inches of soil cover.[70]

In response to discovery, the Company stated that occasionally it uses other approaches to re-establish depth of cover, such as adding fill or concrete bridging for increased protection, but could not identify a single situation where it had actually added soil to

---

[68] Exhibit AG-20 includes WP-MPG-1.
[69] Id. include DR AG-CE-0306d.
[70] Id. DR AG-CE-0306.

achieve the required depth of cover. The two projects identified above appear to be ideal candidates for soil replacement instead of replacing the 300 to 350 feet of pipeline and burying it deeper. They will only require from 15 to 18 inches of additional soil to be added, which seems manageable for the 300 to 350 feet length of the pipeline. Also, soil in agricultural areas can be more easily replaced given the existence of other soil. Although the Company may have a preference to add capital expenditures to rate base and earn a return on it, the addition of soil should be considered a maintenance item that the Company could have undertaken even earlier before the pipeline reached the current loss of cover.

The capital expenditures for the 10 months ending October 2026 and the projected test year sourced from the WP-MGP-1 for the five projects are shown in the table below.

	Capital Expenditures ($000)				
Project	**10 Month Oct. 2026**		**Projected Test Year**		**Reason For Disallowance**
GL-00091	42		2,488		Premature
GL-03470	42		1,134		Premature
B-GL-00617	42		1,653		Premature
GL-00990	2,995		357		Add Soil
GL-02086	1,714		265		Add Soil
	4,835		5,897		

I recommend that the Commission remove $4,835,000 for the 10 months ending October 2026 and $5,897,000 for the projected test year from the Company's forecasted capital expenditures.

2 . Pipeline Integrity –Transmission

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED TRANSMISSION INTEGRITY WORK AND THE RELATED CAPITAL EXPENDITURES.

A. On page 1 of Exhibit A-60 (MPG-4), the Company shows forecasted capital expenditures for Pipeline Integrity-Transmission of $14.6 million for 2025, $7.8 million for the 10 months ending October 2026, and $23.2 million for the projected test year. Mr. Griffin discusses this capital subprogram beginning on page 10 of his direct testimony.

In workpaper WP-MGP-14, the Company shows the list of projects and related capital expenditures for 2026 and 2027. In response to discovery, the Company provided similar information for 2023 through 2025.[71] This information shows that the average cost per pipeline integrity project has increased over the past three years from $461,382 in 2023 to $756,142 in 2025. For 2026, the Company forecasted 18 pipeline integrity projects for a total cost of $8,659,759, translating to a cost per project of $481,098. This cost is within the range of historical costs for the past three years.

However, for 2027, the Company forecasted capital expenditures of $24,953,187 for 17 projects, which translates to an average cost of $1,467,835 per project. Although the Company shows two large projects for 2027, this situation is not unique. In 2023 and 2024, the Company also had projects of similar size and the average cost per project was

---

[71] Exhibit AG-21 includes WP-MPG-14 and DR AG-CE-0313 with attachments.

still much lower than in 2027. The $1,467,835 average project cost for 2027 is excessive at nearly twice the highest cost of the past three years of $756,142, which occurred in 2025.

Adjusted for 2026 and 2027 inflation, the $756,142 increases to $792,098.[72] The difference between this amount and the $1,467,835 in the Company's 2027 forecast is $675,737. Multiplied by the 17 projects planned for 2027, the $675,737 results in an excess cost of $11,488,000. Mr. Griffin's testimony offers no explanation or justification for this large cost increase over recent historical levels.

Therefore, I recommend that the Commission remove the $11,488,000 for the projected test year from the Company's forecasted capital expenditures.

3. Pipeline Integrity –TOD

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES PIPELINE INTEGRITY WORK ON TRANSMISSION LINES OPERATED BY DISTRIBUTION (TOD).

A. On page 1 of Exhibit A-74 (MPG-4), the Company shows forecasted capital expenditures for Pipeline Integrity work for TOD of $6.6 million for 2026, $8.5 million for the 10 months ending October 2026, and $15.9 million for the projected test year. Mr. Griffin discusses this capital subprogram beginning on page 19 of his direct testimony.

---

[72] $756,142 x 1.024 x 1.023 = $792,098.

In workpapers WP-MGP-13 and 15, the Company shows the list of projects and related capital expenditures for 2026 and 2027. In response to discovery, the Company provided similar information for 2023 through 2025.[73] This information shows that the average cost per pipeline integrity project over the past three years ranged from $92,245 to $239,010 with the highest amount occurring in 2025. For 2026, the Company forecasted 16 pipeline integrity projects for a total cost of $10,333,781, translating to a cost per project of $645,861. For 2027, the Company forecasted capital expenditures of $16,939,988 for 20 projects, which translates to an average of $846,999 per project. The forecasted costs per project for 2026 and 2027 vary significantly from recent historical levels.

In his direct testimony, Mr. Griffin does not explain or provide justification for the large escalation in project costs in 2026 and 2027. The 2026 average project cost of $645,861 is more than two and half times higher than the highest average project cost of $239,010 in the past three years. The 2027 average project cost at $846,999 is three and half times higher than the 2025 project cost. The forecasted costs are excessive and need to be moderated.

Adjusted for 2026 inflation, the 2025 average project cost of $239,010 increases to $244,746.[74] The difference between this amount and the $645,861 in the Company's 2026 forecast is $401,115. Multiplied by the 16 projects planned for 2026, the $401,115 results in an excess cost of $6,418,000 or $5,348,000 for the 10 months ending October 2026.

---

[73] Exhibit AG-22 includes WP-MPG-13 and 15, and DR AG-CE-0312 with attachments.

[74] $239,010 x 1.024 = $244,746.

The $244,746 average project cost from 2026 adjusted for inflation results in an average project cost of $250,375 for 2027.[75] The difference between this amount and the $846,999 in the Company's 2027 forecast is $596,624. Multiplied by the 20 projects planned for 2027, the $596,624 results in an excess cost of $11,932,000. The excess cost pertaining to the projected test year is $11,013,000.[76]

I recommend that the Commission remove the $5,348,000 for the 10 months ending October 2026 and $11,013,000 for the projected test year from the Company's forecasted capital expenditures.

4. TED-I Projects

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CAPITAL EXPENDITURES FOR TRANSMISSION ENHANCEMENTS FOR DELIVERABILITY AND INTEGRITY (TED-I).

A. On page 1 of Exhibit A-5 (MPG-5), the Company shows forecasted capital expenditures for TED-I projects of $17.6 million for 2025, $13.4 million for the 10 months ending October 2026, and $24.8 million for the projected test year. In workpaper WP-MPG-7, the Company lists the projects and related dollars that make up the forecasted capital expenditures for 2025 through 2027.[77]

---

[75] $244,746 x 1.023 = $250,375.

[76] $11,932,000 x 10/12 + 6,418,000 x 2/12 = $11,013,000.

[77] Exhibit AG-23 includes WP-MPG-7.

In response to discovery, the Company provided the current phase of project development for four projects.[78] For three of the projects, the Company stated that it is currently refining the project scope and reviewing site locations and will not move to the next phase until late 2026. The fourth project is in the early phase of design but requires an Act 9 filing, which the Company plans to make in July 2026. All four projects are still in the preliminary phase of project development and are still premature to include in rate base in this rate case.

The following table shows the capital expenditures pertaining to each project sourced from WP-MPG-7.

	Capital Expenditures ($000)				
Project	10 Month Oct. 2026		Projected Test Year		Reason For Disallowance
GL-03049			2,127		Premature
GL-00136			973		Premature
GL-00140			1,915		Premature
GL-03212	1,054		10,647		Act 9 Filing
	1,054		15,662		

I recommend that the Commission remove $1,054,000 for the 10 months ending October 2026 and $15,662,000 for the projected test year from the Company's forecasted capital expenditures.

---

[78] Id. includes DR AG-CE-0310 and ST-CE-0038.

5. Deliverability Field Measurement Projects

Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR DELIVERABILITY FIELD MEASUREMENT PROJECTS.

A. On line 3 of page 1 of Exhibit A-75 (MPG-5), the Company included forecasted capital expenditures for Field Measurement projects of $9.2 million for 2025, $9.8 million for 10 months ending October 2026, and $25.4 million for the projected test year. In comparison, the Company spent $5.7 million in 2024. In workpaper WP-MPG-3, the Company provided the list of projects that comprise the total capital expenditures for 2025 through 2027.[79] Beginning on page 36 of his direct testimony, Mr. Griffin describes the program activities, lists the major projects, and points to the Company's goals of improving gas measurement accuracy and reducing lost and unaccounted for (LAUF) gas in support of the capital spending in this area.

In discovery, the Attorney General asked the Company to provide more pertinent information on the larger projects, such as the current phase of project development, the project cost/benefit analysis, what the capital dollars will be spent on, what the project entails, and why it is necessary. In response, the Company reported that most projects are in the early stage of conceptual scope, project planning and scoping, and no design work

---

[79] Exhibit AG-24 includes WP-MPG-3.

has yet started. The Company also reported that no cost/benefit analyses were prepared for any of the projects.[80]

The following table shows the pertinent projects with capital expenditures sourced from WP-MPG-3 and project development phase from DR AG-CE-0307.

	Capital Expenditures ($000)		
Project	**10 Month Oct. 2026**	**Projected Test Year**	**Reason For Disallowance**
GM-01089		11,304	Premature
B-GM-00042	2,053	1,026	Premature
B-GM-00043	4,244	639	Premature
B-GM-00045	224	978	Premature
B-GM-00047	422	944	Premature
B-GM-00049		866	Premature
B-GM-00051		4,326	Premature
B-GM-00053	422	669	Premature
	7,365	20,752	

These projects are still in the preliminary and very early stages of project development with no design work yet started. It is premature to include the preliminary capital expenditures for these projects in rate base in this rate case. I recommend that the Commission remove the $7,365,000 for the 10 months ending October 2026 and the $20,752,000 for the projected test year from the Company's forecasted capital expenditures.

---

[80] Id. includes DR AG-CE-0307 with ATT-1.

Q. ARE THERE OTHER OBSERVATIONS YOU WANT TO MAKE REGARDING ONE OF THE PROJECTS IN THE FIELD MEASUREMENT SUBPROGRAM?

A. Yes. With project GM-01089 Williamston Transmission Meter Proving Station, the Company proposes the construction of a new testing facility to prove and test transmission meters before installation for compliance with API-1164. The total cost of this facility is $11.3 million in the projected test year and has increased from $9.4 million reported in Case No. U-21806. The Company currently uses a third-party testing facility. No cost/benefit analysis was performed by the Company in the last rate and none has been performed in the current rate case to justify this project for bringing the work in-house. In the last rate case, I pointed out the deficiencies in the Company's analysis, and it seems that not much has changed in this rate case filing.[81] Although it may be more convenient for the Company to have its own meter testing facility, the cost to build, equip and staff such a facility is very large. The cost/benefit analysis must compare the full cost of building and operating such a testing facility with the cost of continuing to use a third-party provider and must be thorough and accurate using sound financial analysis. As stated above, in addition to being in the very early phase of project development, this project has not been economically justified.

---

[81] In its Brief in Case No. U-21806, the Company withdrew its request for capital spending for this project.

6. Deliverability Base Pipeline Program

Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR THE DELIVERABILITY BASE PIPELINE PROGRAM.

A. On line 4 of page 1 of Exhibit A-75 (MPG-5), the Company included forecasted capital expenditures for the Deliverability Base Pipeline program of $22.8 million for 2025, $19.8 million for 10 months ending October 2026, and $24.6 million for the projected test year. In comparison, the Company spent $18.8 million in 2024. In workpaper WP-MPG-4, the Company provided the list of projects that comprise the total forecasted capital expenditures for 2025 through 2027.[82] In response to discovery, the Company provided additional details for select larger projects, such as the current phase of project development as of early March 2025.

Discovery response AG-CE-0308 shows that three projects are in the planning and scoping phase, two projects are emergent placeholder projects with no specific project identified, and five projects are at 30% of engineering design.[83] Additionally, on page 5 of WP-MPG-4, the Company included $10,980,000 for unknown emergent projects that may not occur during 2027. In effect, this is as a placeholder amount.

---

[82] Exhibit AG-25 includes WP-MPG-4.

[83] Id. includes DR AG-CE-0308 and SA-CE-189.

The following table shows the pertinent projects with capital expenditures sourced from WP-MPG-4 and the project development phase from DR AG-CE-0308.

	Capital Expenditures ($000)		
Project	**10 Month Oct. 2026**	**Projected Test Year**	**Reason For Disallowance**
GL-03316		761	Planning Scope
GL-03805	1,343	314	Design at 30%
GL-03640	2,710	635	Design at 30%
B-GL-00262	1,506	353	Design at 30%
B-GL-00264	718	168	Design at 30%
B-GL-00268		690	Planning Scope
B-GL-00272		2,524	Placeholder
B-GL-00273		2,524	Placeholder
B-GL-00625		907	Planning Scope
Emergent		10,980	Placeholder
Total	6,277	19,856	

The projects in the planning/scoping phase and with design work at only 30% are still in the preliminary and very early stages of project development with no design work yet started or sufficiently advanced. It is premature to include the preliminary capital expenditures for these projects in rate base in this rate case. Regarding emergent and placeholder amounts for projects not yet known, in prior rate cases, the Commission has rejected the inclusion of placeholder amounts in rate base.

Therefore, I recommend that the Commission remove the $6,277,000 for the 10 months ending October 2026 and the $19,856,000 for the projected test year from the Company's forecasted capital expenditures.

6. T&S City Gate Projects

Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR CITY GATE PROJECTS.

A. On line 6 of page 1 of Exhibit A-75 (MPG-5), the Company included forecasted capital expenditures for T&S City Gates of $45.3 million for 2025, $51.9 million for 10 months ending October 2026, and $48.5 million for the projected test year. In workpaper WP-MPG-6, the Company provided the list of projects that comprise the total forecasted capital expenditures for 2025 through 2027.[84] In response to discovery, the Company provided the phase of development of larger planned projects along with other pertinent information.[85]

Attachment 1 to discovery response AG-CE-0309 (Exhibit AG-26) shows that of the 17 large projects where additional information was solicited by the Attorney General, three projects are in the pre-engineering design phase, meaning that no design work has started on these projects. As with other preliminary and early stages of project development, it is very likely that the cost for these projects will change from the amounts proposed by the Company and the timing of construction could slip into a future year. Therefore, it is

---

[84] Exhibit AG-26 includes WP-MPG-6.
[85] Id. includes DR AG-CE-0309 with attachment.

premature to include the forecasted capital expenditures for these projects in rate base in this case.

Additionally, in WP-MPG-6, the Company included a placeholder amount for potential emergent projects that may or may not arise during 2026 and 2027. As stated earlier, in prior rate cases, the Commission has rejected the inclusion of placeholder amounts in rate base.

The following table shows the pertinent projects with capital expenditures sourced from WP-MPG-6 and the project development phase from DR AG-CE-0309.

	Capital Expenditures ($000)		
Project	**10 Month Oct. 2026**	**Projected Test Year**	**Reason For Disallowance**
B-GL-00319	113	1,607	Pre-Design
B-GL-00320	686	8,689	Pre-Design
B-GL-00473	184	7,186	Pre-Design
Emergent	394	3,347	Placeholder
Total	1,377	20,829	

Therefore, I recommend that the Commission remove $1,377,000 for the 10 months ending October 2026 and $20,829,000 for the projected test year from the capital expenditures forecasted by the Company.

7. Transmission Plant – 2025 Underspent Amount

Q. ARE THERE OTHER ADJUSTMENTS THAT YOU PROPOSE TO CAPITAL EXPENDITURES FOR DISTRIBUTION PLANT?

A. Yes. In response to discovery, the Company provided the actual capital expenditures incurred for 2025 Transmission Plant. The report shows that the Company underspent the forecasted capital expenditures for 2025 included in rate base in this rate case. The Company had forecasted it would spend $198,611,000 on page 1 of Exhibit A-12, Schedule B-5.3 and actually spent $193,061,000.[86] The underspent amount was $5,550,000.

The underspent amount cannot remain in rate base. The Company would be earning a return and recovering depreciation expense on costs that it did not incur because that amount was not actually spent. Therefore, I recommend that the Commission remove the $5,550,000 from rate base.

C. Gas Compression & Storage - Capital Expenditures

On page 1 of Exhibit A-12 (TKJ-4), Schedule B-5.5, the Company forecasted capital expenditures for Gas Compression and Storage projects of $196.6 million for 2025, $153.8 million for the 10 months ending October 2026, and $187.2 million for the 12 months ending October 2027. In comparison, the Company spent $167.8 million in 2024.

---

[86] Exhibit AG-27 includes DR AG-CE-0302 and Attachment 1.

Included in these amounts are capital expenditures for projects where I will recommend certain adjustments as discussed in my testimony below.

1. Lyon 29/34 (Northville Storage) Dehydration

Q. PLEASE DISCUSS THE NORTHVILLE STORAGE GAS DEHYDRATION PROJECT.

A. On line 11 of page 2 of Exhibit A-12 (TKJ-4), Schedule B-5.5, the Company shows the forecasted capital expenditures for the Northville Storage Field of $17.0 million for 2025, $18.6 million for the 10 months ending October 2026, and $0.5 million for the 12 months ending October 2027. Beginning on page 30 of his direct testimony, Mr. Timothy Joyce discusses the Lyon 29/34 project which entails the construction of a dehydration system. The Company has been concerned with the moisture content of the gas withdrawn from the Northville gas storage field not meeting the 7bl. per Mcf required for delivery to customers, as measure at the customer's meter. The Lyon 29/34 is a metering station feeding gas to a transmission line and the Northville storage compressor station. To resolve the occasional excessive moisture content of the gas stream, originating from the Northville storage field during the gas withdrawal period, the Company has been installing a gas purification/dehydration facility near the Northville compressor station.

Mr. Joyce does not identify the cost of this project in his testimony. In response to discovery, the Company provided a schedule that shows the total cost from 2018 to the end of 2028 at $40,396,000.[87] In the last rate case (Case No. U-21806), approximately one year ago, the Company forecasted that the total project cost would be $37,371,000.[88] Therefore, in about 12 months, the cost of the project increased by $3,025,000. In response to discovery, the Company stated that the cost increase is due to higher than budgeted construction contractor cost after the bidding process. No further explanation or justification for the cost overrun was provided.

The Construction of the Lyon 29/34 dehydration facilities has been an item of contention in prior rate cases. In the last three rate cases, I submitted testimony arguing that given the limited use of the field and other alternatives available to the Company to withdraws and blend gas into its pipeline system, the high cost to build a dehydration facility that would be used only occasionally, and in certain years not at all, was not justified. The information provided by the Company in this rate case, both in testimony and discovery responses does not change that fact.

Although in the September 30, 2025 order in Case No. U-21806, the Commission decided to approve the projected capital spending of $3.65 million for the 12 months ending October 2026, that decision presumed total capital spending on the project of $37,371,000, as presented by the Company in that case. The cost overrun of $3,025,000 proposed for recovery in this rate case within the $18,647,000 forecasted for the 10 months ending October 2026 has not been approved by the Commission.

---

[87] Exhibit AG-28 includes DR AG-CE-0318 with ATT_1.

[88] Id. includes DR U-21806 AG-CE-0506 with ASTT_1.

In his direct testimony, Mr. Joyce does not discuss the cost of the project at all and does not address the cost overrun. The explanation provided in response to discovery about construction costs increasing after the Company received a contractor bid is wholly inadequate. In summary, the Company has not justified the cost overrun. Given the already high cost of the project and questionable decision to proceed with construction of the dehydration facility, as discussed above, customers should not be burdened with any cost overruns.

Therefore, I recommend that the Commission remove the $3,025,000 from the Company's forecasted capital expenditures for the 10 months ending October 2026.

2. Storage New Wells

Q. PLEASE PROVIDE AN ASSESSMENT OF THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR DRILLING NEW STORAGE WELLS.

A. On page 2, line 15, of Exhibit A-12 (TKJ-4), Schedule B-5.5, the Company forecasted capital expenditures to drill new storage wells of $24.1 million for 2025, $32.0 million for the 10 months ending October 2026, and $31.0 million for the projected test year. In comparison, the Company spent $15.0 million in 2024. Mr. Joyce discusses the capital expenditures for this program beginning on page 33 of his direct testimony but provides no explanation as to how the forecasted costs to drill new wells and re-entry wells were determined.

In response to discovery, the Company provided an updated Table 7 from Mr. Joyce's testimony with actual expenditures incurred for each well for the applicable year from 2022 to 2027.[89] For new wells, and excluding re-entry wells, the data shows that the average cost to drill a new well in 2023 through 2025 was $5,559,000 and for a re-entry well the cost in 2023 was $3,440,000. Adjusted for inflation the cost for 2026 for a new well is $5,692,000 and for 2027 is $5,823,000.[90] For a re-entry well, the inflation-adjusted cost for 2026 is $3,730,000 and for 2027 is $3,816,000.[91]

For 2026, the Company plans to drill 4 new wells for a total amount of $26,500,000 and at an average cost per well of $6,625,000. This cost is 16% higher than the 2026 inflation-adjusted historical cost per well of $5,692,000 shown above. The Company's forecasted cost per well is excessive and not justified. Using the inflation-adjusted cost $5,692,000 and applying it to the 4 planned wells, the total forecasted cost for 2026 is $22,768,000 and $18,973,000 for the 10 months ending October 2026 with the remaining amount of $3,795,000 carried into the projected test year.

For 2027, the Company plans to drill 4 new wells at a total cost of $24,211,000 or an average cost per well of $6,053,000. This cost is only 4% higher than the historical inflation-adjusted cost and seems reasonable. The amount for the four wells applicable to the projected test year is $20,176,000.[92]

---

[89] Exhibit AG-29 includes DR AG-CE-0319.
[90] $5,559,000 x 1.024 = $5,692,000 x 1.023 = $5,823,000.
[91] $3,440,000 x 1.030 x 1.028 x 1.024 = $3,730,000 x 1.023 = $3,816,000. Inflation rates from Exhibit AG-2.
[92] $24,211,000 x 10/12 = $20,176,000.

For the re-entry well planned for 2026, the Company forecasted a cost of $4,797,000. This amount is 29% higher than the inflation-adjusted historical cost of $3,730,000. The Company's forecasted cost is excessive and needs to be moderated. The inflation-adjusted cost of $3,730,000 is a reasonable cost estimate for the re-entry well planned for 2026. The amount applicable for the 10 months ending October 2026 is $3,108,000 with the remaining amount of $622,000 carried into the projected test year.

For 2027, the Company plans to drill two re-entry wells at a cost of $7,745,000. The average cost per well is $3,873,000. This cost is in line with the inflation-adjusted historical cost and seems reasonable. The amount for the two wells applicable to the projected test year is $6,454,000.[93]

In summary, based on the analysis presented above, I have determined that the total forecasted cost for new wells and re-entry well for the 10 months ending October 2026 is $22,081,000. This amount is $9,870,000 lower than the $31,851,000 forecasted by the Company. For the projected test year, I have determined that the applicable forecasted cost for both new well and re-entry wells is $31,047,000. This amount is nearly equal to the $31,046,000 forecasted by the Company and no adjustment is necessary.

Therefore, I recommend that the Commission remove $9,870,000 for the 10 months ending October 2026 from the Company's forecasted capital expenditures.

---

[93] $7,745,000 x 10/12 = $6,454,000.

3. Gas Compression Projects

Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR GAS COMPRESSION PROJECTS.

A. On line 2 of page 1 of Exhibit A-12 (TKJ-4), Schedule B-5.5, the Company included forecasted capital expenditures for Compression projects of $54.7 million for 2025, $59.1 million for 10 months ending October 2026, and $19.3 million for the projected test year. In workpaper WP-TKJ-4, the Company provided the list of projects that comprise the total forecasted capital expenditures for 2025 through 2027.[94] In response to discovery, the Company provided the phase of development of larger planned projects along with other pertinent information.[95]

Discovery response AG-CE-0324 (Exhibit AG-30) shows that of the 18 large projects where additional information was solicited by the Attorney General, six projects are in the Preliminary Assessment, Conceptual Design or Planning and Scoping phase of project development, meaning that no engineering design work has started on these projects. Three other projects are in the early stage of engineering design with the next phase of contractor bid requests not beginning until late in 2026.

---

[94] Exhibit AG-30 includes WP-TKJ-4.
[95] Id. includes DR AG-CE-0324.

As with other preliminary and early stages of project development, it is very likely that the cost for these projects will change from the amounts proposed by the Company and the timing of construction is still unknown and could slip into a future year past the end of the projected test year. Therefore, it is premature to include the forecasted capital expenditures for these projects in rate base in this rate case.

The following table shows the pertinent projects with capital expenditures sourced from WP-TKJ-4 and the project development phase from DR AG-CE-0324.

	Capital Expenditures ($000)		
Project	**10 Month Oct. 2026**	**Projected Test Year**	**Reason For Disallowance**
GC-00784	1,189	1,406	Early Eng. Design
GC-00801	2,055	2,271	Early Eng. Design
GC-00785	430	3,125	Planning Scoping
GC-00839	3,511	839	Early Eng. Design
GC-00876	215	1,329	Conceptual Design
B-GC-00153		1,651	Planning Scoping
GC-00885	1,771	13,377	Conceptual Design
B-GC-00048		877	Planning Scoping
B-GC-00154		888	Planning Scoping
Total	9,171	25,763	

Therefore, I recommend that the Commission remove $9,171,000 for the 10 months ending October 2026 and $25,763,000 for the projected test year from the capital expenditures forecasted by the Company.

4. Gas Storage and Pipeline Projects

Q. PLEASE DESCRIBE YOUR FINDINGS WITH REGARD TO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY FOR GAS STORAGE AND PIPELINE PROJECTS.

A. On line 4 of page 1 of Exhibit A-12 (TKJ-4), Schedule B-5.5, the Company included forecasted capital expenditures for Gas Storage projects of $30.4 million for 2025, $32.0 million for 10 months ending October 2026, and $19.3 million for the projected test year. Additionally, on line 6 of the exhibit, the Company included forecasted capital expenditures for Gas Storage Pipeline projects of $37.5 million for 2025, $8.6 million for 10 months ending October 2026, and $57.6 million for the projected test year.

In workpaper WP-TKJ-5, the Company provided the list of projects that comprise the total forecasted capital expenditures for 2025 through 2027.[96] In response to discovery, the Company provided the phase of development of larger planned projects along with other pertinent information.[97]

Discovery response AG-CE-0325 (Exhibit AG-31) shows that of the 11 large projects where additional information was solicited by the Attorney General, 8 projects are in the Project Planning, Preliminary Design or early phase of engineering design and project development. Four projects require Act 9 approval by the Commission and the Company

---

[96] Exhibit AG-31 includes WP-TKJ-5.

[97] Id. includes DR AG-CE-0325.

does not plan to file an application until either March or July 2026. For those projects that are in the early stage of engineering design the next phase of contractor bid requests does not begin until 2027.

As with other preliminary and early stages of project development, it is very likely that the cost for these projects will change from the amounts proposed by the Company and the timing of construction is still unknown and could slip into a future year past the end of the projected test year. Therefore, it is premature to include the forecasted capital expenditures for these projects in rate base in this rate case.

The following table shows the pertinent projects with capital expenditures sourced from WP-TKJ-5 and the project development phase from DR AG-CE-0325.

	Capital Expenditures ($000)		
Project	**10 Month Oct. 2026**	**Projected Test Year**	**Reason For Disallowance**
GS-00543		1,317	Project Planning
GS-00504	53	6,242	Preliminary Design
GS-00506	3,488	282	No Act 9 Approval
GS-00509	73	9,165	No Act 9 Approval
GS-00510	63	2,396	Early Eng. Design
GS-00515	989	16,458	No Act 9 Approval
GS-00520	137	14,528	Early Eng. Design
GS-00537	522	7,043	Early Eng. Design
Total	5,325	57,431	

Therefore, I recommend that the Commission remove $5,325,000 for the 10 months ending October 2026 and $57,431,000 for the projected test year from the capital expenditures forecasted by the Company.

5. Gas Compression & Storage – 2025 Capital Expenditures Underspent

In discovery, the Attorney General asked the Company to provide the actual amount spent on all Gas Compression and Storage capital programs during 2025. In response the Company reported that it spent $161,744,000 in 2025.[98] In Exhibit A-12 (TKJ-5), Schedule B-5.5, page 1, the Company shows that it included $196,595,000 of capital expenditures for 2025 in this rate case. The difference is an underspent amount of $34,851,000. This amount should be removed from rate base in this rate case. The Company did not incur this cost and it is not fair or reasonable for the Company to earn a return and recover depreciation expense for costs it did not incur.

Therefore, I recommend that the Commission remove the 2025 underspent amount of $34,851,000 from rate base in this rate case.

D. Information Technology (IT) - Capital Expenditures

Information Technology projects are often presented by both the Company witness in the operating function that requires and sponsors the project and from the IT witness responsible for developing and implementing the project, and who is also responsible for the cost of the project. Therefore, reference is often made to testimony, exhibits, and discovery responses from multiple witnesses.

---

[98] Exhibit AG-32 includes DR AG-CE-0320 with ATT_1.

1. Gas Facilities Tracking and Traceability Project

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE CAPITAL EXPENDITURES FOR THE GAS FACILITIES TRACKING AND TRACEABILITY SYSTEM.

A. On page 80 of his direct testimony, Mr. Warriner discusses the Tracking and Traceability system project with forecasted capital expenditures of $6,619,000 and $509,000 in O&M development costs in the test year. However, on page 50 of her testimony, Company witness Stacey Baker adjusted the capital expenditures down to $5,295,000 to allow for the ROM adjustment.[99] In response to discovery, the Company identified also capital expenditures of $2,772,000 that were included in the 10 months ending October 2026.[100] The project intends to develop a system to identify, track, and trace the Company's gas facilities from pipes to fittings and other components.

This is the third rate case where the Company has proposed undertaking the project and it has not advanced much, if at all, from the initial proposal. The project was also proposed in Case Nos. U-21490 and U-21806. In discovery in U-21806, the Attorney General asked the Company to provide the project cost/benefit analysis and the project development phases including the current phase of the project. In response, the Company provided a copy of the project cost analysis showing that the estimated cost of the project was more than $15 million to be developed over the 2025 to 2027 timeframe. No cost savings or

---

[99] ROM = Rough Order of Magnitude is an adjustment to compensate for forecasting errors in preliminary project cost estimates.

[100] Exhibit AG-33 includes DR AG-CE-0292 with ATT_1.

financial benefits were identified for the project. The Company also disclosed that the project was in the investment planning phase.[101]

In this rate case, the Company reported in response to discovery that the project is still in the Investment planning phase and the detailed requirements phase has not even started.[102] The attachment to DR AG-CE-0292 (Exhibit AG-33) shows an updated project cost of $17.7 million, including O&M development costs. No cost savings or financial benefits have been identified in the financial analysis, and the Benefit/Cost ratio is a negative 1.0, meaning the project entails only costs and no financial benefits.

Q. WHAT IS YOUR ASSESSMENT OF THE TRACKING AND TRACEABILITY PROJECT?

A. Aside from the fact the project is not economically justified, the project is in the early stage of development, being in the Investment Planning phase. It appears that only high-level requirements have been identified and not much work has been done to assess and match detailed system requirements to the prospective system to be acquired or developed. In response to DR AG-CE-0292, the Company stated that the project had been postponed to 2027 and the Company proposed adjusted capital expenditures for the forecasted periods.

Given the preliminary stage of development and the lack of an economic case for the project, I recommend that the Commission remove the capital expenditures of $2,772,000

---

[101] U-21490 Exhibit AG-31 includes DR AG-CE-0221 with related attachments.
[102] Exhibit AG-33 includes DR AG-CE-0292.

for the 10 months ending October 2026 and $5,295,000 from the projected test year, along with $509,000 from O&M expense.

2. ARP-Field Devices

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE PURCHASE OF FIELD DEVICES AND RELATED EQUIPMENT AND COSTS UNDER THE ARP-FIELD DEVICE ASSET MANAGEMENT (FDAM) PROGRAM.

A. On page 8 of Exhibit A-24 (SHB-9), the Company shows the capital expenditures and number of units for ARP-Field devices for total company and the portion applicable to the gas business for each year 2024 through 2027. For the gas business the Company allocated capital expenditures of $1,200,000 for 2024, $772,000 for 2025 and forecasted an amount of $2,040,000 for the projected test year. No allocation amount is shown for the 10 months ending October 2026. The projected test year amount forecasted by the Company is nearly two and half times higher than the amount for 2025 and I find it excessive in comparison to the amount allocated in recent years.

For the three years, 2023 to 2025, the Company allocated an average amount of $1,007,000 to the gas business for unit purchases of 638.[103] Based on this data, the average cost per unit allocated to the gas business was $1,579. Adjusted for inflation the average cost per unit for 2026 is $1,617 and for 2027 is $1,654.[104] On page 76 of her testimony, Ms. Baker

---

[103] Exhibit A-24, page 5, for 2024 and 2025 data, and U-21608 Exhibit A-22, page 4, for 2023 actual data.
[104] $1,579 x 1.024 = $1,617 x 1.23 = $1,654.

states that the Company replaces devices on a four-year cycle, therefore the average of the devices replaced during the past three years should be representative of the annual replacement quantity for 2026 and 2027.

As mentioned above, the Company on average replaced 638 devices during the past three years. Using this quantity and applying the inflation-adjusted cost of $1,617, the forecasted capital expenditures for 2026 are $1,032,000 or $860,000 for the 10 months ending October 2026. This amount is $1,274,000 lower than the $2,134,000 forecasted by the Company.[105]

For 2027, the average unit cost of $1,654 applied to the 638 units results in capital expenditures of $1,055,000 or $1,051,000 for the 12 months ending October 2027.[106] This amount is $989,000 lower than the Company's forecasted amount of $2,040,000.

I recommend that the Commission remove $1,274,000 for the 10 months ending October 2026 and $989,000 for the projected test year from the Company's forecasted capital expenditures.

3. Forward Web Proxy Services

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE FORWARD WEB PROXY SERVICES PROJECT.

---

[105] Total company 2026 forecast $7,577,109 x 33.8% gas allocation from projected test year x 10/12 = $2,134,000.

[106] $1,055,000 x 10/12 + $1,032,000 x 2/12 = $1,051,000.

A. On pages 137 and 138 of her direct testimony, Ms. Baker discusses undertaking this IT system project to replace a system currently in place with a third-party vendor. The Forward Web Proxy Services system works as a filtering process to direct customer internet inquiry traffic to different subsystems in the Company's web server. According to Ms. Baker's direct testimony and responses to discovery in Case No. U-21806, the Company had experienced technical glitches with the vendor service and now wishes to develop its own software at a capital cost of $4.5 million plus an additional $1,013,000 for O&M development and with $1.3 million of the capital cost assigned to the gas business for the projected test year.[107] The Company has adjusted this amount down to $1,008,000 after the ROM adjustment for inclusion in this rate case.

In response to discovery, the Company reported that the service issues with the third-party service provider had been resolved, although it may need to amend or supplement the current licensing agreement to obtain data loss prevention.[108] The Company seems to prefer to develop its own system. However, no cost/benefit analysis has been provided that justifies undertaking this project at an estimated cost of $4.5 million when a less costly alternative exists. The Company's financial analysis for the proposed project shows a cost/benefit ratio of negative 1.0, meaning that no financial benefits have been identified to undertake this project.

---

[107] Exhibit A-22, page 63.

[108] Exhibit AG-34 includes DR AG-CE-0404.

Furthermore, the Company stated in response to discovery that the project is still in the Investment Planning phase and has not advanced from similar proposals made in prior gas and electric rate cases.

My conclusion from the information provided by the Company is that this software development project is not necessary, it is premature, and not a priority project that should be undertaken for the projected test year. Therefore, I recommend that the Commission remove the $1,008,000 from the forecasted capital expenditures for the projected test year along with the $149,000 of O&M expense.

6. OT Data Center Migration Project

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE OT DATA CENTER MIGRATION PROJECT.

A. On pages 114 through 106 of her direct testimony, Ms. Baker discusses the relocation of the servers and systems, which monitor some of the Company's electric and gas operations, from the current location at the Parnel building to another location. Apparently, the Company has experienced some problems with climate and water infiltration into the building and feels that the situation is unrepairable and untenable. The cost of the relocation and associated equipment upgrades is $17.7 million between capital expenditures and O&M development costs, of which at least one-third would be assigned to the gas business.[109] The amount of capital expenditures included in this rate case is

---

[109] Exhibit A-22, page 86.

$988,000 for the 10 months ending October 2026 and $953,000 after the ROM adjustment with $349,000 of O&M development costs for the projected test year.[110]

In her direct testimony, Ms. Baker states that the cost to replace the current climate control equipment and water filtration system would be $5,082,728. In response to discovery, Ms. Baker states that she first reported this cost in rebuttal testimony in Case U-21870 in October 2025.[111] This recent disclosure is troubling, because the Company was asked about this same system and issue in Case U-21806 about a year ago and no mention was made of the cost or need to replace the climate control and water filtrations systems.[112]

However, assuming that the cost to replace the climate control and water filtration systems is accurate, this cost is less than one-third the $17.7 million to undertake a migration of the OT Datacenter to a new location. The need to open a new backup datacenter is also questionable given the ongoing migration of data processing to the cloud. Beginning on page 17 of her direct testimony, Ms. Baker discusses the Company's efforts and advantages to moving more software applications to cloud computing and on page 19 states that "Moving to the cloud allows the Company to avoid the large capital expense of building a new data center."

---

[110] Stacey Baker direct testimony at page 114 and DR AG-CE-0401 included in Exhibit AG-35.
[111] Exhibit AG-35 includes DR AG-CE-0402.
[112] Id. includes DR U-21806 AG-CE-0621.

In the discovery response in this case, the Company also stated that the project is currently in the investment planning phase, as it was in the last rate case, which indicates that it is still in the early stage of development.[113]

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION FOR THE OT DATACENTER MIGRATION PROJECT?

A. The Company has not presented sufficient evidence that the OT Datacenter Migration is economically justified or necessary, particularly with more data processing shifting to the cloud. Furthermore, the project is still in the initial phase of development with no specific systems or vendors evaluated. This project should not be included in rate base and O&M expense in this rate case.

Therefore, I recommend that the Commission remove $988,000 of capital expenditures for the 10 months ending October 2026 and $953,000 for the projected test year along with $349,000 of O&M expense from this rate case.

E. Facilities and Shared Services Capex

Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR FACILITIES AND SHARED SERVICES.

A. On page 1 of Exhibit A-83 (QAG-3), the Company shows forecasted capital expenditures for Emergent Repairs of $1,554,000 for 2025, $1,080,000 for the 10 months ending

---

[113] Id. DR AG-CE-0401.

October 2026, and $1,482,000 for the projected test year. In comparison, the Company incurred capital expenditures of $427,000 in 2024.

In discovery, the Attorney General asked the Company to provide the capital expenditures for known projects to be completed for the 10 months ending October 2026 and for the projected test year. In response the Company stated that emergent repair projects were not known in advance. From this information, it is not clear how the Company arrived at the forecasted expenses for the two projected periods.

During the most recent three years, the Company incurred average emergent capital expenditures of $738,000. This amount adjusted for inflation results in forecasted capital expenditures of $756,000 for 2026 or $630,000 for the 10 months ending October 2026.[114] This amount is $450,000 lower than the $1,080,000 forecasted by the Company. Adjusting the 2026 capital expenditures for inflation results in forecasted capital expenditures of $773,000 for 2027.[115] Based on those calculations, the capital expenditures for the projected test year are $770,000.[116] This amount is $712,000 lower than the Company's forecasted amount of $1,482,000.

Therefore, I recommend that the Commission remove $450,000 for the 10 months ending October 2026 and $712,000 for the projected test year from the Company's forecasted capital expenditures.

---

[114] $738,000 x 1.024 = $756,000.

[115] $756,000 x 1.023 = $773,000.

[116] $773,000 x 10/12 + $756,000 x 2/10 = $770,000.

F. Capital Expenditures - Summary

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING THE LEVEL OF CAPITAL EXPENDITURES?

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

Summary of AG Disallowed Capital Expenditures	
	Amount (millions)
Distribution Plant	$ 365.3
Transmission Plant	137.3
Gas Storage & Compression	145.4
Information Technology	13.3
Transportation Fleet	1.2
Total	**$ 662.6**

Based on my analysis and the information presented in my testimony above, I recommend that the Commission reduce the Company's proposed capital expenditures by $662.6 million and reduce average rate base by $524.8 million, including an adjustment to working capital of $93.2 million, as shown in Exhibit AG-37. The resulting effect of the lower rate base from the reduction in capital expenditures is a reduction in the revenue deficiency of $43.0 million.

V. Depreciation Expense

Q. PLEASE DISCUSS THE DEPRECIATION EXPENSE ADJUSTMENT THAT YOU PROPOSE.

A. In Exhibit AG-37, I identified the adjustments to be made to the Company's proposed capital expenditures. Those reductions lower the amount of depreciation expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in depreciation expense of $12.3 million. I recommend that the Commission reduce the Company's depreciation expense by this amount for the projected test year.

VI. Property Tax Expense

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

A. In Exhibit AG-37, I identified the adjustments to be made to the Company's proposed capital expenditures. Those reductions lower the amount of property tax expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in property tax expense of $4.6 million. I recommend that the Commission reduce the Company's property tax expense by this amount for the projected test year.

VII. Working Capital

Q. THE COMPANY PROPOSED $1.383 BILLION OF WORKING CAPITAL IN THIS CASE.[117] DO YOU AGREE WITH THIS LEVEL OF WORKING CAPITAL?

A. No. I recommend six changes to the working capital balance, which total $93.2 million. These changes reduce the amount of Working Capital to $1.290 Billion. The first change is to reduce the Company's Cash balance by $13.3 million. The second change is a reduction in gas inventory stored underground of $12.3 million to reflect more recent and lower projected pricing of the Company's gas inventory. The third change is an offsetting reduction of $2.9 million in Accounts Payable related to the lower gas prices. The fourth change is the removal of the $9.7 million loss from the sale of the Riverside storage assets. The fifth change is to Accrued Taxes which reduces working capital by $45.9 million. The sixth change is to reduce the deferred balance for the SAP S4 HANA ERP project by $14.9 million. These changes are summarized in Exhibit AG-38.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT OF $13.3 MILLION TO THE COMPANY'S PROPOSED CASH BALANCE.

A. As shown on Exhibit A-12 (HLR-34), Schedule B4, for the 2024 historical test year, the Company reported a cash balance of $16.8 million, which increased to $45.7 million for the 13-months ended June 2025. The Company reduced the June 2025 balance by $20.1 million to a forecasted test year balance of $25.6 million based on its rule of thumb

---

[117] See Exhibit A-12 (HLR-34), Schedule B4.

approach of setting the cash balance in working capital in the rate case at 1% of gas revenues. The Company has used this approach in past cases, and the Commission has accepted it with some reservations.

However, more recently in Case No. U-21870, the Commission rejected the Company's "1% of revenues" approach and adopted the historic test year balance. While the Commission's recent decision is a marked improvement over the Company's "1% of revenue" rule of thumb approach, I still believe that a better methodology is to use a 3-year average balance of cash on hand. This methodology normalizes peaks and valleys in cash balances and avoids the problem of unusual events in any particular year.

Based on information provided by the Company, the average cash balance on hand for the three years ending December 2024 was $12.3 million, as shown in Exhibit AG-38. This amount is $13.3 million lower than the cash balance proposed by the Company for the projected test year. I recommend that the Commission adopt my proposed methodology and reduce working capital by $13.3 million.

However, should the Commission wish to apply the same approach approved in Case U-21870 and use the 2024 historical year cash balance of $16.8 million, the resulting adjustment to the Company's amount is a reduction in working capital of $8.8 million ($25.6 million – $16.8 million).

I will also point out that the Company maintains large lines of credit and short-term borrowing facilities that are currently in excess of $1.4 billion with substantial fees recovered in this rate case. Those facilities can and should be used in lieu of carrying large cash balances to avoid high working capital balances on which the Company earns the overall cost of capital.

Q. PLEASE EXPLAIN THE CHANGE YOU MADE TO THE COMPANY'S GAS INVENTORY LEVEL AND THE ASSOCIATED ACCOUNTS PAYABLE CHANGE?

A. In response to discovery, the Company provided updated gas price data that lowered gas inventory balances for the projected test year. The updated information shows the price per Mcf for gas inventory declining from $3.385 to $3.266 for a reduction of $0.119 per Mcf.[118] This results in a lower average gas storage balance of $424.6 million compared to the $438.9 million balance included in the Company's rate case filing. The result is a $12.3 million reduction to the gas inventory balance and working capital. This change is shown on line 3 of Exhibit AG-38.

Also, consistent with how the Company handled the change in the inventory balance from gas price adjustments in the rate case filing, I adjusted the Accounts Payable balance by an amount equal to 23.86% of the gas inventory change. This adjustment is reflected on line 4 of Exhibit AG-38.[119]

---

[118] DR SA-CE-057 Attachment 1 and Exhibit A-12 (HLR-34) Schedule B4.

[119] Exhibit A-12 (HLR-34), Schedule B4

Q. PLEASE EXPLAIN WHY YOU PROPOSE THE REMOVAL OF THE $9.7 MILLION LOSS FROM THE RIVERSIDE STORAGE ASSETS SALES FROM WORKING CAPITAL.

A. In column (m) of Exhibit A-12, Schedule B4, the Company included the deferred balance of $9.7 million from the sale of the Riverside Storage field. The loss pertains to an asset that no longer exists and is not used and useful. Therefore, the Company should not be earning a return on an amount that has no ongoing value to customers. Although the Commission may want to allow recovery of the loss through annual amortization of the remaining balance, it should disallow inclusion of the unamortized balance in working capital.

Q. ARE THERE PRECEDENTS THAT YOU CAN CITE WHERE THE COMMISSION APPLIED THE APPROACH THAT YOU PROPOSE?

A. Yes. In the January 19, 2016 Order On Rehearing in Case U-17767, the Commission ruled that DTE Electric's (DTEE) deferred costs to license Fermi 3, which was not being built and the deferred costs were of no current value to customers, could be amortized for recovery but DTEE could not earn a return on the deferred license costs. Specifically, the Commission stated:

> DTE Electric sought a 20-year amortization of the costs, with a return of and on the full amount; the Staff advocated a 10-year amortization, with no return on the amount. The Staff provided testimony that the costs are reasonable and prudent, and the Commission has consistently indicated that the original decision to seek the license was a reasonable one. The Commission finds that the most appropriate treatment involves elements of both proposals, and directs the utility to amortize the full $101.9 million over 20 years, without a return on this amount. The

> Commission favors the longer amortization period because of the impact on ratepayers. [120]

Similarly, regarding Consumers Energy's former Marysville plant costs, the Commission ruled as follows:

> The Commission finds that the Marysville plant in its mothballed state is not **used and useful** in the provision of gas service to the public and, therefore, should be removed from Applicant's rate base, because the evidence of record shows that the plant would be unable to respond to a short-term gas supply disruption… Just as it would be unfair and unreasonable to ratepayers to require payment of a return on the investment in the mothballed Marysville plant, the Commission finds it would be unfair and unreasonable to deny investors a return of the investment while the plant is being preserved in the mothballed state as insurance for ratepayers against future long-term supply shortages.[121] [Emphasis added].

The two cases bear strong similarities to the exclusion of the loss from the sale of the Riverside storage assets in that the loss represents a cost that provides no value to customers and is not used and useful. Therefore, I recommend that the Commission remove the $9,720,000 from working capital and rate base and the Company not be allowed to earn a return on it.

Q. PLEASE EXPLAIN YOUR CHANGE TO ACCRUED TAXES.

A. In the calculation of Accrued Taxes for inclusion in working capital for the projected test year in Exhibit A-12 (HLR-34), Schedule B4, the Company starts with the 2024 historical year balance of $195.5 million. This balance increases to $218.0 million for the 13 months average balance on June 30, 2025. The Company then makes an adjustment to remove $45,906,000, which assumes that the outstanding Accrued Income Taxes on June 30, 2025

---

[120] January 19, 2016 Order On Rehearing in Case U-17767 at page 6.
[121] MPSC 1983 decision: 1983 Mich. PSC LEXIS 858, *69-80, 1983 Mich. PSC LEXIS 858.

are paid off after that date, thus lowering the outstanding balance of total Accrued Taxes. However, the Company does not replace the Accrued Income Taxes during the projected test year with new income tax accruals to reflect the additional income it will generate during the period from June 2025 to October 2027, other than for a relatively small amount of $354,000. This serious omission is evident from reviewing workpaper WP-HLR-30.[122]

The Company admitted in response to discovery that it has not accrued any income taxes on the additional revenue and income it would receive during the projected test year and that in calculating accrued taxes for the projected test year it has only considered the forecasted higher expenses and no incremental revenue.[123] The Company justifies this treatment by stating that it has used this approach in the past and the Commission has approved it.

However, the erroneous treatment of such a large item should not be continued. By reducing Accrued Taxes by $45.6 million after June 2025, the Company has increased working capital unnecessarily and will earn a return on that amount by inclusion in rate base. Once the rate case is decided, the Company will resume accruing income taxes payable and accrued taxes will increase again, while receiving a return on a false premise of a lower accrued amount and higher working capital balance in rates.

To correct this flawed approach, I recommend that the Commission adopt the actual Accrued Taxes balance for the 13 months ended June 2025 and remove the $45,906,000

---

[122] Exhibit AG-38 includes WP-HLR-30.
[123] Id. includes DR

reduction after that date for a resulting increase in working capital of the same amount. Exhibit AG-38 shows this adjustment in Line 6. I also recommend that the Commission establish this approach as standard procedure and direct the Company to follow it in future rate cases.

Q. PLEASE DISCUSS YOUR ADJUSTMENT TO WORKING CAPITAL FOR THE SAP S4 HANA REGULATORY ASSET.

A. In column (2) of Exhibit A-12, Schedule B4, the Company included a deferred balance of $29,757,000 for the SAP S4 HANA ERP project on the assumption that it would incur a certain level of expense for the project development from November 2025 to October 2027. However, the actual costs incurred during the first four months of the project development have been 50% lower than forecasted. During the first four months, the Company forecasted that it would incur $8,058,000 in project development expenses but instead it incurred only [Begin CONF] [redacted] [End CONF].[124] It is likely that this lower expense level will continue into future months.

The Company earns a return on the deferred expense balance by inclusion in working capital and rate base. To protect customers from the Company earning a return on overstated costs, it is advisable to reduce the deferred amount to the current actual experience level. Therefore, I recommend that the Commission approve a 50% reduction

---

[124] Exhibit AG-39 CONF includes DR AG-CE-0409 with Confidential attachment.

to the deferred balance included in working capital from $29,757,000 to $14,879,000. This adjustment is shown on line 7 of Exhibit AG-38.

VIII. Capital Structure and Cost of Capital

A. CAPITAL STRUCTURE

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

A. I recommend that the capital structure shown on page 1 of Exhibit AG-40 be used in this case. The first three lines show the projected long-term debt, preferred equity and common equity capital of the Company, which represents the permanent capital structure for the test period ending October 2027. The capital balances in this exhibit reflect the amounts shown in Exhibit A-14 (MRB-1), Schedule D1, with an adjustment to rebalance the capital structure. I increased the long-term debt component in Exhibit AG-40 by $220 million and reduced the common equity component by the same amount. The result is a capital structure with 50% of common equity and 50% of debt and preferred stock.

Q. **WHY DID YOU INCREASE LONG TERM DEBT BY $220 MILLION AND OFFSET THIS CHANGE WITH LOWER COMMON EQUITY?**

A. The Company has proposed a permanent capital structure with a common equity component of 50.75%. This level of common equity exceeds the 50% equity ratio approved by the Commission in the Company’s last two fully contested rate cases, Case

Nos. U-21806 and U-21870.[125] The capital structure in this rate case should similarly mirror the common equity ratio last approved on March 27, 2026 of 50%. As discussed in my testimony below there are several factors that clearly support a 50% common equity level.

These factors include (1) the Commission's consistent directive in the Company's prior electric and gas rate cases, which stated that a 50/50 capital structure is desirable and appropriate to ensure reduced costs to customers and maintain the Company's strong financial position, unless the Company can demonstrate that a higher ratio is justified; (2) The Company's strong cash flow to debt coverage ratio and credit ratings; (3) the Company's common equity capital contributions by the parent company, albeit often funded with long term debt issued at the parent company level; (4) the favorable regulatory environment in Michigan supported by historical returns on common equity above industry averages and in the top tier of the Company's peer group; and (5) the fact that the common equity ratio of the peer group, used to assess the cost of common equity in this case, is approximately 47%.[126]

Q. PLEASE EXPLAIN YOUR ASSESSMENT OF THE COMMISSION'S DIRECTIVE TO THE COMPANY TO REBALANCE ITS CAPITAL STRUCTURE TO EQUAL AMOUNTS OF DEBT AND EQUITY CAPITAL.

---

[125] Case No. U-21806 Commission order dated September, 2025 and Case No. U-21870 dated March 27, 2026.

[126] Exhibit AG-43 shows that the equity ratio for each peer company and the peer group average ratio of 46.5%.

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

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

In subsequent litigated rate cases, the Commission continued to remind the Company of this directive as it led the Company slowly toward a more balanced capital structure.

Q. WHAT POSITION DID THE COMMISSION TAKE IN THE COMPANY'S MOST RECENTLY CONTESTED RATE CASE ON THE CAPITAL STRUCTURE?

A. In the recent March 27, 2026 order in Case No. U-21870, the Commission decided to set the common equity ratio at 50%, as recommended by the Administrative Law Judge (ALJ) and supported by the Attorney General and other parties. On page 129 of the order, the Commission stated the following:

> Given the above, the Commission finds that Consumers' arguments and exceptions are not persuasive. The Commission agrees with the ALJ's determination and finds that the Company has not demonstrated a deviation from the current capital structure is warranted in this case. Therefore, the Commission adopts the ALJ's findings and recommendations with respect to the proposed capital structure, including adopting the Attorney General's rebalancing. PFD, p. 448.

In its testimony in this rate case, the Company has not provided any new evidence or persuasive arguments as to why the Commission should veer from its stated goal of a 50/50 debt/equity capital structure for the Company.

Q. WHAT DID S&P STATE IN ITS MOST RECENT CREDIT REPORT ABOUT CONSUMERS ENERGY'S CREDIT PROFILE?

A. The S&P September 15, 2025 credit report on the Company states "We believe Michigan's regulatory construct is above average compared with peers..." The report also points to the streamlined 10-month rate case process, as well as the power supply and natural gas cost rider adjustments, which help the Company to earn its authorized ROE. S&P also notes that the Company's senior secured debt is rated as "A" by S&P (the middle of the "A" category).[127]

Regarding the cash flow coverage ratio, page 3 of the S&P report under the section "Downside Scenario" states:

> We could lower our rating on CE if the stand-alone financial measures weaken such that FFO-to-debt weakens to consistently below 15% or we lower our rating on parent, CMS Energy.[128]

Page 5 of the report shows that the coverage ratio was 17.9% for 2024. S&P also estimated this ratio in the range of 17% to 20% for 2025 to 2027. These coverage ratios are not indicative of any concerns about a possible debt rating downgrade and are well above the 15% threshold set by S&P.

Q. ON PAGES 16 AND 17 OF HIS TESTIMONY, MR. BLECKMAN INDICATES THAT "THE COMPANY'S FFO TO DEBT RATIOS AS CALCULATED BY MOODY'S AND S&P ARE TRENDING DOWN TO 19% (MOODY'S) AND 17.9% (S&P). DO YOU AGREE WITH THAT STATEMENT?

---

[127] Exhibit AG-50 includes U-21870 DR AG-CE-0227 and the S&P report dated September 15, 2025.

[128] S&P's FFO to debt ratio is similar to the Moody's cash flow ratio "CFO Pre W/C

A. Not entirely. First, none of the Moody's historical cash flow ratios are below the 18% Moody's downgrade threshold until 2025, which I will explain below. Second, Mr. Bleckman fails to explain the unusual and short-term issues faced by the Company in recent years and mischaracterizes the situation in an attempt to mislead the Commission. The cash flow to debt ratio declined somewhat in 2022 due to a temporary increase in natural gas prices in 2022, which required the Company to incur larger short-term borrowings. In 2022, higher gas prices increased the cost of gas purchases and gas inventories. This in turn caused the Company to take on more debt which in turn reduced net income and increased the debt denominator in the calculation of the coverage ratio.

Gas inventory levels increased from $462 million in December 2021 to $840 million in December 2022. This increase of $378 million in gas inventory required more temporary debt financing for the year. The temporary increase in debt receded in 2023 and 2024. Page 2 of Exhibit AG-48 shows that if we adjust for this temporary phenomenon the Moody's FFO to Debt ratio would have been 20.9% instead of the actual result of 20%.

Temporary events from year to year can have either a positive and negative effect on earnings, cash flow, short-term debt, and the cash flow to debt coverage ratio. However, rating agencies look past those temporary issues and focus on the long-term financial health of the Company.

Also, for the year 2024, shown in the Moody's report of May 29, 2025, the Company's results reflect a 19.0% cash flow ratio.[129] The ratio reflects the Company's 8.8% ROE results for 2024, which is below its authorized return.[130] As shown on page 1 of Exhibit AG-48, had the Company earned a 9.7% ROE and maintained a 50% common equity ratio, it would have achieved a cash flow coverage ratio of 19.8% instead of 19.0%.

Q. DO THE CURRENT CREDIT RATINGS FOR THE COMPANY SHOW ANY SIGNIFICANT CONCERNS?

A. No. The Company's bond issuance rating from Moody's is "A1" (top of the "A" category and one notch above the S&P rating) and its S&P rating is "A" (middle of the "A" category). Fitch Investor Service has also rated the Company at the "A" credit rating level.

S&P in its September 2025 report provides the following outlook for the Company:

> The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of 17%-19%.[131]

In its May 29, 2025 report, Moody's provided the following rating outlook:

> The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. The stable outlook also incorporates our view that Consumers Energy will maintain prudent financial policies while managing through its robust investment cycle and that debt levels at the parent will not increase materially.[132]

---

[129] Exhibit AG-51 CONF includes Moody's May 29, 2025 report (DR U-21870 AG-CE-0227)
[130] Sourced from the Company's Form 10-Q Financial Statements of March 31, 2025 and 2024.
[131] Id.
[132] Exhibit AG-51 CONF includes Moody's May 29, 2025 report

Q. IN A RECENT REPORT MOODY'S CHANGED THE COMPANY'S CREDIT OUTLOOK FROM STABLE TO NEGATIVE. WHAT IS YOUR ASSESSMENT?

A. In response to discovery, the Company provided a March 23, 2026, report from Moody's changing the rating outlook of Consumers Energy to negative from stable. At the same time, Moody's affirmed the Company's credit ratings, including its "A1" senior secured First Mortgage Bond rating and the Prime-2 commercial paper rating. Concurrently, Moody's affirmed the ratings of CMS Energy Corporation (CMS), including its Baa2 senior unsecured rating. Moody's stated that the rating outlook of CMS is stable. [133]

Moody's attributed the change in outlook to the Company's further escalation in capital spending by stating "The change in Consumers' rating outlook to negative from stable reflects the company's weakening financial profile in the midst of the company's elevated capital investment plan… Although we view the Michigan regulatory environment to remain credit supportive, the significant step up in the company's planned investments without contemporaneous cost recovery, such as capital structure improvements and more timely cash recovery mechanisms for large projects, will constrain the company's ability to improve its credit metrics to levels that support the current ratings."

Moody's concern is displayed on page 4 of the report where it notes Consumers Energy's latest investment plan over the next five years is approximately $24 billion, which is approximately $4 billion higher than its previous plan and capital expenditures increasing

---

[133] Exhibit AG-52 includes DR AG-CE-0233 with Moody's March 23, 2026 report.

from approximately $3.8 billion in 2025 to approximately $5.9 billion in 2028, an increase of 55%. The Company can alleviate Moody's concern and improve the credit outlook by throttling back its capital spending plans over the next few years.

The negative outlook also seems to be based on the Company's issuance of additional debt in 2025 and a lag in equity infusions from CMS Energy. According to page 10 of Moody's report, total debt increased by $1.3 billion between 2024 and 2025, while equity capital increased by only $723 million. It appears that the Company plans to remedy this short-term imbalance by receiving equity infusion of $2.6 billion from its parent between February 2026 and June 2027 after only receiving an equity infusion of $920 million in 2025.[134] Pages 10 of Moody's March 23, 2026 report also shows that cash flow from operations (CFO Pre-WC) decreased by $146 million between 2024 and 2025 caused by a swing of $239 million in "Other" cash items, which changes from year to year.

These temporary changes will likely reverse in future years, thus improving the 16.1% Cash Flow to Total Debt coverage ratio of 2025 to near or above the 18% threshold. Page 3 of the Moody's report shows this improving trend beginning in 2026 and the Company can improve that trend even further by throttling back its aggressive capital spending and the issuance of new debt.

It is also worth noting that Moody's is currently rating the Company one notch higher than the other two rating agencies. Should the credit rating drop to "A2" from "A1" it would

---

[134] Marc Bleckman's direct testimony at page 10.

be in line with the credit ratings of S&P and Fitch at "A". The lower Moody's rating of "A2" would not have a material impact on the Company's credit rating or the cost of issuing new debt, if at all, and certainly would not even approach the incremental cost to customers of the Company carrying a higher equity ratio above 50%, as discussed further below.

Q. PAGE 19 OF MR. BLECKMAN'S TESTIMONY STARTS WITH A SECTION TITLED "RATING AGENCIES ASSESSMENT OF THE REGULATORY ENVIRONMENT" AND HE CITES PUBLISHED INFORMATION FROM BOTH STANDARD & POOR'S AND UBS. WHAT ARE YOUR VIEWS OF THIS INFORMATION.

A. Regarding UBS, this firm ranks regulators in Michigan and 57 other jurisdictions. However, UBS is not a credit rating agency. It is a stock brokerage and investment banking firm among other things. As discussed in the article in Exhibit A-38 (MRB-15), the UBS analysis is concerned with "fair outcomes for investors" and not necessarily creditors or customers. On page 20 of his testimony, Mr. Bleckman states that "It is apparent that rating agencies and analysts are taking note of the Company's regulatory outcomes and are viewing them unfavorably". It appears that he is drawing that conclusion from the UBS report. The article by UBS does not address any specific regulatory outcomes or concerns related to Consumers Energy or CMS Energy. Moreover, the article was published in May 2023 and is now more than two years old. This is old information provided by witness Bleckman which he mischaracterizes.

Q. ON PAGE 20 OF HIS DIRECT TESTIMONY, MR. BLECKMAN ALSO REFERS TO EXHIBIT A-37 (MRB-14), WHICH IS AN S&P REPORT NOTING CREDIT TRENDS IN THE UTILITY INDUSTRY. DO YOU BELIEVE THAT THIS REPORT IS DIRECTLY APPLICABLE TO CONSUMERS ENERGY?

A. Mr. Bleckman points out in his testimony that Michigan is no longer in the "Above Average" grouping of companies. However, as can be seen from page 9 of this report, Michigan is at the high-end of the average category which puts it above 37 other jurisdictions.

Q. ON PAGE 21 OF HIS TESTIMONY, MR. BLECKMAN POINTS TO THE S&P JANUARY 2025 INDUSTRY CREDIT OUTLOOK 2025, WHICH HE SPONSORS AS EXHIBIT A-39 (MRB-16). HE POINTS TO CERTAIN S&P CONCERNS AS BEING WORTHY OF THE COMMISSION'S ATTENTION. WHAT IS YOUR ASSESSMENT?

A. First, it is worth noting that page 8 of this publication includes a map showing all of the 50 United States based on S&P's Regulatory Assessment ranking in each case. Michigan and five other states rank highest as being "Most Credit Supportive". Second, the article raises three key concerns which are (a) the need for more common equity in the industry; (b) potential tax legislation which could adversely affect the industry; and (c) robust capital spending. In general, the potential for adverse federal corporate tax legislation does not seem to be a concern for the foreseeable future. The applicability of the other two items varies from utility to utility depending on their circumstances. Regarding additional common equity, as discussed above, a balanced capital structure with 50% common equity provides a strong financial position for the Company to continue to raise new capital to address moderate capital spending on infrastructure improvements. The high level of capital spending obviously concerns S&P and other rating agencies, and the Company should try to moderate the projected spending by taking a more gradual escalation in its forecasted capital expenditure in future years.

Q. **YOU STATED EARLIER THAT COMMON EQUITY CAPITAL INFUSIONS INTO CONSUMERS ENERGY BY THE PARENT COMPANY ARE BEING FUNDED TO SOME EXTENT BY LONG TERM DEBT. PLEASE EXPLAIN.**

A. There are several issues in the financial transactions between Consumers Energy and its parent company, which cannot be ignored when analyzing the Company's proposed capital structure. First, CMS can make the Company's common equity ratio whatever it wants. The same executive management that runs CMS Energy also operates the Company. Management can direct at any time how much capital it wants to inject into the Company from the parent company and call it equity capital. In fact, it has done just that over the years. In response to a discovery request, the Company has stated that the injection of common equity from CMS Energy is at the discretion of management with no approval from the Board of Directors.[135] Such freedom to call for equity capital would not exist if Consumers Energy itself was a publicly traded company.

---

[135] CECo response to discovery request U-18322-AG-CE-439.

Over the five years 2021 to 2025, Consumers Energy's Common Equity has increased from \$8.5 billion at year end 2020 to \$12.5 billion in 2025, which is an increase of \$4.0 billion. An analysis of the Company's financial statements filed with the Securities and Exchange Commission shows that the \$4.0 billion increase is due to the following factors:

Table 1

Consumers Energy

Common Equity Change for Five Years (Dec. 2021 - 2025)

		$ Billions
1	Net Income of Consumers Energy	**$ 4.7**
2	Dividends Paid to CMS	**(3.7)**
3	New CMS Investment in Consumers Energy	**3.2**
4	**Total Change in Common Equity**	**$ 4.2**

First, as shown in table 2 below, of the \$3.2 billion of new equity invested by CMS into Consumers approximately one-half being from new long-term debt.

Table 2

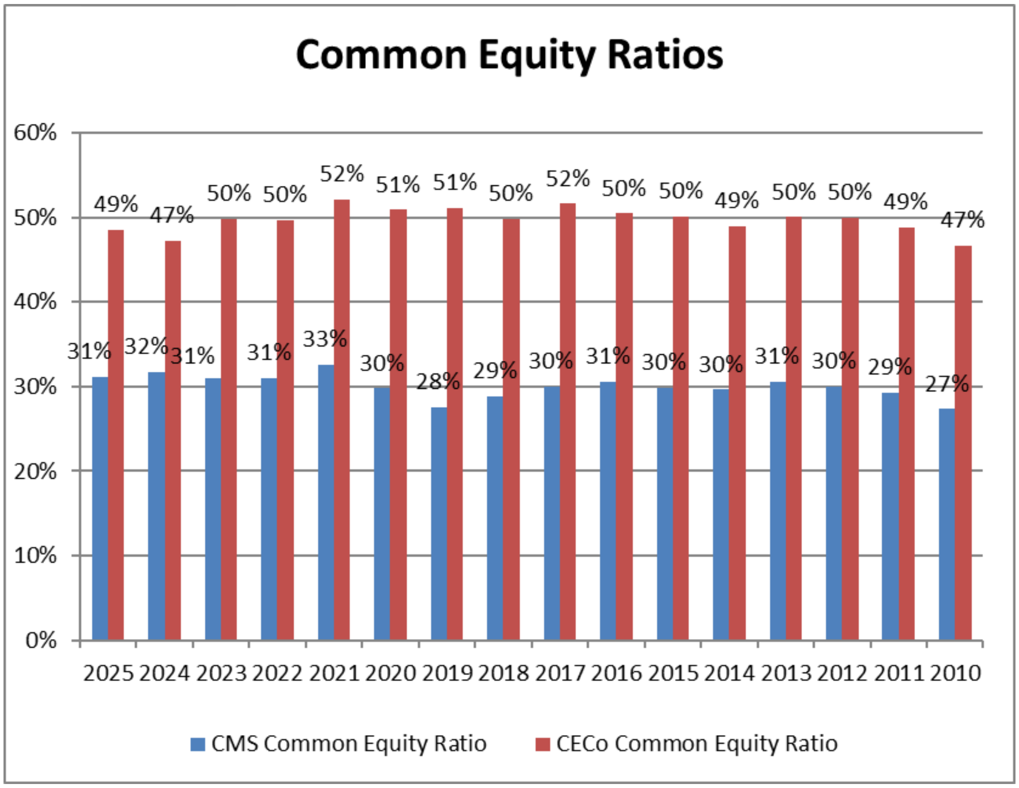
CMS Energy

CMS Funds Available to Invest in Consumers Energy (Dec. 2021 - 2025)

		$ Billions
a.	Dividends From Consumers Energy	**$ 3.7**
b.	Less: Dividends to CMS Shareholders	**(2.9)**
c.	CMS Net Equity Issued	**1.1**
d.	Increase in CMS Equity Capital	**1.9**
e.	Increase in Parent Company Debt	**2.1**
f.	Other CMS Changes	**(0.8)**
g.	**Funds From CMS Invested in Consumers Energy**	**$ 3.2**

Second, to further support my point, CMS Energy is a frequent issuer of long-term debt in the capital markets. Over the last five years, CMS parent-only debt increased $2.1 billion from $4.2 billion at year end 2020 to $6.3 billion at year end 2025.[136] Yet the only substantive business CMS Energy owns is Consumers Energy.

The following chart displays the gap in equity capital between Consumers Energy and CMS over the years 2010 to 2025. While cash raised from the issuance of long-term debt at CMS is not immediately injected into Consumers Energy, it is nonetheless being utilized in part to fund CMS's so-called equity infusions into CECo.



---

[136] From SEC filings on Form 10-K for the years ended 2020 (p. 124) and 2025 (p. 125).

It is important to remember that nearly 95% of CMS' assets and revenue come from Consumers Energy.[137] Therefore, from a practical operating standpoint, CMS and Consumers Energy are one and the same.

Q. **YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP USED TO ASSESS THE COST OF COMMON EQUITY IS APPROXIMATELY 47%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE COMMON EQUITY RATIO FOR THE COMPANY.**

A. As shown in Exhibit AG-45, the average common equity ratio of the peer company group for 2025 was 46.5%. The cost of equity for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure. Thus, it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible, to have consistency with the cost of equity capital derived from those peer group companies. The Company's proposed common equity capital ratio of 50.75% creates a disconnect that is not acceptable and is also more costly to customers.

Q. WITNESS BLECKMAN SPONSORS EXHIBIT A-33 (MRB-10) SHOWING THE COMMON EQUITY RATIOS FOR VARIOUS GAS AND ELECTRIC UTILITY COMPANIES SUPPOSEDLY DECIDED IN RATE CASES DURING 2020 TO 2025. THE EXHIBIT SHOWS AN AVERAGE COMMON EQUITY RATIO OF 54.49%. DO YOU FIND THIS EXHIBIT WORTHY OF CONSIDERATION?

---

[137] CMS Energy 2024 Form 10K at page 171.

A. No. It appears that Mr. Bleckman's purpose in presenting this exhibit showing an average common equity ratio of 54.49% is an attempt to support his recommended 50.75% equity ratio and to suggest that his rate is conservative and very reasonable compared to the equity ratios approved for other utility companies.

The Commission should not rely on the information provided by Mr. Bleckman in Exhibit A-33 because it is neither accurate nor comprehensive to provide a proper context to establish an appropriate common equity ratio for the Company. He presents only selective information. Some of the major flaws are discussed below.

First, three of the 15 companies he shows (lines 1, 2 and 3) are divisions or subsidiaries of Atmos Energy and reflect rate base levels of $300 million to approximately $600 million.[138] These rate base levels are for very small companies that are less than 5% of the Company's rate base level. Regulators are often persuaded to award higher equity levels to smaller companies because they have less financial flexibility. Second, the 58.55% equity capitalization percentage for OneGas on line 12 of the Exhibit was decided together with an 8.94% ROE rate which is significantly lower than the Company's current 9.80% ROE rate.[139] Third, Mr. Bleckman's list of utilities in Exhibit A-33 is very limited since it pertains to only utilities owned by five companies in the Company's peer group. Had Mr. Bleckman wanted to be more thorough, he could have included New York utilities (with five decisions between 2021 and 2022 having a 48% common equity ratio) and other

---

[138] See page 7 of the Atmos 2025 Form 10-K.

[139] See page 8 of the 2025 OneGas Form 10-K

utilities, such as Hope Natural Gas, Puget Sound Gas, Avista, Cascade Natural Gas, Delmarva Natural Gas, and Black Hills that have received common equity ratio of 50% or less in recent rate cases.[140]

In summary, Mr. Bleckman has constructed a selective group of utilities in Exhibit A-33 that are not representative of the gas utility industry and it results in an inflated average equity ratio. The Commission should disregard the Company's presentation of a misleading industry average equity ratio.

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

A. The difference is $8.2 million annually. This reflects (a) the difference between the pre-tax cost of common equity of 14.1% versus the cost of long-term debt of 4.5%; (b) the Company's proposed rate base of approximately $12.5 billion; and (c) the percentage of total capital being shifted from common equity to long term debt.

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

A. No. I adopted the other capital balances sponsored by witness Bleckman in Exhibit A-14 (MRB-1), Schedule D1, page 1.

---

[140] Per Regulatory Research Associates.

B. COST OF CAPITAL

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

A. I am recommending an overall return on capital of 6.12%, which includes a return on common equity of 9.70%, as shown in Exhibit AG-40, page 1.

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

A. For the long-term debt cost rate, I used a rate of 4.51% which is 0.02% less than the 4.53% rate recommended by witness Bleckman.

As can be seen on Exhibit A-14 (MRB-4) Schedule D2, the Company anticipates two new debt issuances in 2027 at rates of 6.27% and 6.28% (inclusive of issuance costs). In the cost build-up section at the bottom of this exhibit page, the Company utilizes 30-year U.S. treasury rates of 4.84% and 4.85% to derive its ultimate interest rates for these two new issues. Instead, I used 30-year U.S. treasury rate of 4.40%, which is 44 basis points below the rate used by the Company. The 30-year treasury rate of 4.40% was sourced from the June 2, 2025 Blue Chip Financial Forecast report provided by the Company.[141] The Company used the 4.40% rate in some of the scenarios to calculate the ROE rate and is appropriately applicable to forecast the cost of future debt issuances.

---

[141] Exhibit AG-53 includes DR AG-CE-223 Attachment with page 14 of the Blue Chip Financial Forecast report.

Utilizing the 4.40% U. S. Treasury rate and a spread of 1.44%, I calculated a total interest rate of 5.84% versus the Company's proposed interest rate of 6.28%, as shown on page 2 of my exhibit AG-40. The lower interest rate reduces interest costs and the revenue requirement by approximately $1.0 million annually.

Q. WHAT COST RATE DID YOU UTILIZE FOR PREFERRED STOCK?

A. For the preferred stock, I used a 4.5% rate, consistent with the rate recommended by Company witness Bleckman.

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

A. For Short Term Debt and Deferred Taxes, I used the cost rates recommended by witness Bleckman. Cost rates for JDITC reflect those rates I used for the permanent capital sources.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF CAPITAL IN EXHIBIT AG-40.

A. To develop the overall cost of capital on line 12, column (f), I first developed the percentage weighting of each capital component in column (d) by dividing the individual capital balances in column (b) by the total of all capital components in that column. Next, I multiplied the weightings in column (d) by the cost rates in column (e) to arrive at the values in column (f). The total of the individual values in column (f) is the total cost of capital of 6.12%.

Regarding the pretax weighted cost of capital on line 12, column (h), I multiplied each cost component in column (f) by the conversion factors in column (g). These conversion factors are included to reflect the impact of income and other taxes paid by CECo for calculation of the pretax weighted cost of 7.53% in column (h).

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

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

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

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

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON EQUITY IN EXHIBIT AG-41.

A. Determining the cost of common equity for an enterprise or an industry group is inexact since investors can only estimate what the future cash flows from any enterprise may be over time. Because of this uncertainty, most financial experts will not rely solely on any particular method. To determine the cost of common equity, I utilized three approaches to assess this cost. These are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), and the Utility Risk Premium approach.

While Exhibit AG-41 shows an average ROE of 9.68% from the three methodologies, I recommend an allowed rate of return on equity of 9.70% for the reasons explained later in this section of my testimony. In connection with these methods for determining the cost of common equity, I have considered the cost of common equity for a proxy group of peer companies.

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

A. To develop an appropriate peer group, I started with six of the nine utility companies followed by the Value Line Investment Survey in its "Natural Gas Utility Industry" sections and added a seventh company, which is WEC Energy Group.[142] The three natural

---

[142] In prior rate cases, the Attorney General included Black Hills as a proxy company due to its significant gas distribution business. However, Black Hills is now involved in a merger with NorthWestern, which makes it a poor peer group candidate at this time.

gas companies followed by Value Line that I eliminated are Spire (due to M&A activity), UGI (due to its large propane and foreign operations), and Southwest Gas Holdings. Regarding this latter company, its finances have been adversely impacted by a reorganization spurred by investor and corporate raider Carl Icahn. Southwest reported a return on equity capital of approximately 6% in 2023 and 2024. As a result, Value Line forecasts earnings per share (EPS) of Southwest will double by 2029 from the low 2024 earnings base.[143] This large increase in EPS is not representative of Southwest's long-term growth in earnings. For these reasons, I have excluded Southwest Gas Holdings from the peer group.

As mentioned above, I added WEC Energy Group to my peer group. Forty percent (40%) of this company's revenues and 48% of its customers are in the natural gas business. [144] Its natural gas subsidiaries include Michigan Gas Utilities, Peoples Gas in Chicago, North Shore Gas in northern Illinois, and Wisconsin Gas.

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

A. My peer group includes four of the five companies in the Company's peer group. These are Atmos, NiSource, NorthWest Natural Gas Holdings, and OneGas. The Company included Southwest Gas Holdings in its peer group, which I excluded due to the residual

---

[143] Corporate non-utility losses of $63 million in 2024 and $77 million in 2023 due to Mountain West Pipeline Goodwill impairment ($50 million) and expenses for separation of Centuri Construction.

[144] WEC Energy Group 2024 Form 10-K at page 19 (revenues) and pages 5 and 11 (customers).

problems stemming from this Company's reorganization and its depressed earnings discussed above. The Company did not include Chesapeake Utilities, New Jersey Resources, and WEC Energy in its peer group, but these companies are in my peer group.

Discounted Cash Flow (DCF) Cost of Equity Method

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

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

$$R = D/P + g$$

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

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-42. The stock price information in column (c) of this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from January 15 to February 28, 2026. The annual dividend in column (d) is the forecasted average dividend level for 2026 and 2027, as projected by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on (1) the estimate of earnings growth through 2030 per Value Line; and (2) the earnings growth estimates per S&P Capital IQ.

The resulting calculation of the DCF Method is an average return on common equity for the proxy group of 9.57%.

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

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

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

A. Company witness Bulkley calculated a DCF cost of equity capital of 11.03%, which is 146 basis points higher than the 9.57% DCF result I calculated.[145] The result of the DCF analysis are dependent upon the dividend yield and the average earnings growth rate of the companies in the peer group.

---

[145] The Company presents nine different DCF results based on stock prices over 30 days 90 days and 180 days with earnings growth rates at minimum levels, average levels and maximum levels. The 11.03% DCF ROE rate is shown on page 1 of Exhibit A-14 (AEB-1) and represents a 30-day stock price calculation with average earnings growth.

The dividend yield in my analysis is 3.13%, but the Company calculated a higher yield of 3.35% for its peer group. This accounts for approximately 22 of the 146-basis point difference. Also, the projected growth rate is higher in the Company's case at 7.68% vs. 6.44% in my analysis, which accounts for the remaining difference of 124 basis points.[146] I will point out that the data on the dividend yield and the earnings growth rates used by the Company were compiled sometime in mid to late 2025 and are now stale. The stock prices of the utilities in the peer group are now higher, thereby justifying a lower dividend yield compared to the Company's filed case.

The Company's 7.68% average peer group earnings growth rate is largely influenced by the 11.17% earnings growth rate for Southwest Gas. This high earnings growth rate for Southwest Gas is not representative of the company's long-term and sustainable growth, as discussed above due to unusual short-term circumstances, and should not have been included in the Company's peer group. Furthermore, the Company's presentation of nine different DCF calculations is unnecessary and confusing in its flawed attempt to search for a result that improperly inflates the final determination of the ROE rate.

Capital Asset Pricing Model

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

---

[146] The 3.75% dividend yield and 6.48% growth rate of the Company's peer group analysis are from page 3 of Exhibit A-14 (AEB-1).

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

$$k_e = R_f + (B \ x \ R_p)$$

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

R_f = *the "risk free" rate of return*

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

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

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

A. This measure of risk reflects the extent to which the price of a particular security varies in relationship to the movement of the overall market. Securities that vary over time more than the overall market will have a Beta that is greater than 1.00. Some securities vary less in price over time than the overall market. In these cases, the Beta will be less than 1.00. Utility stocks tend to move less than the overall market. Reflective of this outcome, the average Beta of my peer group is 0.77.

Q. PLEASE EXPLAIN EXHIBIT AG-43 SHOWING THE RESULTS OF THE CAPM APPROACH.

A. Exhibit AG-43 shows the results of the CAPM method based upon (1) a 4.40% risk-free rate; (2) the Betas of the companies in the Peer Group taken from Value Line; and (3) the 7.45% historical Market Risk Premium (R_p) return from the years 1926 to 2024.[147]

Regarding the use of a risk-free rate for CAPM purposes, I used a 4.40% rate which is the 30-year U.S. Treasury Bond for 2027 sourced from economic projections provided by the Company.[148]

The result of my CAPM approach using the 5.75% adjusted market risk premium (7.45% Risk Premium x 0.77 Beta) plus the 4.40% risk-free rate is a cost of equity capital of 10.15% for the proxy group average.

Q. PLEASE ASSESS THE CAPM APPROACH.

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

---

[147] WP-AG-43A.

[148] Exhibit AG-53 includes DR AG-CE-0223 includes the June 1, 2025 Blue Chip projection showing a 4.40% 30-Year U.S. Treasury rate for 2027 on page 14 of the attached report.

Q. HOW DO YOUR CAPM RESULT COMPARE TO THE RESULTS PRESENTED BY COMPANY WITNESS BULKLEY?

A. Ms. Bulkley presents the results of her projected CAPM and Projected ECAPM methods in Exhibit A-14 (AEB-1), page 1. In the table below, I show the development of Ms. Bulkley's High Case CAPM ROE result compared to mine.

Comparison of CAPM Estimates of AG and Company High Cases

			CECo High Case Results**	
Line		AG Case*	A	B
1	Market Risk Premium (MRP)***	7.45%	8.55%	8.48%
2	Beta (based on proxy group companies)	0.77	0.77	0.77
3	MRP x Beta	5.75%	6.59%	6.52%
4	Risk Free Rate **	4.40%	4.79%	4.87%
5	**CAPM Result (L 3 + L 4)**	**10.15%**	**11.38%**	**11.39%**

* Exh. AG-43

** From Exh. A-14 (AEB-1), Schedule D5, pages 9 and 10
Columns "A" and "B" above reflect different 30-Yr US Treas. Rates (Bulkley testimony)

*** The MRP on line 1 is the key difference (AG vs. CECo cases)

The key differences are the Company's higher Risk-Free Rates and Market Risk Premiums, which I discuss below. The Company also presents ECAPM results that are all slightly higher than the CAPM results. The ECAPM methodology is a variation of the CAPM. This variant methodology is also discussed below in my testimony.

Q. PLEASE DISCUSS THE COMPANY'S USE OF MULTIPLE 30-YEAR U.S. TREASURY RATES AS THE RISK-FREE RATE TO DEVELOP THE ROE ESTIMATES FOR THE PROJECTED TEST YEAR.

A. In her analysis, Ms. Bulkley used three different risk-free rates of 4.87%, 4.79%, and 4.40% to arrive at different CAPM cost of equity estimates. Ms. Bulkley seems uncertain as to which risk-free rate is most appropriate to calculate a reasonable estimate of the cost of equity for the projected test year. The use of multiple rates appears to be a hunt for an approach that will result in the highest ROE rate. The Commission should disregard this variable approach and the attempt to improperly inflate the calculation of the ROE rate.

Q. PLEASE PROVIDE YOUR ASSESSMENT OF THE COMPANY'S CALCULATED MARKET RISK PREMIUM OF 8.48%.

A. Instead of using a proven historical market risk premium (MRP), the Company developed its MRP based largely on future expected stock price growth rates and dividends for a select group of companies from the S&P 500 stock index over the next three to five years**.** Based on her sample of companies, Ms. Bulkley calculates a forecasted stock market return of 13.34%. From this percentage, she deducts the forecasted 30-year U.S. Treasury risk-free rate of 4.87% to arrive at a forecasted MRP of 8.48%.

It is worth pointing out that when witness Bulkley conducted her analysis of projected market returns in case U-21806 in early 2025, her calculated expected market return was 12.04%, or 130 basis points less than in this case. This substantial swing in the stock market return over a short timeframe brings into question the wisdom of placing much reliance on the projected MRP methodology, which is just one of many problems with this approach.

There are also other problems with the Company's approach in developing a projected MRP. First, as can be seen from an examination of pages 13 to 18 of Exhibit A-14 (AEB-1), many of the companies in the S&P 500 Index with dividend yields and long-term growth estimates are omitted. Approximately 175 companies or 35% of the named companies in the S&P 500 are not represented in the calculation of the13.34% stock market return. Second, many large technology companies with high growth prospects have a larger than normal weighting in the calculation of the 13.34% return due to their relatively large market capitalization. Other deficiencies in the projected MRP calculation are discussed below.

Q. PLEASE EXPLAIN FURTHER THE SHORTCOMINGS WITH THE MARKET RISK PREMIUM DEVELOPED BY WITNESS BULKLEY.

A. Witness Bulkley is using an extremely short period of 3 to 5 years to measure stock market returns in determining the MRP. The projected MRP does not include a complete cycle of economic expansion and contraction, which is what occurs over the long-term. To adopt the Company's approach would be akin to only selecting the positive return years over the 98-year historical period of stock market returns I used and not the losses in the downturn years. Expectedly and incorrectly, we would derive a far higher overall return for the market and a far higher market risk premium, which is the flawed result achieved by witness Bulkley in the 13.34% market return and her forecasted MRP.

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

> Therefore, an historical risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earn a lower risk premium than they expect are offset by short-run periods during which investors earn a higher risk premium than they expect. Only over long time periods will investor return expectations and realizations converge. Clearly, the accuracy of the realized risk premium as an estimator of the prospective risk premium is enhanced by increasing the number of years used to estimate it…

Clearly, Ms. Bulkley's approach to calculating the projected market risk premiums is not academically or practically sound.

For the above reasons, witness Bulkley's development of the forecasted MRP used in her calculation of the CAPM and ECAPM cost of equity is seriously flawed and should be rejected.

Q PLEASE COMMENT ON MS. BULKLEY'S USE OF THE ECAPM METHOD.

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

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

Dr. Morin points out this key difference on page 191 of his book "New Regulatory Finance" where he states that "…the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free rate version which has been tested."

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

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

A. No. In response to previous discovery, the Company stated that ECAPM "… is supported by orders from regulatory bodies in Maryland, Mississippi and Alberta…" As a result of this claim, the Company was asked to provide the specific rate orders from these regulatory commissions.[149] This information was less than convincing.

Regarding the purported acceptance of the ECAPM in the State of Mississippi, the filing requirements of the Mississippi Commission require ECAPM filings. However, the extent to which Mississippi relies upon these estimates is unknown.

Regarding the Maryland commission, Company witness Maddipati pointed out on page 58 of his direct testimony in Case No. U-18424 that the Maryland Commission stated that they found the DCF and ECAPM "helpful" in Case 9326. However, in a subsequent case involving PEPCO (case 9418) with an order issued on November 15, 2016, the result is different. As shown in the summary positions articulated in the order in this case, no party involved in the proceedings, other than the company, put forth an ECAPM ROE estimate. The Maryland commission basically adopted the Staff's position with no ECAPM estimate and rounded down the Staff's recommended ROE of 9.57% to 9.55%.

In this regard, the Maryland Commission stated on page 100 of the order the following. *"Our Decision today most closely aligns with Staff's recommendation of 9.57% although we do not expressly reach the same conclusion as Staff. We find that a slightly lower ROE of 9.55% is both adequate and appropriate for Pepco…"* Furthermore, in its decision in this case, the Maryland commission expressed no position on ECAPM. I am not aware of

---

[149] CECo responses to U-18424 AG-CE-206 and AG-CE-386.

any more recent cases that show a change in the commission's view of the ECAPM methodology.

Utility Risk Premium Approach

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

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

Q. PLEASE EXPLAIN YOUR UTILITY RISK PREMIUM ANALYSIS RESULTS.

A. Exhibit AG-44 shows the components required to derive a cost of common equity capital for the peer companies on lines 3 and 4. The 5.59% on line 3 is the projected average rate for utility bonds rated "A". This rate reflects (a) the projected 30-year U.S. Treasury bond rate (discussed above in my CAPM section) of 4.40% plus (b) the average spread of 1.19% for 30-year "A" rated utility bonds issued in 2024 compared to U.S. Treasury bonds. Added to this result is the spread rate of 3.86% on line 4 of the exhibit, which is the historical rate of gas utility stock returns versus "A" rated debt yields from 1954 to the present. The total of the two rates equals the Risk Premium return rate of 9.45% on line 5 of the exhibit.

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

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

Q. PLEASE SUMMARIZE THE BYRP ANALYSIS DISCUSSED BEGINNING ON PAGE 30 OF WITNESS BULKLEY'S DIRECT TESTIMONY.

A. In her direct testimony, Ms. Bulkley compares the authorized ROEs from gas utility rate case decisions from 1980 to early 2025 to the 30-year U.S. bond yields. Based on this information, she ran a regression model claiming to have found a strong relationship between bond yields and authorized ROEs. Using this unorthodox approach, she concluded that the average risk premium over the 1980-2025 period was 5.86%.[150] To the 5.86% calculated risk premium, she adds her estimated 30-year U.S. bond rate of 4.68% to arrive at a 10.54% ROE rate for the projected test year. The calculations are shown on page 19 of Exhibit A-14 (AEB-1).

Q. WHAT IS YOUR ASSESSMENT OF THE BYRP APPROACH PRESENTED BY MS. BULKLEY?

A. There are three major flaws with Ms. Bulkley's Bond Plus Risk Premium methodology. First, it lacks any comparison of actual utility returns achieved from price appreciation and dividends to bond yields. It is the actual return on utility common equities that is the key and necessary measurement in any risk premium analysis. Using authorized ROEs as a

---

[150] Reflects the average of Ms. Bulkley's three interest rate scenarios.

substitute ignores investors' return expectations. Second, the analysis is biased because it covers a period when interest rates were declining from 12.1% in late 1980 to approximately 4.5% in 2025.

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

Q. HAVE REGULATORS IN OTHER JURISDICTIONS EMBRACED THE BOND YIELD RISK PREMIUM APPROACH?

A. No. The Attorney General asked the Company to identify any state regulatory commissions that have relied on this methodology. The Company's response was that "Ms. Bulkley has not conducted an exhaustive search for the information requested." The Company mentioned the Minnesota regulatory commission use of the BYRP as another point of reference in setting the ROE rate.[151] On the other hand, the BYRP method was recently rejected by the Utah regulatory commission in its rate case decision in April 2025 in Docket 24-035-04 involving Rocky Mountain Power (RMP), a subsidiary of PacifiCorp. The Utah commission agreed with the arguments of the Office of Consumer Services

---

[151] DR AG-CE-231.

(OCS) by stating that "As persuasively argued by OCS, and not disputed by RMP, a fundamental component of the BYRP model is commission behavior (i.e., the authorized ROEs set by commissions over a historical period) and not investor behavior."[152] The Utah commission concluded that the RMP calculation of the ROE result using the BYRP method to be unreliable. The Utah commission's position on this matter clearly recognizes that the "investor behavior component" is absent in the BYRP model approach. In contrast, investor behavior is a key component in the DCF, CAPM, and the Utility Risk Premium methodologies I use in this rate case.

Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER REGULATORY COMMISSIONS HAVE GRANTED DURING THE TWO YEARS ENDED SEPTEMBER 2025.

A. Exhibit AG-47 shows the ROEs granted by state regulatory commissions for U.S. gas utilities during the two years ending in September 2025. The majority of the 40 ROE decisions in the year ended September 2024 and the 43 decisions in the year ended June 2025 are at rates well below 9.80%, which is CECo's current authorized ROE from the last gas rate case.[153] As noted on page three of the exhibit, only three decisions in the year ending September 2024 and seven decisions in year ended September 2025 were at rates above 9.80%. These higher rates, which are summarized on page 3 of Exhibit AG-47 are primarily from regulatory commissions in California, Florida, or pertain to small utilities

---

[152] Utah Commission order of April 2025 in Docket 24-035-04 at pages 25 and 26.

[153] The 2023 and 2024 decisions exclude Limited Issue Rider cases.

in other states. ROEs in California have been at or above 10% reflecting the unique challenges for utilities in that state with wildfires and earthquakes. ROEs in Florida reflect damage to utility property and financial losses from hurricanes, which is an on-going challenge for the utilities in this state. High ROEs in other jurisdictions tend to reflect smaller utilities or unique geographical challenges, such as in Alaska, as shown on page 3 of Exhibit AG-47.

For most of the other gas utilities that have business and financial risks comparable to Consumers Energy's operations, the ROE rates have averaged around 9.63% to 9.69% in the past two years. This evidence supports my calculations of an overall cost of equity of 9.68% and suggests that the Company's current ROE rate of 9.80% is excessive and "out of line" with comparable gas utilities and the true cost of equity capital. The Company's proposed ROE rate of 10.25% is even further removed from reality and clearly unsupportable. My recommended ROE rate of 9.70% is reasonable and in line with industry average ROEs.

I will also point out that the average ROE rate during the two years ended September 2025 for the utilities in my peer group is 9.66%. Exhibit AG-49 shows this information. This is another benchmark that shows the 9.70% ROE rate I have proposed is reasonable if not generous in comparison to peer companies.

Q. IN THIS RATE CASE, MR. BLECKMAN SPONSORS EXHIBITS A-34 (MRB-11) REFLECTING A SELECT ANALYSIS OF UTILITIES WITH HIGH ROES AND EQUITY RATIOS WHAT IS YOUR ASSESSMENT?

A. In general, the companies shown in this exhibit are electric utilities, which have different characteristics than gas utilities, and in some cases involve special situations. Mr. Bleckman's attempt to inflate the ROE recommendation by pointing to select and inapplicable ROE rates granted to other utilities fails to provide convincing evidence and should be rejected by the Commission.

Q. PLEASE EXPLAIN THE PURPOSE OF EXHIBIT AG-45 TITLED "PEER GROUP NON-UTILITY AND NON-REGULATED OPERATIONS."

A. Exhibit AG-45 shows the percentage of non-utility on non-regulated operations for each of the peer companies. In general, approximately 15% of the total operations of these companies are non-utility or non-regulated which makes them riskier than their utility operations. Non-utility and non-regulated businesses do not benefit from regulatory protection and nearly assured cost recovery. It is important to keep in mind in establishing an appropriate ROE for utility companies given that the traditional operations of a gas utility unit, such as that owned by Consumers Energy, are less risky than the peer group as awhole.

I will also point out that the most recent average ROE rates for gas utilities in my peer group is 9.66%. Exhibit AG-47 shows this information. This is another benchmark that shows the 9.70% ROE rate I have proposed is reasonable and appropriate for the Company in this rate case.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN AUTHORIZED ROE AT 9.70% IN THIS CASE WILL LEAD TO IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?

A. No. From time to time in general rate case proceedings, certain applicants, including the Company, have raised arguments that they should receive higher ROEs to ensure the financial soundness of the business and to maintain its strong ability to attract capital in addition to being compensated for risk. However, those concerns are not supported by the evidence. Exhibit AG-47 shows several electric utilities that have accessed the capital markets at competitive interest rates since receiving ROEs near or below the average rate of 9.69%.

As shown on Exhibit A-32 (MRB-9), the market for new utility debt issues has been very robust with over 400 new issues completed in 2024 and 2025. In 2025, Consumers Energy issued $1.125 billion of new long-term debt at rates of 4.5% (for 5.5 years to maturity) and 5.05% (for 10 years to maturity). Also, Consumers Energy issued $700 million of long-term debt in July 2024 at an interest rate of 4.7% and a 5-year term and in January 2024 issued $600 million of new 10-year debt at an interest rate of 4.6%. CMS Energy has also come to market and issued $2.1 billion of new debt at rates of 3.125% to 6.5% for different maturities.

Similarly, there is no evidence that equity investors have abandoned utilities that have been granted ROEs near or below the industry average. On the contrary, stock investors continue to migrate to utility stocks, recognizing that authorized ROEs are still above the true cost of equity. Exhibit AG-46 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past few years reflecting ROEs as low as 9.20%. Yet this group of companies has an average Market to Book common equity value ratio of approximately 1.9 times.

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

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

The fact that the Company needs to raise capital because of a large capital investment program to upgrade its infrastructure and for other purposes is not unique to Consumers Energy. Most gas utilities face the same issues and are able to raise capital with ROEs at or below the 9.69% average rate. Therefore, this issue often is another “red herring”.

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

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

As a supporting point, in Exhibit AG-54, I have included a Value Line Funds article written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not risk. For example, he points out that volatility in 2017 was low by historical standards and it was near normal levels in 2018. Mr. Appel goes on to say later in this article that "…volatility is only risk if you act during down times, that is, only if you sell a stock." This principle still applies to events today.

Additionally, I will submit that those who invest money in equity portfolios over longer periods of time and particularly in utility stocks have an aversion to market volatility and the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market. This is reflected in the average Beta value of 0.77 of the utility peer group used in the CAPM discussed earlier, in contrast with the general stock market value of 1.0. The stock market volatility in 2025 due to the imposition of trade tariffs and the current war in Iran are examples where utility stocks have outperformed the general stock market as a safer haven for investment. As an example, from since the beginning of the year and through

April 3, 2026, CMS Energy's common stock was up nearly 12% while the S&P 500 Index was down 4.0% during the turmoil of the war with Iran, lingering effects from changing tariffs, and other economic events.[154] Therefore, the Commission should not give any weight to arguments that the Company's ROE should reflect investors' concerns with stock market volatility or international economic events.

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

A. In Exhibit AG-41, I summarized the cost of equity rates from the three methods I discussed above. The range of returns for the industry peer group is from 9.45% at the low-end, using the Utility Risk Premium approach and 10.15% at the high end using the CAPM approach.

As explained earlier in my testimony, I give 50% weight to the DCF method as a more reliable approach to estimating the cost of equity for a utility, which from my analysis is a rate of 9.57%. In this regard, on line 4 of Exhibit AG-41, I have calculated a weighted return on equity from the three methodologies using a 50% weight for DCF and 25% for each of the other two methods. The result is a weighted average cost of common equity of 9.68%. I rounded this rate up to a recommended ROE rate of 9.70% for Consumers Energy's gas business. With investors significant interest in utility stocks and expected

---

[154] As another example, DTE Energy's stock price for the same period was up nearly 14%.

stable to lower interest rates in coming months, the 9.70% proposed ROE rate is reasonable if not very generous to the Company. Therefore, there is no need to further increase the ROE rate above 9.70% and I urge the Commission to adopt this proposed rate.

Q. IF THE COMMISSION APPROVES A 9.80% COST OF COMMON EQUITY IN THIS CASE INSTEAD OF A 9.70% RATE, WHAT IS THE ADDITIONAL COST TO CUSTOMERS COMPARED TO AN ROE OF 9.70%.

A. If the Commission were to approve a 9.80% ROE in this case versus a 9.70% ROE, the additional cost to customers is approximately $7.8 million annually. An increase of the ROE to 9.90% from the currently approved 9.80% would double the cost to customers to nearly $16 million. There is absolutely no need to burden customers with this additional cost.

I recommend that the Commission take note of the evidence and arguments I have presented in my testimony and grant the Company a ROE rate of no more than 9.70%.

IX. Operations and Maintenance Expenses

Q. WHAT ARE YOUR FINDINGS IN ANALYZING THE COMPANY'S LEVEL OF O&M EXPENSES INCLUDED IN THIS RATE CASE?

A. Exhibit A-13 (HLR-41), Schedule C-5, shows the Company forecasted total O&M expenses of $347.4 million for the projected test year, which are an increase of $54.4

million over the 2024 historical year.[155] The increases are primarily in distribution, pipeline integrity work, gas storage, and compression operations with increases also in information technology and employee benefits.

In my testimony below, I recommend that the Company's forecasted O&M expense should be reduced by $42.4 million. Exhibit AG-55 shows a summary of my proposed O&M expense adjustments.

Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE OTHER O&M EXPENSES SHOULD BE REDUCED?

A. Yes. I have analyzed O&M expenses by major department or area, and I have identified more appropriate and reasonable expense levels that the Commission should consider.

A. Distribution

1. Distribution Pipelines Expense

Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR DISTRIBUTION PIPELINES FOR THE PROJECTED TEST YEAR.

A. On line 2 of page 1 of Exhibit A-117 (JPP-2), the Company shows Distribution Pipelines O&M expenses increasing from $11,542,000 in the historical year to $13,797,000 for the projected test year. On page 17 of his direct testimony, Mr. James Pnacek attributes the

---

[155] See line 34 of Exhibit A-13 (HLR-41), Schedule C-5, excluding LAUF and Company Use Gas.

increase to several reasons with no specific quantification or explanation why some or most of those attributes cannot be managed within existing resources

In response to discovery the Company provided the number of work orders and hours spent each year from 2021 to 2025 to complete work activities in this subprogram and forecasted for 2026, 2027, and the projected test year along with related annual expenses.[156] The information shows that during the most recent three years, 2023-2025, the Company completed on average 16,223 work orders employing 51,723 hours to complete that work at an average hourly rate of $208.73. Historical years prior to 2023 shows fewer orders and hours spent to operate and maintain the distribution pipelines. However, for all future periods, the Company forecasted higher work order numbers of 22,700 with 66,100 hours of work at a higher expense amount.

The lack of justification for the higher forecasted level of activity leads me to rely on the most recent three-year average number of work hours of 51,723 at the average rate of $208.73 adjusted for inflation for 2026 and 10 months of 2027. The result is a forecasted expense level of $11,268,000 for the projected test year.[157] This amount is $2,529,000 lower than the Company's forecasted amount of $13,797,000.

Therefore, I recommend that the Commission reduce the Company's forecasted O&M expense for the projected test year by $2,529,000.

---

[156] Exhibit 56 includes DR AG-CE-0329 with ATT_1.

[157] 51,273 x $208.73 x 1.024 x 1.0192 = $11,268,000.

2. Distribution Leak Repair & Survey Expense

Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR LEAK REPAIR AND SURVEY FOR THE PROJECTED TEST YEAR.

A. On line 7 of page 2 of Exhibit A-117 (JPP-2), the Company shows Distribution Leak Repair and Survey O&M expenses increasing from $19,867,000 in the historical year to $33,840,000 for the projected test year. Mr. Pnacek discusses this subprogram beginning on page 33 of his direct testimony. On page 34 of his testimony, he attributes the increase to several reasons from implementing mobile leak detection technology with AMD, increasing the number of units and miles to be surveyed for leaks, increasing leak repairs, and an array of other reasons with no specific quantification or explanation how each reason contributes to the increase in expense and why the mobile AMD technology is not making the survey process more efficient and reducing O&M expense instead of increasing it.

Table 23 on page 35 of Mr. Pnacek's testimony shows the number of survey units or locations will more than double to 1,150,226 units in the projected test year from 512,729 units in 2024, which had increased 39% from 2023. In response to discovery, the Company provided the actual expense for Leak Repair and Survey for 2025 and forecasted amount for 2026 and 2027. This information shows that the actual 2025 expense increased $3.2 million to $23,047,000 from the 2024 actual expense of $19,867,00. However, for 2026, the Company is forecasting a decline in expense to $15,350,000 and then more than doubling for 2027 to $34,754,000.[158] These large swings in expense levels from one year to the next do not engender confidence in the Company's expense projections.

Although the Company seems eager to undertake a large escalation in leak surveys in 2027, the Company began purchasing the AMD technology with mobile units and vehicles as early as 2021. In fact, as discussed above in the Capital Expenditures section of my testimony, the Company now believes that the AMD technology previously purchased is approaching the end of life and wants to upgrade or replace it. It is then befuddling why the Company wants to undertake a surge in 2027 when the technology has already been available and hopefully used. Furthermore, there has been no evidence presented that surveying all or most of the Company's facilities annually is advantageous and cost justified versus a two- or three-year cycle with priority ranking of higher risk locations or facilities. The Company's shotgun approach seems misplaced and is extremely costly.

A more measured approach and gradual increase in future years, if necessary, is more reasonable and advisable. As stated earlier, in 2024, the Company completed 512,729 surveys, which is the highest level since at least 2021. It also completed 28,552 repairs, which is the highest number since 2021. Furthermore, the 2025 expense reached a new threshold level at $23,047,000. This amount, adjusted for 2026 and 2027 inflation, would result in O&M expense for the projected test year of $24,053,000. This higher expense

---

[158] Exhibit AG-57 includes DR AG-CE-0330 with ATT_1.

level should give the Company the ability to further increase the number of leak surveys and repairs above the number completed in 2024.

Therefore, I recommend that the Commission approve the expense of $24,053,000 for the projected test year and disallow the excess amount of $9,787,000 from the Company's forecasted expense of $33,840,000.

3. Meter Technology & Management System Expense

Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR METER TECHNOLOGY AND MANAGEMENT SYSTEM FOR THE PROJECTED TEST YEAR.

A. On line 14 of page 3 of Exhibit A-117 (JPP-2), the Company shows O&M expenses for Meter Technology and Management Support increasing from $1,994,000 in the historical year to $3,853,000 for the projected test year. Mr. Pnacek discusses this subprogram beginning on page 72 of his direct testimony. On page 73 of his testimony, he attributes the increase primarily to higher labor costs, materials, other operating costs, and the inclusion of $240,000 for managing the proposed Gas Smart Meter Pilot program.

In response to discovery, the Company provided the actual expense for 2025, which reached $3,074,000 and increased approximately $1.1 million over the 2024 expense amount. The 2025 expense detail shows salaries basically remaining flat with 2024 amounts and Meter Correctors reaching a peak amount of $2.0 million in 2025 or more than double the amount in 2024.[159] According to Mr. Pnacek's testimony on page 74, the number of meter correctors purchased in 2025 reached a normal level, although he forecasts a further increase in the projected test year.

The discovery response also shows an increase in employee salaries and labor costs of 25% between 2025 and the projected test year. This increase over an 18-month period is excessive. To develop a reasonable forecast of O&M expense for this subprogram for the projected test year, I used the 2025 actual expense of $3,073,557. This is the most recent and highest expense amount in the last three years. After adjusting the 2025 expense for future inflation in 2026 and 10 months of 2027, the result is an expense amount of $3,208,000. This amount is $645,000 lower than the Company's forecast of $3,853,000.

I recommend that the Commission remove this excess amount of $645,000 from the Company's forecasted O&M expense for the projected test year. As apparent from my calculations, I did not include the O&M expense for the Smart Meter Pilot program in the projected test year. As discussed earlier in the Capital Expenditures section of my testimony, I recommend that this pilot program be rejected at this time.

4. EIRP Training Expense

Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR EIRP TRAINING FOR THE PROJECTED TEST YEAR.

---

[159] Exhibit AG-58 includes DR AG-CE-0342 with attachment.

A. On line 8 of page 1 of Exhibit A-118 (JPP-3), the Company shows forecasted O&M expenses of $4,440,000 for the EIRP for the projected test year, which is an increase in expense of $1,407,000 from the 2024 historical year. Beginning on pages 100 of his direct testimony, Company witness James Pnacek discusses the major components of the increase in expense. Table 62 shows that approximately $1.0 million of the increase pertains to EIRP Labor OM&C Training. Mr. Pnacek attributes the increase in expense primarily to expansion and training of the workforce assigned to perform EIRP work. Other than general explanations, there are no calculations in the testimony to show how the increase in expense was determined.

In discovery, the Attorney General asked the Company to expand the table on page 100 of Mr. Pnacek's testimony and provide the historical expenses for 2023-2025. The Company was also asked to provide number of EIRP employees trained each year from 2023 to 2025 and forecasted for 2026 and 2027. The information provided by the Company shows that the training expense declined for two years in a row in 2024 and 2025 with 2025 at $2,468,000 while 2023 expense was $3,348,000. Furthermore, although the Company has experienced turnover in employees working on the EIRP, the number of employees hired for the program decline to 15 in 2025 and for the prior three years the number hired ranged from 23 to 38 employees.[160] The data does not show a significant influx of new employees that justifies a large increase in expense.

---

[160] Exhibit AG-59includes DR AG-CE-0348 with attachments.

The Company provided some additional information on the number of employees to be trained and number of hours of training from 2023 to 2027, but it is not clear whether it pertains to only EIRP employees or broader employee training. In any case, the forecasted number of employees to be trained for 2026 and 2027 is in line with the number in 2023 and 2024. The purported increase in training sessions, which more than doubles in 2026 and 2027 from historical years, is unexplained and unsupported.[161]

The EIRP is a mature program and employees working on the program should already be knowledgeable and trained on how to install pipe, services, and other parts and equipment. No evidence of a high turnover in employees has been presented to justify the training of a larger number of employees or contractors. Furthermore, as I proposed in the Capital Expenditures section of my testimony, the EIRP should be scaled back beginning with the projected test year to stay within a reasonable cost budget. This reduction in spending will require fewer resources,

Using the most recent actual 2025 expense amount of $2,467,978 and adjusting it for inflation results in a reasonable forecast of $2,576,000 for the projected test year. This amount is $1,864,000 lower than the Company's forecast of $4,440,000. I recommend that the Commission remove the $1,864,000 from the Company's forecasted O&M expense.

---

[161] Id.

5. Field Operations Expense

Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR FIELD OPERATIONS FOR THE PROJECTED TEST YEAR.

A. On line 3 of page 1 of Exhibit A-118 (JPP-3), the Company shows forecasted O&M expenses of $5,004,000 for Field Operations for the projected test year, which is an increase in expense of $3,655,000 from the 2024 historical year amount of $1,349,000. Beginning on pages 92 of his direct testimony, Company witness James Pnacek discusses the major components of the increase in expense. It appears that a one-time reduction in expense for gas bond deposits in 2024 reduced that expense by approximately $2.4 million. Adjusting for that item, the annual expense in this area has been rather consistent in the $3.4 million area from 2023 to 2025.

However, in response to discovery, the Company provided the forecasted expense for 2026, which shows that the total expense for the year declines to $2,953,000. For 2027 and the projected test year, the Company forecasts large increases, including $2.5 million for expenses to test and investigate new technology for leak detection, smart meter technology, GPS asset tracking, and other ideas.[162] Although the Company claims that these prospective technologies will create work efficiencies and provide other benefits, no cost savings have been identified or proposed. Furthermore, the details of these proposals are very sketchy and no plans or other justification have been provided to support why

---

[162] Exhibit AG-60 includes DR AG-CE-0345 with attachment and AG-CE-0346.

undertaking such initiatives is necessary at this time when bill affordability is a large concern for customers.

I find the Company's forecast for 2026, which excludes the technology investments, to be a sound basis to forecast normal operating expenses in this area. The 2026 forecasted expense of $2,953,000 adjusted for 10 months of 2027 inflation results in an expense amount of $3,010,000 for the projected test year.[163] This amount is $2,051,000 below the Company's forecast of $5,004,000.

I recommend that the Commission remove the $2,051,000 from the Company's forecasted expense for the projected test year.

B. Transmission and Compression Expense

1. Compression Expense

Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR COMPRESSION OPERATIONS FOR THE PROJECTED TEST YEAR.

A. On line 18 of page 3 of Exhibit A-117 (JPP-2), the Company shows forecasted O&M expenses of $20,463,000 for Compression operations for the projected test year, which is an increase in expense of $3,321,000 from the 2024 historical year amount of $17,142,000. Beginning on pages 83 of his direct testimony, Company witness James Pnacek discusses the major components of the increase in expense. The reasons for the increase are general

---

[163] $2,953,000 x 1.0192 = $3,010,000.

and vague. Where costs are identified on page 87 of his testimony there is no timeframe associated with the expense and often appear to apply to historical years. The testimony is not helpful in pinpointing why the expenses in this area are increasing for the projected test year.

In response to discovery, the Company provided the historical expenses for 2023-2025 and the forecasted expense for 2026. During the past three years, compression expense has averaged \$18.3 million with an increase in 2025 after a decline in 2024. For 2026, the Company provided a forecasted expense of \$17.6 million, which is in line with the historical expense of \$17.1 million in 2024 and \$17.9 million in 2023. However, the Company forecasted an increase to \$20.5 million for the projected test year in all categories of costs for labor, material, and overheads.[164]

In the attachment to the discovery response in Exhibit AG-61 the Company identifies several labor cost increases between 2024 and the projected test year. Most of those increases should already be reflected in the Company's expense forecast for 2026. Therefore, I find the Company's 2026 forecasted expense to be a sound base to forecast the projected test year expense for compression operations. The 2026 forecasted O&M expense of \$17,600,000 adjusted for 10 months of 2027 inflation results in an expense amount of \$17,938,000 for the projected test year. This amount is \$2,525,000 lower than the Company's forecast of \$20,463,000.

---

[164] Exhibit AG-61 includes DR AG-CE-0343 with attachments.

I recommend that the Commission remove the $2,525,000 from the Company's forecasted expense for the projected test year.

2. Transmission Pipeline Integrity Expense

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO FORECASTED TRANSMISSION PIPELINE INTEGRITY O&M EXPENSE FOR THE PROJECTED TEST YEAR.

A. On line 4 of page 1 of Exhibit A-72 (MPG-1), the Company shows forecasted expense for Transmission Pipeline Integrity of $26,351,000, which is an increase of $7,907,000 over the 2024 expense of $18,444,000. Mr. Griffin discusses this expense item beginning on page 17 of his direct testimony. The testimony shows that the number of pipeline miles inspected decreased by 50% from 374.6 miles in 2024 to 198.7 miles in 2025 and rebounded in 2026 to 297 miles and to 329.7 miles in 2027 but was still below the 2024 miles. However, the forecasted expense for the forecasted test year ending October 2027 is increasing 43% from 2024. Mr. Griffin provides general explanations about additional activities, such as more digs, geohazard assessments, pipe movement studies, EMAT inspections, but no specific cost increases are shown from year to year to ascertain how these activities are contributing to the large increase in expense for the projected test year.

Using the most recent historical expense for years 2023-2025 and related number of miles of pipeline integrity inspections is a reasonable basis to forecast the expense for the projected test year. During 2023-2025, the Company inspected 280 miles on average per year at an average cost of $63,117 per mile.[165] This cost adjusted for inflation for 2026 and 10 months of 2027 results in a cost per mile of $65,873.

The Company forecasted 297 miles of pipeline inspections for 2026 and 329.7 miles for 2027, which would translate to 324 miles for the projected test year. However, in response to discovery, the Company stated that it does not have a target mileage per year and the total mileage inspected is determined by the length of the segments scheduled each year.[166] Therefore, the Company's forecasted miles to be inspected in 2026 and 2027 are questionable. A more reliable basis is the actual miles inspected on average during the most recent three years. Using the 280 miles and applying the forecasted cost per mile results in an expense amount of $18,444,000 for the projected test year. This amount is $7,907,000 lower than the Company's forecast of $26,351,000.

I recommend that the Commission remove the $7,907,000 from the Company's forecasted expense for the projected test year.

---

[165] Exhibit AG-62 includes DR AG-CE-0298 and AG-CE-0303 with attachment for number of miles, historical and forecasted expense by year, and page 3 of Exhibit A-72 to develop the historical average cost per mile. 2023: $17,089,000 / 266.5 miles = $64,124. 2024: $18,444,000 / 374.6 miles = $49,237. 2025: $15,099,000 / 198.7 miles = $75,989. ($64,124 + $49,237 + $75,989) / 3 = $63,117 average cost per mile.
[166] Exhibit AG-62 DR AG-CE-0298.

C. Customer Service Expense

1. Customer Contact Center Expense

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR THE PROJECTED TEST YEAR FOR THE CUSTOMER CONTACT CENTER.

A. On line 4 of page 3 of Exhibit A-132 (MNW-2), the Company shows forecasted expense of $13,767,000 for the Customer Contact Center function for the projected test year, which is an increase of $896,000 from the 2024 historical expense of $12,871,000. Company witness Melissa Wiersema briefly addresses the increase in expense in her direct testimony on page 21.

From responses provided to discovery by the Commission Staff, it is evident that the Company is experiencing a decrease in customer calls to the Contact Center and is forecasting reductions in the number of customer service representatives needed in future years, which is driven by customers' use of digital self-service tools. These cost savings are not reflected in the Company's forecasted expense for the projected test year. In response to discovery, the Company reported that in 2023 it received 2,748,882 customer calls, which declined to 2,613,744 in 2024 and to 2,416,529 in 2025 (January to October call of 2,013,774 annualized).[167] The average annual decrease in the number of calls from 2023 to 2025 is 6%.[168]

---

[167] Exhibit AG-63 includes DR SA-CE-006 and 007.

[168] 2,748,882 – 2,416,529 = 332,353 / 2,748,882 = 12% / 2 = 6%.

Applying the 6% annual rate of decline to the number of customer calls in 2025 results in 265,818 fewer calls for the projected test year.[169] This number multiplied by the average cost per call of $13.46 results in total cost savings of $3,586,000. The portion applicable to the gas business is $1,757,000.[170]

Q. IS THERE OTHER EVIDENCE THAT CUSTOMER CONTACT CENTER EXPENSES WILL DECLINE FOR THE PROJECTED TEST YEAR?

A. Yes. In response to a Staff discovery request, the Company stated that it currently has 211 employees in the Contact Center and expects that number to decline to 185 employees by yearend 2026 and decline further to 149 employees by yearend 2027.[171] With a forecasted average employee count of 167 during 2027, this represents a decline in employees of approximately 20% from 2025 with the associated labor costs declining commensurately.

For 2025, the Company reported that it incurred labor expense of $9,528,000 for the Customer Contact Center applicable to the gas business.[172] Applying the 20% reduction to the 2025 labor costs results in a labor expense reduction of approximately $1.9 million. This amount affirms My calculations above for an expense reduction of $1,757,000 for the projected test year.

---

[169] 2,416,529 x 6% x 22/12 (January 2026 to October 2027 = 265,818 reduction in calls.

[170] Gas customers 1,851,766 + Electric customers 1,918,106 = 3,769,872 total customers (sourced from Exhibit A-16, Schedule F-1, page 1 in Case No. U-21981 and U-21870, respectively: 1,851,766 / 3,769,872 = 49% x $3,586,000 = $1,757,000.

[171] Exhibit AG-63 includes DR SA-CE-011.

[172] DR AG-CE-0420 ATT_1.

Therefore, I recommend that the Commission remove $1,757,000 from the Company's forecasted expense for the projected test year.

2. Analytics and Outreach Expense

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR THE PROJECTED TEST YEAR FOR ANALYTICS AND OUTREACH.

A. On line 1 of page 3 of Exhibit A-132 (MNW-2), the Company shows forecasted O&M expense of $2,905,000 for the Analytics & Outreach function, which is an increase of $1,577,000, or more than double the expense incurred in 2024. Ms. Wiersema's direct testimony is devoid of any explantions addressing this expense item. In discovery, the Attorney General asked the Company to provide the historical and forecasted expense for 2025 and 2026 with explanations about the increase in labor costs from 2024 to the projected test year.

In response, the Company points to increases in employees to fill open positions in Customer Strategy and Transportation, Branding work, and various reorganizations affecting the 2024 expense base.[173] None of these new initiatives have been explained or justified. The reorganizations should have been completed, and vacant positions should have been filled in 2025. Otherwise, it is questionable why those positions are still needed.

---

[173] Exhibit AG-64 includes DR AG-CE-0420 with attachment.

For 2025, the Company reported actual expense of $2,094,000.[174] This amount should be a sound basis to forecast the expense for the projected test year. Applying the inflation factors for 2026 and 10 months of 2027 results in an expense of $2,185,000.[175] This amount is $720,000 lower than the Company's forecast of $2,905,000.

Therefore, I recommend that the Commission remove the $720,000 from the Company's forecasted expense for the projected test year.

3. Business Customer Care Expense

Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO THE FORECASTED O&M EXPENSE FOR THE PROJECTED TEST YEAR FOR BUSINESS CUSTOMER CARE.

A. On line 2 of page 3 of Exhibit A-132 (MNW-2), the Company shows forecasted O&M expense of $2,549,000 for the projected test year for the Business Customer Care function, which is an increase of $1,032,000 from the expense in 2024. Ms. Wiersema briefly addresses this business function on pages 7 and 21 of her direct testimony and makes vague reference to the addition of a growth team.

In response to discovery, the Company disclosed that it has added six employees to the existing team of 8 employees in the Economic Development area and attributes the increase in expense of $1.0 million to be spent on these employee additions to the Growth

---

[174] Id.

[175] $2,094,000 x 1.024 x 1.0192 = $2,185,000.

Team. Some of the employees are transferring from other areas within the Company and the expense for those employees should not be incremental for the projected test year. In additional discovery responses, the Company provided a list of responsibilities that the employees would assume, including business retention, energy efficiency, connecting customers with local and state agencies, offering renewable energy options, etc.[176]

Although some of these functions may be more appropriate for prospective electric customers, it is not clear what additional gas load the Company is targeting and how that would come about, from where, and when. No increase in load from such economic development activities has been included in gas sales in this rate case to offset the higher expense. Furthermore, some of the responsibilities listed in the discovery response are more appropriate for government agencies that have economic development teams in place. It would be duplicative and unnecessary for the Company to undertake such roles outside its function of delivering utility services.

In summary, the Company has not adequately justified why the additional employees are necessary and why the expense increase of $1.0 million for the projected test year should be approved. Therefore, I recommend that the Commission remove this amount from the Company's forecast.

---

[176] Exhibit AG-65 includes DR SA-CE-083, 084, 138, and 186.

D. Information Technology Expense

1. IT Security Expense

Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO IT SECURITY O&M EXPENSE.

A. On line 2 of page 1 of Exhibit A-17 (SHB-1), the Company shows forecasted IT Security O&M expense of $7,640,000 for the projected test year. The forecasted expense is an increase of $2,539,000 over the 2024 historical expense of $5,101,000. Ms. Baker briefly addresses this expense increase on page 27 of her direct testimony.

In response to discovery, the Company provided a few more details showing that $1.2 million of the increase is for cloud subscription costs for the Digital-Hybrid Cloud and Data Center Migration and the SAP HANA Database Migration projects.[177] However, the subscription costs for these projects have been included in either the IT Operations or IT Investment O&M expenses and it is duplicative to include those expenses also under the IT Security area. Therefore, I recommend that this additional cost be removed from the projected test year.

The Company also identified $0.4 million of network costs that moved to Cyber Security due to a reorganization in 2025.[178] These costs are not incremental to the IT department

---

[177] Exhibit AG-66 includes DR AG-CE-0400.

[178] Id.

or the Company and should be removed from the IT Security expense for the projected test year.

Therefore, in total, I recommend that the Commission remove $1.6 million from the IT Security area's forecasted expense for the projected test year.

2. IT Operations Expense Savings

Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO IT OPERATIONS O&M EXPENSE.

A. In response to discovery, the Company identified annual operational cost savings of $1,420,000 in hardware maintenance and software licensing/maintenance from the Digital-Hybrid Cloud and Data Center Migration project.[179] This expense reduction has not been reflected in the projected test year expense forecasted by the Company. Therefore, I recommend that the Company remove this amount from the Company's forecast.

3. IT Projects Disallowed - Expense

Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO IT INVESTMENT O&M EXPENSE PERTAINING TO IT CAPITAL PROJECTS YOU HAVE PROPOSED BE DISALLOWED.

---

[179] Id. includes DR SA-CE-129.

A. As discussed in the Capital Expenditures section of my testimony, the O&M expense for the following three capital IT projects should be disallowed in addition to the capital costs. The three projects and related O&M expense for the projected test year are:

1. Web Proxy Service: $149,000
2. OT Data Center Migration: $349,000
3. Gas Tracking and Traceability: $509,000

The total expense for the three projects is $1,007,000. I recommend that the Commission remove this amount from the Company's forecasted OM expense.

E. Corporate O&M Expense

Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO CORPORATE SERVICES O&M EXPENSE.

A. On lines 7 and 11 of Exhibit A-58 (MJF-2), the Company shows Corporate Services expenses for the projected test year totaling to $37,512,000. The forecasted expense increased $13,088,000, or more than 50%, from the total expense of $24,424,000 in 2024. In discovery, the Attorney General asked the Company to explain the annual changes in costs in each of the expense categories from 2023 through 2027. The explanations provided by the Company show that the 2024 expenses included some one-time cost items that did not repeat into 2025 and employee positions vacancies that were filled in 2025, among other items.[180] The Company also provided the actual corporate services expenses allocated to the gas business for 2025.[181]

Based on the Company's explanations, I determined that the actual Corporate Services expenses allocated to the gas business for 2025 provide a more accurate and reasonable basis to forecast the expenses for the projected test year. The following table shows the 2025 expenses, adjusted for inflation for 2026 and 10 months in 2027, compared to the Company projected test year expenses.

Corporate Expenses Allocated to Gas Business	**2025 Actual Gas Expense**	**Inflation @ 4.37%**	**AG PTY Expense**	**CECo PTY Expense**	**Reduction**
Sustainability & External Affairs	$ 2,559	$ 112	$ 2,671	$ 3,761	$ (1,090)
Legal, Ethics, Regulatory, and Risk	7,059	308	7,367	9,431	(2,064)
People & Culture and Learning and Development	14,343	627	14,970	15,851	(881)
Finance and Shared Services	10,828	473	11,301	11,565	(264)
General Activities	(6,754)	(295)	(7,049)	(4,837)	(2,212)
Administration & Other-Gas Portion	1,889	83	1,972	1741	231
Total	**$ 29,924**	**$ 1,308**	**$ 31,232**	**$ 37,512**	**$ (6,280)**

The result is a reduction in projected test year expense of $6,280,000, showing that the Company forecasted expenses are highly inflated and excessive. I recommend that the Commission remove this amount from the Company's test year forecast.

---

[180] Exhibit 67 includes DR AG-CE-0247 and 0248 with ATT_3.

[181] Id.

F. Active Health Care Expenses

Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO THE COMPANY'S PROJECTED TEST YEAR EXPENSE FOR ACTIVE HEALTH CARE.

A. In Exhibit A-78 (KKG-1), the Company shows actual health care, life insurance and long-term disability (Health Care & Other) expense of $36,586,000 for the projected test year. In discovery, the Attorney General asked the Company to identify the cost savings of various initiatives taken in recent years and anticipated to be taken in 2025 through 2027 to reduce health care costs. In response, the Company identified cumulative cost savings by year from 2023 to 2027. For 2025, the Company identified $870,000 of incremental cost savings that have not been reflected in the Company's projected test year expense.[182]

I recommend that the Commission reduce the Company's Active Health Care expense for the projected test year by the identified cost savings of $870,000.

G. Rate Case Expenses

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

A. With the Company filing rate cases nearly every year, the costs incurred to prepare, file, and litigate each case are becoming significant. Currently, the Company expenses those costs and they become part of the base O&M expenses that it recovers in rates. In this rate

---

[182] Exhibit AG-68 includes DR AG-CE-0258.

case, the Attorney General asked the Company to provide the total costs incurred to complete each of the last three rate cases and the number of hours spent on the case by Company employees. The Company was also asked to provide the amount paid to external consultants retained to work on the rate cases. In response, the Company provided the amounts paid to an external consultant and provided an estimate of the internal costs incurred on rate cases by certain departments. The costs provided by the Company total to $733,000.[183]

Q. PLEASE PROVIDE YOUR ASSESSMENT OF THE RATE CASE EXPENSES PROVIDED BY THE COMPANY.

A. The estimated internal costs provided by the Company seem significantly understated. They do not include any legal and regulatory area costs and probably the support staff that is involved in handling and processing thousands of documents involved in the initial case filing and subsequent processing of the case through final resolution. In response to the discovery request, the Company stated that it does not track rate case costs. Although the Company estimate provides a minimal cost estimate, the actual costs included in the Company O&M expenses remain a significant burden to customers if the utility continues to recover 100% of that expense.

---

[183] Exhibit AG-69 includes DR AGDG-0264 and 0265 with attachment.

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

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

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that in this case the Commission disallow recovery of at least 50% of the $733,000 of the estimated costs, or $367,000, and remove this amount from the projected test year O&M expense. Additionally, I recommend that the Commission direct the Company to establish a mechanism to keep track of all costs to complete future rate cases and provide that cost with each new rate case filing.

H. Incentive Compensation Expense

Through the testimony of witnesses Amy Conrad and Angel Green, the Company proposes to recover in rates $1,080,000 of short-term incentive compensation.[184]

In the following pages of my testimony, I will analyze the Company proposal to include in rates the cost of incentive compensation and the alleged benefits to customers provided

---

[184] Exhibit A-53 (AMC-3).

in the testimony of Ms. Green. Over the past few years, the Company has made several changes to the incentive plan that have made it easier for the Company to payout incentive compensation. For example, the operating performance measures that drive the short-term incentive payouts under the plan were revamped in recent years. Beginning in 2022, the ability to trigger a payout has been modified to make it much easier for employees to receive incentive compensation payments. I will discuss these changes in more detail later in my testimony.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S SHORT-TERM INCENTIVE COMPENSATION PLAN.

A. The Company has a short-term incentive compensation plan for officers and a slightly different plan for non-officer employees. The Company refers to each of these plans as the Employee Incentive Compensation Plan (EICP).

The major components of the EICP for non-officer employees are shown in Exhibit A-51 (AMC-1). Fifty percent (50%) of the target award in 2023 was based on achieving 6 performance measures related to employee safety, employee satisfaction surveys, customer experience surveys, electric reliability, waste elimination and methane emission reduction.

This 50/50 combination of operating and financial measures started in 2012. In 2010 and 2011, the calculation of the non-officer EICP was based solely on achieving operating performance measures. The requirement to achieve 100% payout of target was also stricter with accomplishment of 9 measures out of 11 needed. The Company then adjusted this percentage based on the percent payout of the officers' EICP. Over the last seven years, non-officer employees have received incentive payouts as a percentage of target of 123% in 2018, 111% in 2019, 139% in 2020, 77% in 2021, 160% in 2022, 140% in 2023, 136% in 2024, and 129% in 2025.[185] The only year in the past fourteen years where a bonus payout was not made to non-officer employees was in 2011 when only 6 of the 11 operating measures were achieved. These consistent payouts indicate that incentive compensation is not at-risk compensation based on achieving superior performance, but it simply supplements base pay.

For the officers' EICP, the target payout has been based almost entirely on earnings per share and operating cash flow. However, more recently, 70% of the target payout is from achieving the CMS Energy earnings per share goal and 30% from achieving similar operating performance measures of non-officer employees.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF BOTH THE OFFICER AND NON-OFFICER EICP?

A. Generally, the Company's short-term incentive plans are too heavily weighted toward financial measures that mostly benefit shareholders and not customers.

---

[185] DR AG-CE-0414 with attachments, U-21608 AG-CE-0672, and U-21490 DR AG-CE-165 with attachments.

For the 2025 plan cycle, half of the non-officer employee EICP payouts and 70% of the Officer EICP payouts were dependent upon the financial metrics. As such, the officer group that sets the direction of the Company is still far too focused on financial results. Customers do not directly benefit from shareholders achieving a higher return on their investment. Although the Company has argued in the past that happy investors will be more attracted to the Company debt and common stock issues and therefore provide a lower cost of capital, it has not offered direct proof to support this argument. The argument is particularly hollow since the Company has not issued any significant common stock in more than five years. Later in my testimony, I will discuss in more detail the customer benefits put forth by Company witness Angel Greene.

Q. DO YOU SEE ANY OTHER PROBLEMS WITH THE MEASURES INCLUDED IN THE EICP?

A. Yes. In the past, the Company had to achieve at least a minimum number of operating metrics to trigger an incentive payout. Although, the number of operating metrics to be achieved was relatively low to demonstrate exceptional performance even that minimal requirement has now been dropped. Therefore, even mediocre performance will be rewarded if only a single metric is achieved. This is a very generous incentive plan that is not directly connected to achieving superior customer benefits before making threshold incentive payouts.

Additionally, the fact that the performance measures use CMS Energy financial information and comingle electric and gas business measures is a concern. Although the

Company is a combined gas and electric utility and makes up 95% of CMS Energy, appropriate cost segregation is required to avoid having gas customers subsidize other businesses, particularly non-utility operations.

Lastly, the Company has stated that it continues to pay merit, and salary increases each year of approximately 3.5%.

Q. PLEASE BRIEFLY SUMMARIZE AND PROVIDE YOUR ASSESSMENT OF THE CUSTOMER BENEFITS PRESENTED BY THE COMPANY TO JUSTIFY RECOVERY OF INCENTIVE COMPENSATION COSTS.

A. In her testimony, Ms. Green attempts to quantify certain benefits related to the operating performance measures that are part of the EICP. In Exhibit A-69 (ALG-2), Ms. Green shows the number of Safety Incidents, which were 135 in 2021 and 139 in 2024. The actual trend of safety incidents has been upwards. To calculate cost savings, the Company assumed it would be able to reduce the number of incidents to 83 in 2025 and based the calculation on that lower number. However, this is wishful thinking and not actual cost savings achieved. The 2025 results show that the Company did not achieve this goal. The exhibit also shows that the Company's Workers Compensation and other related costs have been erratic from 2021 to 2024 with no consistent downward trends to create cost savings. Clearly, these results do not show superior performance or an improving trend.

In Exhibit A-70 (ALG-3), Ms. Greene shows the Company's SAIDI Index results as a measure of Electric Reliability. This goal has nothing to do with the gas business and any performance achievements should be attributed to the electric business.

Ms. Green also calculates certain savings related to the Company's Culture Index based on purported cost savings from lower employee turnover. However, Exhibit A-71 shows that employee turnover was 2.6% in 2024 compared to 2.0% in 2021 and previously 1.1% in 2020, which is no longer shown in the exhibit schedule. Clearly, this is not an improving trend. To try and show some costs savings, the Company makes a comparison to other utilities. However, there is a clear mismatch between the employee satisfaction measures which are solely based on internal company surveys and cost savings calculated based on peer company turnover rates.

In summary, the cost savings calculated by Ms. Green are inconsistent with recent trends in performance, aspirational, and not based on actual achievements. They do not justify the $1.1 million of incentive compensation that the Company seeks to recover in this rate case.

Q. BASED ON YOUR REVIEW OF RESULTS DURING THE PAST FIVE YEARS, HAS THE COMPANY ACHIEVED THE TARGET LEVEL OF PERFORMANCE FOR THE OPERATING MEASURES DURING THOSE YEARS?

A. No. In discovery, the Attorney General asked the Company to provide the target operating measures, and the actual performance achieved for each year from 2021 to 2025. The information provided by the Company shows that in 2021 the Company only met 5 of the 9 operating performance measures at 100% of target or higher for an average achievement rate 56% of target. In 2022, only 3 of 5 metrics were met at least at 100% for a 60% achievement rate. In 2023, 2 of the 5 operating measures were achieved at least at 100% of target for a 40% achievement rate. In 2024, only 3 of the 5 operating measures were met at least at 100% for a 60% achievement rate, and in 2025 only 2 of the 5 measures were met at 100% of target for a 40% achievement rate. The average achievement rate for the past five years was 51%.[186]

In forecasting the amount of EICP expense of $1,080,000 included in the forecasted test year, the Company assumed that all operating measures would be achieved at least at 100% of target for both the officer and non-officer EICP. The results of the last five years do not support this expected performance level. Customers should not pay for expected performance that does not materialize. Therefore, recovery of incentive compensation at less than 100% of target is warranted. Using the 51% average performance achievement rate, the most that the Company should be allowed to recover in this rate case is $551,000 ($1,080,000 x 51%). The remaining amount of $529,000 should be disallowed.

Q. WHAT CONCLUSIONS AND RECOMMENDATIONS HAVE YOU REACHED WITH REGARD TO RECOVERY OF INCENTIVE COMPENSATION COSTS IN RATES?

---

[186] Exhibit AG-70 includes DR AG-CE-0414 with attachments and Part III Item 86 Information.

A. As discussed above, the focus of the short-term incentive compensation plans is overwhelmingly directed at creating shareholder value, not customer benefits, and the officer group that directs the day-to-day operations is only minimally incentivized to meet operational goals. Certain design flaws with the EICP tend to reward mediocre performance and diminish any real customer benefits. Incentive compensation should be paid for exceptional performance, at least to pass the test of cost recovery in rates. Performance that is ordinary and achieves basic goals and efficient operations is paid for in base salaries.

Both management and other employees have received large annual merit salary increases since at least 2009. The Company argues that it must pay a competitive compensation package to retain talented management and employees. Although that may be the case, it does not mean that customers should pay for all or most of that expense. Shareholders also significantly benefit from talented management, perhaps even more so than customers. Customers are paying for higher base pay each year. Shareholders can share the burden by paying for the incentive compensation that disproportionally favors their interests.

The Company's proposed incentive compensation expense of $1,080,000 for the projected test year assumes that the Company will achieve target performance for all its goals. There is no track record that supports that conclusion. It is probable that the Company may fall short of achieving 100% of the performance measures in the projected test year.

In recent rate cases the Commission has approved a portion of incentive compensation pertaining to operating measures and if it decides to do so in this case, I recommend that the Commission approve at most recovery of the $551,000 based on the Company achieving 51% of the operating performance measures. Therefore, the Commission should disallow the remaining amount of $529,000 from the Company's forecasted O&M expense for the projected test year.

I. O&M Adjustments - Summary

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO O&M EXPENSE.

A. Operations and maintenance expenses represent a large part of the Company's cost structure. My analysis of the expense level proposed by the Company has shown that in the following areas these expenses are excessive or not needed and should be removed.

Summary of O&M Expense Reductions	Amount ($ Millions)
Gas Distribution Operations	$ 16.4
Gas Transmission & Compression	10.4
Customer Service	3.5
Information Technology	4.0
Corporate Expenses	6.3
Health Care Costs	0.9
Rate Case Expenses	0.4
Incentive Compensation	0.5
Total	$ 42.4

I recommend that the Commission reduce the amount of total O&M costs proposed by the Company by $42.4 million and reduce the revenue deficiency accordingly. Exhibit AG-55 provides further details.

X. Adjustments To Revenue Deficiency

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

A. Exhibit AG-71 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of $93.8 million, which is a reduction of $146.2 million from the Company's requested level of $240 million.

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding $93.8 million.

XI. Revenue Decoupling Mechanism

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO ESTABLISH A REVENUE DECOUPLING MECHANISM (RDM).

A. Beginning on page 18 of her direct testimony, Heidi Myers discusses the Company's proposal to re-establish an RDM. Ms. Myers reviews the Company's history with a previous RDM, which was limited to certain residential customer sales and small commercial customers. This previous RDM was based on weather-normalized sales and the premise that the Company would encourage customer energy conservation without losing the related revenue from lower sales. Certain annual limits were set in each rate case to ensure the revenue recovery would not exceed the lost sales from energy conservation (EWR). In Case No. U-21308, the Company did not see a need to continue the RDM and stopped requesting it.

In this rate case, the Company is requesting an RDM with a sales weather-normalization clause and open-ended mechanism that would allow it to recover the full revenue lost from any sales and transportation deliveries shortfall from the level set in rates in this and subsequent rate cases. Although the Company positions the proposal as safeguarding customers, the real intent of the Company is to remove all financial risk from any shortfall in sales due to warmer weather and lost market sales. In her testimony, Ms. Myers points to lost sales to electrification and EWR. However, in response to discovery, the Company admitted that there has been no quantifiable impact of electrification on gas sales.[187] Regarding EWR losses, the Company also admitted that those losses are reflected in the projected test year sales and the Company is already recovering the lost revenue.[188] Therefore, these are no valid reasons to justify the need for an RDM.

The Company's position that eliminating all revenue risk should not lower the ROE rate is laughable. Although some other utilities may have some form of an RDM or weather normalization revenue clause, as stated above in my Cost of Capital testimony, the Company currently enjoys one of the highest ROE rates in the country at 9.80% while the

---

[187] DR AG-CE-0416.

[188] Id.

average gas utility has a ROE around 9.60%. If the Commission were to approve the Company's RDM proposal it should lower the ROE to 9.60% or even lower.

Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE PROPOSED RDM?

A. No compelling evidence has been presented that the proposed RDM is needed or is desirable to protect customers. The Company has not presented any evidence that revenue lost to warmer weather from time to time, or from other events, is creating a significant detrimental impact on its financial position.

Therefore, I recommend that the Commission deny the Company request to establish the proposed RDM.

XII. Deferred Accounting Request

Q. PLEASE PROVIDE YOUR RECOMMENDATION REGARDING THE DEFERRED ACCOUNTING REQUEST FOR STAKING VOLUME VARIABILITY MADE BY THE COMPANY.

A. In their direct testimony both witnesses Matthew Foster and James Pnacek request that the Commission approve deferred accounting treatment of staking and locating expense because increasing staking volumes and external factors contribute to volatility in staking and locating requests and the expense amount. The Commission should reject this proposal. No compelling evidence has been presented that staking and locating requests have been highly volatile to cause significant expense variations from year to year. The only large variation in expense in this area has been the Company's pursuit to change from a shared contractor model to a Company-only dedicated model discussed in Mr. Pnacek's testimony.

XIII. Rate Design

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

A. In his direct testimony, Company witness Austin Smith proposes to increase the monthly service charge for residential customers from $17.00 to $20.00 per month.

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

A. No. The proposed change from $17.00 to $20.00 per month represents nearly an increase of 18%. This significant increase could cause financial hardship for customers in smaller households who use less gas than the average customer. They would see their monthly gas bill increase without using any more gas. Fixed monthly charges also discourage energy conservation. It is best to increase the volumetric rate paid by customers because the higher cost encourages conservation. The customer can take steps to reduce usage and thus lower the gas bill. The customer cannot reduce fixed monthly charges.

Q. WHAT DO YOU RECOMMEND?

A. The Company received a 13% increase in the monthly service charge in the last rate case less than a year ago from $15.00 to $17.00. Another increase of 18% in less than a year is excessive and burdensome to small households. I recommend that the Commission reject the proposed increase and keep the residential customer monthly charge at $17.00.

Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR GENERAL SERVICE GS-1 CUSTOMERS HAS THE COMPANY PROPOSED?

A. In his direct testimony, Mr. Smith proposes to increase the monthly service charge for customers on Rate GS-1 from $21.00 to $27.00 per month.

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

A. No. The proposed change from $21.00 to $27.00 per month represents an increase of 29%. Such a large increase could cause some hardship to customers with smaller businesses who use less gas than the average commercial customer. They would see their monthly gas bill increase without using any more gas. As stated above, fixed monthly charges also discourage energy conservation. It is best to increase the volumetric rate paid by customers because the higher cost encourages conservation. The customer can take steps to reduce usage and thus lower the gas bill. The customer cannot reduce fixed monthly charges.

Q. WHAT DO YOU RECOMMEND?

A. In the last rate case, the Company received approval to increase the GS-1 monthly customer charge by nearly 17% from $18.00 to $21.00. At this time, another increase of 29% one year later is also excessive. I recommend that the Commission reject the Company's request and keep the monthly charge at $21.00.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

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

Experience and Qualifications
of Sebastian Coppola

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

EMPLOYMENT BACKGROUND

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

ENERGY INDUSTRY EXPERTISE

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

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

ENERGY INDUSTRY AND REGULATORY EXPERIENCE

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

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

After 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. SEMCO

Experience and Qualifications
of Sebastian Coppola

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) 2023-2024 GCR reconciliation in case No. U-21272.
    - Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2025 gas rate case U-21973 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 Electric Company (DTEE) 2024 PSCR reconciliation in Case No. U-21426.
    - Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) proposed sale of hydroelectric power generating assets in Case No. U-21985.

Appendix A

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2024-2025 GCR plan reconciliation in Case No. U-21446.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2024 PSCR reconciliation in Case N-. U-21424.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2025 electric rate case U-21870 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 2025 electric rate case U-21860 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 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 DTEE 2023 PSCR Plan Case No. U-21594.
- Filed testimony on behalf of the Michigan Attorney General in 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.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 PSCR reconciliation in case No. U-21260.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR reconciliation in case No. U-21270.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan reconciliation in case No. U-21278.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21258.
- Filed testimony on behalf of the Michigan Attorney General in CECo 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 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.
- 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 CECo 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2022-2023 GCR plan in case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Power Company 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Act 9 application in Case No. U-20993 by Saginaw Bay Pipeline Company to set transportation rates for services to DTE Gas Company.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 electric rate Case U-20836 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed rebuttal testimony on behalf the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gaslight & Coke Company (Peoples Gas) in Docket 17-0137.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 gas rate Case U-21148 on several issues, including operation and

Experience and Qualifications
of Sebastian Coppola

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 CECo 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR plan reconciliation case No. U-20236.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Ameren Illinois Company (Ameren) in Docket 20-0323.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan case No. U-20822.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales,

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

- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in CECo 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.

Experience and Qualifications
of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Reconciliation in case U-20202.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.

Experience and Qualifications of Sebastian Coppola

- 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 CECo 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 gas rate Case U-20322 on several issues, including operation and

Experience and Qualifications of Sebastian Coppola

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 CECo Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 gas rate Case U-18424 on several issues, including revenue,

operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.

- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.

Experience and Qualifications
of Sebastian Coppola

- 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 UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CECo Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue,

revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CECo Gas Choice and End-User Transportation tariff changes case U-17900.
- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 PSCR reconciliation case U-17317-R.

Experience and Qualifications
of Sebastian Coppola

- 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 CECo 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2014 gas general rate case U-17643 on a several issues, including

Experience and Qualifications
of Sebastian Coppola

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

Experience and Qualifications
of Sebastian Coppola

- 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 CECo's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- 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.
- 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.

Experience and Qualifications of Sebastian Coppola

- 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 CECo's gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo's electric business Pilot Revenue Decoupling Mechanism in case U-16566.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.

Experience and Qualifications of Sebastian Coppola

- 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.
- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.

Experience and Qualifications
of Sebastian Coppola

- 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.
- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.

Experience and Qualifications
of Sebastian Coppola

- 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.

Corporate Analytics

Exhibit: AG-1
Case No.: U-21981
Date: April 15, 2026
Page 1 of 17

LEADING THE CLEAN ENERGY TRANSFORMATION

Investor Meetings

March 2026

CMS ENERGY

This presentation is made as of the date hereof and contains "forward-looking statements" as defined in Rule 3b-6 of the Securities Exchange Act of 1934, Rule 175 of the Securities Act of 1933, and relevant legal decisions. The forward-looking statements are subject to risks and uncertainties. All forward-looking statements should be considered in the context of the risk and other factors detailed from time to time in CMS Energy's and Consumers Energy's Securities and Exchange Commission filings. Forward-looking statements should be read in conjunction with "FORWARD-LOOKING STATEMENTS AND INFORMATION" and "RISK FACTORS" sections of CMS Energy's and Consumers Energy's most recent Form 10-K and as updated in reports CMS Energy and Consumers Energy file with the Securities and Exchange Commission. CMS Energy's and Consumers Energy's "FORWARD-LOOKING STATEMENTS AND INFORMATION" and "RISK FACTORS" sections are incorporated herein by reference and discuss important factors that could cause CMS Energy's and Consumers Energy's results to differ materially from those anticipated in such statements. CMS Energy and Consumers Energy undertake no obligation to update any of the information presented herein to reflect facts, events or circumstances after the date hereof.

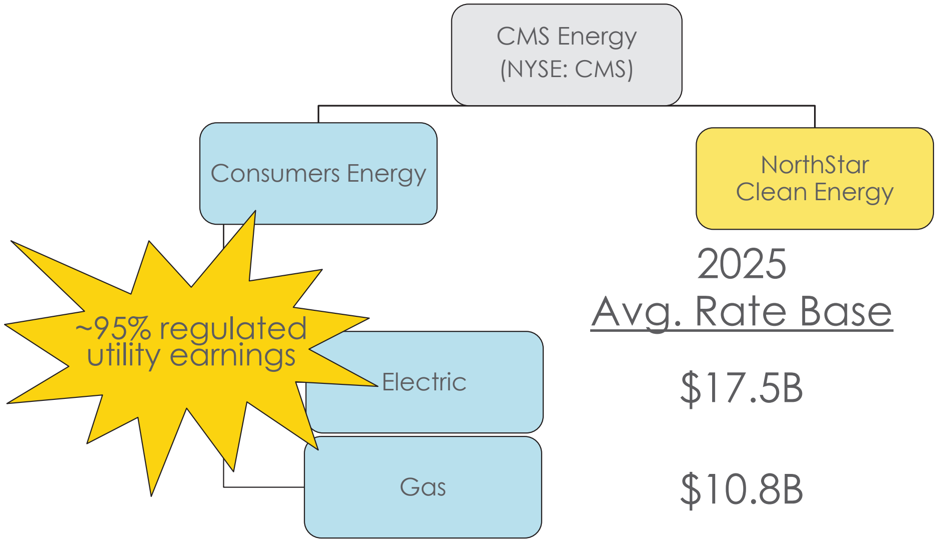
The presentation also includes non-GAAP measures when describing CMS Energy's results of operations and financial performance. A reconciliation of each of these measures to the most directly comparable GAAP measure is included in the appendix and posted on our website at www.cmsenergy.com.

Investors and others should note that CMS Energy routinely posts important information on its website and considers the Investor Relations section, www.cmsenergy.com/investor-relations, a channel of distribution.

Presentation endnotes are included after the appendix.

CMS Energy Overview

Corporate Structure



CMS Energy (NYSE: CMS)

Consumers Energy

NorthStar Clean Energy

~95% regulated utility earnings

	2025 Avg. Rate Base
Electric	$17.5B
Gas	$10.8B

Key Information

2025 Financial Statistics

Based in Jackson, MI

>8,300	Employees (44% unionized)[a]
$8.5B	Revenue
$1.1B	Adjusted net income[b]
23 years	Industry-leading financial performance
6% to 8%	Long-term adj. EPS[b] growth
~55%[c]	Payout ratio over time

Leadership Team

Garrick Rochow President & Chief Executive Officer	Rejji Hayes EVP & Chief Financial Officer	Tonya Berry EVP & Chief Operating Officer
Shaun Johnson EVP & Chief Legal & Admin Officer	Brandon Hofmeister SVP Sustainability & External Affairs	Lauren Snyder SVP & Chief Customer & Growth Officer

Presentation endnotes are included after the appendix.

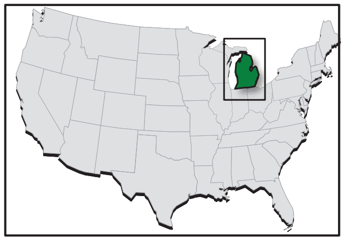
Consumers Energy Positioned Well . . .

Service Territory

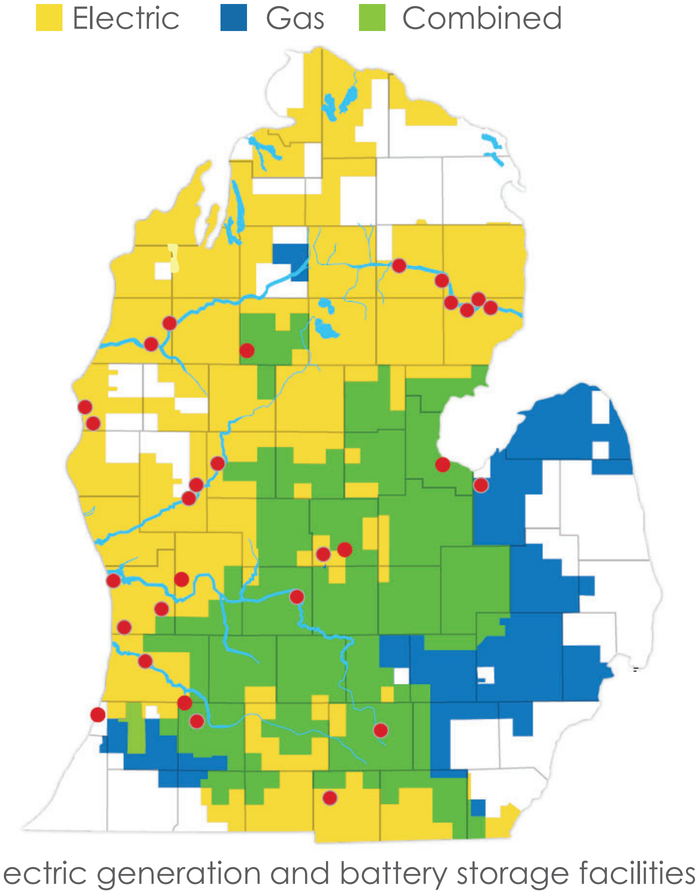
- **Electric Utility**
  1.9M electric customers
  9,190 MW of capacity
- **Gas Utility**
  1.8M gas customers
  300 Bcf gas storage
- **Serving 6.8M Michigan residents**

Planet Goals[a]

- Exit coal[b]
- Net zero methane emissions by 2030
- 60% renewable energy by 2035
- 100% clean energy by 2040
- Net zero GHG emissions by 2050
  - Interim goal of 25% by 2035



>1,450 MW cumulative contracted load since 2015[c]



Presentation endnotes are included after the appendix.

. . . for decarbonization and to lead the Clean Energy Transformation.

NorthStar Clean Energy[a] Provides Flexible Solutions . . .

NORTHSTAR™
CLEAN ENERGY
A CMS ENERGY COMPANY

Renewable Platform

- 318 MW of wind (OH, TX)
- 64 MW of biomass (MI, NC)
- 267 MW of solar (AR, MI, OH, WI)

Dearborn Industrial Generation (DIG) & Other

- >1,000 MW in MI (including DIG & Peakers)
- Upside: tightening capacity markets with future retirements

Presentation endnotes are included after the appendix.

. . . to help companies meet their decarbonization targets.

Near- and Long-Term Objectives . . .

CMS ENERGY

	2026	Long-Term Plan
Adjusted EPS guidance	$3.83 – $3.90 *Toward the high end*	+6% to +8% *Toward the high end*
Dividend Payout Ratio	~60%	~55% over time
Target credit ratings	Solid investment grade *FFO/Debt target: Mid-teens*[a]	Solid investment grade *FFO/Debt target: Mid-teens*[a]
Utility investment ($B)	$4.1	$24 *2026 - 2030*
Electric sales growth *Incl. Energy Efficiency ~2%/yr*	~3%	2% - 3%
Planned equity issuance ($M)	~$700	~$750/yr

Presentation endnotes are included after the appendix.

. . . provide sustainable benefits for customers AND investors.

ESG Disclosures are Transparent . . .

- CMS Energy & Consumers Energy Websites
- SEC Filings (10-K & Proxy)
- Sustainability Report
- DE&I Website
- SASB Index (Electric Utilities & Power Generation)
- SASB Index (Gas Utilities & Distributors)
- TCFD Index
- Global Reporting Initiative (GRI) Index
- Global Reporting Initiative (GRI) Human Capital Data
- Political Engagement

. . . and align with SASB, TCFD and GRI reporting frameworks.

CMS ENERGY

INVESTMENT THESIS

Investment Thesis . . .

Over two decades of industry-leading financial performance

Industry-leading clean energy commitments

Top-tier regulatory jurisdiction[a] with attractive growth

Excellence through the CE WAY

Track record of managing customer bills below inflation

Premium total shareholder return
6% to 8% adjusted EPS growth + ~3% dividend yield

Presentation endnotes are included at the end of the presentation.

. . . is simple, clean and lean.

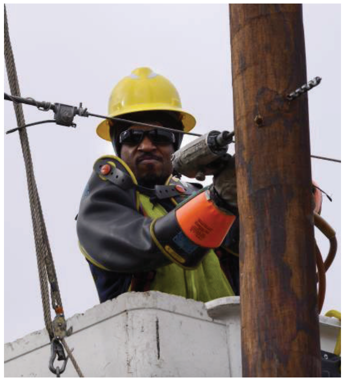
Infrastructure Renewal is Necessary . . .

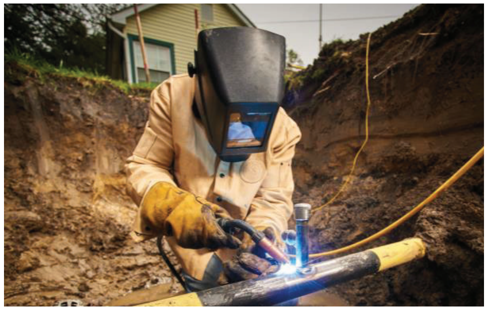
10-yr Electric Reliability Roadmap

Includes up to 400 miles of undergrounding and 20k pole replacements per year

New Energy Legislation

Provides capital opportunity to meet 60% Renewable Portfolio Standard by 2035 and 100% Clean Energy Standard by 2040





Adding 8 GW of solar and 2.8 GW of wind over the next decade
Add >850 MW of battery storage by 2030

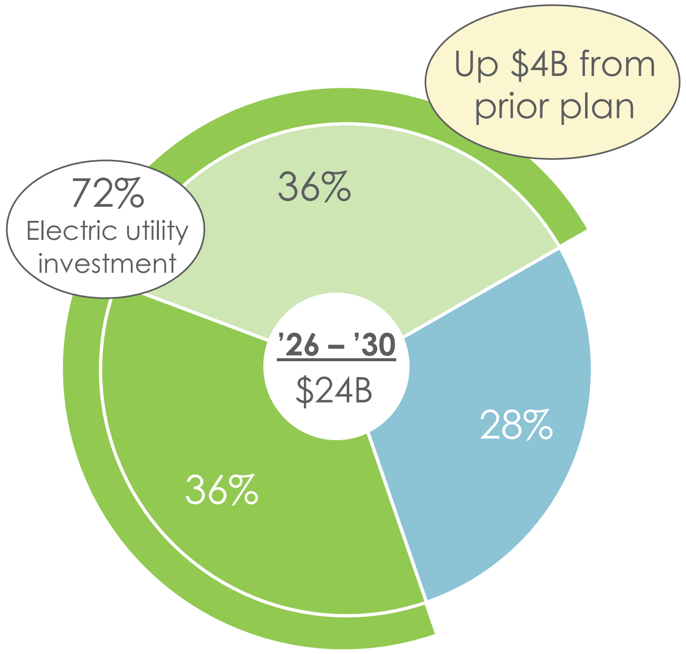
25 years of main replacement through Enhanced Infrastructure Replacement Program

. . . to modernize electric and gas systems and lead the Clean Energy Transformation.

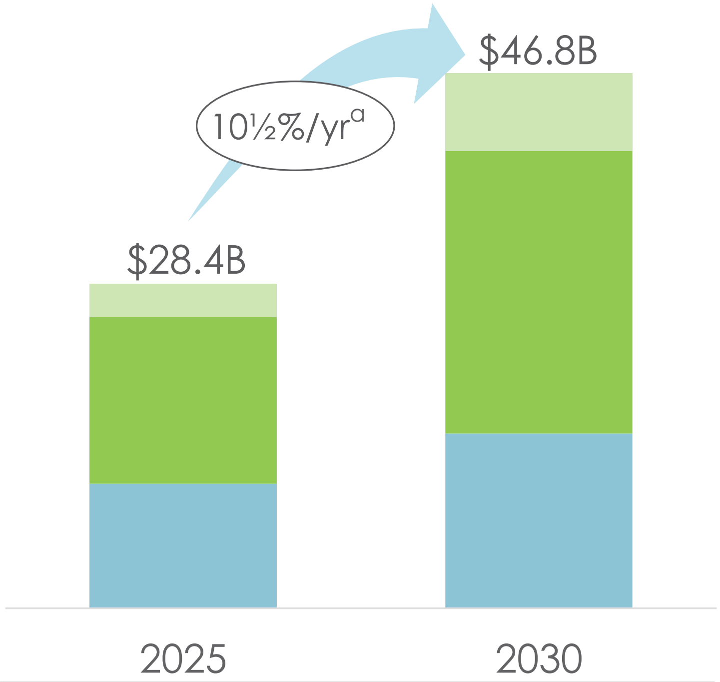
Updated Customer Investment Plan . . .

CMS ENERGY

New Utility Investment Plan



Rate Base Growth



🟩 Electric Generation 🟩 Electric Distribution & Other 🟦 Gas Utility

Non-Rate Base Earnings[b]

- ✓ **~$50M** pre-tax for FCM by 2030 with additional upside
- ✓ **~$65M/yr** pre-tax for Energy Efficiency incentive
- ✓ NorthStar – DIG re-contracting opportunities

Presentation endnotes are included after the appendix.

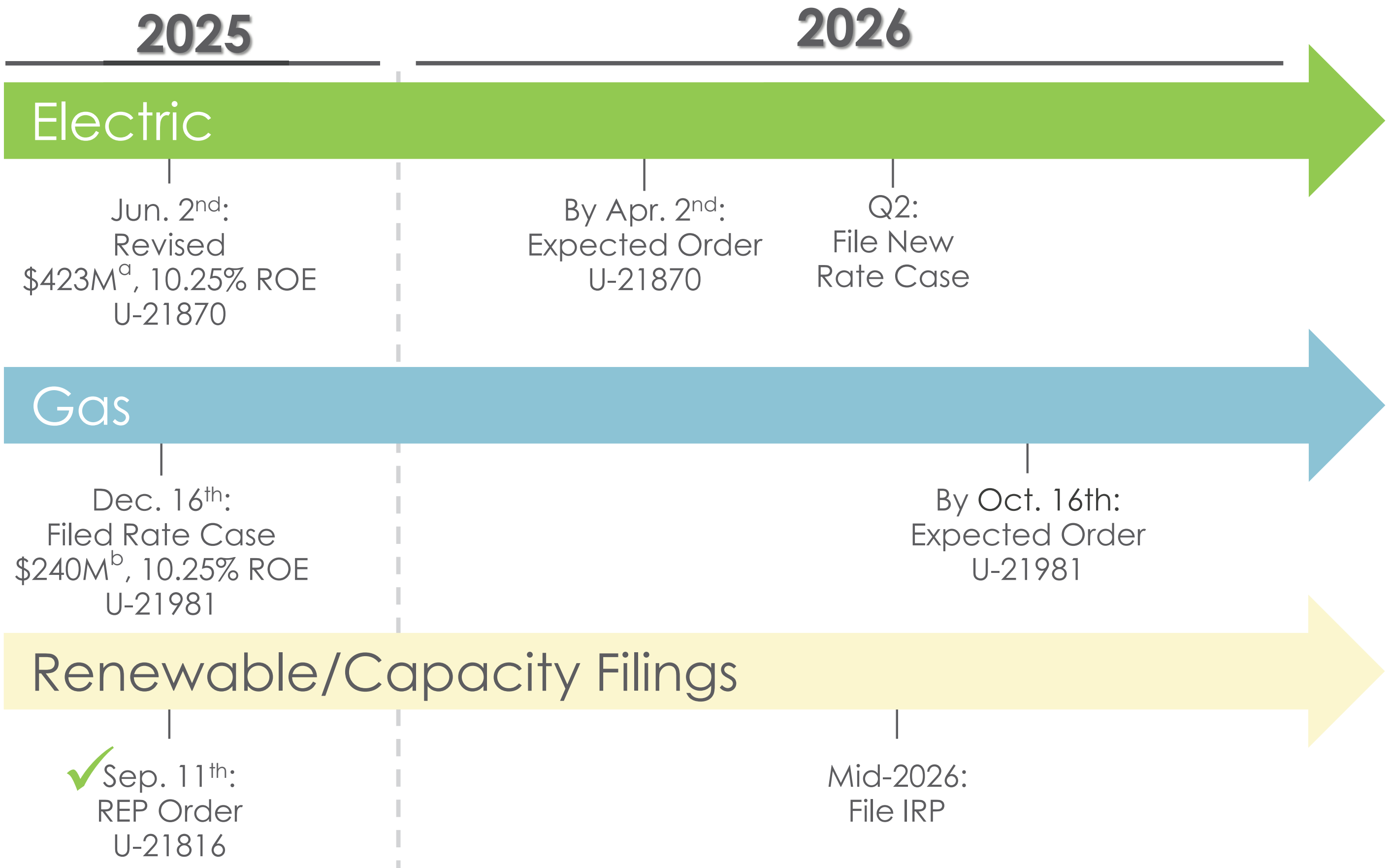
. . . delivers benefits for customers and investors.

Michigan's Strong Regulatory Environment . . .

CMS ENERGY

Supportive Energy Policy

- **Timely recovery of investments**
  - ✓ Forward-looking test years/earn authorized ROEs
  - ✓ 10-month rate cases
  - ✓ Monthly fuel adjustment trackers (PSCR/GCR)
  - ✓ Constructive ROEs
- **Supportive incentives enhanced w/ 2023 Michigan Energy Law**
  - ✓ Energy efficiency incentives
  - ✓ FCM adder on PPAs
- **Appointed commissioners**
  - ✓ Staggered 6-year terms



2025 | **2026**

Electric

Jun. 2nd:
Revised
$423M[a], 10.25% ROE
U-21870

By Apr. 2nd:
Expected Order
U-21870

Q2:
File New
Rate Case

Gas

Dec. 16th:
Filed Rate Case
$240M[b], 10.25% ROE
U-21981

By Oct. 16th:
Expected Order
U-21981

Renewable/Capacity Filings

✓ Sep. 11th:
REP Order
U-21816

Mid-2026:
File IRP

Presentation endnotes are included at the end of the presentation.

. . . provides constructive outcomes and forward-looking visibility.

Constructive Regulatory Outcomes. . .

	Order ($M)	Bid/Ask	Final Ask ($M)
Electric (U-21585)[a]	✓ $154	~60%	$255
Gas (U-21806)[b]	✓ $157.5	~75%	$208
Renewable Energy Plan Customer Investments (U-21816)[c]	✓~$14,000	+8 GW of solar and +2.8 GW of wind	~$14,000

Other Cases:

U-21914:
✓1st ever storm deferral approved

U-21859:
✓ Large Load tariff approved

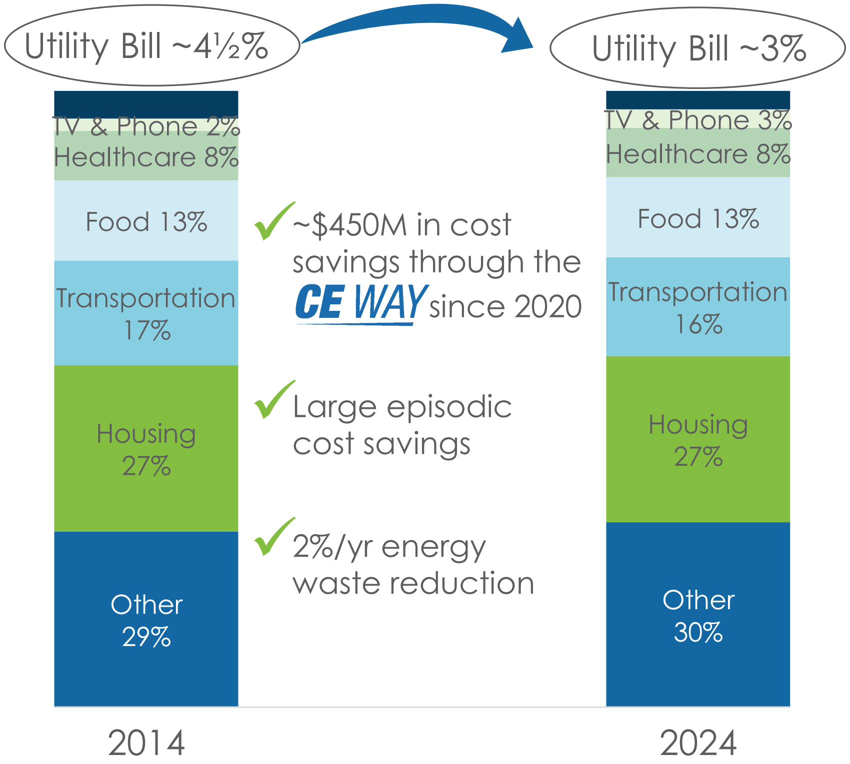
Presentation endnotes are included at the end of the presentation.

. . . provide certainty for future investments and reaffirm Michigan’s top tier regulatory environment.

Managing Customer Bills . . .

Residential Bills as % of Wallet[a]

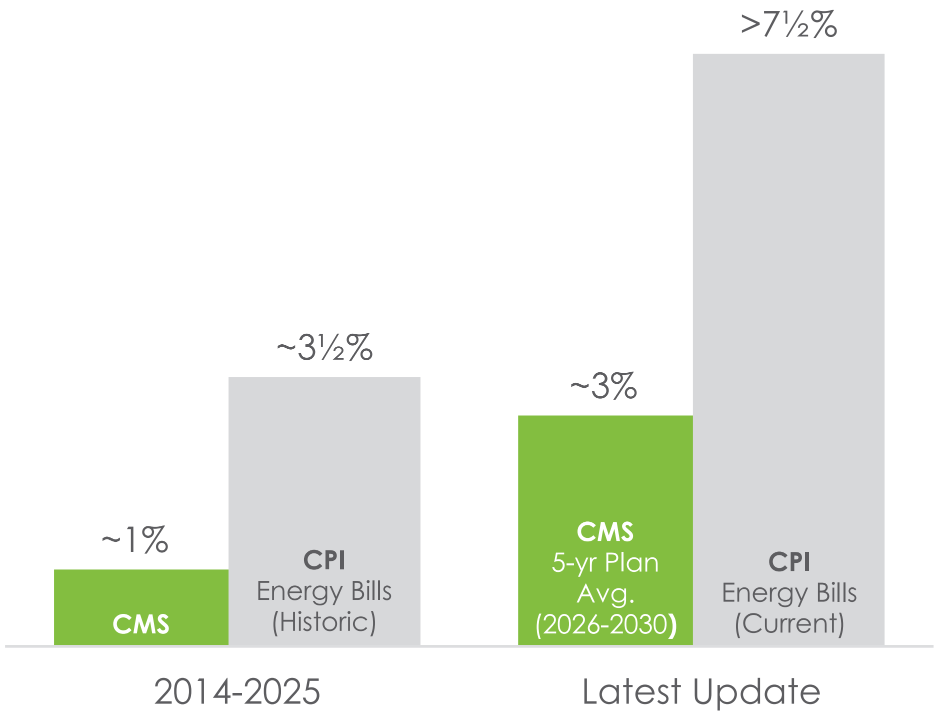
(Electric & Gas)



- ✓ ~$450M in cost savings through the **CE WAY** since 2020
- ✓ Large episodic cost savings
- ✓ 2%/yr energy waste reduction

Residential Bill Growth[b]

(Electric & Gas)

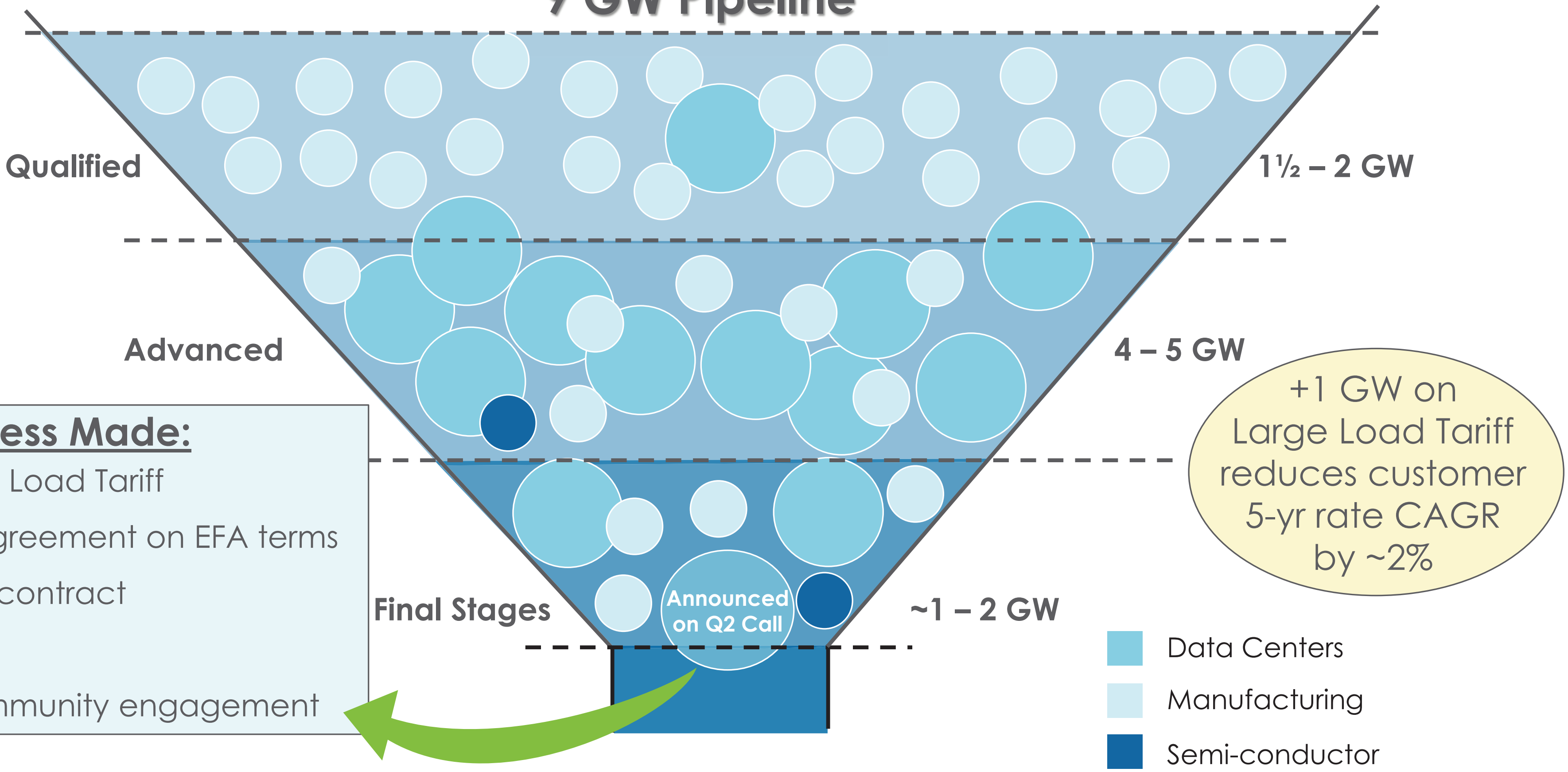


Presentation endnotes are included at the end of the presentation.

. . . through execution of the CE Way and other cost savings.

Expansive Economic Development Efforts . . .

9 GW Pipeline



+1 GW on Large Load Tariff reduces customer 5-yr rate CAGR by ~2%

Progress Made:

- Order on Large Load Tariff
- Commercial agreement on EFA terms
- Near-final rate contract
- Supply solution
- Continued community engagement

. . . drive diversified growth across Michigan while improving affordability.

Strong Balance Sheet . . .

Consumers Energy	S&P	Moody's	Fitch
Senior Secured	A	A1	A+
Commercial Paper	A-2	P-2	F-2
Outlook	Stable	Stable	Stable
CMS Energy			
Senior Unsecured	BBB	Baa2	BBB
Junior Subordinated	BBB-	Baa3	BB+
Outlook	Stable	Stable	Stable
Last Review	**Dec. 2025**	**May 2025**	**Mar. 2025**

Key Strengths

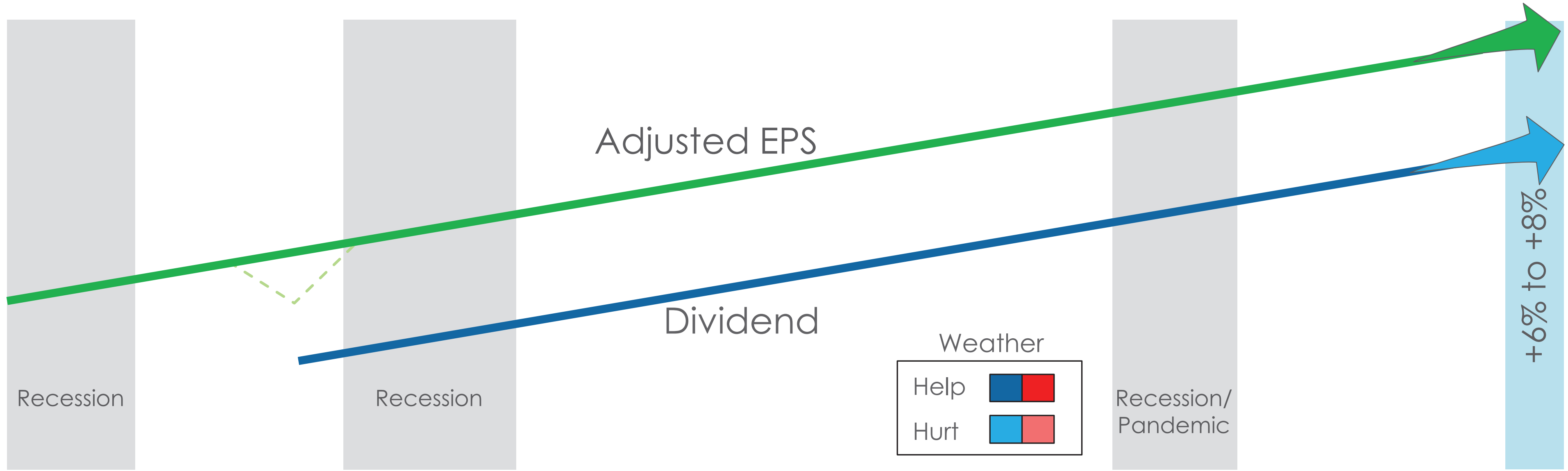
- ✓ Forward-looking recovery
- ✓ Constructive rate construct
- ✓ Strong operating cash flow generation

- ✓ 100% fixed rate debt
- ✓ Hybrid debt (w/ equity credit)
- ✓ Limited near-term maturities

. . . maintains credit metrics and solid investment-grade ratings.

Industry-Leading Financial Performance . . .

CMS ENERGY



2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026+
Cold winter	Mild summer	Hot summer	Warm winter	Mild summer	Cold winter	Summer-less	Hot summer	Hot summer	Warm winter	Mild summer	Polar vortex	Mild winter	Warm winter	Warm winter	Hot summer	Storms	Hot summer	Storms	Hot summer	Mild w/ storms	Mild w/ storms	Hot w/ storms	

Ken Whipple | Dave Joos | John Russell | Patti Poppe | Garrick Rochow

Governor (D) | Governor (R) | Governor (D)

Commission (D) | Commission (D) | Commission (R) | Commission (I) | Commission (D)

. . . for over two decades, regardless of conditions.

U21981-AG-CE-0249
Page **1** of **1**

Question:

29. Refer to lines 12-14 on page 8 of Mr. Foster's direct testimony on the CPI data. Please provide a copy of the source document showing the CPI forecast factors used by the Company. Provide also a copy of the same most recent CPI forecast document available to the Company.

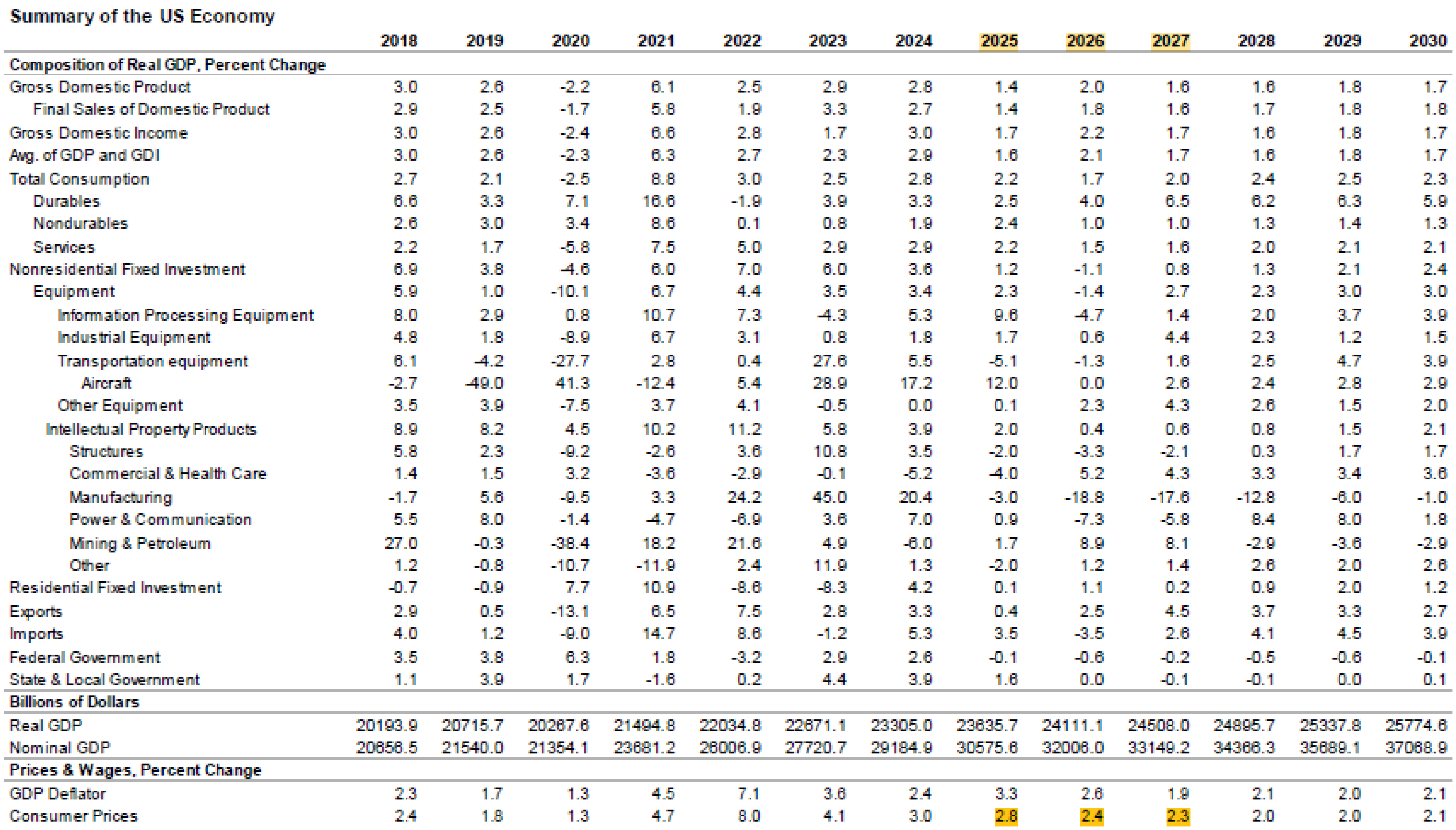
Response:

Please see the attached U21981-AG-CE-0249_Foster_ATT_1 for the source document showing the CPI forecast factors used by the Company and the most recent CPI forecast document.

Witness: Matthew J. Foster
Date: April 2, 2026

U21981-AG-CE-0249_FOSTER_ATT_1
CPI forecast factors

June 2025 edition of S&P Global U.S. Economic Outlook publication



Summary of the US Economy

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Composition of Real GDP, Percent Change													
Gross Domestic Product	3.0	2.6	-2.2	6.1	2.5	2.9	2.8	1.4	2.0	1.6	1.6	1.8	1.7
Final Sales of Domestic Product	2.9	2.5	-1.7	5.8	1.9	3.3	2.7	1.4	1.8	1.6	1.7	1.8	1.8
Gross Domestic Income	3.0	2.6	-2.4	6.6	2.8	1.7	3.0	1.7	2.2	1.7	1.6	1.8	1.7
Avg. of GDP and GDI	3.0	2.6	-2.3	6.3	2.7	2.3	2.9	1.6	2.1	1.7	1.6	1.8	1.7
Total Consumption	2.7	2.1	-2.5	8.8	3.0	2.5	2.8	2.2	1.7	2.0	2.4	2.5	2.3
Durables	6.6	3.3	7.1	16.6	-1.9	3.9	3.3	2.5	4.0	6.5	6.2	6.3	5.9
Nondurables	2.6	3.0	3.4	8.6	0.1	0.8	1.9	2.4	1.0	1.0	1.3	1.4	1.3
Services	2.2	1.7	-5.8	7.5	5.0	2.9	2.9	2.2	1.5	1.6	2.0	2.1	2.1
Nonresidential Fixed Investment	6.9	3.8	-4.6	6.0	7.0	6.0	3.6	1.2	-1.1	0.8	1.3	2.1	2.4
Equipment	5.9	1.0	-10.1	6.7	4.4	3.5	3.4	2.3	-1.4	2.7	2.3	3.0	3.0
Information Processing Equipment	8.0	2.9	0.8	10.7	7.3	-4.3	5.3	9.6	-4.7	1.4	2.0	3.7	3.9
Industrial Equipment	4.8	1.8	-8.9	6.7	3.1	0.8	1.8	1.7	0.6	4.4	2.3	1.2	1.5
Transportation equipment	6.1	-4.2	-27.7	2.8	0.4	27.6	5.5	-5.1	-1.3	1.6	2.5	4.7	3.9
Aircraft	-2.7	-49.0	41.3	-12.4	5.4	28.9	17.2	12.0	0.0	2.6	2.4	2.8	2.9
Other Equipment	3.5	3.9	-7.5	3.7	4.1	-0.5	0.0	0.1	2.3	4.3	2.6	1.5	2.0
Intellectual Property Products	8.9	8.2	4.5	10.2	11.2	5.8	3.9	2.0	0.4	0.6	0.8	1.5	2.1
Structures	5.8	2.3	-9.2	-2.6	3.6	10.8	3.5	-2.0	-3.3	-2.1	0.3	1.7	1.7
Commercial & Health Care	1.4	1.5	3.2	-3.6	-2.9	-0.1	-5.2	-4.0	5.2	4.3	3.3	3.4	3.6
Manufacturing	-1.7	5.6	-9.5	3.3	24.2	45.0	20.4	-3.0	-18.8	-17.6	-12.8	-6.0	-1.0
Power & Communication	5.5	8.0	-1.4	-4.7	-6.9	3.6	7.0	0.9	-7.3	-5.8	8.4	8.0	1.8
Mining & Petroleum	27.0	-0.3	-38.4	18.2	21.6	4.9	-6.0	1.7	8.9	8.1	-2.9	-3.6	-2.9
Other	1.2	-0.8	-10.7	-11.9	2.4	11.9	1.3	-2.0	1.2	1.4	2.6	2.0	2.6
Residential Fixed Investment	-0.7	-0.9	7.7	10.9	-8.6	-8.3	4.2	0.1	1.1	0.2	0.9	2.0	1.2
Exports	2.9	0.5	-13.1	6.5	7.5	2.8	3.3	0.4	2.5	4.5	3.7	3.3	2.7
Imports	4.0	1.2	-9.0	14.7	8.6	-1.2	5.3	3.5	-3.5	2.6	4.1	4.5	3.9
Federal Government	3.5	3.8	6.3	1.8	-3.2	2.9	2.6	-0.1	-0.6	-0.2	-0.5	-0.6	-0.1
State & Local Government	1.1	3.9	1.7	-1.6	0.2	4.4	3.9	1.6	0.0	-0.1	-0.1	0.0	0.1
Billions of Dollars													
Real GDP	20193.9	20715.7	20267.6	21494.8	22034.8	22671.1	23305.0	23635.7	24111.1	24508.0	24895.7	25337.8	25774.6
Nominal GDP	20656.5	21540.0	21354.1	23681.2	26006.9	27720.7	29184.9	30575.6	32006.0	33149.2	34366.3	35689.1	37068.9
Prices & Wages, Percent Change													
GDP Deflator	2.3	1.7	1.3	4.5	7.1	3.6	2.4	3.3	2.6	1.9	2.1	2.0	2.1
Consumer Prices	2.4	1.8	1.3	4.7	8.0	4.1	3.0	2.8	2.4	2.3	2.0	2.0	2.1

Question:

52. Refer to Table 8 on page 14 of Mr. Warriner's direct testimony on new Large Business service connections. Please:
a. For each of the projects for 2026, identify the amount and the date the contract with each customer was signed.
b. Explain to which contracts for 2026, the $6,432,000 applies, how much, and why. If it does not apply to any of the 2026 contracts, explain further what this amount represents.

Response:

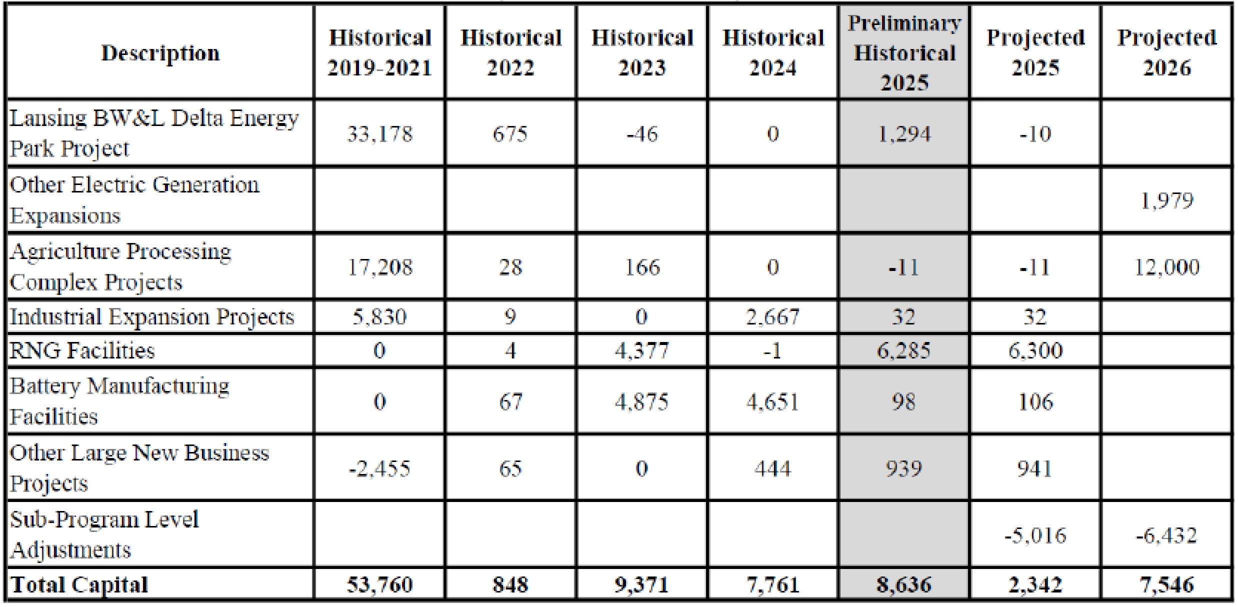
Responses are as follows:

a. **2026 Projects**:
   i. **Other Electric Generation Expansions** **($1,979k)**: A contract is not required for this project because the investment level is relatively low compared to expected incremental revenue, and the Company has several years of history serving multiple gas fired generating units at this site. The requesting customer has a long, consistent record of fulfilling their utility obligations. The contracts that support large new business projects are intended to protect the Company and existing ratepayers from capital investment risks. Because there is no foreseen risk, a signed contract is not necessary to construct this project.
   ii. **Agricultural Processing Complex Projects** **($12,000k):** The Company is having ongoing discussions with this customer, the current estimate is that contract signatures will be obtained in the third or fourth quarter of 2026. Project construction is likely to be rescheduled for mid-2027.

b. **Sub-program level adjustments** **(-$6,432k)**: The adjustments in 2025 and 2026 are explained on page 23, line 6 through page 24, line 7 of my direct testimony. The program level adjustments are unrelated to the Other Electric Generation Expansion or the Agricultural Processing Complex Projects shown for 2026 and are also unrelated to the specific customer projects listed for 2025. The adjustments are displayed when projected project costs are out of balance with the total subprogram projection. They are conceptually similar to the program level adjustment of -$9,923k that was included in Table 17 on page 48 of my direct testimony in our last rate case (Case No. U-21806).

Table 8 is updated with the 2025 Preliminary Actual capital expenditures in the following table:

Table 8: Large New Business Capital Expenditures
(in thousands of dollars)



Description	Historical 2019-2021	Historical 2022	Historical 2023	Historical 2024	Preliminary Historical 2025	Projected 2025	Projected 2026
Lansing BW&L Delta Energy Park Project	33,178	675	-46	0	1,294	-10	
Other Electric Generation Expansions							1,979
Agriculture Processing Complex Projects	17,208	28	166	0	-11	-11	12,000
Industrial Expansion Projects	5,830	9	0	2,667	32	32	
RNG Facilities	0	4	4,377	-1	6,285	6,300	
Battery Manufacturing Facilities	0	67	4,875	4,651	98	106	
Other Large New Business Projects	-2,455	65	0	444	939	941	
Sub-Program Level Adjustments						-5,016	-6,432
Total Capital	**53,760**	**848**	**9,371**	**7,761**	**8,636**	**2,342**	**7,546**

Witness: LINCOLN D WARRINER
Date: March 31, 2026

U21981-AG-CE-0274
Page **1** of **1**

Question:

54. Refer to Table 10 on page 28 of Mr. Warriner's direct testimony on Asset Relocations. Please expand the table to include actual information for 2025 and forecasted for 2026 and 2027 and provide it in Excel.

Response:

Please see the Excel file attachment named U21981-AG-CE-0274-Attachment_1.xlsx.

Witness: LINCOLN D WARRINER
Date: March 31, 2026

U21981-AG-CE-0274-Attachment_1.xlsx

Table 10: Asset Relocation – Civic Improvement Project History

	2020	2021	2022	2023	2024	5-Year Average	Preliminary 2025	Projected 2026	Projected 2027
Projects completed	124	152	170	122	147	**143**	134	152	152
Feet of Distribution Main Installed	169,202	195,305	297,246	181,953	98,507	**188,443**	141,896	166,085	166,085
Services Replaced	1,729	2,377	2,494	1,228	1,448	**1,855**	1,388	1,579	1,579

Note: 2025 values are preliminary estimates, final results will be available after completion of the EIRP annual performance report.

U21981-AG-CE-0273
Page **1** of **1**

Question:

53. Refer to Table 9 on page 25 of Mr. Warriner's direct testimony on Asset Relocations. Please:

a. Expand the table to include actual information for each year 2022 to 2025 and forecasted information for 2026 and 2027 and provide it in Excel.

b. For the 2026, 2027, 10 months ending October 2026, and 12 months ending October 2027, provide the capital expenditures that pertain to unknown projects as of the time of filing testimony in this rate case.

c. For reimbursable projects, provide the total capex spent or to be spent by the Company before reimbursement and the amount of reimbursements in Excel for each year 2022-2025 actual and forecasted for 2026, 2027, 10 months ending October 2026, and 12 months ending October 2027.

Response:

Responses are as follows:

a. The requested table expansion is provided in the Excel attachment named U21981-AG-CE-0273-Attachment_1.xlsx
b. A current list of Civic Improvement projects is included in the Excel attachments named U21981-AG-CE-0273_Attachment_2.xlsx and U21981-AG-CE-0273_Attachment_3.xlsx. Two separate formats are provided. The list named U21981-AG-CE-0273_Attachment_2.xlsx summarizes the project list by calendar year for 2026 and 2027. The list named U21981-AG-CE-0273_Attachment_3.xlsx summarizes the project list for the 10 months ending 10/31/26 and the 12 months ending 10/31/27. The list of civic improvement projects provided in these attachments should not be considered a final list of projects. There is not a comparable list of projects for reimbursable asset relocation work.
c. The requested split of reimbursable project capital expenditures is included in the Excel file attachment named U21981-AG-CE-0273-Attachment_1.xlsx.

Witness: LINCOLN D WARRINER
Date: March 31, 2026

U21981-AG-CE-0273-Attachment_1.xlsx

Table 9: Asset Relocation Program Capital Expenditures
(in thousands of dollars)

Program Description	Historical 12 Mos Ended 12/31/2022	Historical 12 Mos Ended 12/31/2023	Historical 12 Mos Ended 12/31/2024	Preliminary Historical 12 Mos Ending 12/31/2025	12 Mos Ending 12/31/2025	10 Mos Ending 10/31/2026	22 Mos Ending 10/31/2026	12 Mos Ending 12/31/2026	Projected Test Year 12 Mos Ending 10/31/2027	12 Mos Ending 12/31/2027
Asset Relocation – Civic Improvement	103,075	83,518	49,276	49,640	63,652	63,526	127,178	72,703	76,213	76,572
Asset Relocation - Reimbursable	13,429	14,167	23,236	17,891	17,659	12,012	29,671	14,307	15,047	15,317
Total Asset Relocation	**116,504**	**97,685**	**72,512**	**67,530**	**81,311**	**75,538**	**156,849**	**87,010**	**91,260**	**91,890**

Table 9: Asset Relocation Program Capital Expenditures
(in thousands of dollars)

Program Description	Historical 12 Mos Ended 12/31/2022	Historical 12 Mos Ended 12/31/2023	Historical 12 Mos Ended 12/31/2024	Preliminary Historical 12 Mos Ending 12/31/2025	12 Mos Ending 12/31/2025	10 Mos Ending 10/31/2026	22 Mos Ending 10/31/2026	12 Mos Ending 12/31/2026	Projected Test Year 12 Mos Ending 10/31/2027	12 Mos Ending 12/31/2027
Asset Relocation – Civic Improvement	103,075	83,518	49,276	49,640	63,652	63,526	127,178	72,703	76,213	76,572
Asset Relocation - Reimbursable	13,429	14,167	23,236	17,891	17,659	12,012	29,671	14,307	15,047	15,317
1) Capital Costs Incurred	*18,179*	*18,133*	*28,909*	*22,234*	*22,343*	*14,928*	*36,874*	*17,780*	*18,700*	*19,036*
2) Reimbursements	*-4,750*	*-3,966*	*-5,673*	*-4,343*	*-4,684*	*-2,916*	*-7,203*	*-3,473*	*-3,653*	*-3,718*
Total Asset Relocation	**116,504**	**97,685**	**72,512**	**67,530**	**81,311**	**75,538**	**156,849**	**87,010**	**91,260**	**91,890**

Note regarding Asset Relocation - Reimburseable segmentation between capital costs incurred and reimbursements:
The cost component projections for 2025 and beyond are based upon the 2024-2025 18 month average (Jan 2024 - Jun 2025) actual percentage of the breakdown of these components in this sub-programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes.

U21981-AG-CE-0273-Attachment_3

10 Months Ending October 2026, 12 Months Ending October 2027 Summary Page 1 of 4

DAPP #	Identifer	Status	Basic Finish Date	Total Proposed Main Footage	Service RNW Longside	Service RNW Shortside	Estimated Capital Expenditure
31575	CIVIC	Field Completed	01/23/26	51	0	0	10,498
21891	CIVIC	Field Completed	01/30/26	268	0	0	80,722
31598	CIVIC	Field Completed	01/30/26	95	1	0	24,269
31673	CIVIC	Released	01/30/26		3	0	16,801
31403	CIVIC	Field Completed	02/16/26	172	0	1	33,547
30484	CIVIC	Field Completed	02/26/26	254	0	0	85,550
30991	CIVIC	Field Completed	02/27/26	3,318	3	31	1,248,914
31348	CIVIC	Field Completed	02/27/26	401	4	6	131,127
23127	CIVIC	Field Completed	02/28/26	1,531	1	4	323,576
23148	CIVIC	Field Completed	02/28/26	577	2	0	138,669
30905	CIVIC	Field Completed	02/28/26	103	0	0	39,093
31261	CIVIC	Under Construction	03/13/26	3,271	4	20	926,147
30635	CIVIC	Under Construction	03/20/26	9,955	0	0	3,052,816
31297	CIVIC	Under Construction	03/20/26	191	0	0	264,583
31324	CIVIC	Field Completed	03/20/26	421	0	0	86,663
30720	CIVIC	Released	03/26/26	1,687	3	4	590,207
30936	CIVIC	Under Construction	03/27/26	1,739	0	0	925,943
31408	CIVIC	Under Construction	03/27/26	2,004	20	21	763,706
30912	CIVIC	Under Construction	03/31/26	2,293	0	1	1,192,657
31171	CIVIC	Under Construction	03/31/26	2,633	32	19	790,962
31533	CIVIC	Under Construction	03/31/26	1,957	6	7	540,941
22673	CIVIC	Field Completed	03/31/26	700	0	0	332,961
31260	CIVIC	Released	03/31/26	240	0	0	234,799
30762	CIVIC	Out for Survey	03/31/26	750	0	0	183,446
31435	CIVIC	Released	03/31/26		8	0	44,803
31689	CIVIC	Released	03/31/26		8	0	44,803
31772	CIVIC	Released	03/31/26		5	0	28,002
31532	CIVIC	Under Construction	03/31/26		2	1	16,701
30892	CIVIC	Under Construction	04/01/26	1,053	2	2	231,472
21814	CIVIC	Defer - Future Year	04/01/26	1,250	11	5	224,113
31292	CIVIC	Under Construction	04/03/26	730	0	0	134,867
22725	CIVIC	Cancel-3rd Party	04/03/26	561	2	3	98,279
31668	CIVIC	Designed	04/04/26		11	0	61,605
31428	CIVIC	Released	04/08/26		1	2	16,601
31634	CIVIC	Released	04/10/26	1,963	9	0	604,016
31409	CIVIC	Under Construction	04/10/26	530	0	0	108,856
30973	CIVIC	Design 90%	04/10/26	467	0	1	94,807
31443	CIVIC	Released	04/10/26		4	0	22,402
31619	CIVIC	Released	04/15/26	5,951	55	75	1,797,042
30507	CIVIC	Under Construction	04/17/26	3,863	7	12	1,007,028
30871	CIVIC	Designed	04/17/26	2,826	20	16	753,070
30282	CIVIC	Under Construction	04/17/26	2,105	0	0	670,504
31701	CIVIC	Designed	04/17/26	458	0	0	634,445
31530	CIVIC	Released	04/17/26	1,186	8	5	272,055
31439	CIVIC	Under Construction	04/17/26		12	0	67,205

U21981-AG-CE-0273-Attachment_3

10 Months Ending October 2026, 12 Months Ending October 2027 Summary

Page 2 of 4

DAPP #	Identifer	Status	Basic Finish Date	Total Proposed Main Footage	Service RNW Longside	Service RNW Shortside	Estimated Capital Expenditure
31001	CIVIC	Released	04/17/26		8	1	55,334
30872	CIVIC	Designed	04/24/26	1,732	11	8	407,902
30499	CIVIC	Designed	04/24/26	594	4	0	220,114
21025	CIVIC	Under Construction	04/24/26	693	0	0	145,832
31829	CIVIC	Design Not Started	04/24/26	204	1	2	53,444
31638	CIVIC	Designed	04/24/26	164	0	0	36,937
31531	CIVIC	Designed	04/24/26		4	0	22,402
31550	CIVIC	Design 90%	04/27/26	418	0	0	135,557
30643	CIVIC	Designed	04/30/26	773	57	4	470,852
31354	CIVIC	Released	04/30/26	1,058	0	0	436,832
31539	CIVIC	Under Construction	04/30/26		24	0	134,410
31617	CIVIC	Designed	04/30/26	660	0	1	132,191
31440	CIVIC	Under Construction	04/30/26		22	0	123,209
31436	CIVIC	Released	04/30/26		20	0	112,008
31618	CIVIC	Defer - Future Year	04/30/26	375	0	1	90,096
31032	CIVIC	Released	04/30/26		16	0	89,607
31438	CIVIC	Released	04/30/26		16	0	89,607
31008	CIVIC	Released	04/30/26	376	0	0	68,068
31033	CIVIC	Released	04/30/26		10	0	56,004
31538	CIVIC	Under Construction	04/30/26		10	0	56,004
31644	CIVIC	Designed	04/30/26	321	0	0	52,343
31540	CIVIC	Under Construction	04/30/26		4	0	22,402
31541	CIVIC	Field Completed	04/30/26		2	0	11,201
31481	CIVIC	Released	04/30/26		2	0	11,201
31616	CIVIC	Designed	04/30/26		0	2	11,001
31542	CIVIC	Under Construction	04/30/26		1	0	5,600
31603	CIVIC	Designed	04/30/26		0	1	5,500
31275	CIVIC	Released	05/01/26	2,552	9	12	687,302
31615	CIVIC	Designed	05/01/26		0	3	16,501
31520	CIVIC	Design 30%	05/02/26	200	0	0	36,191
31492	CIVIC	Designed	05/08/26	2,144	10	10	512,987
23043	CIVIC	Designed	05/08/26	1,490	10	4	437,774
31544	CIVIC	Design 90%	05/15/26	5,190	4	2	2,958,255
31314	CIVIC	Design in Progress	05/15/26	1,025	10	9	717,945
30716	CIVIC	Released	05/15/26	3,368	7	11	676,329
30137	CIVIC	Designed	05/15/26	2,059	1	6	435,193
31343	CIVIC	Design 90%	05/15/26	613	0	0	202,374
31012	CIVIC	Designed	05/16/26		1	0	5,600
31558	CIVIC	Designed	05/22/26		2	6	44,203
31527	CIVIC	Designed	05/22/26		1	2	16,601
22660	CIVIC	Design 90%	05/25/26	5,043	0	6	1,149,014
31607	CIVIC	Designed	05/29/26	2,313	0	3	1,019,445
30851	CIVIC	Under Construction	05/29/26	3,447	3	1	968,717
31155	CIVIC	Designed	05/29/26	3,826	13	12	846,942
30970	CIVIC	Designed	05/29/26	1,043	0	0	682,889

U21981-AG-CE-0273-Attachment_3

10 Months Ending October 2026, 12 Months Ending October 2027 Summary

DAPP #	Identifer	Status	Basic Finish Date	Total Proposed Main Footage	Service RNW Longside	Service RNW Shortside	Estimated Capital Expenditure
31498	CIVIC	Design in Progress	05/29/26	2,456	1	1	477,167
31373	CIVIC	Design 90%	05/29/26	973	0	2	290,563
31487	CIVIC	Design Not Started	05/29/26	800	0	0	259,440
31437	CIVIC	Released	05/29/26		45	0	252,019
31488	CIVIC	Design 90%	05/29/26	394	0	1	136,453
30898	CIVIC	Design 90%	05/29/26	332	0	1	87,062
22858	CIVIC	Design Not Started	05/29/26	165	0	0	37,543
31691	CIVIC	Design in Progress	05/29/26	150	0	0	27,638
31580	CIVIC	Designed	06/05/26	1,320	1	0	268,375
31517	CIVIC	Design 90%	06/05/26	457	2	2	129,985
31100	CIVIC	Design 90%	06/06/26	3,480	19	6	1,130,265
31630	CIVIC	Designed	06/06/26	570	0	1	165,929
31505	CIVIC	Released	06/12/26	10,076	56	60	2,686,617
30733	CIVIC	Released	06/19/26	11,480	5	9	12,956,999
31710	CIVIC	Design 90%	06/19/26	2,176	5	4	513,726
31623	CIVIC	Designed	06/19/26		12	16	155,212
23057	CIVIC	Design 90%	06/26/26	1,738	2	0	711,117
31326	CIVIC	Design in Progress	06/26/26	475	3	4	133,748
22972	CIVIC	Design Not Started	06/26/26	565	0	0	122,661
31509	CIVIC	Released	06/26/26		7	14	116,209
31643	CIVIC	Released	06/26/26	570	3	0	112,925
31687	CIVIC	Released	06/26/26		6	5	61,105
31554	CIVIC	Design in Progress	06/30/26	5,614	1	0	1,852,845
30960	CIVIC	Design in Progress	06/30/26	4,200	2	4	1,032,073
31417	CIVIC	Designed	06/30/26	4,421	22	22	1,024,572
31419	CIVIC	Designed	06/30/26	1,668	1	4	306,348
31418	CIVIC	Designed	06/30/26	1,159	6	7	298,676
31551	CIVIC	Design in Progress	07/03/26	3,093	5	7	1,501,047
31629	CIVIC	Design in Progress	07/03/26	3,800	17	25	941,388
31396	CIVIC	Released	07/03/26	330	0	0	67,931
31587	CIVIC	Design in Progress	07/03/26	50	0	0	15,060
31625	CIVIC	Design in Progress	07/17/26	1,480	8	7	361,999
31628	CIVIC	Design in Progress	07/17/26	775	2	6	191,246
31327	CIVIC	Design in Progress	07/24/26	1,600	10	7	436,352
31328	CIVIC	Design in Progress	07/24/26	377	14	13	291,487
30803	CIVIC	Design 90%	07/31/26	2,016	0	0	3,053,464
31640	CIVIC	Survey Returned	07/31/26	2,345	0	0	872,559
31633	CIVIC	Design 90%	07/31/26	1,696	7	3	612,226
21722	CIVIC	Designed	07/31/26	490	0	0	79,901
31692	CIVIC	Released	07/31/26		9	3	66,905
31614	CIVIC	Designed	07/31/26		3	4	38,803
31604	CIVIC	Designed	07/31/26		2	1	16,701
31480	CIVIC	Design 90%	08/01/26	261	0	0	42,560
31489	CIVIC	Designed	08/15/26	1,750	0	0	546,918
31346	CIVIC	Design in Progress	08/29/26	2,410	3	3	858,180

U21981-AG-CE-0273-Attachment_3

10 Months Ending October 2026, 12 Months Ending October 2027 Summary

Page 4 of 4

DAPP #	Identifer	Status	Basic Finish Date	Total Proposed Main Footage	Service RNW Longside	Service RNW Shortside	Estimated Capital Expenditure
31721	CIVIC	Survey Returned	08/31/26	12,390	97	95	3,728,136
22795	CIVIC	Designed	08/31/26	9,042	5	12	3,142,474
31507	CIVIC	Design 90%	09/01/26	7,474	34	40	2,102,866
31466	CIVIC	Released	09/04/26	2,730	15	11	747,933
31444	CIVIC	Design 90%	09/04/26	1,451	2	5	381,528
22179	CIVIC	Design in Progress	09/25/26	4,045	0	0	1,285,325
31699	CIVIC	Design Not Started	09/30/26	6,700	76	64	1,879,717
20718	CIVIC	Defer - Future Year	10/31/26	1,812	0	9	416,536
30819	CIVIC	Defer - Future Year	10/31/26	632	0	0	123,724
		10 Mths Ending 10/31/26		223,223	1,035	821	82,571,431
31441	CIVIC	Design Not Started	11/13/26	5,205	62	65	1,580,454
31510	CIVIC	New Project	11/24/26	25,000	0	0	6,618,167
31037	CIVIC	Scope in Progress	12/18/26	5,420	12	24	1,236,431
23095	CIVIC	Cancel-3rd Party	12/18/26	180	0	0	29,351
22865	CIVIC	Design Not Started	12/31/26	400	0	0	65,225
31576	CIVIC	Design Not Started	05/14/27		0	0	10,000
31759	CIVIC	Out for Survey	06/01/27	10,301	44	43	3,140,060
31535	CIVIC	Designed	06/11/27	340	0	0	76,745
31577	CIVIC	Design Not Started	09/30/27	600	0	0	158,836
		12 Mths Ending 10/31/27		47,446	118	132	12,915,269
30249	CIVIC	Defer - Future Year	11/01/27	3,105	2	2	638,142

U21981-AG-CE-0279
Page **1** of **1**

Question:

59. Refer to lines 1-3 on page 42 of Mr. Warriner's direct testimony on the Meters subprogram. Please:

a. Explain for which customer classes the rotary and top connected diaphragm meters are used for.

b. Provide the number of each type of meters purchased for each year 2022-2025 and forecasted for 2026 and 2027 with related dollars and cost per unit in Excel. If the meters do not include the AMR or AMI communication module, provide the number purchased with related cost and cost per unit for the same periods and explain whether the costs are included in the Meters line in Table 15 of your testimony.

c. Confirm that the Company has not purchased and does not plan to purchase ultrasonic meters to replace the diaphragm meters. If not confirming, provide details on the number purchased annually during 2022-2025 and forecasted for 2026 and 2027 with related dollars in Excel, and explain why those purchases were not identified in your testimony.

d. Confirm that the Company has not purchased and does not plan to purchase meter bypass devices with ultrasonic meters when replacing the diaphragm meters. If not confirming, provide details on the number purchased annually during 2022-2025 and forecasted for 2026 and 2027 with related dollars in Excel, and explain why those purchases were not identified in your testimony.

Response:

a. Meter types are selected for individual customers based on their unique service requirements. Rotary meters are typically used for medium to high flow and pressure applications, generally within the Industrial and Commercial classes, but could potentially be used in a unique residential site. Diaphragm meters are commonly used for residential customers as well as small commercial or industrial sites that do not require higher gas flow or pressure.

b. Please see the Excel file attachment named U21981-AG-CE-0279-Attachment_1.xlsx.

c. It is correct that the Company has not purchased ultrasonic meters during 2022 through 2025 and does not plan on purchasing ultrasonic meters during 2026. The Company has requested approval to include in rates the capital expenditures to purchase 1,000 ultrasonic gas smart meters with cellular communication technology during 2027 for use in a pilot evaluation as described in my direct testimony.

d. Meter bypass devices are installed with any top connect diaphragm meter and would also be installed with an ultrasonic meter. They are managed as minor materials and are not purchased through the Meters capital sub-program.

Witness: LINCOLN D WARRINER
Date: March 31, 2026

U21981-AG-CE-0279_Attachment_1.xlsx

	2022 Actual	**2023 Actual**	**2024 Actual**	**2025 Preliminary Actual**	**2025 Projection**	**2026 Projection**	**2027 Projection**	**Test Year**
New Business	9,730	16,192	19,463	22,440	21,871	25,965	25,965	22,874
All Other	11,422	19,008	23,788	26,343	25,675	30,480	30,480	26,852
Smart Meter Pilot							1,000	1,000
Total Units	21,152	35,200	43,251	48,783	47,546	56,445	57,445	50,725
By Meter Type								
250	16,394	27,172	33,120	40,320	39,041	47,040	47,040	40,320
425	2,664	5,880	7,488	6,192	6,192	6,912	6,912	6,912
800	1,584	1,404	1,728	1,440	1,440	1,620	1,620	1,620
2M	168	336	294	336	336	336	336	336
3M	108	180	216	216	216	216	216	216
5M	93	93	217	155	155	155	155	155
7M	60	60	80	40	60	60	60	60
11M	60	60	60	60	80	80	80	80
16M	15	15	40	20	20	20	20	20
23M	6	-	8	4	6	6	6	6
Smart Meter Pilot							1,000	1,000
Total Units	21,152	35,200	43,251	48,783	47,546	56,445	57,445	50,725
Capital Expenditures By Meter Type								
250	8,174,300	8,433,682	10,359,718	13,677,297	[redacted]	[redacted]	[redacted]	[redacted]
425	1,503	3,295,823	4,093,460	3,364,431	[redacted]	[redacted]	[redacted]	[redacted]
800	3,149	2,456,830	2,440,160	2,284,996	[redacted]	[redacted]	[redacted]	[redacted]
2M		552,519	456,251	492,855	[redacted]	[redacted]	[redacted]	[redacted]
3M		313,927	363,906	377,177	[redacted]	[redacted]	[redacted]	[redacted]
5M		172,670	444,518	260,700	[redacted]	[redacted]	[redacted]	[redacted]
7M		126,467	164,834	76,955	[redacted]	[redacted]	[redacted]	[redacted]
11M		177,316	155,070	146,826	[redacted]	[redacted]	[redacted]	[redacted]
16M		58,477	132,900	63,087	[redacted]	[redacted]	[redacted]	[redacted]
23M					[redacted]	[redacted]	[redacted]	[redacted]
Meter Test Equip	174,419	49,342	111,718	84,406	[redacted]	[redacted]	[redacted]	[redacted]
Other Meter Equip	2,513,844	2,123,718	2,540,797	1,655,153	[redacted]	[redacted]	[redacted]	[redacted]
Gas Comm Module	691,422	2,689,596	3,326,499	3,799,825	[redacted]	[redacted]	[redacted]	[redacted]
Projected Meter Costs	[redacted]	[redacted]	[redacted]	[redacted]	26,641,190	30,555,226	32,215,969	29,432,078
Smart Meter Pilot Meter/Mtr Stand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000,000	1,000,000
Smart Meter Pilot Software Impl	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	977,482	977,483
Total Meters	11,558,636	20,450,366	24,589,830	26,283,708	26,641,190	30,555,226	33,215,969	30,432,078
Total Meter Unit Costs	546	581	569	539	560	541	571	592
Smart Meter Pilot Unit Cost							1,977	1,977

U21981-AG-CE-0280
Page **1** of **1**

Question:

60. Refer to Table 43 on page 43 of Mr. Warriner's direct testimony on the Meters subprogram. Please:

a. Expand the table to show 2025 actual information and provide in Excel.

b. Explain the basis for the unit cost increases in 2026 and 2027. Explain why the projected test year unit cost for the projected test year is higher than both the 2026 and 2027 unit costs when the projected test year unit cost is derived from the 2026 and 2027 costs.

c. Provide the number of smart meters and meter stands to be purchased in 2027. If the unit cost for the smart meters and meter stands is the same, explain why.

d. Identify what the $977,482 for 2027 will be spent on by component.

Response:

a. There are two tables presented on page 43, Table 17 and Table 18. Both tables are updated with preliminary 2025 actual capital expenditures in the Excel file attachment named "U21981-AG-CE-0280-Attachment_1.xlsx".

b. Please refer to the response provided to U21981-SA-CE-301. That response provides unit projections by type of meter and describes the calculation of the projected test year capital expenditures. Given that the 250-meter category is the highest volume and lowest priced meter, the variations in the 250 meter category purchases tend to impact the calculated unit cost.

c. The gas smart meter pilot discussed in my direct testimony would result in the purchase and installation of 1,000 meters in 2027. It is expected that meter stand conversions would be required for all 1,000 meters to accommodate a top connect meter configuration. The unit cost identified for the planned 2027 gas smart meter pilot is $1000 per meter. This includes $650 per meter (Meter cost of $250 per meter, Meter set cost of $100 per meter, and Capital loadings of $300 per meter), and $350 per meter for installation of a top connect bypass meter stand.

d. 2027 software implementation costs of $977,482 are detailed in the response provided to U21981-SA-CE-326. Please refer to that part e. of that response.

Witness: LINCOLN D WARRINER
Date: March 31, 2026

U21981-AG-CE-0281
Page **1** of **1**

Question:

61. Refer to lines 1-10 on page 44 of Mr. Warriner's direct testimony on the Meters subprogram. Please:

a. Provide the year that the Company began installing the AMR and AMI modules on its meters.

b. Provide the number of meters that the Company has with AMR and AMI modules, separately.

Response:

a. The timeline for initial AMR and AMI module installation is noted in the Company's Natural Gas Delivery Plan (Exhibit No. A-30 TMB-1) on page 48. That document states that "From 2015 to 2019, the Company installed gas meter communication modules ("GCM") manufactured by Itron on more than 1.8 million existing gas meters as part of the Advanced Metering Infrastructure ("AMI") and Automated Meter Reading ("AMR") projects."

b. The Company has approximately 1.2 million gas meters read using AMR modules and approximately 0.7 million gas meters read using AMI modules.

Witness: LINCOLN D WARRINER
Date: March 31, 2026

Question:

62. Refer to lines 13-23 on page 46 of Mr. Warriner's direct testimony on the Smart Meter Pilot. Please:

a. Explain why aging diaphragm meters cannot be replaced with new diaphragm meters like the Company has been doing so far.

b. Explain why modules with failing batteries cannot be replaced with new modules like the Company has been doing with other failing modules up to now.

c. Explain what the Company is replacing electric smart meters with, when did this replacement program start, and what is the plan? Has the cost recovery for this electric meter replacement plan been approved by the Commission? If yes, in which order and page number?

d. Explain why any disruption or non-disruption of gas data transmission cannot be determined now.

Response:

a. The need for investigating ultrasonic meter technology with integrated cellular communication capabilities is described on pages 48 and 49 of the Natural Gas Delivery Plan, provided in this proceeding as Exhibit No. A-30 (TMB-1). In summary, the Company is transitioning to top connect ("TC") metering configurations due to discontinued regulated meter ("RM") diaphragm meter and replacement parts supply. As a result, meter stand rebuilds are required to enable the current replacement of RM diaphragm meters with TC diaphragm meters. In addition, there is potentially incremental customer value for ultrasonic gas smart meters that may result in the advanced meters becoming the industry standard. These meters also use the same meter stand configuration as the TC diaphragm meters. The Company believes it is prudent to explore and assess the potential value of gas smart metering technology in our gas utility.

b. In the long-term, replacing gas communication modules ("GCMs") for battery expiration will be more difficult than replacing those that fail in the near term, and will eventually cease to be sustainable. This expectation is based on the recent manufacturer obsolescence of RM diaphragm gas meters and the announcement that the production shutdown of current GCMs is likely in the near term. It is important to recognize that the mechanical design of any specific GCM is intended to be compatible with a specific gas meter model. The Company is currently finding it increasingly challenging to purchase replacement parts that are needed to safely refurbish and return to service existing RM diaphragm meters. Manufacturer obsolescence plans, the aging batteries in existing GCMs, and diminishing refurbishment options require the Company to determine a sustainable long range supply strategy.

c. The Company is not currently proposing a system-wide replacement program of existing electric smart meters, nor is it seeking approval for recovery of an electric smart meter replacement program in this proceeding. The gas smart meter pilot discussed in this case is not dependent on approval of an electric meter replacement plan. This pilot is intended to evaluate gas metering technologies that best serve all gas customers and does not presume long-term dependence on future electric meter designs and associated communication capabilities, thereby allowing the Company to develop proactive plans for managing foreseeable gas meter and GCM obsolescence risks.

d. Future electric meters have not yet been selected or tested, therefore, compatibility with existing GCMs is unknown.

Witness: LINCOLN D WARRINER
Date: March 31, 2026

Question:

63. Refer to page 47 of Mr. Warriner's direct testimony on the Smart Meter Pilot. Please:

a. Explain why the Company cannot perform a cost/benefit analysis (CBA) before the start of the pilot to determine whether the smart gas meter installation program is economically viable based on meter costs and installation data gathered from other utilities that have installed smart gas meters, vendor information, and the Company's experience with meter installations, and refined later after completion of the pilot if the project is first found to be economically viable.

b. Provide a list of other utilities that have installed smart gas meters in the last five years, when they started, when they completed the program, and the number of gas smart meters installed. Identify any problems experienced by these utilities with the installation and operation of the meters.

c. Explain what type of meters the smart gas meters are, such as diaphragm, rotary, or ultrasonic, etc., and the unit cost of the meters including and excluding installation forecasted for 2027.

d. Confirm that gas meters with AMI modules have been considered smart meters. If not confirming, explain.

e. Provide the unit cost of the current meters including and excluding installation and the cost of the AMI and AMR module if separately installed.

f. Confirm that the current gas AMI meters do not have a gas shut-off feature. If not confirming explain.

g. Provide the number of occasions during 2024 that the Company would have used the meter shut-off feature, if it had been available, by type of need: emergency, unsafe conditions, theft, change of customer (move in, move out), etc.

h. Provide the number of customers who have expressed a need to know their consumption during the month by day or hour of use. Explain why you state that the cellular network may allow this feature instead of saying it will allow it.

i. Does the Company anticipate that with a smart gas meter it would shut off the meter when a customer reports a gas leak and would still send a service technician to check the source of the gas leak and relight the gas water heater and furnace?

j. How long would the pilot last and what specifically would be targeted to demonstrate accomplishment or show success, and how many residential and commercial locations would be piloted?

Response:

a. The Company is working with consultants to develop an initial cost/benefit analysis prior to the start of the pilot. The estimates of future costs and benefits will be most reliable when informed by actual operational and technology integration experience, and anticipate any process or technological impacts specific to Consumers Energy. Gas smart meters are substantially different from the traditional regulated (or "RM") meters and installation procedures, safety features, communications performance, and system integration capabilities all require assessment. The purpose of the pilot is to responsibly gather real-world, company specific data so that the cost-benefit analysis used for planning and decision making is based on verified performance, costs, and safety outcomes.

b. The Company does not have the list requested. Based on industry surveys and discussions, the Company is aware that multiple utilities are at various stages of deploying ultrasonic gas meters, with adoption ranging from small pilot programs to nearly complete system conversions. Because natural gas utilities differ substantially in customer population, system design, regulatory requirements, climate, and operating practices, experiences from other utilities cannot be generally applied to the Company's natural gas operations. The fact that one single solution doesn't fit every gas utility reinforces the need for the Company to conduct its own pilot in order to best support long-term gas metering technology decisions.

c. The meters that are envisioned for use in the smart gas meter pilot would be ultrasonic meters. Unlike traditional diaphragm meters, ultrasonic meters have no moving parts, which improves long-term accuracy and reliability and enables advanced safety and monitoring capabilities. The unit cost identified for the planned 2027 gas smart meter pilot is $1000 per meter.

   a. This includes $650 per meter, including set and test costs, and $350 per meter for installation of a top connect bypass meter stand.

   b. The $650 meter cost includes the meter vendor cost of $250 per meter to reflect the additional technology, safety features, and integrated cellular communications expected in ultrasonic smart meters, a meter set cost of $100 per meter, and capital expenditure loadings of $300 per meter which include indirect costs of deploying new metering technology.

d. Gas meters with AMI modules are considered part of the Company's smart meter network because the module enables integration with electric smart meter communication technology. However, the meter that has a GCM installed is still a traditional gas meter. The smart gas meters planned for the 2027 pilot integrate advanced gas measurement capabilities, safety, diagnostic, and communication functions directly into the meter itself. The Company's current diaphragm gas meters are not designed to identify and automatically respond to abnormal operating conditions or safety events, even with the GCMs that have been installed.

e. The Company has provided a unit cost analysis of current gas meters in response to U21981-SA-CE-301. Please refer to that response.

f. The Company's current meters do not have the technical capability to perform an automated or remote gas service shut off. That is one of the primary safety features that distinguishes a gas smart meter from the Company's existing installed meters.

g. The number of occasions that a gas smart meter automated or remote shut-off feature would be utilized is unknown because the capability does not exist today. A reasonable full meter conversion expectation would likely exceed 112,000 occasions annually, primarily in support of past-due collection activities and customer move in, move out activity. This is based on documented utilization of electric smart meters for past-due and non-past-due remote shutoffs. Expectations for the frequency of emergency, unsafe conditions, or theft condition shut-off operations is a desired outcome of the planned meter pilot. The pilot intends to provide a better understanding of the frequency and circumstances that this capability would be used to enhance customer safety.

h. The number of customers who would utilize near real time feedback on gas consumption has not been determined. It is reasonable to anticipate that customers would be most interested in that information during the winter heating season to support thermostat setting decisions that balance comfort and cost. The cellular network would support this use case but the provision of feedback to customers would also require supporting technology enhancements.

i. Yes. If a smart gas meter detects conditions indicative of a potential gas leak, it could automatically shut off gas flow while a service technician is dispatched. A technician visit would still be required to investigate the source of the leak, complete repairs, and safely restore service. The automated shut-off capability is intended to enhance safety by reducing the time between detection of hazardous conditions and protective action. It does not replace field response but helps reduce risk while crews respond.

j. The Company expects to conduct the gas smart meter pilot in two phases spanning two years. Phase 1 will install 1,000 meters during 2027 to enable the Company to evaluate meter functionality, communication performance, safety features, installation practices, and system integration on a small scale. Phase 2 is planned for 2028, and will expand the smart meter deployment to approximately 100,000 meters, enabling the Company to assess large-scale operational performance, logistics, customer experience, and technology reliability under broader field conditions.

Witness: LINCOLN D WARRINER
Date: March 31, 2026

U21981-SA-CE-302
Requested By: Cindy L. Creisher (CLC-5)
Respondent: LINCOLN D WARRINER
Date of Response: 3/3/2026
Page **1** of **1**

Question:

With reference to the testimony of Company witness Lincoln Warriner, pages 45-46 and Exhibit A-30 (page 48), regarding the smart meter pilot, what meter manufacturer(s) and model(s) is the Company planning to use in the pilot? Include the current unit cost of the ultrasonic meters considered as well as anticipated long-term unit costs. Additionally, provide a breakdown of the smart pilot cost for the meter and meter stand as shown in Table 17.

Response:

The Company has not yet selected a vendor(s) for the smart gas meter pilot. Final meter vendor selection will occur after completion of a competitive sourcing and evaluation process that considers safety, technical capabilities, interoperability, availability, and cost. The Company is considering various cellular based ultrasonic residential gas smart meter options including:

- Itron Intellis
- Pietro Fiorentini SSM-iCON
- Honeywell NXU
- Landis+Gyr G480

For modeling purposes only, the Company evaluated Itron's Intellis ultrasonic gas meter as a representative technology option. This meter is a useful example because it is a currently available ultrasonic residential gas meter (in a non-cellular version) and aligns with the capabilities the Company expects a future smart gas meter to include (e.g., ultrasonic measurement, safety shutoff valve, and integrated communications). However, the specific ultrasonic meter vendor options require additional analysis before a selection is made for the pilot.

The Company currently utilizes an Itron AMI OpenWay collection engine, or head-end system, that is not compatible with the Itron Intellis ultrasonic gas meter. Therefore, if the Company were to ultimately select Itron as the gas smart meter vendor, the existing head-end cannot be used to support the pilot or any future smart gas metering implementation. Regardless of the meter manufacturer ultimately selected, the Company will require a system integration and development to utilize a new or upgraded collection engine capable of supporting the selected ultrasonic smart gas meter technology. These costs are identified separately as software implementation costs in Table 17.

The unit cost identified for the planned 2027 gas smart meter pilot is $1000 per meter. This includes $650 per meter, including set and test costs, and $350 per meter for installation of a top connect bypass meter stand.

The Company anticipates that long-term costs for ultrasonic smart gas meters may be lower than pilot phase costs due to economies of scale in full deployment and competitive bidding among qualified meter manufacturers. The actual long-term unit costs will be determined after the Company completes the competitive sourcing process and negotiates long-term supply agreements.

U21981-AG-CE-0284
Page **1** of **1**

Question:

64. Refer to lines 11-13 on page 48 of Mr. Warriner's direct testimony on the Company's pressure test records not meeting PHMSA requirements for traceable, verifiable, and completed (TVC) documentation. Please:

a. Explain why the Company lacks this documentation and TVC records.

b. What specific records are missing and why were these basic records not kept?

Response:

The Company completed a documentation search and review of historical work order records that would support pipeline MAOP in response to 49 CFR 192.624. This standard engineering analysis determined if the available material and pressure test records contained in pipeline work order records met the PHMSA standard of Traceable, Verifiable, and Complete ("TVC"). Available documentation to support MAOP for material and pressure test records for 49 CFR 192.619 varies by individual work order. Specific examples provided by PHMSA that demonstrate the characteristics of TVC MAOP documentation are provided in the following document:

Traceable *records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, which include mechanical and chemical properties; purchase requisition; or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.*

Verifiable *records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a pipeline segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipeline segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by a qualified individual who observed the test or inspection being performed.*

Complete *records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking such as a corporate stamp or seal. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipeline segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.*

Another common record is a pressure test record, which must be traceable, verifiable, and complete. For the pressure test record to be traceable, it would need to identify a specific and unique segment of pipe that was tested (such as mileposts, survey stations, etc.) or have some other link relating the pressure test to the physical location of the test segment, such as a work order, project identification, or alignment sheet. For the pressure test record to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the pressure test record to be complete, it should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, elevation information, and any other information required by § 192.517, as

Definitive identification of root causes for specific work order records not meeting the specific TVC requirements is unknown.

Witness: LINCOLN D WARRINER
Date: March 31, 2026

U21981-AG-CE-0285
Page **1** of **1**

Question:

65. Refer to Table 19 on page 50 of Mr. Warriner's direct testimony on the Company's MAOP projects. Please:

a. Expand this table to include the actual amounts spent in 2025 and provide it in Excel. At the bottom of the expanded table provide the total miles completed or planned for each year.

b. For each project of $1 million or greater in 2026 and 2027, identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

c. Provide a similar table with 2022 and 2023 information and list of projects with the total miles replaced for each year.

Response:

a. Please see the Excel file named U21981-AG-CE-0285-Attachment_1.xlsx

b. Please see the Excel file named U21981-AG-CE-0285-Attachment_2.xlsx. The date when the next phase will start is not a readily available data point in the distribution project database, therefore I have provided a column that indicates the design completion date and the construction completion date.

c. 2022 and 2023 are included in U21981-AG-CE-0285-Attachment_1.xlsx. Capital expenditures incurred in 2022 and 2023 were for preconstruction activities, therefore no actual construction miles are identified for those two years.

In addition, please note that PHMSA amended 49 CFR 192.624(a)(1) in October of 2025 to clarify that traceable, verifiable, and complete pressure test records are required for testing that was performed on and after the adoption of the pipeline safety regulations on August 19, 1970. For any testing done prior to the adoption of the pipeline safety regulations on August 19, 1970, pressure test records are not required to meet the traceable, verifiable, and complete standard promulgated by PHMSA in 2019, and the pressure test records requirements enforcement will revert back to Michigan Gas Safety Code that was applicable at the time of construction. The Company is also monitoring if any additional guidance comes from PHMSA on pre-1970 pressure test records.

As an outcome of the revised PHMSA direction discussed above, the Company has reviewed the Michigan Gas Safety Code test record requirements and has determined that some planned MAOP reconfirmation projects that contain applicable pre-1970 gap segments can either be cancelled or reduced in scope. The adjustments for Line 1022 and Line 1093 Shattuck Rd projects (total $34.389 million) will be removed from the projected bridge period, and the Line 1041 Lapeer Rd and Line 1006 Ph 2 11 Mile Mound to RR St. (total $32.781 million) will be removed from the projected test year.

Witness: LINCOLN D WARRINER
Date: April 1, 2026

U21981-AG-CE-0285_Attachment_1.xlsx

Table 19: MAOP Distribution sub-program

Compliance Project List

Project Number(s)	Project Name	2023 Actual ($000)	2023 Actual ($000)	2024 Actual ($000)	Preliminar 2025 Actual ($000)	2025 Projected ($000)	2026 Projected ($000)	2027 Projected ($000)	Construction Completion Year
21788	Line 1009, Huron Park to I-94		24	3,159					2024
22532	Line 1090n, Davis St			253	292	9			2024
23139	Line 1087b Phase 1			179	276				2024
22409	Line 1020, Greenfield Rd			427	301	29			2024
22150	Line 1002f, Macomb ITC Corridor			300	3,323	4,473			2025
22157	Line 1009/1009c I-94 to Little Mack, 10 Mile to 11 Mile				8,489	4,730			2025
22511	Line 1022f, Vermontville				833	562			2025
21674 21675	Line 1087b Phase 2				758	758	3,460		2025
22702	Line 1006, Groebel Dr to Mound Rd			98	422		4,002		2026
22996	Line 1026f, Mt Hope				385	16	3,979		2026
21250 21948	Line 1080, Kalamazoo	239	363	2,779	25,722	26,262	193		2025
22861	Line 1022, Airport Rd.		41	63	1,664	1,358	38,939		2026
22781	Line 1041, Lapeer Rd		244	70	123	27		25,021	2027
22393 30380 to 30390 30483 30491 to 30494	Line 1002c, 4 Cities Metro Pipeline Project (Royal Oak, Madison Heights, Clawson, and Warren)		934	3,091	28,194	28,199	60,261	46,442	2029
22494	Line 1009c Ph 3 Little Mack – 10 mile to 9 mile, Macomb						6,144		2026
21676	Line 1093, Shattuck Rd Saginaw				50		13,988		2026
TBD	Line 1002, 14 mile – Lorraine Ave to Red Run Drain							3,852	2027
22496	Line 1009c Ph 4, 11 mile – Little Mack to RS22, Macomb							3,658	2027
22998	Line 1026i, MSU PP							2,670	2027
30920	Line 1082 Lovers Lane							2,701	2027
30817	Line 1087f, S Saginaw Rd							497	2027
22738	Line 1006 Ph 2, 11 Mile Mound to RR St.							13,419	2027
	Total	239	1,607	10,419	70,830	66,423	130,966	98,260	
	Miles completed by year (source WP-LDW-13, page 1 of 4)	0.000	0.000	0.567		9.148	4.568	5.541	
	- Adjusted for mileage installed for 1087b Ph 1 in 2024								

U21981-AG-CE-0285-Attachment_2.xlsx

MAOP Project Status as of 03/31/2026

DAPP #	Project Name	Status	Design Complete	Construction Finish Date
21788	MAOP HP LINE1009-1009c PH1 Type IIa	Complete	12/04/23	05/31/24
22409	MAOP_HP_LINE_1020_Type_IIa	Field Completed	09/20/24	11/15/24
22532	MAOP HP LINE1090n Type l	Complete	09/17/24	11/22/24
23139	MAOP LINE 1087b - ADD MP N BAKER RD Type lla	Complete	10/21/24	11/22/24
30492	MAOP_1002C_YR0_JOHN R_TYPE III	Field Completed	03/10/25	05/01/25
30380	MAOP_1002C_YR0_MAIN ST_TYPE III	Field Completed	03/04/25	05/15/25
22511	MAOP 1022f W 3rd St, Type I	Complete	11/07/24	05/30/25
21674	MAOP HP LINE1087b PH1 Type lla	Field Completed	01/27/25	06/30/25
30863	MAOP_1002C_YR0_CROOKS_TYPE III	Field Completed	05/17/25	08/01/25
30483	MAOP_YR 0_NAKOTA_VTG_MAIN__1002C_TYPE IIA	Field Completed	06/02/25	08/29/25
22150	MAOP HP Line1002f Type IIb	Field Completed	04/02/25	09/30/25
30491	1002C_YR0_ROCHESTER RD_TYPE III	Field Completed	03/05/25	09/30/25
30493	MAOP_1002C_YR 0_NAKOTA_2_VTG_MAIN_TYPE IIA	Field Completed	08/04/25	11/24/25
22157	MAOP HP LINE1009-1009c PH2 Type IIa	Field Completed	06/03/25	11/28/25
21948	Line 1080 MAOP East, Type III	Field Completed	12/20/24	12/31/25
21250	Line 1080 MAOP, Type III	Field Completed	05/09/24	12/31/25
30494	MAOP_1002C_YR 0_WOODLAWN_VTG_MAIN_TYPE IIA	Under Construction	10/06/25	03/31/26
30352	MAOP HP Line 1022 (MP-P Segments), Type IIa	Released	01/02/26	04/10/26
30390	MAOP_1002C_YR1_COOLIDGE_ CITY_GATE_TYPE III	Released	02/14/26	05/15/26
30382	MAOP_1002C_YR1_11 MILE RD_TYPE III	Released	02/14/26	06/20/26
30381	MAOP_1002C_YR1_NAKOTA_TYPE III	Released	02/14/26	08/27/26
30383	MAOP_1002C_YR1_WASHINGTON_TYPE III	Released	02/14/26	08/27/26
21675	MAOP HP LINE1087b PH2 Type lla	Released	02/11/25	08/31/26
30887	MAOP HP LINE 1087b PH3 Type lla	Released	02/16/26	08/31/26
22861	MAOP HP Line 1022, Type IIb	Designed	02/16/26	09/30/26
22996	MAOP HP Line 1026f Mt Hope, Type IIa	Design 90%	10/24/25	09/30/26
22702	MAOP HP LINE1006 PH1 Type IIb	Design 90%	03/02/26	09/30/26
21676	MAOP HP LINE1093 Type llb	Cancel - Field Review	12/01/25	10/30/26
22494	MAOP HP LINE 1009-1009c-PH3 Type IIa	Design 60%	03/02/26	10/30/26
22393	MAOP HP LINE 1002C Type III	Design in Progress	08/29/24	12/31/26
22496	MAOP HP LINE 1009-1009c-PH4 Type IIa	Design 30%	11/30/26	06/30/27
22998	MAOP HP Line 1026i MSU Type I	Design in Progress	02/01/27	08/31/27
22738	MAOP HP LINE1006 PH2 Type IIb	Design 30%	12/31/26	08/31/27
30817	MAOP HP LINE 1087f Type I	Survey Returned	03/02/27	08/31/27
31023	MAOP HP LINE 1091, Type I	Design 60%	03/02/27	09/30/27
22781	MAOP HP Line 1041 Type IIB Replacement - Davison Twp	Cancel - Field Review	11/30/26	10/29/27
30995	MAOP HP Line 1002 Type IIb	Design Not Started	12/31/26	10/29/27
30920	MAOP HP Line 1082, Type IIa Lovers Ln	Design 60%	12/31/26	10/29/27
31309	MAOP_1002C_YR2_RED_OAKS_DRIVE_MDHT	Design 60%	12/31/26	10/30/27
30384	MAOP_1002C_YR2_S. DEQUINDRE RD_TYPE III	Design 60%	10/06/26	12/30/27
30385	MAOP_1002C_YR2_N. DEQUINDRE RD_TYPE III	Design 60%	10/06/26	12/30/27

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Exhibit AG-8
Case No. U-21981
April 15, 2026
Page 1 of 1

Disallowance of Capital Expenditures for Cancelled and Premature Projects
For 10 months ending October 2026 and Porjected Test Year

Compliance Project List ($000)

Project Number(s)	Project Name	2023 Actual ($000)	2024 Actual ($000)	Preliminary 2025 Actual ($000)	2025 Projected ($000)	2026 Projected ($000)	2027 Projected ($000)	10 months ending Oct 2026	Projected Test Year	Project Phase	Construction Completion Year
22861	Line 1022, Airport Rd.	$ 41	$ 63	$ 1,664	$ 1,358	$ 38,939		$ 32,449	$ 6,490	Scope Change	2026
22781	Line 1041, Lapeer Rd	244	70	123	27		25,021		20,851	Cancelled	2027
22393 **30380 to 30390** **30483** **30491 to 30494** **30863**	Line 1002c, 4 Cities Metro Pipeline Project (Royal Oak, Madison Heights, Clawson, and Warren)	934	3,091	28,194	28,199	60,261	46,442		38,702	2027 project phase not yet designed	2029
21676	Line 1093, Shattuck Rd Saginaw			50		13,988		11,657	2,331	Cancelled	2026
TBD	Line 1002, 14 mile – Lorraine Ave to Red Run Drain						3,852		3,210	Unknown	2027
22496	Line 1009c Ph 4, 11 mile – Little Mack to RS22, Macomb						3,658		3,048	30% Design	2027
22998	Line 1026i, MSU PP						2,670		2,225	Prelim Design	2027
30920	Line 1082 Lovers Lane						2,701		2,251	60% Design	2027
30817	Line 1087f, S Saginaw Rd						497		414	Survey only, No design	2027
22738	Line 1006 Ph 2, 11 Mile Mound to RR St.						13,419		11,183	Scope Change 30% Design	2027
	Total	$ 1,219	$ 3,224	$ 30,031	$ 29,584	$ 113,188	$ 98,260	$ 44,106	$ 90,705		

Source: U-21981-AG-CE-0285_Attachment_1.xlsx

U21981-AG-CE-0290
Page **1** of **1**

Question:

70. Refer to Table 20 on page 72 of Mr. Warriner's direct testimony on Capacity and Deliverability Augmentation projects. Please expand the table to include actual amounts for 2022 through 2025 and forecasted for 2026 and 2027. Provide also the number of miles or units worked on or completed each year and provide it in Excel.

Response:

Please see the Excel file attachment named U21981-AG-CE-0290-Attachment_1. Please note that the units reported beneath the table are the feet of main installed for each time period.

Witness: LINCOLN D WARRINER
Date: April 1, 2026

U21981-AG-CE-0290-Attachment_1.x,sx

Table 20: Capacity/Deliverability Capital Expenditures
(in Thousands of Dollars)

Program Description	Historical 12 Mos Ended 12/31/2022	Historical 12 Mos Ended 12/31/2023	Historical 12 Mos Ended 12/31/2024	Preliminary Historical 12 Mos Ending 12/31/2025	12 Mos Ending 12/31/2025	10 Mos Ending 10/31/2026	22 Mos Ending 10/31/2026	Projected 12 Mos Ending 12/31/2026	Projected Test Year 12 Mos Ending 10/31/2027	Projected 12 Mos Ending 12/31/2027
Augment	10,196	4,446	7,031	828	6,466	4,866	11,332	5,849	14,347	16,024
Total Capacity/ Deliverability	**10,196**	**4,446**	**7,031**	**828**	**6,466**	**4,866**	**11,332**	**5,849**	**14,347**	**16,024**
Main Footage Installed	34,558	13,888	14,949	5,409	7,990	17,400	25,390	19,981	15,616	17,441
Cost per foot	$ 295	$ 320	$ 470	$ 153	$ 809	$ 280	$ 446	$ 293	$ 919	$ 919

U21981-AG-CE-0291
Page **1** of **1**

Question:

71. Refer to Table 21 on page 74 of Mr. Warriner's direct testimony on Capacity and Deliverability Augmentation projects. Please:

a. Expand the table to show the amount spent in total for 2025 on each project and the projects planned for 2026 and 2027 with the respective forecasted cost. Provide the expanded table in Excel.

b. For projects in 2022 through 2025 and forecasted for 2026 and 2027 provide the number of miles worked on or completed each year.

c. For projects forecasted for 2026 and 2027, provide the current phase of development and identify the next phase with the start month and year.

Response:

The requested information is included in the Excel file attachment named U21981-AG-CE-0291. Please note that the current phase of development is provided, but the start month and year of the next phase is not readily available in the distribution project planning application.

Witness: LINCOLN D WARRINER
Date: March 31, 2026

U21981-AG-CE-0291-Attachment_1.xlsx

Table 21: Historical Actual Augment Investments by Year

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	Preliminary 2025 Actual	Projected 2026	Projected 2027
Caledonia HP Phase 1	$488							
Caledonia HP Phase 2			($512)					
Caledonia HP Phase 3	$35,961	($153)						
Gratiot Ave HP		$2,803,277	$1,514,207					
Caledonia MP / Cherry Valley Ave	$1,778,302	$287,842	($100)					
Hickory Corners		$910,795	$455,855					
Shaffer Rd East of Alamando			$4,052,568	$18,338	0	$15,311		
Imlay City Rd & Lk Pleasant			$1,626,475	($13,529)				
W Sanilac Rd			$1,032,909					
Climax CG				$1,925,844	$45	($37,731)		
Walled Lake – Welch & Oak				$1,723,201	($22,405)	$31		
Galesburg – Celery & River St.					$5,190,751	$108,883		
Corunna - E King Street						$148,399		
Lytle Rd						$121,436		
M-71 & Lytle Rd						$89,668		
Giddings Rd Lk Orion						$103,928		
Pleasant Valley Rd						$99,723		
I94 Crossing at 44th - HP fr Climax CG	Released						$2,606,148	
Beaverton 12 inch HP (Shaffer Rd E of Apple Dr	Design 90%						$5,154,985	
W German Rd at Bullock Rd	Field Completed						$535,964	
W German Rd West of S Lincoln Rd	Field Completed						$395,092	
N Pine Rd and W Cass Ave	Released						$179,160	
Front Ave & Western Ave	Design in Progress						$183,332	
Sheldon Rd Augment	Design Not Started						$684,202	
Retire ST 713 & 352 Almont Twp	nder Construction						$409,163	
Orchard Lk Rd HP Augment	Survey Returned							$10,668,807
140th Ave. 6 In. West - Dorr	Design Not Started							$1,256,663
140th Ave. 6 Inch East - Dorr	Design Not Started							$1,477,949
Industrial Park Dr & Freeway Park Dr Augment	Design Not Started							$139,910
Program Level Adjustments							($4,299,018)	
Other Projects	$1,784,195	$2.501,265	$1,514,431	$792,074	$1,862,587	$178,130		$2,480,385
Total Augment	**$3,598,945**	**$6,503,025**	**$10,195,833**	**$4,445,928**	**$7,030,978**	**$827,777**	**$5,849,026**	**$16,023,714**
Note: 2026 and 2027 Project estimates and status are current as of 03/31/2026								
Feet of main installation	13,427	24,410	34,558	13,888	14,949	5,409	19,981	17,441
- 2025 is prelimary actual								

U21981-AG-CE-0362
Page **1** of **1**

Question:

140. Refer to Table 2 on page 38 of Ms. Pascarello's direct testimony on the EIRP pipe retired and remaining miles. Please update this information with 2025 actual data and provide the remaining miles at end of 2025 in Excel.

Response:

Please see U21981-AG-CE-0362_Pascarello_Attachment_1.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0362_Pascarello_Attachment_1

Table 2: Miles of EIRP Main Pipe Retired by Year

MILES OF EIRP CLASSIFIED MAIN PIPE REPLACED BY YEAR												
PIPE TYPE:	Miles of Pipe by Pipe Type in EIRP Program Scope	EIRP 2012 - 2019 Actuals[1]	EIRP 2020 Actuals[1]	EIRP 2021 Actuals[1]	EIRP 2022 Actuals[1]	EIRP 2023 Actuals[1]	EIRP 2024 Actual [1]	Preliminary EIRP 2025 Actual [1]		Cumulative EIRP Retired as of 12/31/25[1]	Estimated Cumulative Retired by Other Programs as of 12/31/25	Est. Miles Remaining as of 12/31/25
TOTAL:	2,869.2	439.2	62.5	124.2	84.9	87.1	102.5	106.3		1,006.6	461.9	1,400.7
Cast Iron	580	166.5	13.9	50.6	23.0	32.6	40.0	22.1		348.8	115.4	115.9
Bare Steel	1033.4	137.2	26.6	51.6	56.6	44.1	33.8	38.2		388.0	132.2	513.2
Threaded & Coupled	1061.7	80.3	19.8	14.9	4.2	3.95	21.6	41.0		185.7	205.1	671.0
Wrought Iron	21.6	4.7	0.0	0.4	0.0	0.0	0.2	0.2		5.4	8.7	7.4
X-trube	0.9	0.9	0.0	0.0	0.0	0.0	0.0	0.0		0.9	0.0	0.0
Copper	1.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0		0.6	0.6	0.4
TOD	100	10.6	2.3	6.7	1.1	6.4	6.9	4.8		38.8		
LFERW	70	38.4	0.0	0.0	0.0	0.0	0.0	0.0		38.4		
Coated & Wrapped on Standard Pressure[3]	108.35	0.0	0.0	2.2	10.2	10.0	6.8	3.8		33.0		
Additional Pipe Replacement:												
Plastic[2]		8.4	1.7	3.2	6.6	9.9	3.9	5.4		39.1		
Coated & Wrapped[2, 3]		76.1	7.4	10.2	29.3	35.8	20.6	16.9		196.4		

Notes:

1) Does not include miles of EIRP pipe type that were replaced as part of other programs like Civic Improvement or Emergent CE
2) It is necessary to replace some plastic and/or coated and wrapped steel as part of EIRP projects due to the configuration of the
3) Coated and Wrapped steel pipe on standard pressure does qualify under EIRP while Coated and Wrapped steel pipe on medium

---

U21981-AG-CE-0363
Page **1** of **1**

Question:

141. Refer to lines 7-10 on page 39 of Ms. Pascarello's direct testimony on the miles of installed pipe under the EIRP. Please provide a schedule similar to Table 2 showing the number of miles of pipe installed and services replaced by year with the cumulative total at the end of 2025 and provide it in Excel.

Response:

Please see U21981-AG-CE-0363_Pascarello_Attachment_1.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0363_Pascarello_Attachment_1

MILES OF EIRP INSTALLED MAIN PIPE AND SERVICES BY YEAR

PIPE TYPE:	EIRP 2012 Actuals[1]	EIRP 2013 Actuals[1]	EIRP 2014 Actuals[1]	EIRP 2015 Actuals[1]	EIRP 2016 Actuals[1]	EIRP 2017 Actuals[1]	EIRP 2018 Actuals[1]	EIRP 2019 Actuals[1]	EIRP 2020 Actuals[1]	EIRP 2021 Actuals[1]	EIRP 2022 Actuals[1]	EIRP 2023 Actuals[1]	EIRP 2024 Actual [1]	Preliminary EIRP 2025 Actual	2012-2025
Plastic	10.7	56.8	53.3	79.8	79.5	76.5	47.7	49.1	68.2	152.7	160.6	102.3	123.0	123.9	1184.0
Steel	0.9	6.7	7.9	4.8	1.5	0.2	5.2	1.6	3.1	4.5	1.5	6.6	8.4	21.4	74.4
TOTAL MILES:	**11.6**	**63.5**	**61.3**	**84.6**	**81.0**	**76.7**	**52.9**	**50.8**	**71.2**	**157.2**	**162.1**	**108.9**	**131.4**	**145.3**	**1,258.4**
Servicers Replaced	1,161	6,880	5,460	9,846	9,930	7,884	4,632	4,951	8,556	13,880	14,074	8,649	10,631	11,182	117,716

Question:

143. Refer to lines 19-34 on page 45 and lines 1-9 of Ms. Pascarello's direct testimony on the EIRP cost per mile. Please:

a. Provide the same information for each year 2021-2023 and 2025 actual.

b. If the actual costs for 2025 vary by 10% or more from the forecast, explain why.

c. Explain why the Northeast cost per mile for steel pipe for 2026 is 56% higher than the 2025 forecasted cost and 10% higher in 2027 over 2026. Explain what steps the Company is taking to significantly reduce the increase in both years.

Response:

a. This data is also provided in U21981-SA-CE-231_Pascarello_Attachment_1.

For SP/MP projects (plastic pipe):

- 2021: The overall cost-per-mile for installed plastic pipe was $1,306,506. This is based on regional costs of $1,044,905 (Southwest), $1,452,108 (Northeast), and $1,588,771 (Southeast).
- 2022: The overall cost-per-mile is $1,421,541 for installed plastic pipe. This is based on regional costs of $1,149,363 (Southwest), $1,433,446 (Northeast), and $1,717,247 (Southeast).
- 2023: The overall cost-per-mile is $1,625,519 for installed plastic pipe. This is based on regional costs of $2,343,464 (Southwest), $1,434,706 (Northeast), and $1,537,740 (Southeast).
- 2025 preliminary actual: The overall cost-per-mile is $1,273,622 for installed plastic pipe. This is based on regional costs of $1,383,714 (Southwest), $1,268,017 (Northeast), and $1,225,377 (Southeast).

For HP steel/TOD projects (steel pipe):

- 2021: The overall cost-per-mile for installed steel pipe was $5,882,372. This is based on regional costs of $0 (Southwest), $5,889,526 (Northeast), and $0 (Southeast).
- 2022: The overall cost-per-mile is $0 for installed steel pipe. The cost for the steel pipe installed is included in the plastic pipe cost-per-mile provided above.
- 2023: The overall cost-per-mile is $1,545,348 for installed steel pipe. This is based on regional costs of $0 (Southwest), $1,545,348 (Northeast), and $0 (Southeast).
- 2025 preliminary actual: The overall cost-per-mile is $3,297,195 for installed steel pipe. This is based on regional costs of $6,004,536 (Southwest), $2,603,883 (Northeast), and $3,750,773 (Southeast).

b. As shown in U21981-SA-CE-231_Pascarello_Attachment_1, the projected EIRP 2025 capital expenditures were $231,434,509 and preliminary 2025 actuals are $231,466,227. The percentage difference is 0.014%.

c. The Northeast steel cost-per-mile increases in 2026 compared to the 2025 forecast are primarily due to changes in project mix and scale. The 2025 cost-per-mile presented in testimony was a projection based on estimate-at-completion data available at the time; actual 2025 Northeast steel costs were $2,603,888 per mile. The lower Northeast steel miles in 2026, result in fixed project costs, such as mobilization, traffic control, engineering, permitting, and inspection, being allocated across fewer miles. In addition, the remaining Northeast steel projects are disproportionately larger-diameter (8-inch to 12-inch) and higher complexity installations. These factors increase per-mile costs due to higher material prices, lower production rates, and increased labor and coordination requirements. The additional cost increase in 2027 over 2026 reflects continued low steel mileage and a similar concentration of complex, large-diameter projects.

The Company is actively taking steps to mitigate these cost pressures. These efforts include bundling steel work with adjacent EIRP or non-EIRP projects where feasible to improve economies of scale, standardizing designs and construction methods to increase productivity, and sequencing projects to reduce redundant mobilization and contractor inefficiencies. The Company also continues to evaluate opportunities to substitute plastic pipe for steel where engineering standards allow and to optimize contractor engagement strategies to reduce risk premiums associated with isolated steel projects. While remaining Northeast steel replacements are inherently more complex, these actions are intended to materially limit further cost escalation while continuing to meet safety, regulatory, and reliability objectives.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0384
Page **1** of **1**

Question:

162. Refer to Exhibit A-112, page 3, sponsored by Ms. Pascarello. For the projects on lines 4, 10, and 24 through 35, please identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Response:

Please see U21981-AG-CE-0384_Pascarello_Attachment_1.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0384_Pascarello_Attachment_1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Capital Expenditures
Material Condition Program
($000)

Case No.: U-21981
Exhibit No.: A-112 (KAP-4)
Page: 3 of 3
Witness: KAPascarello
Date: December 2025

	(a)	(b)	(c)	(d)	(e)	(f)			
		Historical Year	**Projected Bridge Year**			**Projected Test Year**			
Line No	**Description**	**12 Mos Ended 12/31/2024**	**12 Mos Ending 12/31/2025**	**10 Mos Ending 10/31/2026**	**22 Mos Ending 10/31/2026**	**12 Mos Ending 10/31/2027**	**Current Phase**	**Next Phase**	**Projected Start of next phase [1]**
					[Col. (c) + (d)]				
	Projects Over $5 Million (with spend in test year)								
1	EIRP - Distribution								
2	LAN4	11,774	14,194	2,435	16,629	332			
3	ROK7	-	-	18,671	18,671	8,616			
4	MAC11	-	-	10,891	10,891	14,312			
						2026 Phases	Construction	Closeout	Dec-26
						2027 Phases	Engineering Design	Construction	Jan-27
5	MAC12	1,571	19,245	2,435	21,681	332			
6	BCY2	1,776	8,353	5,214	13,567	7,812			
7	FLT5	3,615	14,518	2,551	17,069	5,387			
8	LIV6	32	5,039	3,784	8,823	516			
9	ALM5	102	5,108	5,947	11,055	811			
10	ALM2	85	9,401	7,654	17,055	10,893			
						2025 Phases	Completed	n/a	n/a
						2026 Phases	Construction	Closeout	Dec-26
						2027 Phases	Engineering Design	Construction	Feb-27
11	LIV4	2	9,824	580	10,404	79			
12	LAN10	-	65	6,217	6,283	848			
13	KAL8	-	3	7,839	7,842	1,069			
14	FLT11	-	-	15,308	15,308	2,087			
15	OWS3	-	-	5,219	5,219	712			
16	SAG4	-	-	15,680	15,680	2,135			
17	ROK12	-	-	4,754	4,754	648			
18	KAL3	-	-	4,987	4,987	680			
19	KAL7	-	-	8,652	8,652	1,180			
20	KAL11	-	0	9,046	9,046	1,233			
21	LAN13	-	-	6,488	6,488	885			
22	LAN14	-	-	5,567	5,567	759			
23	ROK10	-	0	17,627	17,628	2,404			
24	FLT12	-	-	-	-	18,896	Engineering Design	Construction	Mar-27
25	~~SAG3~~ SAG13	-	-	-	-	21,072	Engineering Design	Construction	Mar-27
26	MAC7	-	-	-	-	16,491	Engineering Design	Construction	May-27
27	ROK18	-	-	-	-	5,153	Engineering Design	Construction	Jan-27
28	ROK27	-	-	-	-	5,955	Engineering Design	Construction	Dec-26
29	ROK29	-	-	-	-	13,218	Conceptual Design	Engineering Design	Apr-26
30	LIV8	-	-	-	-	12,826	Engineering Design	Construction	Aug-27
31	LIV9	-	-	-	-	7,902	Engineering Design	Construction	Oct-27
32	KAL9	-	-	-	-	11,330	Engineering Design	Construction	Sep-27
33	KAL2	-	-	-	-	9,276	Engineering Design	Construction	Dec-26
34	JAC2	-	-	-	-	24,863	Engineering Design	Construction	Dec-26
35	LAN11	-	-	-	-	8,183	Engineering Design	Construction	Jan-27
36	Material Condition Non Modeled								
37	Line 1010 Project	5,799	1,061	19,100	20,161	-			
38	Material Condition Renewals								
39	None identified	-	-	-	-	-			
40	Vintage Service Replacements								
41	None identified	-	-	-	-	-			
42	Commercial and Industrial Meters								
43	None identified	-	-	-	-	-			
	Projects Under $5 Million								
44	EIRP - Distribution	174,017	145,650	28,831	174,481	15,287			
45	Material Condition Non Modeled	33,644	51,744	26,458	78,202	47,205			
44	Material Condition Renewals	38,636	41,688	37,407	79,094	66,330			
45	Vintage Service Replacements	19,352	30,113	43,689	73,802	65,761			
46	Commercial and Industrial Meters	754	2,296	1,888	4,184	2,364			
47	**Total Capital**	**291,159**	**358,301**	**324,919**	**683,220**	**415,842**			

Notes:

[1] Dates provided are preliminary planning estimates and are subject to change. While specific construction start dates have not yet been finalized, construction activities are projected to begin within the test year.

U21981-AG-CE-0383
Page **1** of **1**

Question:

161. Refer to Exhibit A-112, page 1, sponsored by Ms. Pascarello. Please:

a. Expand the exhibit to include actual information for 2023 and 2025 and forecasted information for 2026 and 2027 and provide it in Excel.

b. For the EIRP capital expenditures, provide a schedule in Excel showing the actual annual amount spent on the program in comparison to the amount forecasted for the year along with variance amount for each year from inception of the program to 2025.

c. For the Material Condition Non-Modeled on line 2, provide a schedule in Excel showing the projects and programs included under this category with related capital expenditures and units for each year 2023-2025 actual and forecasted 2026 and 2027.

Response:

Please see U21981-AG-CE-0383_Pascarello_Attachment_1.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0383_Pascarello_Attachment_1

MICHIGAN PUBLIC SERVICE COMMISSION	Case No.:	U-21981
Consumers Energy Company	Exhibit No.:	A-112 (KAP-4)
Actual & Projected Gas Capital Expenditures	Page:	1 of 3
Material Condition Program	Witness:	KAPascarello
($000)	Date:	December 2025

	(a)		(b)				(c)	(d)	(e)	(f)
		Historical Year	**Historical Year**	**Preliminary Actuals**	**Projected**	**Projected**	**Projected Bridge Year**			**Projected Test Year**
Line No	**Description**	**12 Mos Ended 12/31/2023**	**12 Mos Ended 12/31/2024**	**12 Mos Ending 12/31/2025**	**12 Mos Ending 12/31/2026**	**12 Mos Ending 12/31/2027**	**12 Mos Ending 12/31/2025**	**10 Mos Ending 10/31/2026**	**22 Mos Ending 10/31/2026**	**12 Mos Ending 10/31/2027**
1	**EIRP - Distribution**	**181,927**	**192,974**	**231,466**	**223,153**	**235,690**	**231,400**	**196,377**	**427,777**	**234,183**
22%	Labor	38,053	44,245	45,943	48,184	50,891	49,965	42,402	92,367	50,565
22%	Capitalized E&S	44,266	43,346	49,033	48,563	51,291	50,357	42,736	93,093	50,963
6%	Materials	8,319	9,730	14,573	13,131	13,869	13,616	11,556	25,172	13,780
25%	Contractor	38,437	45,514	66,860	56,393	59,561	58,477	49,627	108,104	59,180
10%	Non-Labor Overhead	20,859	19,535	18,637	21,642	22,858	22,442	19,045	41,487	22,712
16%	Non-Labor Other	31,993	30,602	36,420	35,240	37,220	36,542	31,012	67,554	36,982
	Contingency				0	0	0	0	0	0
2	**Material Condition Non Modeled**	**38,516**	**39,443**	**48,970**	**54,119**	**45,010**	**52,805**	**45,558**	**98,363**	**47,205**
17%	Labor	6,552	6,441	7,953	9,258	7,700	9,034	7,794	16,828	8,076
22%	Capitalized E&S	9,517	8,702	11,525	11,689	9,722	11,405	9,840	21,246	10,196
9%	Materials	2,677	3,013	4,852	5,027	4,181	4,905	4,232	9,137	4,385
30%	Contractor	10,070	12,674	13,809	16,131	13,416	15,739	13,579	29,319	14,070
3%	Non-Labor Overhead	1,938	1,053	1,257	1,517	1,262	1,480	1,277	2,757	1,323
19%	Non-Labor Other	7,761	7,561	9,574	10,496	8,729	10,241	8,835	19,076	9,155
	Contingency				0	0	0	0	0	0
3	**Material Condition Renewals**	**31,816**	**38,636**	**50,338**	**40,854**	**66,479**	**41,688**	**37,407**	**79,094**	**66,330**
36%	Labor	11,783	13,393	18,098	14,795	24,074	15,097	13,546	28,643	24,021
21%	Capitalized E&S	6,971	8,790	10,116	8,591	13,979	8,766	7,866	16,632	13,948
11%	Materials	1,324	3,718	7,284	4,665	7,592	4,761	4,272	9,032	7,575
6%	Contractor	2,347	2,306	2,539	2,267	3,690	2,314	2,076	4,390	3,681
6%	Non-Labor Overhead	2,462	2,231	2,608	2,344	3,814	2,391	2,146	4,537	3,805
20%	Non-Labor Other	6,929	8,198	9,693	8,192	13,330	8,359	7,501	15,860	13,301
	Contingency				0	0	0	0	0	0
4	**Vintage Service Replacements**	**11,354**	**19,352**	**32,244**	**43,689**	**65,761**	**30,113**	**43,689**	**73,802**	**65,761**
15%	Labor	2,989	3,351	3,745	6,720	10,115	4,632	6,720	11,352	10,115
22%	Capitalized E&S	2,744	4,473	6,771	9,778	14,718	6,740	9,778	16,518	14,718
2%	Materials	135	336	584	762	1,147	525	762	1,288	1,147
31%	Contractor	739	6,402	13,284	13,545	20,388	9,336	13,545	22,881	20,388
3%	Non-Labor Overhead	929	708	791	1,444	2,173	995	1,444	2,439	2,173
26%	Non-Labor Other	3,820	4,082	7,069	11,440	17,219	7,885	11,440	19,325	17,219
	Contingency				0	0	0	0	0	0
5	**Commercial and Industrial Meters**	**2,684**	**754**	**2,352**	**2,289**	**2,380**	**2,296**	**1,888**	**4,184**	**2,364**
23%	Labor	344	193	456	538	559	539	443	983	555
21%	Capitalized E&S	677	167	492	492	512	493	406	899	508
28%	Materials	367	138	743	632	657	633	521	1,154	652
10%	Contractor	771	117	309	236	245	237	195	431	244
3%	Non-Labor Overhead	49	25	46	63	66	63	52	116	65
14%	Non-Labor Other	476	113	306	329	342	330	271	601	339
	Contingency				0	0	0	0	0	0
6	**Total Capital**	**266,297**	**291,159**	**365,370**	**364,104**	**415,319**	**358,301**	**324,919**	**683,220**	**415,842**
	Labor	59,721	67,623	76,195	79,495	93,340	79,266	70,906	150,172	93,332
	Capitalized E&S	64,175	65,479	77,937	79,113	90,222	77,762	70,626	148,388	90,333
	Materials	12,822	16,937	28,036	24,218	27,446	24,441	21,343	45,784	27,540
	Contractor	52,364	67,012	96,800	88,572	97,300	86,103	79,022	165,124	97,563
	Non-Labor Overhead	26,236	23,553	23,340	27,010	30,172	27,372	23,964	51,336	30,078
	Non-Labor Other	50,979	50,555	63,063	65,696	76,840	63,357	59,059	122,416	76,996
	Contingency	0	0	0	0	0	0	0	0	0

U21806-AG-CE-0389
Page **1** of **1**

Question:

102. Refer to lines 3-4 on page 48 of Ms. Pascarello's direct testimony on the 2035 EIRP completion date. Please:

a. State what significant increase in risk the Company would anticipate if the program completion date for the remaining pipe replacement was extended by five years to 2040.

b. Provide any engineering analysis that the Company has performed in the past five years that determined all remaining vintage pipe needs to be replaced by 2035 due increased degradation occurring with the existing pipe in the ground.

Response:

a. While leak data on Company mains shows a downward trend, as provided in response U21806-AG-CE-0406, the Company expects more leaks due to the continued deterioration of the remaining aging pipe if the program completion date is extended to 2040. The current pace of the EIRP will continue to lead to an overall reduction in leaks. As shown in Figure 20 in Exhibit A-42 (NPD-1), page 47, much of the remaining vintage pipe was installed between 1920 and 1950. At approximately 75 years and older, this pipe has reached the end of its useful life. Continuing prolonged use increases the likelihood of incidents occurring as the pipe continues to deteriorate due to factors such as soil conditions and ground movement. The Company continues to experience emergent incidents, including two within the FLT4 grid project in early 2024. This system experienced issues in different locations while EIRP crews were replacing pipe in other parts of this grid. In January 2024, water infiltrated a 4" cast iron main on the standard pressure system. The water froze and blocked the flow of gas to customers. In February 2024, a leak occurred in another section of this grid, leading the Company to cut out the section of leaking pipe. These incidents, occurring as the Company was starting to replace vintage mains in the area, support the project's pace and prioritization.

b. The Company's Engineering department runs the Distribution Risk Analysis Modeling ("DRAM") annually. The DRAM uses inputs such as pipe material type, pipe age, soil conditions, and leak data to risk rank 7,000 segments of distribution pipe. The DRAM risk ranking for 2025 and 2026 are included in WP-KAP-3. Risk models are essential tools in engineering analysis because they provide a structured approach to identifying, assessing, and managing potential risks.

Witness: Kristine A. Pascarello
Date: March 13, 2025

U21806-AG-CE-0391
Page **1** of **1**

Question:

104. Refer to Table 7 on page 49 of Ms. Pascarello's direct testimony on the scope and the cost of the EIRP for 2023. Please provide the end year of the EIRP if the same pace of pipe replacement in 2023 continued into future years.

Response:

Based on the following assumptions:

1. EIRP continues at the same pace as 2023 for remainder of program.
2. Vintage main retired by other programs continues at current pace and retires approximately 50 miles per year (total: 300 miles) by 2030.
3. Cast Iron pipe, Wrought Iron pipe, and the Standard Pressure system are eliminated by 2030.
4. All miles after 2030 would be retired exclusively by EIRP.

The Company projects the end year of EIRP would be 2038.

Witness: Kristine A. Pascarello
Date: March 12, 2025

U21981-AG-CE-0361
Page **1** of **1**

Question:

139. Refer to lines 4-17 on page 36 of Ms. Pascarello's direct testimony on the Company's goal to complete removal of all vintage pipe by 2035. Please provide a copy of any engineering studies conducted by the Company that concluded all vintage pipe must be removed by 2035 because of increasing deterioration of the pipe.

Response:

Consumers Energy does not have an engineering study concluding that all vintage gas distribution pipes must be removed by 2035 due to increasing deterioration. The Enhanced Infrastructure Replacement Program ("EIRP") was established in response to the Pipeline and Hazardous Materials Safety Administration's 2011 national "Call to Action," which reflected PHMSA's recognition, based on industry experience and incidents, that certain vintage pipeline materials are associated with higher safety risk. PHMSA encouraged gas utilities to proactively address older pipeline materials through deliberate, planned replacement programs rather than reactive repairs. As originally approved, the EIRP was structured as a long-term program of approximately 25 years, with an anticipated completion around 2036, and the Company's current 2035 target represents a one-year adjustment to that originally approved timeframe. As the Commission has previously recognized, the program reflects a prudent and reasonable approach to improving system safety and reliability through planned, coordinated infrastructure replacement, rather than waiting for failures to occur. The program schedule reflects the long-standing execution of an approved replacement strategy established in response to PHMSA's recognition of the elevated safety risks associated with certain vintage pipeline materials. The remaining schedule projects replacement of approximately five percent of vintage materials annually, which is a pace that balances safety risk reduction with constructability, customer disruption, and cost considerations, consistent with the long-term approach previously approved by the Commission.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-MEC-CE-0101
Page **1** of **3**

Question:

3. Refer to Pascarello Direct on pages 35-36 where it states, "This risk-based methodology, combined with subject matter expert input, guides the selection of EIRP replacement projects that eliminate vintage mains and standard pressure systems." Please describe in detail how the risk-based methodology and subject matter expert review processes interact to guide the selection of EIRP replacement projects. Specifically, please discuss the sequencing of these two processes and describe the factors that each process considers.

a. Does the risk-based methodology factor in the probability of occurrence of the event?
b. Does the risk-based methodology factor in the impact of occurrence of the event?
How is impact measured (e.g., cost (dollars), operational impact)?
c. Does the risk-based methodology factor in risk reduction per dollar spent?
d. How do subject matter experts determine which EIRP projects to prioritize?
i. How are subject matter experts identified? Please describe in detail the background and job experience that make them subject matter experts.
ii. Is there a decision rubric, form, or scoring structure management personnel uses to review and reject or approve all projects that are necessary and appropriate? If so, please provide a copy of the decision rubric, form, or scoring structure. If not, why not?
iii. Did management personnel reject any projects in the last two years? If so, please identify the units rejected and provide the reason why each was rejected.

Response:

The risk-based methodology and subject matter expert review processes described below are tools used to prioritize and select individual EIRP projects. These methodologies govern how projects are chosen and sequenced within the program, not the reason for the existence of the EIRP itself, which originated from federal safety guidance and the need to eliminate aging, higher-risk pipeline materials. The EIRP was initiated in 2012 in response to the U.S. Department of Transportation and Pipeline and Hazardous Materials Safety Administration's 2011 national "Call to Action," which urged pipeline operators to accelerate replacement of aging, higher-risk pipeline infrastructure. The Company's project selection process is designed to meet this safety objective while efficiently modernizing the gas distribution system. The risk model identifies areas of comparatively higher risk on the gas distribution system, and Engineering and SMEs then apply professional judgment and practical considerations to determine which projects are most appropriate for execution within the 3-year planning window of the EIRP.

a. No. The Company's risk-based methodology does not calculate the probability that a specific failure or event will occur. The DIMP model used for EIRP planning is a relative risk model, meaning it compares segments of the gas distribution system to one another based on known characteristics such as material type, age, pressure, and operating conditions. It is intended to rank system segments consistently rather than predict the likelihood of a specific incident.
b. No. The risk-based methodology does not calculate the consequences or impact of a failure event. Impacts are not measured in terms of cost (dollars) or quantified operational consequences. Instead, the model is used as a screening tool to identify comparatively higher-risk assets that warrant further engineering review and consideration within the EIRP.

c. No. The methodology does not calculate risk reduction per dollar and does not perform a cost-benefit optimization calculation. Cost considerations are evaluated later in the process during engineering and SME review to ensure resources are used efficiently and projects are feasible, but cost is not a calculated output of the risk model itself.

d. After higher-risk segments are identified through the DIMP relative risk model, engineering personnel define project limits to create safe and constructible work packages. When a project boundary is established, all vintage pipes and services within that boundary are generally included for replacement, even if certain individual segments within the boundary rank lower than others in the risk model. This approach allows the Company to complete work efficiently, avoid repeated construction in the same neighborhoods, reduce disruption to customers and municipalities, and lower long-term costs compared to addressing small segments individually over multiple construction seasons. It also ensures that remaining vintage materials do not continue to pose future integrity risks within an area that has already been disturbed for construction.

Projects are then reviewed during a prioritization process that includes:

- Review and validation of underlying data inputs and assumptions;
- Review of TOD prioritization and selection of TOD projects;
- Review of DRAM model results, including top-ranked risk segments and grid-based prioritization; and
- Selection of projects for detailed scoping.

During this review, SMEs consider multiple practical and safety-related factors, including construction feasibility, availability of engineering and construction resources, coordination with municipalities or transportation agencies, customer impacts, opportunities to coordinate with other Company programs, whether the project removes EIRP-eligible vintage materials, and the overall effect on the safe and reliable delivery of natural gas.

i. Subject matter experts are identified based on their professional experience, technical qualifications, and direct responsibility for gas system safety, integrity, and planning. These individuals have extensive knowledge of the Company's gas distribution system, integrity management requirements, and regulatory obligations, which qualifies them to evaluate and prioritize EIRP projects.

ii. The Company does not use a formal written decision rubric, scoring form, or numerical approval matrix to approve or reject EIRP projects. Instead, projects are evaluated and prioritized by committee using consistent engineering, safety, and practicality considerations. This approach allows flexibility to account for project specific conditions, construction challenges, and coordination requirements that may not be fully captured in a standardized scoring tool.

iii. EIRP projects are developed with specific scope and eligibility criteria and are subject to an extensive upfront review process by a committee that includes engineering personnel, subject matter experts, and management. As a result of this comprehensive review, projects that advance into the EIRP plan are not typically rejected by management.

U21981-MEC-CE-0101
Page **3** of **3**

In the last two years, one proposed replacement project was reviewed during the scoping and eligibility evaluation process and determined not to qualify as an EIRP project because the pipe segments did not meet the program's definition of vintage material. Specifically, the proposal involved approximately 250 feet of 4-inch steel medium-pressure pipe installed in 1997 and suspended on an overpass over I-94 in Macomb County. Because the asset did not meet EIRP eligibility criteria, it was not included in the EIRP.

Proposed work that does not meet EIRP eligibility requirements may still be addressed, where appropriate, through other Company programs based on asset condition, safety considerations, and system needs.

Witness: KRISTINE A PASCARELLO
Date: March 18, 2026

Question:

9. Refer to Pascarello Direct on page 55 where it states, "The Company plans to replace 6.8 miles of wrought iron mains and any other intermingled vintage material mains, under the Material Condition Non-Modeled Program . . . . The remaining wrought iron miles are planned to be replaced within the EIRP program."

a. Please provide the risk score for each segment/project of wrought iron main referenced above and indicate whether the segment/project falls under the Material Condition Non-Modeled Program or the EIRP. If the Company did not calculate a risk score for these segments, please explain in detail why not.

b. Please explain in detail how the Company determined which segments of wrought iron main to address in the Material Condition Non-Modeled Program versus the EIRP.

Response:

a. The Company notes the following updates regarding the wrought iron main segments referenced in Table 8 of my direct testimony:

- First, the total mileage of wrought iron planned for replacement under the MCNM program from 2025 to 2027 has decreased from 6.8 miles to approximately 5.4 miles. This reduction reflects wrought iron project work that has since been completed, including work completed in 2024 that had not yet been fully reflected in Company records at the time of filing. As a result, those segments are no longer counted within the remaining MCNM mileage.
- Second, since the filing of my direct testimony, the Company has realigned certain planned wrought iron replacement projects, including the associated capital dollars, from the MCNM program to the Asset Relocation – Civic Improvement (CIVIC) program. This adjustment was made to better coordinate construction activities, align project timing and scopes within the CIVIC program, and improve overall execution efficiency, particularly where work could be bundled with other CIVIC driven system improvements. While these projects continue to address wrought iron risk, they are now executed under the CIVIC program rather than MCNM to ensure consistent program alignment. The capital dollars associated with these realigned projects are reflected in the test year of Case U-21806, and the Company projects spending $1.6 million in the MCNM program in the test year for wrought iron replacement (project DAPP#s 20475 and 30249) in this proceeding.

The remaining wrought iron segments included in the MCNM program have risk scores calculated within the Company's risk model; however, as described in my direct testimony, those scores are not used to determine replacement prioritization due to the model's inability to fully capture the non-weldable characteristics of wrought iron and the associated operational risk.

Based on these characteristics, the Company plans to replace 5.4 miles of wrought iron and intermingled vintage material under the MCNM and CIVIC programs from 2025-2027, with the remaining miles replaced through the EIRP. The 2025-2028 wrought iron project list and risk scores are included in U21981-MEC-CE-0107_Pascarello_Attachment_1.

b. The Company determines whether wrought iron main segments are addressed through the MCNM program or the EIRP based on the nature of the risk presented and whether that risk is adequately captured in the Company's risk model.

Wrought iron mains exhibit unique operational characteristics, including non-weldable material properties, which are not fully reflected in the risk model used to prioritize EIRP projects. As a result, reliance solely on model-driven prioritization would not appropriately elevate these assets for timely replacement. Accordingly, short segments of wrought iron main, typically less than one mile in length as shown in U21981-MEC-CE-0107_Pascarello_Attachment_1, are addressed through the MCNM Program, which is designed to proactively mitigate material-driven operational risk that is not well captured in the model. This approach is also consistent with the Company's decision, as described in my direct testimony, to fully eliminate the remaining wrought iron pipe from the distribution system.

Conversely, when wrought iron or other vintage material is associated with a broader, model-scorable project or can be efficiently bundled with other system improvements, those segments are addressed through EIRP or other aligned capital programs. Third-party and municipal construction activity presents additional risk for wrought iron facilities because older, non-weldable pipe is more susceptible to damage, leaks, or service interruptions during nearby excavation or road work. Accordingly, projects such as DAPP# 30249 and those realigned to the CIVIC program were scheduled to ensure that wrought iron mains are replaced in coordination with municipal construction activities, reducing the likelihood of leaks and service disruptions. Vintage miles replaced under the MCNM Program are removed from the EIRP project scope to avoid duplication. This approach allows the Company to balance modeled and non-modeled work while continuing to advance long-term infrastructure planning and respond effectively to system condition risks.

Witness: KRISTINE A PASCARELLO
Date: March 19, 2026

Question:

146. Refer to lines 9-13 on page 51 of Ms. Pascarello's direct testimony on the Non-Modeled Program. Please:

a. Explain what makes the 5,500 residential meters obsolete, what problems are occurring, and why they need to be replaced.

b. Explain why the cost per unit to replace the meters is $1,200 and provide the basis for this unit cost.

c. Explain why there are 400 incremental leak mitigations and the basis for the unit cost of $5,000.

d. Explain why these two items are discussed under the Renewals program when the $8.6 million is included under the Non-Model Program.

Response:

a. The 5,500 residential meters identified in this program are regulated diaphragm meters ("RM") that are considered obsolete because they are no longer manufactured or available for purchase. Vendors have discontinued this meter design and no longer support it with new meters or replacement parts, as described in the direct testimony of Company witness Warriner and the Natural Gas Delivery Plan (Exhibit A-30 (TMB-1)). Because replacement parts are unavailable, these meters can no longer be effectively repaired or maintained as they fail. As these RM meters age, internal regulator components and diaphragms deteriorate, which can impact pressure regulation, measurement accuracy, and overall reliability. Continued operation increases the risk of service disruptions, measurement issues, and safety concerns. Because like-for-like replacement is no longer possible and failures cannot be addressed incrementally, continued reliance on these meters is not sustainable. These meter replacements are planned and engineered projects that are identified in advance, designed by Distribution Engineering, and scheduled as part of an engineered work plan, rather than being field-initiated work identified during emergency or reactive response and ensure the continued safe and reliable delivery of natural gas service.

b. Replacing an obsolete RM meter also requires rebuilding the meter stand to accept a top connect ("TC") meter. Meter stands designed for RM meters are not compatible with TC meters. As a result, meter replacement involves more than a simple meter swap. Rebuilding the meter stand is necessary to safely install the new meter and ensure proper operation. The $1,200 per-meter cost reflects the total installed cost and includes:

- The purchase of the new meter,
- Labor to remove the existing meter, rebuild the meter stand, and safely install the replacement,
- Associated fittings, pressure testing, and safety checks,
- Travel time, job setup, and site restoration where applicable, and
- Overhead costs required to plan, manage, and complete the work safely and efficiently.

This unit cost is based on recent actuals performing similar meter replacements and reflects average conditions across the service territory.

c. These are known, existing system leaks that have been identified through normal inspection and integrity management activities. While they do not require immediate emergency replacement, addressing them in a planned manner reduces long-term safety and reliability risk. Because these leaks are known, they can be bundled together and planned as part of a coordinated work effort. Distribution Engineering evaluates the locations, designs the work, and schedules the replacements in a coordinated way, which is more efficient and cost-effective than responding to leaks individually on an emergency basis. The $5,000 unit cost reflects the average cost of replacing these types of known leaks and includes engineering evaluation, labor, materials, traffic control where needed, safety procedures, and site restoration. This cost is based on historical experience performing similar planned leak mitigation work across the system.

d. As explained in my direct testimony, both the Renewals program and the Non-Modeled Program include expenditures related to obsolete meter replacements and leak renewals. The determining factor for program placement is whether the work is field-initiated and reactive or Company-initiated, planned, and engineered. Field-identified, emergent replacements are included in the Renewals program, while replacements and mitigations that are planned and designed by Distribution Engineering are included in the Non-Modeled Program. Accordingly, the $8.6 million associated with the meter replacements and incremental leak mitigations discussed here is included in the Non-Modeled Program because this work is planned, engineered, and scheduled as part of an organized work plan rather than triggered by emergent field conditions. At the same time, the Renewals program also includes spending on obsolete meters and leak renewals when those conditions are identified in the field and require immediate action. As shown in Table 10 of my direct testimony, the Renewals program reflects a significantly larger overall level of spending associated with these types of activities. As a result, discussion of obsolete meters and leak renewals is included in the Renewals section of the testimony to avoid repetition and to provide a consolidated discussion of those activities, even though the specific costs addressed in this response are appropriately included in the Non-Modeled Program based on how the work is initiated and executed.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0370
Page **1** of **1**

Question:

148. Refer to Table 8 on page 55 of Ms. Pascarello's direct testimony on the wrought iron replacement miles and spending. Please:

a. Expand this table to include the actual miles and amount spent for each year 2023-2025 and provide it in Excel.

b. Explain why the number of miles and capital spending spike in 2026 to $5 million, which is more than 3 times the spending of $1.5 million in 2025

Response:

a. Please see U21981-AG-CE-0370_Pascarello_Attachment_1 for the updated Table 8 information. In 2023, the Company did not execute a targeted wrought iron replacement project; any activity in that year reflects emergent replacements. The changes in Table 8 reflect wrought iron replacement projects that were advanced and executed in late 2024. This earlier start means the wrought iron work plan will now be completed in 2026. As described in my direct testimony, the Company also plans to replace other intermingled vintage materials encountered as part of the wrought iron projects; the inclusion of approximately 3 additional miles of these materials increases the projected cost of this work from $7.5 million to $10.2 million. The associated increase in projected spending is attributable to the replacement of additional intermingled vintage material mains encountered as part of the wrought iron projects. In addition, the projected test year capital spending increased from approximately $1.0 million to $1.6 million due to coordination with a Michigan Department of Transportation ("MDOT") roadway project, with the incremental spending planned to occur primarily between November and December 2026.

b. The increase in wrought iron replacement miles and associated capital spending to approximately $5 million in 2026 reflects the execution of work that has already been reviewed and approved by the Commission. Considering the low number of installed miles of wrought iron, these facilities continue to experience a disproportionate number of leaks, as shown in Figure 3 in my direct testimony, due to their age, material properties, and operation at medium pressure. Wrought iron mains cannot be permanently welded because of inconsistent material characteristics, leaving replacement as the only prudent long-term solution to address ongoing integrity and safety risks.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0370_Pascarello_Attachment_1

Table 8: Wrought Iron Replacements

Year	Miles Replaced	Location	$
2023	n/a	n/a	n/a
2024	0.85	Hartford, Lawton	$ 909,843
Preliminary 2025	1.72	Hartford, Lawton, Kalamazoo	$ 3,280,537
Projected 2026	3.67	Comstock, Paw Paw, Kalamazoo, Vicksburg, Lawerence, Parchment, Galesburg, Schoolcraft	$ 6,000,133
Test Year	0.71	Schoolcraft	$ 1,638,142

U21981-AG-CE-0383
Page **1** of **1**

Question:

161. Refer to Exhibit A-112, page 1, sponsored by Ms. Pascarello. Please:

a. Expand the exhibit to include actual information for 2023 and 2025 and forecasted information for 2026 and 2027 and provide it in Excel.

b. For the EIRP capital expenditures, provide a schedule in Excel showing the actual annual amount spent on the program in comparison to the amount forecasted for the year along with variance amount for each year from inception of the program to 2025.

c. For the Material Condition Non-Modeled on line 2, provide a schedule in Excel showing the projects and programs included under this category with related capital expenditures and units for each year 2023-2025 actual and forecasted 2026 and 2027.

Response:

Please see U21981-AG-CE-0383_Pascarello_Attachment_1.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0383_Pascarello_Attachment_1

Project Type		**2023**	**2024**	**Preliminary 2025**	**Projected 2026**	**Projected 2027**
Emergent Mains	Units	99	128	141	55	125
	$$	$ 20,772,962.10	$ 17,113,561.03	$ 26,522,025.18	$ 8,705,400.24	$ 24,394,660.31
Emergent Services	Units	2197	3464	2687	858	2500
	$$	$ 10,313,620.00	$ 12,532,271.00	$ 15,186,291.41	$ 4,287,734.45	$ 12,015,280.45
Line 1010	Units	2	1	1	2	0
	$$	$ 460,901.00	$ 5,799,491.00	$ 560,776.95	$ 19,600,000.00	$ -
Standard Pressure	Units	72	0	231	0	0
	$$	$ 4,447,328.27	$ -	$ 4,061,628.64	$ -	$ -
Wrought Iron	Units	0	34	95	215	0
	$$	$ -	$ 615,930.13	$ 2,187,937.21	$ 8,842,317.43	$ -
HP Waterway	Units	0	0	0	7	0
	$$	$ -	$ -	$ -	$ 4,983,570.69	$ -
Obsolete Meter	Units	0	0	0	5500	5500
	$$	$ -	$ -	$ -	$ 3,700,000.00	$ 6,600,000.00
Leaks	Units	0	517	43	800	400
	$$	$ -	$ 3,049,406.00	$ 451,510.43	$ 4,000,000.00	$ 2,000,000.00
Line 1099	Units	1	1	0	0	0
	$$	$ 2,521,087.00	$ 332,734.00	$ -	$ -	$ -
Total Expenditures		$ 38,515,898	$ 39,443,393	$ 48,970,170	$ 54,119,023	$ 45,009,941

U21981-AG-CE-0337
Page **1** of **1**

Question:

117. Refer to Table 25 on page 43 of Mr. Pnacek's direct testimony on the number of gas leaks found above and below grade. Please:
a. Expand this table to include 2025's actual information and provide it in Excel.
b. Provide a schedule in Excel showing the number of found leaks by grade 1-3 for each year 2023 to 2025 and the definition of each grade.
c. Explain what is causing the large number of above-grade gas leaks and what the Company is doing to proactively preventing those leaks. Would efforts to prevent gas leaks not be more productive than spending more money on surveying for gas leaks more frequently?

Response:

a) Please see attachment U21981-AG-CE-0337_Pnacek_ATT_1.xlsx
b) Please see attachment U21981-AG-CE-0337_Pnacek_ATT_1.xlsx. Grade definitions are on page 44, line 14 to 18 of my direct testimony.
c) The Company's above-grade gas leaks are primarily driven by the age of infrastructure, long-term exposure of above-grade components to weather, corrosion, and normal wear on meter sets, valves, lock wings, nipples and fittings. While the Company looks for preventive programs to address these issues, prevention alone cannot eliminate the formation of leaks. Above-grade equipment is continuously exposed to environmental conditions that can cause leaks to develop unpredictably between maintenance cycles. For this reason, more frequent leak surveying is an important and effective tool for managing above-grade leaks. Surveys serve a different purpose than preventive maintenance: they identify leaks that have already formed but would otherwise remain undetected for longer periods. Because above-grade leaks can develop at any time due to sudden material degradation, temperature swings, or mechanical stress, relying solely on preventive measures does not provide the same level of assurance as a more frequent detection cycle.

Witness: JAMES P PNACEK
Date: April 2, 2026

Table 25 p43 U21981-AG-CE-0337_Pnacek_AT

Year (Jan-Dec)	Above Grade	Below Grade	Total
2017	5,220	1,555	6,775
2018	7,931	1,715	9,646
2019	18,393	2,697	21,090
2020	9,842	1,589	11,431
2021	12,009	1,577	13,586
2022	9,714	1,516	11,230
2023	9,151	343	9,494
2024	19,308	846	20,154
2025 Preliminary	15,752	619	16,371
2025 Projected	15,552	635	16,187

U21981-AG-CE-0337_Pnacek_ATT_1

	Hazardous	Non-hazardous	
	Grade 1	Grade 2	Grade 3
	Immediate	Scheduled	Deferred
2021	5,492	5,904	9,139
2022	5,148	4,278	6,952
2023	8,579	1,362	3,884
2024	6,596	1,624	3,808
2025	6,907	5,631	14,596

U21981-AG-CE-0373
Page **1** of **1**

Question:

151. Refer to Table 10 on page 62 of Ms. Pascarello's direct testimony on the Material Condition Renewals. Please expand the table to include 2023 and 2025 actual information and forecasted information for 2026 and 2027, along with the related units for each year 2023 to 2026 and provide it in Excel.

Response:

Please see U21981-AG-CE-0373_Pascarello_Attachment_1.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0373_Pascarello_Attachment_1

Table 10: Material Condition Renewals Expenditures

($000)	Historical Year 12 Mos Ended 12/31/2023		Historical Year 12 Mons Ending 12/31/2024		Projected Year 12 Mons Ending 12/31/2025		Preliminary Actual Year 12 Mons Ending 12/31/2025		Projected Year 12 Mons Ending 12/31/2026		Projected Year 12 Mons Ending 12/31/2027		Projected 10 Mos Ending 10/31/2026		Projected Test Year 12 Mos Ending 10/31/2027	
	$	Units	$	Units	$	Units	$	Units	$	Units	$	Units	$	Units	$	Units
Leak Renew Main	$ 7,157	62	$ 2,387	72	$ 3,435	70	$ 3,398	69	$ 4,551	89	$ 4,740	89	$ 4,384	86	$ 4,733	89
Leak Renew Service	$ 13,866	1,512	$ 17,642	2,219	$ 15,482	2,485	$ 16,557	1,726	$ 17,286	2,485	$ 30,012	5,849	$16,387	2,356	$29,904	5,828
Leak Renew Mtr/Stand	$ 1,745	1,325	$ 1,628	1,180	$ 1,985	1,396	$ 3,327	1,845	$ 1,399	1,727	$ 1,465	1,727	$ 1,222	1,508	$ 1,453	1,727
Damages	$ 9,047	14,261	$ 16,980	22,287	$ 20,786	16,000	$ 27,056	22,284	$ 17,618	16,633	$ 30,411	15,980	$15,415	13,124	$30,241	25,000
Total	**$ 31,816**	17,160	**$ 38,636**	25,758	**$ 41,688**	19,951	**$ 50,338**	25,924	**$ 40,854**	20,934	**$ 66,628**	23,645	**$37,408**	17,074	**$66,330**	32,644

U21981-AG-CE-0375
Page **1** of **1**

Question:

153. Refer to lines 19-23 on page 63 of Ms. Pascarello's direct testimony on the number of capitalized renewals from gas leak surveys. Please provide the number of such renewals completed and capitalized each year 2023-2025 and forecasted for 2026 and 2027.

Response:

Capital Leaks from Survey				
2023	**2024**	**2025**	**2026 Projected**	**2027 Projected**
2,671	2,274	1,900	2,795	8,182

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0378
Page **1** of **1**

Question:

156. Refer to lines 10-23 on page 68 of Ms. Pascarello's direct testimony on the total removal of vintage services by 2035. Please provide a copy of any engineering studies conducted by the Company that concluded all vintage services needed to be replaced by 2035 because of increasing deterioration of the pipe.

Response:

The Company has not conducted a specific engineering study concluding that all vintage services must be replaced by 2035 solely due to increasing deterioration of pipe. The Vintage Service Replacement ("VSR") Program was originally established in Case No. U-18124 and, at that time, was projected to be completed over approximately ten years. In Case No. U-18424, Michigan Public Service Commission Staff suggested that the Company align the timeline of the VSR Program with the Enhanced Infrastructure Replacement Program ("EIRP"), which informed subsequent long-term planning horizons.

The 2035 timeframe reflected in Company planning and testimony represents the continued execution of a long-standing, infrastructure replacement strategy for the elimination of vintage mains and services.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0379
Page **1** of **1**

Question:

157. Refer to Table 11 on page 69 of Ms. Pascarello's direct testimony on the replacement of vintage services. Please:

a. Update this table with actual 2025 information and provide it in Excel.

b. Explain why the unit cost for 2027 and the projected test year increase by approximately $1,400 over 2025.

Response:

a. Please see U21981-AG-CE-0379_Pascarello_Attachemnt_1.

b. The increase in unit cost in the projected test year relative to 2025 is driven by several factors related to the evolving scope, complexity, and execution conditions of the Vintage Service Replacement ("VSR") program. As discussed in my direct testimony beginning on page 68, line 17, the projected 2027 work reflects a more complex mix of service replacements, including a higher proportion of commercial and institutional services, which generally require larger diameter piping, specialized fittings, and more complex installation methods.

In addition, the program is increasingly addressing difficult "barrier" service replacements. These include services with significant physical constraints, such as parking areas built over/along roadways, and locations where customers have installed backfill, retaining walls, or other structures directly over service tees and mains. These conditions require additional excavation, shoring, coordination, and restoration activities, materially increasing unit costs.

Unit costs are also impacted by evolving permitting requirements imposed by local and state agencies. In some cases, permitting authorities require replacement of hard surfaces well beyond the actual pavement area disturbed to complete the work, resulting in increased restoration scope and expense that is not directly tied to the size of the service replacement.

Finally, certain projects require removal of mature trees that are located directly over service tees within the public right-of-way. Tree removal and associated restoration activities add incremental cost and construction complexity that were less prevalent in earlier years of the program.

Collectively, these factors, changes in customer mix, increased prevalence of constrained and barrier services, expanded permitting requirements, and additional restoration activities, drive the approximately $1,400 increase in projected unit costs in the test year relative to 2025.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0379_Pascarello_Attachment_1

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Projected 2025	Preliminary Actual 2025	Projected 2026	Projected 2027	Projected 12 Mos Ending 10/31/2027
VSR Program Units	6,307	9,381	5,571	5,456	5,056	2,176	1,228	2,569	4,194	4,392	5,913	7,683	7,683
VSR Unit Cost	$5,322	$6,037	$7,260	$7,848	$6,518	$7,888	$9,246	$7,533	$7,180	$7,342	$7,389	$8,559	$8,559
VSR Program Spend ($000)	$33,564	$56,634	$40,443	$42,818	$32,955	$17,165	$11,354	$19,352	$30,113	$32,244	$43,689	$65,761	$65,761
EIRP/Other Programs	5,169	4,042	4,064	4,291	5,245	8,235	3,576	3,803	3,172	3,227	3,134	2,617	2,198
Total Services Replaced	11,476	13,423	9,635	9,747	10,301	10,411	4,804	6,372	7,366	7,619	9,047	10,300	9,881
Total Services Remaining	170,478	157,055	147,420	137,673	127,372	116,961	112,157	105,785	98,419	98,166	89,372	79,072	79,491
										Adjusted remaining	89,119	78,819	79,238

U21981-AG-CE-0380
Page **1** of **1**

Question:

158. Refer to lines 25-34 on page 70 and lines 1-8 on page 71 of Ms. Pascarello's direct testimony on the incremental spending of $3.6 million on new technology and specialized tools. Please explain why this spending is necessary and identify what cost savings or financial benefits it will generate.

Response:

The additional $3.6 million in spending on new technology and specialized tools is necessary to replace outdated equipment, improve operational efficiency, and support the Company's safety, reliability, and affordability commitments.

Approximately $1 million of this investment is to replace existing Electron Fusion ("EF") boxes that are no longer supported by the vendor. Because the vendor no longer provides support, the Company is experiencing increasing repair and maintenance costs. Replacing this equipment reduces ongoing operations and maintenance expenses, minimizes service disruptions, and avoids greater long-term costs associated with keeping obsolete technology in service.

The investment also includes GPS-enabled antennas that integrate directly with the Company's geographic information system ("GIS"). This technology improves the accuracy of system records and ensures field crews perform work according to approved plans. More accurate data and real-time visibility help reduce rework, shorten job durations, and improve workforce productivity. While the Company continues to quantify the full financial impacts, these improvements are expected to drive operational efficiencies that help control costs over time.

In addition, funding is included for enhanced methane detection tools that help crews pinpoint leaks faster and more accurately. These tools reduce the need for time-consuming manual methods, such as repeated pin barring, and allow crews to quickly narrow in on the source of potential leaks. By improving the speed and precision of leak identification, the Company can repair issues sooner, improve safety, reduce gas loss, and use field resources more efficiently. This investment includes handheld devices with updated programming and tighter detection limits, and potentially other similar emerging technologies that provide comparable functionality. These tools are focused on day-to-day operational efficiency and field performance.

Overall, these investments are not discretionary enhancements, but targeted replacements and upgrades that modernize essential tools, reduce maintenance and inefficiencies, improve safety and regulatory compliance, and help manage long-term costs.

Witness: KRISTINE A PASCARELLO
Date: April 7, 2026

U21981-AG-CE-0293
Page **1** of **1**

Question:

73. Refer to Exhibit A-12, Schedule B-5.8, page 1, sponsored by Mr. Warriner. Please expand this schedule to include actual amounts for lines 1-5 for each year 2022-2025 and provide it in Excel.

Response:

Please see the Excel attachment named U21981-AG-CE-0293-Attachment_1.xlsx.

Witness: LINCOLN D WARRINER
Date: March 26, 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CECo Response to AG-CE-0293

Case No: U-21981
Exhibit: AG-19
April 15, 2026

($000)

Witness: LDWarriner
Date: December 2025

	(a)			(b)		(c)	(d)	(e)	(f)
		Historical Year	Historical Year	Historical Year	Preliminary Historical Year	Projected Bridge Period			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	12 Mos Ending 12/31/2025	10 Mos Ending 10/31/2026	22 Mos Ending 10/31/2026	12 Mos Ending 10/31/2027
1	New Business	74,088	76,320	60,032	68,071	54,024	49,236	103,260	52,270
2	Asset Relocation	116,504	97,685	72,512	67,530	81,311	75,538	156,849	91,260
3	Regulatory Compliance	22,832	34,488	47,750	110,596	109,785	159,533	269,317	144,012
4	Capacity/Deliverability	10,196	4,446	7,031	828	6,466	4,866	11,332	14,347
5	Total Distribution Capital	223,619	212,938	187,325	247,025	251,586	289,173	540,758	301,890

				Projected				
				10 Mos Ending 10/31/2025		12 Mos Ending 10/31/2026	12 Mos Ending 10/31/2027	34 Mos Ending 10/31/2027
6	New Business			44,555		58,705	52,270	155,530
7	Asset Relocation			68,207		88,642	91,260	248,109
8	Regulatory Compliance			97,431		171,887	144,012	413,329
9	Capacity/Deliverability			4,284		7,048	14,347	25,679
10	Total Distribution Capital			214,476		326,282	301,890	842,648

U21981-AG-CE-0295
Page **1** of **1**

Question:

75. Refer to lines 17-21 on page 6 of Mr. Griffin's direct testimony on the depth of transmission pipelines. Please provide the depth of cover required by state and federal regulations.

Response:

49 CFR 192.327(a) requires each buried transmission line be installed with a minimum depth of cover of 30" for normal soil in class 1 locations, 36" for normal soil conditions in class 2, 3, and 4 locations or drainage ditches of public roads and railroad crossings. 49 CFR 192.327(a) further details lesser requirements of cover for installations within consolidated rock for each class location. 49 CFR 192.327(e) requires a depth of 48" for pipe installed in navigable river, stream or harbor. The Michigan Gas Safety Standards fully align with the federal requirements of 49 CFR 192.327.

Witness: JORDAN L. WAGGENER
Date: March 25, 2026

U21981-AG-CE-0296
Page **1** of **2**

Question:

76. Refer to lines 20-23 on page 8 of Mr. Griffin's direct testimony on the depth of transmission pipelines of 3.0 to 4.5 feet. Please:

a. State which depth the Company uses, under which conditions, why, and the predominant depth used now and in the past.

b. Identify at what level of loss of cover the Company determines that the section of pipeline needs to be replaced or reburied and explain why.

c. Does the Company in all cases replace the segment of pipeline that does not conform to the required depth of cover, or does it use other methods to re-establish the required depth? Provide a list of projects in the last three years where the Company has used other methods than replacement, describe those methods and the cost of those methods per mile versus the replacement cost.

d. Provide a list of projects in the last three years, where the Company chose to replace the dirt cover on the pipeline without replacing the pipeline segment.

e. For the depth of cover replacement projects completed in the past three years, has the Company determined what the condition of the replaced pipe was and whether that pipe could have lasted for several more years if the depth of cover was not an issue and had not been replaced? Provide a report of your findings, including any testing of the pipe condition and laboratory analysis.

Response:

a. New Transmission pipelines are installed at depths no less than 3 feet by the Company, regardless of class location. In certain instances, pipelines may be installed at depths beyond 3 feet for additional protection (navigable waterways, rivers, farm fields, road-crossings, etc.). Prior to the requirements of 49 CFR Part 192, transmission facilities may have been installed at depths less than today's practice – but generally no less than 30 inches, which is commensurate with today's class 1 location requirements per 192.327(a) for normal soil.

b. Though established code requiring specified depths at the time of pipeline installation, 49 CFR Part 192 is used as the general benchmark triggering further assessment and risk evaluation when identifying shallow pipeline segments. Identified segments are prioritized for long-term remediation as segments having less cover are subject to higher risk of third-party contact and/or damage.

c. The Company does not always replace segments of pipeline that do not conform to the required depth of cover. In certain instances, the Company evaluates the project conditions to determine if alternative options, such as adding fill to re-establish cover or concrete bridging for increased protection, are acceptable and will be successful long-term. However, these options are not always feasible, especially in tillable farm fields where equipment activity and the inability to stabilize fill with vegetation can lead to soil erosion and eventual cover degradation. Additionally, fill or concrete bridging will not be added in shallow pipeline locations with compressible soils to avoid introducing undue external loading stresses upon the pipeline.

Project GL-03397 in 2023 added approximately 53 liner feet of concrete bridging over a section of the existing 36” Line 100B and approximately 53 liner feet of concrete bridging over a section of the existing 22” line 100A. This project was completed in conjunction with a road project to reduce costs and meet schedule requirements. The cost of this project was $58,930.05 which would equate to $2,935,383.62 on a cost per mile basis. Bridging was determined to be adequate during the scoping of this project therefore no costs for replacement were evaluated for comparison.

d. There were no projects completed where fill was added in-lieu of replacing the pipeline during this period for reasons outlined in subpart c of this response.

e. Line lowerings are to remediate depth of cover concerns, not integrity issues, therefore analysis is irrelevant. Regular in-line inspection methods are coordinated by System Integrity to assess pipeline integrity and address identified anomalies accordingly.

Witness: Jordan L Waggener
Date: April 1, 2026

U21981-AG-CE-0306
Page **1** of **3**

Question:

86. Refer to WP-MPG-1 on Asset Relocations. For each of the following projects: BGL-00091, GL-00988, GL-00990, GL-00991, GL-02086, GL-03498, GL-03470, and B-GL-00617, please:

a. Provide the current depth of cover that needs to be remedied and explain when it reached the current level of depth.

b. Explain what caused the shallow depth and over what timeframe.

c. Explain what vehicular traffic or activity occurs near the targeted segment of the pipeline to present a potential risk for damage or rupture.

d. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Response:

a. The current depth of cover that needs remediated and when first discovered, for each identified project as follows:

- **B-GL-00091 STC 600 22" Lowering/Relocation – Console St.:** 15" of cover within an HCA area., February 13, 2024
- **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** 6" of cover within Wetland BR017, July 2014
- **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng:** 18" of cover within Wetland BR014 and agricultural farmland., July 2014
- **GL-00991 KZO 1200A Townline Rd Ln Lwrng:** 10" of cover within a drain and agricultural farmland., July 2014
- **GL-02086 KZO 1200A Needham Rd Ln Lwrng:** 21" of cover within agricultural farmland., July 2014
- **GL-03498** is not identified in WP-MPG-1.
- **GL-03470 STC Line 600 22" Lowering South of Judah Rd East of Baldwin Rd.:** 16" of cover within an HCA area., May 8, 2024
- **B-GL-00617 STC 2070 Butler Rd Galloway Crk Ln Lwrng:** Exposed line in Galloway Creek., June 2, 2025

b. The following explains the anticipated cause of cover degradation for each identified project. Exact timeframes remain unknown as effects such as soil erosion associated with stormwater runoff may be gradual or rapidly occurring.

- **B-GL-00091 STC 600 22" Lowering/Relocation – Console St.:** gradual residential developments in area since original pipeline installation.
- **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** gradual soil erosion associated with stormwater runoff, seasonal wetland water level fluctuation.

- **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng:** gradual soil erosion associated with stormwater runoff, seasonal wetland water level fluctuation and annual agricultural activity within the area.
- **GL-00991 KZO 1200A Townline Rd Ln Lwrng:** gradual soil erosion associated with stormwater runoff and annual agricultural activity within the area.
- **GL-02086 KZO 1200A Needham Rd Ln Lwrng:** gradual soil erosion associated with stormwater runoff and annual agricultural activity within the area.
- **GL-03498** is not identified in WP-MPG-1.
- **GL-03470 STC Line 600 22" Lowering South of Judah Rd East of Baldwin Rd.:** gradual soil erosion associated with stormwater runoff and annual agricultural activity within the area.
- **B-GL-00617 STC 2070 Butler Rd Galloway Crk Ln Lwrng:** gradual scouring since time of installation within the creek crossing; attributed to changing creek bottom dynamics associated with seasonal water velocities and flow characteristics.

c. Explain what vehicular traffic or activity occurs near the targeted segment of the pipeline to present a potential risk for damage or rupture.

- **B-GL-00091 STC 600 22" Lowering/Relocation – Console St.:** Daily commuters and delivery vehicles through the residential subdivision.
- **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** Right-of-way clearing and maintenance equipment.
- **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng:** Right-of-way clearing, maintenance and agriculture equipment.
- **GL-00991 KZO 1200A Townline Rd Ln Lwrng:** Agriculture equipment.
- **GL-02086 KZO 1200A Needham Rd Ln Lwrng:** Agriculture equipment.
- **GL-03498** is not identified in WP-MPG-1.
- **GL-03470 STC Line 600 22" Lowering South of Judah Rd East of Baldwin Rd.:** Agriculture equipment.
- **B-GL-00617 STC 2070 Butler Rd Galloway Crk Ln Lwrng:** There is a bike path and road near the exposed area.

d. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

- **B-GL-00091 STC 600 22" Lowering/Relocation – Console St.**: Currently in Conceptual Design awaiting survey information, Engineering and design is scheduled to start in the third quarter of 2026.
- **GL-00988 KZO 1200A Wetland BR017 Ln Lwrng:** Engineering and design complete, material purchased and currently awaiting contractor bids. Construction is scheduled to start on 4 May 2026.
- **GL-00990 KZO 1200A Wetland BR014 Ln Lwrng**: Detailed engineering and design nearing completion, material purchased and currently awaiting contractor bids. Construction is scheduled to start on 4 May 2026.

- **GL-00991 KZO 1200A Townline Rd Ln Lwrng**: Engineering and design complete, material purchased and currently awaiting contractor bids. Construction is scheduled to start on 4 May 2026.
- **GL-02086 KZO 1200A Needham Rd Ln Lwrng:** Engineering and design complete, material purchased and currently awaiting contractor bids. Construction is scheduled to start on 4 May 2026.
- **GL-03498** is not identified in WP-MPG-1.
- **GL-03470 STC Line 600 22” Lowering South of Judah Rd East of Baldwin Rd.:** Currently in Conceptual Design awaiting survey information, Engineering and design is scheduled to start in the third quarter of 2026.
- **B-GL-00617 STC 2070 Butler Rd Galloway Crk Ln Lwrng:** Currently in Conceptual Design awaiting survey information, Engineering and design is scheduled to start in the third quarter of 2026.

Witness: Jordan L Waggener
Date: April 1, 2026

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-21981
Consumers Energy Company WP-MPG-1
Asset Relocation Transmission Capital Projects Page 1 of 2

Project ID	Project Description	Project Summary & Reason	Location	Qty. & Size Pipe Removed	Qty. & Size Pipe Installed	2024 Actual	2025 YE Forecast	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Start Date	Completion Date	Internal Approval? Y/N
GL-00982	KZO-1200A Wetland BR038 Ln Lwrng	Replace and lower approximately 1200 feet of 26" piping at wetland BRO38 along Line 1200A as a measure to protect it from possible contact and damage as result of its shallow depth and comply with 49 CFR 192.327(a).	Hodunk, MI	759 ft. of 26" pipe	1193 ft. of 26" pipe	(106,954)	-					7/12/2021	9/1/2021	Y
B-GL-00091	STC - Line 600 22" Lowering/Relocation - Console S	Replace and lower approximately 1100 feet of 22" pipeline along Console St. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Independence Charter Twp, MI	1100 ft. of 22" pipe	1100 ft. of 22" pipe	-	44,924	44,560	2,662,988	41,589	2,488,441	4/1/2027	11/1/2027	Y
GL-00979	SAG-L700 Ln Lwrg Co Drain-165	Replace and lower approximately 250 feet of 26" pipeline in County Drain 165 south of E. Jefferson Road, east of Mason Road. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Wheeler, MI	250 ft. of 26" pipe	250 ft. of 26" pipe			-	44,980	-	41,981	4/1/2029	11/1/2029	Y
GL-00983	KZO-1200A Wetland BR032 Ln Lwrng	Replace and lower approximately 1300 feet of 26" pipeline in wetlands near Mauer Road on Line 1200A. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Union, MI	1300 ft. of 26" pipe	1300 ft. of 26" pipe	2,799	1,410			-	-	4/1/2031	11/1/2031	Y
GL-00988	KZO-1200A Wetland BR017 Ln Lwrng	Replace and lower approximately 1200 feet of 26" pipeline in wetland near M-86 and Farrand Road on Line 1200A. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Matteson Township, MI	1,200 ft. of 26" pipe	1,200 ft. of 26" pipe	24,759	29,278	7,416,426	152,932	6,922,041	637,122	4/1/2026	11/1/2026	Y
GL-00990	KZO-1200A Wetland BR014 Ln Lwrng	Replace and lower approximately 350 feet of 26" pipeline in wetland between Comm Road and M-86 on Line 1200A. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Matteson Township, MI	350 ft. of 26" pipe	350 ft. of 26" pipe	(34)	40,270	3,209,329	152,932	2,995,393	356,674	4/1/2026	11/1/2026	Y
GL-00991	KZO-1200A Townline Rd Ln Lwrng	Replace and lower approximately 2,800 feet of 26" pipeline in private drain located south of Townline Road. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Burr Oak Township, MI	2,800 ft. of 26" pipe	2,800 ft. of 26" pipe	13,692	42,855	10,449,424	152,932	9,752,856	839,305	4/1/2026	11/1/2026	Y
GL-02037	KZO-1800 Weick Drain Line Lwrng	Replace and lower approximately 300 feet of 20" pipeline at Weick Drain located west of 26th Street. Reduce risk of potential contact and damage as result of its shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Allegan, MI	300 ft. of 20" pipe	300 ft. of 20" pipe			-	44,980	-	41,981	4/1/2029	11/1/2029	Y
GL-02085	KZO-1200A Crooked Creek Rd Line Lwrng	Final settlement costs: Replace and lower approximately 500 feet of 26" piping at Cooked Creek, along Line 1200A, as a measure to protect it from possible contact and damage as result of its shallow depth. And also to comply with 49 CFR 192.327(a).	White Pigeon, MI	503 ft. of 26" pipe	507 ft. of 26" pipe	106,934	-			-	-	7/12/2021	9/1/2021	Y
GL-02086	KZO-1200A Needham Rd Line Lwrng	Replace and lower approximately 300 feet of 26" pipeline in cultivated area approximately 600' east of Needham Road. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Burr Oak Township, MI	300 ft. of 26" pipe	300 ft. of 26" pipe	5,687	54,369	1,836,207	152,932	1,713,804	265,140	4/1/2026	11/1/2026	Y
GL-02087	KZO-1300 E Ave Line Lwrng	Replace and lower approximately 300 feet of 12" pipeline south of East E Avenue along Line 1300. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Kalamazoo, MI	300 ft. of 12" pipe	300 ft. of 12" pipe	-	44,924			-	-	4/1/2036	11/1/2036	Y
GL-03021	SAG-100B Sleepy Hollow Re-route	Re-route of Line 100B through the Sleepy Hollow State Park area would potentially eliminate the HCA and reduce the risk to the public through the park/beach area. Installing the 26" pipe during the Line 100A replacement, through the proposed re-route would minimize the disturbance to the park area, while taking advantage of utilizing the contractor that will already be on site to install the new 36" 100A pipe. Additional benefits will be gained by utilizing the consultant designer who is performing the design for the new/replacement 100A pipe as well.	Laingsburg, MI	3,000 ft. of 26" pipe	3,000 ft. of 26" pipe	12,604,969	45,785			-	-	10/2/2024	10/17/2024	Y
GL-03072	KZO-1300 S.116 Ave/E.19th St Ln Lwrng	Replace and lower approximately 300 feet of 12" pipeline near 116th Ave and 19th St. on Line 1300. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Watson Twp, MI	300 ft. of 12" pipe	300 ft. of 12" pipe	2,071	-			-	-	4/1/2030	11/1/2030	Y
GL-03173	NVL-1600 Taft Rd Ln Lwrng	Replace and lower approximately 915 feet of 16" pipeline along Taft Road in Novi on Line 1600. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR 192.327(a) and company requirements.	Novi, MI	915 ft. of 16" pipe	915 ft. of 16" pipe	10,659	-			-	-	5/15/2023	6/14/2023	Y
GL-03195	SAG-300 Parker Drn Lwr	Replace and lower approximately 100 feet of 12" pipeline in Parker Swamp Drain on Line 300. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR 192.327(a) and company requirements.	Tittabawassee Township, MI	100 ft. of 12" pipe	100 ft. of 12" pipe	1,470,875	45,736			-	-	8/5/2024	9/30/2024	Y

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-21981
Consumers Energy Company WP-MPG-1
Asset Relocation Transmission Capital Projects Page 2 of 2

Project ID	Project Description	Project Summary & Reason	Location	Qty. & Size Pipe Removed	Qty. & Size Pipe Installed	2024 Actual	2025 YE Forecast	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Start Date	Completion Date	Internal Approval? Y/N
GL-03326	SAG-100A Chippewa River Line Lwrng	Replace and lower approximately 1200 feet of 22" pipeline in the Chippewa River on Line 100A. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Mt. Pleasant, MI	1,200 ft. of 22" pipe	1,200 ft. of 22" pipe	456,655	2,633,302	277,961	-	259,432	18,529	4/1/2025	11/1/2025	Y
GL-03327	SAG-100C Chippewa River Line Lwrn	Replace and lower approximately 1400 feet of 16" pipeline in the Chippewa River on Line 100C. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Mt. Pleasant, MI	1,400 ft. of 16" pipe	1,400 ft. of 16" pipe	254,347	2,904,644	151,502	-	141,403	10,099	4/1/2025	11/1/2025	Y
GL-03342	KZO-1800 Al Sabo 20" Ln Lwr	Replace and lower via horizontal directional drill approximately 1700 feet of 20" pipeline and address continued washout potential previously addressed by O&M temporary repairs on Line 1800. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Kalamazoo, MI	1700 ft. of 20" pipe	1700 ft. of 20" pipe			44,560	31,486	41,589	32,357	4/1/2028	11/1/2028	Y
GL-03348	SAG-100B Chippewa River Ln Lwrng	Replace and lower approximately 1100 feet of 26" pipeline in the Chippewa River on Line 100B. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Mt. Pleasant, MI	1,100 ft. of 26" pip	1,100 ft. of 26" pip	652,051	3,013,819	151,502	-	141,403	10,099	4/1/2025	11/1/2025	Y
GL-03351	OVS-LN 1300 114th Ave Ln Lwrng	Replace and lower approximately 750 feet of 12" pipeline near 114th Ave on Line 1300. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Watson, MI	750 ft. of 12" pipe	750 ft. of 12" pipe	1,197,117	47,987			-	-	9/3/2024	10/21/2024	Y
GL-03353	OVS-1100 Rabbit River Ln Lwrng	Replace and lower approximately 1920 feet of 24" pipeline crossing the Rabbit River on Line 1100. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Overisel Township, MI	1,920 ft. of 24" pipe	1,920 ft. of 24" pipe	92,968	5,442,246	151,502	-	141,403	10,099	4/1/2025	11/1/2025	Y
GL-03460	NVL-1600 Amberlund Ct Ln Lwrng	Project cancelled in 2024 with capital dollars written over to O&M				(627)				-	-	n/a	n/a	Y
GL-03468	STC-600 Stevens Rd 22” Ln Lwr	Replace and lower approximately 100 feet of 22" pipeline at Stevens Rd along Line 600. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Clarkston, MI	100 ft. of 22" pipe	100 ft. of 22" pipe	-	44,924	44,560	1,980,483	41,589	1,851,433	4/1/2027	11/1/2027	Y
GL-03469	OVS - Line 1800 20" Lowering - 124th Ave Line Lwr	Replace and lower approximately 100 feet of 20" pipeline at 124th Ave along Line 1800. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Hopkins, MI	100 ft. of 20" pipe	100 ft. of 20" pipe			-	44,980	-	41,981	4/1/2029	11/1/2029	Y
GL-03470	STC-600 Judah Rd 22” Ln Lwr	Replace and lower approximately 300 feet of 22" pipeline near Judd and Baldwin Roads along Line 600. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Lake Orion, MI	300 ft. of 22" pipe	300 ft. of 22" pipe	-	44,924	44,560	1,211,464	41,589	1,133,677	4/1/2027	11/1/2027	Y
GL-03583	STC-Line 1700 Clinton River Line Lowerin	Replace and lower approximately 1700 feet of 26" pipeline crossing the Clinton River on Line 1700. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Sterling Heights, MI	1700 ft. of 26" pipe	1700 ft. of 26" pipe	230,714	10,385,316	2,461,368	-	2,297,291	164,077	4/1/2025	11/1/2026	Y
B-GL-00049	JXN-Line 400-24" Lowering-Mabley Hill Rd	Replace and lower approximately 100 feet of 24" pipeline at the gravel road crossing at Mabley Hill Rd on Line 400. Reduce risk of potential contact and damage as result of shallow depth, comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Fenton, MI	100 ft. of 24" pipe	100 ft. of 24" pipe			44,560	31,486	41,589	32,357	4/1/2033	11/1/2033	Y
B-GL-00092	STC - Line 1900 26" Lowering - near Mountain Esta	Replace and lower approximately 100 feet of 26" pipeline near Mountain Estates Ct. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Leonard, MI	100 ft. of 26" pipe	100 ft. of 26" pipe			-	31,486	-	29,387	4/1/2028	11/1/2028	Y
B-GL-00498	STC 1900 26" North Ave Line Lwng	Replace and lower approximately 350 feet of 26" pipeline near intersection of Lines 1700 and 1900. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Armada, MI	300 ft. of 26" pipe	300 ft. of 26" pipe			44,560	31,486	41,589	32,357	4/1/2028	11/1/2028	Y
B-GL-00617	STC 2070 Butler Rd Galloway Crk Ln Lwrng	Replace and lower approximately 100 feet of 36" pipeline on Line 2070. Reduce risk of potential contact and damage as result of shallow depth; comply with 49 CFR Parts 192.317, 192.327(a) and company requirements.	Rochester Hills, MI	100 ft. of 36" pipe	100 ft. of 36" pipe			44,560	1,767,521	41,589	1,652,667	4/1/2027	11/1/2027	Y
						17,018,681	**24,866,713**	**26,417,138**	**8,495,065**	**24,656,150**	**9,689,766**			

Business cases have not been conducted on these projects as they are required due to civic improvement activities, due to depth of cover issues or to eliminate conflicts with other utilities. GL-03021 received a Certificate of Necessity to Operate and Construct in MPSC Case No. U-21179

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program
Pipeline Integrity - Transmission Capital and O&M Projects - 2026

Case No. U-21981
WP-MPG-14
Page 1 of 3

Work Tag	Work Item	Assessment Classification	Capital Expenditure	Inspection Tool
Construction - Integrity	1060-1 Launchers / Receivers - Installation / Enhancements 1060-1		$ 386,653	
Construction - Integrity	1500-2 Launchers / Receivers - Installation / Enhancements 1500-2		$ 386,653	
Construction - Integrity	300-4 Pipe segment replacement 300-4		$ 1,686,653	
Inspect and Remediate	100A-22-1A Ovid VS-E. M21 Hwy to Mt. Pleasant VS-M20 Hwy	HCA	$ 786,653	
Inspect and Remediate	2800-4 Thetford VS to Bridgeport CG	HCA	$ 386,653	
Inspect and Remediate	600-3 Squirrel Rd VS to Rochester VS-Sheldon Rd	HCA	$ 386,653	
Inspect and Remediate	700-1 St. Louis VS-Begole Rd to Saginaw CG & Jct.-Dutch Rd	HCA	$ 386,653	
Inspect and Remediate	700-2 St. Louis VS-Begole Rd to Saginaw CG & Jct.-Dutch Rd	HCA	$ 386,653	
Inspect and Remediate	C-ML-20in TRS 200602- Stevenson Rd 1200' North of Keehn Rd to Muskegon Riv	192.710	$ 386,653	
Inspect and Remediate	Dx1027b_10-2 Dewitt CG-Turner Rd to Lansing CG-Dewitt Rd	192.710	$ 386,653	
Remediation Only	1200A-4 Chelsea VS-M52 Hwy to Northville CS	HCA	$ 386,653	
Trans DA	4010-2 Northville Reef Meter Run Site to 8 Mile Rd VS	Risk Mitigation	$ 361,653	Direct Assessment
Trans DA	Flint CG-Branch Rd Flint City Gate at Branch Road	Risk Mitigation	$ 361,653	Direct Assessment
Trans DA	Macomb JCT Macomb Junction and Interchange	HCA	$ 361,653	Direct Assessment
Trans DA	Muskegon River CS - PLT2 Muskegon River Compressor Station - Plant 2	192.710 Outside of HCA	$ 536,653	Direct Assessment
Trans DA	Newburg CG Newburg City Gate	HCA	$ 361,653	Direct Assessment
Trans DA	Novi-Wixom CG Novi - Wixom City Gate	Risk Mitigation	$ 361,653	Direct Assessment
Trans DA	RV-LAT-81E Riverside Lateral 81E	HCA	$ 361,653	Direct Assessment
Total Capital Expenditure			**$ 8,659,759**	

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-21981
Consumers Energy Company WP-MPG-16
Regulatory Compliance Program Page 1 of 1
Pipeline Integrity - Transmission Capital and O&M Projects - 2027

Work Tag	**Work Item**	**Assessment Classification**	**Capital Expenditure**	**Inspection Tool**
Construction - Integrity	1200A-3 Pipe segment replacement 1200A-3		$ 5,632,540	
Construction - Integrity	1700-1 Pipe segment replacement 1700-1		$ 5,632,540	
Construction - Integrity	1900-4 Launchers / Receivers - Installation / Enhancements 1900-4		$ 1,032,540	
Inspect and Remediate	100B-26-3 Laingsburg Int & CG- Round Lake Rd to Ovid MS	HCA	$ 832,540	
Inspect and Remediate	100B-26-6 Ovid MS to St. Louis JCT & VS-Begole Rd	HCA	$ 1,032,540	
Inspect and Remediate	1090-1 Clintonia Rd VS to Charlotte CG-Benton Rd	192.710	$ 832,540	
Inspect and Remediate	1100-5 Middleville-Caledonia CG-Grand Rapids Rd to Clintonia Rd VS	HCA	$ 832,540	
Inspect and Remediate	1300-2 Overisel Compressor Station to Plainwell Valve Site-Hill Rd	192.710	$ 1,032,540	
Inspect and Remediate	1300-4 Plainwell VS-Hill Rd aka 107th Ave to Kalamazoo CG-Palmer Str.	HCA	$ 1,232,540	
Inspect and Remediate	300-6 Midland CG-M20/M30 Hwy to Zilwaukee CG & JCT-Tittabawasee Rd	HCA	$ 832,540	
Remediation Only	R-ML-24-E Ray (East Header) CS to TRS 046301	192.710	$ 832,540	
Trans DA	Freedom CS Freedom Compressor Station	HCA	$ 982,540	Direct Assessment
Trans DA	JacksonCGParkRd Jackson City Gate - Park Road	HCA	$ 807,540	Direct Assessment
Trans DA	Kern Rd VS Kern Road Valve Site	HCA	$ 807,540	Direct Assessment
Trans DA	Mt Pleasant CG Mount Pleasant Station, City Gate	HCA	$ 807,540	Direct Assessment
Trans DA	Sheldon Rd CG Sheldon Road City Gate	HCA	$ 807,540	Direct Assessment
Trans DA	St Clair CS St. Clair Compressor Station	HCA	$ 982,540	Direct Assessment
Total Capital Expenditure			**$ 24,953,187**	

U21981-AG-CE-0313
Page **1** of **1**

Question:

93. Refer to WP-MPG-14 and 16 on Transmission Pipeline Integrity. Please provide a similar schedule with actual information for 2023, 2024, and 2025 and provide it in Excel.

Response:

Please refer to attachments U21981-AG-CE-313-WAGGENER_ATT_1, U21981-AG-CE-313-WAGGENER_ATT_2 and U21981-AG-CE-313-WAGGENER_ATT_3 for the requested information.

Witness: Jordan L Waggener
Date: March 26, 2026

U21981-AG-CE-313-WAGGENER_ATT_3

Case No. U-21981

MICHIGAN PUBLIC SERVICE COMMISSION ~~WP-MPG-12~~

Consumers Energy Company ~~Page 1 of 4~~

Regulatory Compliance Program JLWaggener

Pipeline Integrity - Transmission Capital and O&M Projects - 2025 March 2026

Project Definition	**Description**	**Capital Expenditure**	**Year End Capital Expenditure**
GL-01598	NVL-1070 Northville to Sheldon C-REM	$ (2,351)	$ (2,351)
GL-02452	MAR-2400A GillowRd to MRCS C-REM	$ (5,094)	$ (2,873)
GL-02879	STC-4070 C-DA	$ (26)	$ (26)
GL-02886	STC-42 C-DA	$ 16,963	$ 16,963
GL-03064	WPC-WPCS C-DA	$ (603)	$ (603)
GL-03069	SAG-Clarkston Jct to Fish Lake Rd C-DA	$ 156,127	$ 161,933
GL-03070	SAG-Flint CG to Torrey Rd C-DA	$ (2,012)	$ (2,012)
GL-03106	SAG-100A AirportRd VS to MRCS C-REM	$ 742,172	$ 750,061
GL-03110	JXN-400 Lngsbrg Int to Fentn Int C-REM	$ 165,058	$ 165,058
GL-03147	STC-600 Clarkston Jnct LR Barrel Repl	$ (5,556)	$ (5,556)
GL-03177	JXN-Pipeline Integrity Material Issues	$ (29,158)	$ (29,158)
GL-03251	STC-L1500-2 Sheldon Rd C-REM	$ 164	$ 164
GL-03279	SAG-Carpenter Rd VS C-DA	$ (18,848)	$ (14,561)
GL-03284	STC-Lasher CG C-DA	$ (48)	$ (48)
GL-03287	SAG-Mt Pleasant Station C-DA	$ 29,873	$ 35,815
GL-03288	KZO-Three Rivers Lndfl C-DA	$ 213,384	$ (0)
GL-03384	KZO-1200A WPCS to V Drv VS C-REM	$ 23,918	$ 23,918
GL-03385	KZO-1200A V Drv VS to Chlsea VS C-REM	$ 108,792	$ 108,792
GL-03386	SAG-300 ClmnBvrtn CG to Mdlnd CG C-REM	$ 306,073	$ 307,441
GL-03390	SAG-2100 Wlsn Rd VS to Akron CG C-REM	$ 254,295	$ 246,785
GL-03392	MAR-2400A GillowRd to MuskRvr VS C-REM	$ 20,449	$ 20,449
GL-03394	STC-31mi Rd VS to Dutton Rd INT C-REM	$ 265	$ 265
GL-03396	MAR - Winterfield Mainline - C-REM	$ 842,126	$ 842,151
GL-03423	STC-Dutton Rd Int C-DA	$ (13,054)	$ (13,054)
GL-03424	OVC-Mid/Cal CG C-DA	$ (33,449)	$ (33,449)
GL-03425	KZO-Olmsted Rd VS C-DA	$ (938)	$ (938)
GL-03426	NVL-Pontiac Tr VS C-DA	$ (808)	$ (808)
GL-03428	NVL-Farm Hills CG C-DA	$ (11,060)	$ (11,060)
GL-03429	STC-Greenfield CG C-DA	$ (15)	$ (15)
GL-03466	SAG-700 Thomas Twp LR Inst	$ 4,911,477	$ 3,687,228
GL-03498	JXN-1100-6A Clintonia to Dewitt C-REM	$ 37,186	$ 37,186
GL-03508	MAR-2400B-2 Gillow to MRCS C-REM	$ 568,133	$ 337,708
GL-03511	NVL-1200A-4 Chelsea to Northville C-REM	$ 17,879	$ 17,879
GL-03526	SAG-700-1 St.Louis VS - Saginaw C-REM	$ 86,532	$ 179,150
GL-03538	STC-Ray North Mainline C-REM	$ 909,012	$ 577,776
GL-03578	OVS-Mainline C-REM	$ 2,443,131	$ 2,436,878
GL-03593	GRO-Squirrel Rd VS C-DA	$ 128,458	$ 167,046
GL-03597	FDM-Laingsburg CG C-DA	$ 770,488	$ 1,578,488
GL-03599	STC - Ray CS C-DA	$ 752,887	$ 783,395
GL-03605	STC-1500 Roch L-R EQ Ln Repl	$ 138,495	$ 140,147
GL-03644	STC-Macomb VS-C-DA	$ 349,221	$ 315,845
GL-03660	SAG- Dutch Rd CG Blowdown Inst	$ 741,596	$ 772,121
GL-03705	SAG-100A OvidVS to Mt. PleasantVS C-REM	$ (0)	$ 226,743
GL-00212	SAG-Line 2100 Wilson LR to Akron LR	$ (0)	$ (0)
GL-02654	FDM-L3070 4in LR Inst	$ (0)	$ (87,689)
GL-03517	SAG-300-1 MRCS to Coleman Bvrton C-REM	$ (0)	$ 3,648,831
GL-03523	SAG-100C Airport to Herrick C-REM	$ (0)	$ 3,789,970
Total Capital Expenditure		**$ 14,611,130**	**$ 21,171,985**

U21981-AG-CE-313-WAGGENER_ATT_2
Case No. U-21981
2024
JLWaggener
March 2026

PI-Transmission Capital

Program	Project Definitior	Description	Activity	CAP Expense
Pipeline Integrity T&S	GL-00548	FDM-100A Dansville VS-Ovid VS C-REM	Remediation	$ 40,582
Pipeline Integrity T&S	GL-01774	STC-Ira Mainline 20" C-REM	Remediation	$ 21,219
Pipeline Integrity T&S	GL-01776	NVL-Northville to Coolidge C-REM	Remediation	$ 23,410
Pipeline Integrity T&S	GL-02154	KZO-V Drive VS to Chelsea VS, M52 C-REM	Remediation	$ (150,005)
Pipeline Integrity T&S	GL-02165	STC-Lenox Mainline C-REM	Remediation	$ (92,137)
Pipeline Integrity T&S	GL-02168	FDM-Fenton Int to Clrkstn C-REM	Remediation	$ 115,224
Pipeline Integrity T&S	GL-02452	MAR-2400A GillowRd to MRCS C-REM	Remediation	$ 4,734
Pipeline Integrity T&S	GL-02620	STC-31 Mile Rd VS C-DA	Direct Assessment	$ 6,075
Pipeline Integrity T&S	GL-02691	MAR-Cranberry Lat 62W2 C-REM	Remediation	$ 12,781
Pipeline Integrity T&S	GL-02867	OVS-1100 Midcal to Clntnia C-REM	Remediation	$ 33,045
Pipeline Integrity T&S	GL-02922	OVC-1300 OVCS to Plainwell VS C-REM	Remediation	$ 25,802
Pipeline Integrity T&S	GL-02922	OVC-1300 OVCS to Plainwell VS C-REM	Remediation	$ 3,484
Pipeline Integrity T&S	GL-02932	STC-600 Clrkstn JCT to Squirel VS C-REM	Remediation	$ 16,025
Pipeline Integrity T&S	GL-02933	STC-24W Ray Mainline C-REM	Remediation	$ (824,942)
Pipeline Integrity T&S	GL-02933	STC-24W Ray Mainline C-REM	Remediation	$ 849,687
Pipeline Integrity T&S	GL-03064	WPC-WPCS C-DA	Direct Assessment	$ 379,662
Pipeline Integrity T&S	GL-03069	SAG-Clarkston Jct to Fish Lake Rd C-DA	Direct Assessment	$ 102,327
Pipeline Integrity T&S	GL-03106	SAG-100A AirportRd VS to MRCS C-REM	Remediation	$ (161,591)
Pipeline Integrity T&S	GL-03106	SAG-100A AirportRd VS to MRCS C-REM	Remediation	$ 6,423,748
Pipeline Integrity T&S	GL-03106	SAG-100A AirportRd VS to MRCS C-REM	Remediation	$ 583,186
Pipeline Integrity T&S	GL-03110	JXN-400 Lngsbrg Int to Fentn Int C-REM	Remediation	$ 7,269
Pipeline Integrity T&S	GL-03110	JXN-400 Lngsbrg Int to Fentn Int C-REM	Remediation	$ 74,943
Pipeline Integrity T&S	GL-03147	STC-600 Clarkston Jnct LR Barrel Repl	Replacement	$ 16,712
Pipeline Integrity T&S	GL-03177	JXN-Pipeline Integrity Material Issues	Material	$ (645,062)
Pipeline Integrity T&S	GL-03211	SAG-LN 100A Mt Pleasant VS-1950s Repl	Replacement	$ 107,437
Pipeline Integrity T&S	GL-03249	STC-L1060-1 Dunham Rd C-REM	Remediation	$ 26,634
Pipeline Integrity T&S	GL-03250	OVS-L1100-4 18th St C-REM	Remediation	$ 6,058
Pipeline Integrity T&S	GL-03251	STC-L1500-2 Sheldon Rd C-REM	Remediation	$ 10,000
Pipeline Integrity T&S	GL-03279	SAG-Carpenter Rd VS C-DA	Direct Assessment	$ 1,702
Pipeline Integrity T&S	GL-03280	NVL-Novi Wixom CG C-DA	Direct Assessment	$ 8,996
Pipeline Integrity T&S	GL-03282	STC-St Clair CS C-DA	Direct Assessment	$ 55,823
Pipeline Integrity T&S	GL-03287	SAG-Mt Pleasant Station C-DA	Direct Assessment	$ 3,857,672
Pipeline Integrity T&S	GL-03384	KZO-1200A WPCS to V Drv VS C-REM	Remediation	$ 779,960
Pipeline Integrity T&S	GL-03385	KZO-1200A V Drv VS to Chlsea VS C-REM	Remediation	$ 2,436,546
Pipeline Integrity T&S	GL-03386	SAG-300 ClmnBvrtn CG to Mdlnd CG C-REM	Remediation	$ 2,239,214
Pipeline Integrity T&S	GL-03391	JXN-2200 Chlsea VS to Fenton INT C-REM	Remediation	$ 1,101,823
Pipeline Integrity T&S	GL-03392	MAR-2400A GillowRd to MuskRvr VS C-REM	Remediation	$ 466,878
Pipeline Integrity T&S	GL-03394	STC-31mi Rd VS to Dutton Rd INT C-REM	Remediation	$ 19,652
Pipeline Integrity T&S	GL-03423	STC-Dutton Rd Int C-DA	Direct Assessment	$ 777,462
Pipeline Integrity T&S	GL-03424	OVC-Mid/Cal CG C-DA	Direct Assessment	$ 317,725
Pipeline Integrity T&S	GL-03425	KZO-Olmsted Rd VS C-DA	Direct Assessment	$ 85,717
Pipeline Integrity T&S	GL-03426	NVL-Pontiac Tr VS C-DA	Direct Assessment	$ 421,730
Pipeline Integrity T&S	GL-03428	NVL-Farm Hills CG C-DA	Direct Assessment	$ 573,316
Pipeline Integrity T&S	GL-03429	STC-Greenfield CG C-DA	Direct Assessment	$ 14
Pipeline Integrity T&S	GL-03442	SAG-Red Run CG C-DA	Direct Assessment	$ 489,706
Pipeline Integrity T&S	GL-03466	SAG-700 Thomas Twp LR Inst	Barrel Installation	$ 62,921
Pipeline Integrity T&S	GL-03578	OVS-Mainline C-REM	Remediation	$ (917,783)
Pipeline Integrity T&S	GL-03578	OVS-Mainline C-REM	Remediation	$ 37,727
Pipeline Integrity T&S	GL-03578	OVS-Mainline C-REM	Remediation	$ 2,144,753
Pipeline Integrity T&S	GL-03592	KZO-Kzoo CG M Ave C-DA	Direct Assessment	$ (1,910)
Pipeline Integrity T&S	GL-03593	GRO-Squirrel Rd VS C-DA	Direct Assessment	$ 3,641
Pipeline Integrity T&S	GL-03594	NVL - Sheldon Rd CG C-DA	Direct Assessment	$ 584
Pipeline Integrity T&S	GL-03595	GRO-Holly CG C-DA	Direct Assessment	$ (620)
Pipeline Integrity T&S	GL-03596	FDM-Kinder Morgan VS C-DA	Direct Assessment	$ (1,169)
Pipeline Integrity T&S	GL-03597	FDM-Laingsburg CG C-DA	Direct Assessment	$ (316)
Pipeline Integrity T&S	GL-03598	STC- Mt Clemens CG C-DA	Direct Assessment	$ (404)
Pipeline Integrity T&S	Result			**$ 21,977,670**

U21981-AG-CE-313-WAGGENER_ATT_1			Case No. U-21981
Pipeline Integrity - Transmission - Capital 2023 Costs by Forecast ID			JLWaggener
			March 2026
Project Description	**Work Type**	**CAP Expense Remediation Digs**	
MAR-2400B LR MichCon CE Jnct Inst	Construction	$ (29,721.20)	
FDM-L3070 4in LR Inst	Construction	$ 3,319.00	
FDM-L3070 4in LR Inst	Construction	$ 114.09	
STC-600 Clarkston Jnct LR Barrel Repl	Construction	$ 19,425.41	
SAG-LN 100A Mt Pleasant VS-1950s Repl	Construction	$ 1,524,846.98	
JXN-Pipeline Integrity Material Issues	Materials	$ (144,297.30)	
FDM-Line 400 HDD Pipe	Materials	$ (410,970.79)	
MAR-MichconInt to GillowRd VS C-REM	Remediation	$ (37,260.99)	
STC-SquirelRd VS to RochstrRd VS C-REM	Remediation	$ 60,360.81	
SAG-MRCS to ColemanBeaverton C-REM	Remediation	$ 241,372.26	
NVL-ClarkstonInt to NVLCS C-REM	Remediation	$ 31,209.00	
OVS-Salem Mainline Sta to Fld C-REM	Remediation	$ 177,175.01	
JXN-DwitStaTrnrRd to Lngsbrg CG C-REM	Remediation	$ 1,492.59	
SAG-100A Dnsvl VS to Ovid VS C-REM	Remediation	$ (78,331.79)	
SAG-100B Ovid VS to StLouis Jnct C-REM	Remediation	$ (643.60)	
MAR-Cranberry Lat 63W2 C-REM	Remediation	$ 3,231.32	
MAR-Cranberry Lat 62W2 C-REM	Remediation	$ (7,000.50)	
SAG-100A Ovid to Mt Pleasant C-REM	Remediation	$ (2,771.47)	
MAR-Riverside Mainline C-REM	Remediation	$ 15,858.74	
OVS-1100 Midcal to Clntnia C-REM	Remediation	$ (75,939.55)	
OVS-1100 Midcal to Clntnia C-REM	Remediation	$ 958,934.81	
OVC-1300 OVCS to Plainwell VS C-REM	Remediation	$ (11,519.85)	
OVC-1300 OVCS to Plainwell VS C-REM	Remediation	$ 14,392.67	
OVC-1300 OVCS to Plainwell VS C-REM	Remediation	$ 7,794.61	
SAG-100B Ovid VS to StLou JCT C-REM	Remediation	$ 9,371.36	
STC-600 Clrkstn JCT to Squirel VS C-REM	Remediation	$ 526,008.40	
STC-24W Ray Mainline C-REM	Remediation	$ 461,146.37	
JXN-100A FDMCS to Dansville C-REM	Remediation	$ (3,113.03)	
JXN-100A Dansville to Ovid C-REM	Remediation	$ 68,426.42	
MAR-Cranberry Lat 65E C-REM	Remediation	$ (76,110.17)	
STC-2010 Squirrel Rd to Pont CG C-REM	Remediation	$ 39,571.65	
SAG-100A AirportRd VS to MRCS C-REM	Remediation	$ 137,162.73	
SAG-100A AirportRd VS to MRCS C-REM	Remediation	$ 614,263.57	
JXN-400 Lngsbrg Int to Fentn Int C-REM	Remediation	$ 5,013,288.26	
MAR-2400A GilowRd VS to M72 VS C-REM	Remediation	$ 888.31	
OVS-L1100-4 18th St C-REM	Remediation	$ 96,685.80	
		$ 9,148,659.93	
Direct Assessment			
STC-4070 C-DA	Remediation / Dig Cost	$ (3,307.59)	
SAG-50 C-DA	Remediation / Dig Cost	$ 5,685.13	
KZO-Plainwell VS C-DA	Remediation / Dig Cost	$ 565.62	
NVL-SLyon Whitmore Lk CG C-DA	Remediation / Dig Cost	$ 3,778.19	
SAG-47 C-DA	Remediation / Dig Cost	$ 4,139.10	
WPC-WPCS C-DA	Remediation / Dig Cost	$ 1,247.01	
RAY-RCS C-DA	Remediation / Dig Cost	$ 642.59	
SAG-Clarkston Jct to Fish Lake Rd C-DA	Remediation / Dig Cost	$ 1,894,022.17	
SAG-Flint CG to Torrey Rd C-DA	Remediation / Dig Cost	$ 111,609.01	
SAG-Carpenter Rd VS C-DA	Remediation / Dig Cost	$ 1,156,065.33	
NVL-Novi Wixom CG C-DA	Remediation / Dig Cost	$ 13,700.98	
STC-St Clair CS C-DA	Remediation / Dig Cost	$ 2,472,857.15	
STC-Lasher CG C-DA	Remediation / Dig Cost	$ 20,076.04	
NVL-SLyon Whtmr Lk CG C-DA	Remediation / Dig Cost	$ 110,264.11	
SAG-Mt Pleasant Station C-DA	Remediation / Dig Cost	$ 1,208,375.58	
KZO-Three Rivers Lndfl C-DA	Remediation / Dig Cost	$ -	
		$ 6,999,720.42	
			2023 Actual
		$ 16,148,380.35	**16,148,380.35**

MICHIGAN PUBLIC SERVICE COMMISSION			Case No. U-21981
Consumers Energy Company			WP-MPG-15
Regulatory Compliance Program			Page 1 of 1
Pipeline Integrity - TOD Capital and O&M Projects - 2027			
Work Tag	**Work Item**	**Assessment Classification**	**Capital Expenditure**
Construction	Dx1019w	Construction	$4,429,626.56
Facility Component	AkronCG_Dx1090n_FacilityComponent	Facility Component	$704,626.56
Facility Component	KalamazooCGMAve_Dx1080_FacilityComponent	Facility Component	$704,626.56
Facility Component	KalamazooCGPalmerSt_Dx1080_FacilityComponent	Facility Component	$704,626.56
Facility Component	NewburghCG_Dx1019k North_FacilityComponent	Facility Component	$704,626.56
Facility Component	NewburghCG_Dx1019k South_FacilityComponent	Facility Component	$704,626.56
Facility Component	NewburghCG_Dx1019z_FacilityComponent	Facility Component	$704,626.56
Facility Component	RedRunCG_Dx1002g_FacilityComponent	Facility Component	$704,626.56
Facility Component	WalledLakeCG_Dx1015_FacilityComponent	Facility Component	$704,626.56
Risk Mitigation	Risk Mitigation	Risk Mitigation	$903,083.56
TOD ECDA	Dx1019	HCA	$774,626.56
TOD ECDA	Dx1019-192710	192.710 Outside of HCA	$521,626.56
TOD ECDA	Dx1024	HCA	$590,626.56
TOD ECDA	Dx1041	HCA	$452,626.56
TOD ECDA	Dx1062	HCA	$452,626.56
TOD ECDA	Dx1064	HCA	$452,626.56
TOD ECDA	Dx1065	HCA	$475,626.56
TOD ECDA	Dx1082	HCA	$590,626.56
TOD ICDA	ICDA Digs	ICDA Digs	$1,179,626.56
Tool Program	Tool Program	Tool Program	$479,626.56
Total Capital Expenditure			**$16,939,988.13**

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-21981
Consumers Energy Company WP-MPG-13
Regulatory Compliance Program Page 1 of 1
Pipeline Integrity - TOD Capital and O&M Projects - 2026

Work Tag	**Work Item**	**Assessment Classification**	**Capital Expenditure**
Casings	Casings	Casings	$1,330,648
Facility Component	Buckeye36Well_Dx1085d_FacilityComponent	Facility Component	$605,648
Facility Component	Coleman-BeavertonCG_Dx1085b_FacilityComponent	Facility Component	$605,648
Facility Component	CoolidgeCG_Dx1002a_FacilityComponent	Facility Component	$605,648
Facility Component	CoolidgeCG_Dx1002c_FacilityComponent	Facility Component	$605,648
Facility Component	JacksonCGHartRd_Dx1064_FacilityComponent	Facility Component	$605,648
Facility Component	OrionCG_Dx1014_FacilityComponent	Facility Component	$605,648
Facility Component	RedRunCG_Dx1002g_FacilityComponent	Facility Component	$605,648
Risk Mitigation	Risk Mitigation	Risk Mitigation	$1,028,068
TOD ECDA	Dx1008	HCA	$445,648
TOD ECDA	Dx1009	HCA	$537,648
TOD ECDA	Dx1014	HCA	$422,648
TOD ECDA	Dx1022	HCA	$422,648
TOD ECDA	Dx1022-192710	192.710 Outside of HCA	$445,648
TOD ICDA	ICDA Digs	ICDA Digs	$1,080,648
Tool Program	Tool Program	Tool Program	$380,648
Total Capital Expenditure			**$10,333,781**

U21981-AG-CE-0312
Page **1** of **1**

Question:

92. Refer to WP-MPG-13 and 15 on TED-I Pipeline Integrity. Please provide a similar schedule with actual information for 2023, 2024, and 2025, and provide it in Excel.

Response:

The question refers to TED-I but the Work Papers referenced are TOD Pipeline Integrity work plans. The Company believes there was a typing error in the question and has assumed TOD was requested.

Please refer to attachments U21981-AG-CE-312-WAGGENER_ATT_1, U21981-AG-CE-312-WAGGENER_ATT_2 and U21981-AG-CE-312-WAGGENER_ATT_3 for 2023, 2024 and 2025 actuals, respectively.

Witness: Jordan L Waggener
Date: March 26, 2026

U21981-AG-CE-312-WAGGENER_ATT_3				
MICHIGAN PUBLIC SERVICE COMMISSION			Case No. U-21981	
Consumers Energy Company			~~WP-MPG-11~~	
Regulatory Compliance Program			JLWaggener	
Pipeline Integrity - TOD Capital and O&M Projects - 2025				
Work Type	**Work Item**	**Assessment Classification**	**Capital Expenditure**	**Year End Capital Expenditure**
Casings	Casings	Casings	$977,403	$493,739
Facility Component	FlintCGBranchRd_Dx1053_FacilityComponent	Facility Component	$252,403	$127,502
Facility Component	FreeportCG_Dx1054_FacilityComponent	Facility Component	$252,403	$127,502
Facility Component	Marshall-LansingCG_Dx1022d_FacilityComponent	Facility Component	$252,403	$127,502
Facility Component	MidlandCG_Dx1087b_FacilityComponent	Facility Component	$252,403	$127,502
Facility Component	ZilwaukeeCG_Dx1087i_FacilityComponent	Facility Component	$252,403	$127,502
Risk Mitigation	Risk Mitigation	Risk Mitigation	$1,998,960	$1,009,781
TOD ECDA	Dx1002MAC	HCA	$161,403	$81,533
TOD ECDA	Dx1087	HCA	$69,403	$35,059
TOD ECDA	Dx1088	HCA	$161,403	$81,533
TOD ECDA	Dx1092	HCA	$46,403	$23,441
TOD ECDA	Dx1092-192710	192.710 Outside of HCA	$23,403	$11,822
TOD ECDA	Dx1093	HCA	$23,403	$11,822
TOD ICDA	ICDA Digs	ICDA Digs	$1,900,204	$959,894
Total Capital Expenditure			**$6,624,000**	**$3,346,134**

U21981-AG-CE-312-WAGGENER_ATT_2

U-21981
JLWaggener
March 2026

PI-Distribution Capital

Programs	Project Definition	Description	Activity	CAP Expense
Pipeline Integrity - Dist	GL-95908	2022 Capital Tools-New Technicians	Tools	$ (487)
Pipeline Integrity - Dist	GL-95908	2024 Capital Tools-New Technicians	Tools	$ 19,944
Pipeline Integrity - Dist	GL-95908	LVN ECDA Line 1019w D3 - Capital	Remediation	$ 1,236
Pipeline Integrity - Dist	GL-95908	DAPP 18640 DX1085K 1of6 M13 at CodyEstey	Remediation	$ (14,067)
Pipeline Integrity - Dist	GL-95908	Jxn Brooklyn Reg St 100 ICDA Digs.2022	Remediation	$ 75
Pipeline Integrity - Dist	GL-95908	LAN ECDA Line 1026f D4 - Capital	Remediation	$ 1,676
Pipeline Integrity - Dist	GL-95908	LAN RM Line 1023 D6 - Capital	Remediation	$ 1,249
Pipeline Integrity - Dist	GL-95908	Line 1010 Dig A	Remediation	$ 474
Pipeline Integrity - Dist	GL-95908	Line 1028g Dig E	Remediation	$ 171,307
Pipeline Integrity - Dist	GL-95908	ICDA Line 1082 Dig C	Remediation	$ 1,562
Pipeline Integrity - Dist	GL-95908	MAC ECDA Line 1006 D8 - Capital	Remediation	$ -
Pipeline Integrity - Dist	GL-95908	ICDA Line 1091c Dig K	Remediation	$ 5,117
Pipeline Integrity - Dist	GL-95908	ICDA Line 1027 Dig C	Remediation	$ 8,772
Pipeline Integrity - Dist	GL-95908	LVN ECDA Line 1099 D1 - Capital	Remediation	$ 54,269
Pipeline Integrity - Dist	GL-95908	LVN ECDA Line 1099 D2 - Capital	Remediation	$ 44,006
Pipeline Integrity - Dist	GL-95908	ROK ECDA Line 1020 D1 - Capital	Remediation	$ 29,488
Pipeline Integrity - Dist	GL-95908	ROK ECDA Line 1020 D2 - Capital	Remediation	$ 38,405
Pipeline Integrity - Dist	GL-95908	ROK ECDA Line 1020 D3 - Capital	Remediation	$ 81,461
Pipeline Integrity - Dist	GL-95908	ROK ECDA Line 1020 D4 - Capital	Remediation	$ 61,415
Pipeline Integrity - Dist	GL-95908	LVN ECDA Line 1015 D1 - Capital	Remediation	$ 40,237
Pipeline Integrity - Dist	GL-95908	LVN ECDA Line 1015 D3 - Capital	Remediation	$ 50,906
Pipeline Integrity - Dist	GL-95908	LVN RM Line 1015 D1 - Capital	Remediation	$ 28,902
Pipeline Integrity - Dist	GL-95908	LVN RM Line 1019k D1 - Capital	Remediation	$ 426,851
Pipeline Integrity - Dist	GL-95908	FLT RM Line 1049d D1 - Capital	Remediation	$ 33,489
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049d D1 - Capital	Remediation	$ 28,052
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049c D2 - Capital	Remediation	$ 53,287
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049d D3 - Capital	Remediation	$ 27,989
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049d D4 - Capital	Remediation	$ 40,058
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049d D5 - Capital	Remediation	$ 66,247
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049d D6 - Capital	Remediation	$ 34,518
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049d D7 - Capital	Remediation	$ 31,354
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049c D9 - Capital	Remediation	$ 140,276
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049d D10 - Capital	Remediation	$ 33,646
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049d D11 - Capital	Remediation	$ 63,172
Pipeline Integrity - Dist	GL-95908	ICDA Line 1002x Dig A	Remediation	$ 632,057
Pipeline Integrity - Dist	GL-95908	DAPPP22912-4015 EMERALD DR	Remediation	$ -
Pipeline Integrity - Dist	GL-95908	DAPP22912-4015 EMERALD DR	Remediation	$ -
Pipeline Integrity - Dist	GL-95908	ICTE Line 1020e Dig F	Remediation	$ 98,814
Pipeline Integrity - Dist	GL-95908	ICDA Line 1002k Dig J	Remediation	$ 70,314
Pipeline Integrity - Dist	GL-95908	ICDA Line 1048d Dig B	Remediation	$ 62,272
Pipeline Integrity - Dist	GL-95908	ICDA Line 1002g Dig B	Remediation	$ 120,668
Pipeline Integrity - Dist	GL-95908	ICDA Line 1006c Dig C	Remediation	$ 998,909
Pipeline Integrity - Dist	GL-95908	ICDA Line 1048d Dig C	Remediation	$ 137,454
Pipeline Integrity - Dist	GL-95908	Line 1048d Dig E	Remediation	$ 86,266
Pipeline Integrity - Dist	GL-95908	ICDA Line 1064 Dig R	Remediation	$ 85,764
Pipeline Integrity - Dist	GL-95908	KAL ECDA Line 1080 D2 - Capital	Remediation	$ 26,672
Pipeline Integrity - Dist	GL-95908	KAL ECDA Line 1080 D3 - Capital	Remediation	$ 21,098
Pipeline Integrity - Dist	GL-95908	KAL ECDA Line 1080 D5 - Capital	Remediation	$ 34,112
Pipeline Integrity - Dist	GL-95908	KAL ECDA Line 1080 D6 - Capital	Remediation	$ 25,370
Pipeline Integrity - Dist	GL-95908	KAL RM Line 1080 D1 - Capital	Remediation	$ 21,645
Pipeline Integrity - Dist	GL-95908	KAL RM Line 1080 D3 - Capital	Remediation	$ 20,562
Pipeline Integrity - Dist	GL-95908	KAL RM Line 1080 D4 - Capital	Remediation	$ 22,102
Pipeline Integrity - Dist	GL-95908	KAL RM Line 1080 D5 - Capital	Remediation	$ 23,049
Pipeline Integrity - Dist	GL-95908	DAPP22668_1065_DIG_F_PROSPECT-JACKSON	Remediation	$ 629,495
Pipeline Integrity - Dist	GL-95908	ICDA Line 1002x Dig B	Remediation	$ 95,508
Pipeline Integrity - Dist	GL-95908	1002c Dig D	Remediation	$ 21,794
Pipeline Integrity - Dist	GL-95908	1080 Dig F Capital UT Sensor Material	Material	$ 21,794
Pipeline Integrity - Dist	GL-95908	MAOP HP Line 1041 Type III Rplc (FEE)	Replacement	$ 3,013
Pipeline Integrity - Dist	GL-95908	DAPP 22051 BROOKLYN RD JACKSON HP	Replacement	$ 888,461
Pipeline Integrity - Dist	GL-95908	FLT ECDA Line 1049c D13 - Capital	Remediation	$ 47,552
Pipeline Integrity - Dist	GL-95908	ICTE Line 1054 Dig A	Remediation	$ 3,488
Pipeline Integrity - Dist	GL-95908	OWO LANSING & LEMON 120 SEPARATOR REMV	Remediation	$ 5,109
Pipeline Integrity - Dist	GL-95908	ICTE Line 1087b Dig B	Remediation	$ 37,641
Pipeline Integrity - Dist	GL-95908	M-43/Rupp Rd HP Dist STN REPL- 9-12-25	Replacement	$ 57,835
	Result			**$ 5,903,703**

U21981-AG-CE-312-WAGGENER_ATT_1			U-21981
Pipeline Integrity - Distribution (TOD)- CAP 2023 Costs by Forecast ID			JLWaggener
			March 2026
Portfolio	**Assessment ID**	**Work Type**	**CAP Expense**
Pipeline Integrity - TOD	Dx1002 - ROY	ECDA	$ (36,501)
Pipeline Integrity - TOD	Dx1006 - Macomb	ECDA	$ 497,207
Pipeline Integrity - TOD	Dx1026 - Lansing	ECDA	$ 309,601
Pipeline Integrity - TOD	Dx1028 - Greenville	ECDA	$ 380,869
Pipeline Integrity - TOD	Dx1070 - Alma	ECDA	$ 177,938
Pipeline Integrity - TOD	Dx1071 - Alma	ECDA	$ 214,491
Pipeline Integrity - TOD	Dx1089 - Alma	ECDA	$ 243,142
Pipeline Integrity - TOD	Dx1090 - Saginaw	ECDA	$ 207,411
Pipeline Integrity - TOD	Dx1091 - Bad Axe	ECDA	$ 163,603
Pipeline Integrity - TOD	Dx1094 - Saginaw	ECDA	$ 282,904
Pipeline Integrity - TOD	Dx1002 - ROY	ICDA	$ 83,620
Pipeline Integrity - TOD	Dx1010 - Shelby	ICDA	$ 117,599
Pipeline Integrity - TOD	Dx1022 - Grand Ledge	ICDA	$ 97,308
Pipeline Integrity - TOD	Dx1024 - Williamston	ICDA	$ 159,364
Pipeline Integrity - TOD	Dx1027 - Lansing Turner	ICDA	$ 399,119
Pipeline Integrity - TOD	Dx1041 - Flint Lapeer	ICDA	$ 221,017
Pipeline Integrity - TOD	Dx1049 - Flint Torey	ICDA	$ 259,792
Pipeline Integrity - TOD	Dx1064 - Jackson Park	ICDA	$ (202,369)
Pipeline Integrity - TOD	Dx1065 - Jackson Park	ICDA	$ 253,783
Pipeline Integrity - TOD	Dx1080 - Kalamazoo M Ave	ICDA	$ 479,307
Pipeline Integrity - TOD	Dx1082 - Kalamazoo M Ave	ICDA	$ 716,659
Pipeline Integrity - TOD	Dx1085 - Zilwaukee	ICDA	$ 121,986
Pipeline Integrity - TOD	Dx1087 - Zilwaukee	ICDA	$ 530,377
Pipeline Integrity - TOD	Dx1088 - Zilwaukee	ICDA	$ 321,294
Pipeline Integrity - TOD	Dx1090 - Akron	ICDA	$ 533,705
Pipeline Integrity - TOD	Dx1091 - Bad Axe	ICDA	$ 55,936
Pipeline Integrity - TOD	Dx1092 - Saginaw Dutch	ICDA	$ 244,360
Pipeline Integrity - TOD	Dx1094 - Saginaw Dutch	ICDA	$ 254,548
Pipeline Integrity - TOD	2022 Capital Tools-New Technicians	Project, pipeline repair / replacement	$ 3,544
Pipeline Integrity - TOD	2023 Capital Tools-New Technicians	Project, pipeline repair / replacement	$ 218
Pipeline Integrity - TOD	DAPP 18640 DX1085K 1of6 M13 at CodyEstey	Project, pipeline repair / replacement	$ 1,577,894
Pipeline Integrity - TOD	DAPP 18641 DX1085K CODY ESTEY @ 11 MILE	Project, pipeline repair / replacement	$ (62,933)
Pipeline Integrity - TOD	DAPP 19038 LINE 1008 SECTION REPLACEMENT	Project, pipeline repair / replacement	$ 342,063
Pipeline Integrity - TOD	DAPP 19698 LINE 1022 CAPITOL AIRPORT	Project, pipeline repair / replacement	$ 5,283
Pipeline Integrity - TOD	DAPP 19963 LINE 1022 WAVERLY	Project, pipeline repair / replacement	$ (12,246)
Pipeline Integrity - TOD	DAPP 20051 26" MAIN REPLACMENT MUE - Mar	Project, pipeline repair / replacement	$ 140,441
Pipeline Integrity - TOD	DAPP 21114 WAVERLY RD SAGINAW HWY HP	Project, pipeline repair / replacement	$ 2,347,672
Pipeline Integrity - TOD	LAN-DAPP 21114 Waverly Rd Saginaw Hwy	Project, pipeline repair / replacement	$ (2,204,420)
Pipeline Integrity - TOD	LIV-DAPP11151 Mdlblt, Joy 10" HP Repl	Project, pipeline repair / replacement	$ 48,035
Gas Delivery Systems > Distribution > Pipeline Integrity - TOD > Pipeline		**Total**	**$ 9,273,622**

U21981-AG-CE-0310
Page **1** of **1**

Question:

90. Refer to WP-MPG-7 on the TED-I Program. For each of the following projects: GL-03049, B-GL-00136, B-GL-00140, GL-03212, please:

a. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

b. For project GL-03212, explain why the pipeline needs to be rerouted and retired at this time. Identify other lower cost alternatives were considered.

Response:

a. For GL-03049, B-GL-00136, and B-GL-00140; these projects are currently refining the project scopes and reviewing the site locations. These projects will not move to the next phase of development until Q4 of 2026. GL-03212 is currently being engineered and designed with environmental and real estate studies taking place. The project is currently progressing toward a 30% Design milestone, scheduled for mid-May 2026.

b. The Company would like to return the line from a temporarily reduced pressure as practically as possible due to a class location change and need to be able to operate the system at its full capacity. In addition to the class location change, we are eliminating a line lowering, a navigable waterway crossing and from infringing on an existing eagle's nest habitat.

Witness: Jordan L Waggener
Date: March 27, 2026

U21981-ST-CE-0038
Page **1** of **1**

Question:

15. Referring to page 36, lines 7-9, of Company witness Michael P. Griffin's direct testimony; please provide an updated estimate as to when the Act 9 Application for the Line 300 reroute project will be filed with the Commission. If an Act 9 Application has already been filed with the Commission for the Line 300 Reroute Project, please identify the associated MPSC case number, "U-XXXXX".

Response:

The Company anticipates filing the Act 9 application around July 31, 2026.

Witness: MICHAEL P. GRIFFIN
Date: February 19, 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission Capital Expenditures
TED-I Program

Case No. U-21981
WP-MPG-7
Page 1 of 2

Project ID	Project Description	Project Type	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N	Business Case Y/N	Act 9 Y/N
Remote Control Valve (RCV) Projects											
GL-02413	NVL-2800 S Lyon RCV Inst	Install RCV	149,331	18,021	781,553		773,737	7,816	Y		
GL-02421	NVL-1600 W Wayne CG RCV Inst	Install RCV	1,999	0					Y		
GL-02661	MAR-2400 Vlv 2423,2424A,2433 Act Inst	Install RCV				214,867		212,719	Y		
GL-02662	SAG-500 Vlv 504-26, 504T12E Act Inst	Install RCV	-25,411	153,755					Y		
GL-02664	SAG-500 Vlv 506-26 Act to RTU Inst	Install RCV	0	154,636					Y		
GL-02668	STC-1700 Ray CS to Red Run RCV Ist	Install RCV	7,558	261					Y		
GL-02825	FDM-1200B Moscow VS Vlv 1252B Repl	Install RCV			911,457		902,342	9,115	Y		
GL-02826	KZO-1200B Wht Pign to Lutes RCV Inst	Install RCV			695,305		688,352	6,953	Y		
GL-02829	SAG-300 Midlnd CG to Zil Jnct RCV Inst	Install RCV	42	0					Y		
GL-02863	SAG-100/250 Mt Pleasant CG RCV Inst	Install RCV	15,946	0					Y		
GL-02941	NVL-1070 Sheldon Rd VS RCV Inst	Install RCV	1,505,726	52,634					Y		
GL-02943	FDM-2800 FDM,Milr,Hdsn,Sutn RCV Inst	Install RCV	695,780	61,633					Y		
GL-02944	FDM-400 8 Sites RCV Inst	Install RCV	3,125	960,203					Y		
GL-02947	KZO-1300 Plnwl to Palmer RCV Inst	Install RCV	-275,363	83,470					Y		
GL-02997	STC-2070 Dutton Rd VS PLD Inst	Install RCV	-48,925	-149					Y		
GL-02998	STC-1500 Rochester VS PLD Inst	Install RCV	-29,506	0					Y		
GL-03016	KZO-1800 RCV's Inst	Install RCV	-62	0					Y		
GL-03025	KZO-1800 MAve Check Valves Inst	Install RCV	1,774	2,990					Y		
GL-03027	FDM-2200 Chelsea to Fenton RCV Inst	Install RCV	-9,486	401,135					Y		
GL-03040	STC-600 Hillsboro VS RCV Inst	Install RCV	7,553	0					Y		
GL-03041	STC-2700 Hillsboro VS RCV Inst	Install RCV	4,883	0					Y		
GL-03049	SAG-250 MtPl to Zilwke RCV Inst	Install RCV	0	5,400		2,148,674		2,127,187	Y		
GL-03050	OVS-1800 30thSt to Plnwl RCV Inst	Install RCV	622	75,344					Y		
GL-03121	FDM-3200 VectrLesli to KndrMrgn RCV Inst	Install RCV	847	383					Y		
GL-03123	SAG-100C Airport to Herrick RCV Inst	Install RCV	12,051	842,079					Y		
GL-03125	NVL-LN 1020 V4018 & V4028 RCV Inst	Install RCV	634	287					Y		
GL-03265	KZO-1200A 1207, 1208A, 1208C RCV	Install RCV	13,708	0					Y		
GL-03267	STC- 1500 Vlv 1528 RCV Inst	Install RCV	0	107,874					Y		
GL-03268	SAG 100B Mt Pleasant VS 112-26 Repl	Install RCV	11,518	-831					Y		
GL-03318	SAG-2060 Flint CG Branch Rd Vlv Repl	Install RCV	0	95,292					Y		
GL-03324	STC-2700 Squirrel Rd Vlv RCV Updt	Install RCV	272	0					Y		
GL-03329	STC-1200A Chelsea VS RCV Inst	Install RCV	-6,235	0					Y		
GL-03480	JXN-1100 Lburg Int Vlv 1164 RCV Inst	Install RCV	0	7,130					Y		
GL-03611	SAG-500 Ovid VS Vlv 501x20N & 501-26 RCV	Install RCV	0	242,456					Y		
GL-03612	STC-1900 Leonard Lkville 1936 RCV	Install RCV	0	150,651					Y		
GL-03613	FDM-1100 Clintonia VS Vlv 1148 Repl	Install RCV	0	110,190					Y		
GL-03614	STC-1500 St. Clair FS Vlv 1532T2S RCV	Install RCV	0	119,056					Y		
GL-03615	NVL- 1400 Highland CG Vlv 1412 RCV	Install RCV	0	128,057					Y		
GL-03616	STC-1500 New Haven VS Vlv 1531	Install RCV	0	557,683					Y		
GL-03639	FDM-400 Bancroft Vlv 402S-24 RCV Inst	Install RCV	0	347,510					Y		

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-21981
Consumers Energy Company WP-MPG-7
Actual & Projected Gas Transmission Capital Expenditures Page 1 of 2
TED-I Program

Project ID	Project Description	Project Type	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N	Business Case Y/N	Act 9 Y/N
Remote Control Valve (RCV) Projects											
GL-03662	STC-LN2070 Hamlin Rd VS Vlv 2072 Act Rep	Install RCV	0	383,917					Y		
GL-03718	Pontiac Walton Vlv 2014 Rotork Rplc	Install actuator	0	56,169					Y		
B-GL-00119	TEDI-St Louis VS	Install RCV			676,139		669,378	6,761	Y		
B-GL-00120	TEDI-Three Rivers Landfill	Install RCV			891,887		882,968	8,919	Y		
B-GL-00121	TEDI-Brocker Rd VS	Install RCV			707,018		699,947	7,070	Y		
B-GL-00122	TEDI- Campground VS	Install RCV			841,181		832,769	8,412	Y		
B-GL-00123	TEDI-M-72 VS	Install RCV			704,888		697,839	7,049	Y		
B-GL-00124	TEDI-Military VS	Install RCV			704,888		697,839	7,049	Y		
B-GL-00125	TEDI- Processing Plant	Install RCV				786,415	0	778,551	Y		
B-GL-00126	TEDI- Gray VS	Install RCV				786,415	0	778,551	Y		
B-GL-00127	TEDI-Johnson Rd VS	Install RCV				786,415	0	778,551	Y		
B-GL-00128	TEDI-Gillow Rd VS	Install RCV				786,415	0	778,551	Y		
B-GL-00129	TEDI-North Bradley VS (Coleman-Beaverton)	Install RCV			664,426		657,782	6,644	Y		
B-GL-00132	TEDI-Carpenter Rd VS	Install RCV			791,136		783,224	7,911	Y		
B-GL-00135	TEDI-Goodison CG	Install RCV			911,457		902,342	9,115	Y		
B-GL-00136	TEDI-Hackman Rd VS	Install RCV				983,018	0	973,188	Y		
B-GL-00138	TEDI-Charlotte CG	Install RCV				645,677	0	639,220	Y		
B-GL-00139	TEDI-MGU Dayburg	Install RCV				686,501	0	679,636	Y		
B-GL-00140	TEDI-Blanchard Rd VS	Install RCV				1,933,807	0	1,914,468	Y		
B-GL-00152	TEDI-Trunkline VS	Install RCV				671,461	0	664,746	Y		
B-GL-00154	TEDI-Alma CG	Install RCV				649,974	0	643,474	Y		
B-GL-00161	TEDI-Manistee	Install RCV				649,974	0	643,474	Y		
B-GL-00162	TEDI-Tyler Excelsior	Install RCV				786,415	0	778,551	Y		
B-GL-00214	Babcock VS	Install RCV			695,305		688,352	6,953	Y		
B-GL-00652	St. Louis VS-Begole Rd to Saginaw CG & Jct.Dutch Rd	Install RCV			716,601		709,435	7,166	Y		
B-GL-00653	STC-1700 Red Run Vlv1719S RCV Inst	Install RCV			425,914		421,655	4,259	Y		
B-GL-00659	Farewell VS	Install RCV			699,564		692,569	6,996	Y		
B-GL-00660	Maple Dale Rd	Install RCV				868,064	0	859,384	Y		
	RCV Subtotal		**2,038,383**	**5,117,237**	**11,818,717**	**13,384,090**	**11,700,530**	**13,368,436**			

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission Capital Expenditures
TED-I Program

Case No. U-21981
WP-MPG-7
Page 2 of 2

Project ID	Project Description	Project Type	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N	Business Case Y/N	Act 9 Y/N
Other TED-I Projects											
GL-01629	TED-I 100A Will to Chelsea Pipe Repl	Mid Mich Pipeline Install Ph 1	6,207,791	1,523,336					Y	Y	Y
GL-01656	FDM-1100 Laingsburg Interchange PLD	Install PLD	-7,700	0					Y		
GL-02045	FDM-Freedom VS MAOP Pipe Repl	Mid Mich Pipeline	-1,607	0					Y	Y	Y
GL-02059	FDM-4060 Vector Int PLD Inst	Install PLD	52,994	537					Y		
GL-02070	STC-2700 Squirrel Rd VS PLD Inst	Install PLD	-71,931	0					Y		
GL-02113	STC-West Wayne CG Tie In Inst	South Oakland Macomb Network	0	-811					Y	Y	
GL-02114	STC-14 Mile Rd Augment Inst	South Oakland Macomb Network	-1,062	0					Y	Y	
GL-02116	STC-I696 Crossing Pipe Inst	South Oakland Macomb Network	1,546						Y	Y	
GL-02382	STC-12" Utica Lateral Inst	South Oakland Macomb Network	0	-51,681					Y	Y	
GL-02579	SAG-250 GL Chipwa Int PLD Inst	Install PLD	0	-2,568					Y		
GL-02629	TED-I 100A Ovid to Will Pipe Repl	MMPL Ph 2	123,404,794	5,985,639	392,573	146,470	311,109	191,316	Y	Y	Y
GL-03026	KZO-1200A CE-ANR Stag Lk VS PLD Inst	Install PLD	20,048	53,867					Y		
GL-03212	SAG-300 Reroute and Retire	Pipeline Replacement reroute	0	240,625	1,064,786	10,743,370	1,054,138	10,646,584	Y		Y*
GL-03312	STC-Oakland Resilience Interconnect	Interconnection with DTE Gas	1,339,368	4,509,772	266,196		263,534	2,662	Y	Y	Y
GL-03506	TED-I 2800 Clio to G.Blanc	Saginaw Trail Pipeline Ph. 3	615,442	0					Y	Y	Y
GL-04506	TED-I 2800 G.Blanc to Clawson Control	Saginaw Trail Pipeline Ph. 4	579,959	553,812	597,555	507,178	106,241	544,322	Y	Y	Y
GM-00410	SAG-Zilwaukee CG Rbld	Saginaw Trail Pipeline City Gate	-50,373	0					Y	Y	Y
GM-00411	FDM-Stockbridge CG Rbld	Mid Mich Pipeline	-65,473	118					Y	Y	Y
GM-00479	FDM-Pleasant Lk CG Rbld	Mid Mich Pipeline	72,580	59,020					Y	Y	Y
GM-00511	FDM-Ovid CG Rbld	Mid Mich Pipeline	4,688,358	-54,392					Y	Y	Y
GM-00512	NVL-Walled Lk CG Rbld	South Oakland Macomb Network	-136,312	0					Y	Y	
GM-00527	NVL-Plymouth CG Conversion	South Oakland Macomb Network	119,928	0					Y	Y	
GM-00528	STC-Coolidge CG Rbld	South Oakland Macomb Network	-62,056	-308,381					Y	Y	
GM-00530	STC-Pontiac Adams CG Rbld	South Oakland Macomb Network	42,354	0					Y	Y	
GM-00531	STC-Utica CG Ret, Reg Sta Inst	South Oakland Macomb Network	0	0					Y	Y	
GM-01413	SAG-Birch Run Montrose CG Rbld	Saginaw Trail Pipeline City Gate	-87,319	0					Y	Y	Y
GM-01415	SAG-Clio CG Rbld	Saginaw Trail Pipeline City Gate	67,034	0					Y	Y	Y
	Other Projects Subtotal		136,728,363	12,508,892	2,321,110	11,397,018	1,735,023	11,384,884			
	PROGRAM TOTAL		**138,766,746**	**17,626,130**	**14,139,826**	**24,781,108**	**13,435,552**	**24,753,321**			

The Mid-Michigan Pipeline, Saginaw Trail Pipeline, Oakland Resilience Interconnect and South Oakland Macomb Network projects have business cases.

The Mid-Michigan Pipeline, Oakland Resilience Interconnect and Saginaw Trail Pipeline projects have received a Certificate of Necessity to Operate and Construct (Act 9)

Business cases have not been conducted on RCVs. They are being installed to reduce response time and to improve public safety. RCVs reduce the loss of natural gas should a pipeline failure occur and can be operated remotely by Gas Control for potential reduction in response times.

Business cases have not been conducted on PLD projects. The PLD installation locations are selected pursuant to 49 CFR 192.619 and 49 CFR 192.195.

*The Company plans to file for an Act 9 for the Sag-300 Reroute in the first quarter of 2026

U21981-AG-CE-0307
Page **1** of **1**

Question:

87. Refer to WP-MPG-3 on Field Measurement Program. For each of the following projects: GM-01089, GM-01133, GM-95001, B-GM-00042, B-GM-00043, B-GM-00045, B-GM-00047, B-GM-00049, B-GM-00051, and B-GM-00053, please:

a. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

b. For project GM-01089, explain how the Company has been able to perform testing of the transmission measurement devices up to now and why it cannot continue to do so. Provide the annual cost of the current testing program. Provide a breakdown of what the proposed $14.1 million would be spent on. Provide a copy of the cost/benefit analysis in Excel that shows this project has a net present value benefit for customers.

c. For project B-GM-00042, explain how the Company has been able to operate without this proposed device up to now and why it cannot continue to do so. Identify what significant problems the Company is facing currently with measurement accuracy. Provide a breakdown of what the proposed $3.1 million would be spent on. Provide a copy of the cost/benefit analysis in Excel that shows this project has a net present value benefit for customers.

d. For projects B-GM-00043, B-GM-00045, B-GM-00047, B-GM-00049, BGM-00051, and B-GM-00053, identify what significant problems the Company is facing currently with measurement accuracy at these locations and the devices targeted for replacement or upgrade. Show in Excel that the improvements in measurement accuracy are economically justified and provide a net present value benefit to customers.

Response:

a. See attachment U21981-AG-CE-0307-WAGGENER_ATT_1.

b. See attachment U21981-AG-CE-0307-WAGGENER_ATT_1.

c. See attachment U21981-AG-CE-0307-WAGGENER_ATT_1.

d. See attachment U21981-AG-CE-0307-WAGGENER_ATT_1.

Witness: Jordan L Waggener
Date: April 1, 2026

U21981-AG-CE-0307-WAGGENER_ATT_1

Page 1 of 1

Project ID	Project	Location	Project Reason	Current Phase	Further Questions/Neccesity	Project Benefit
GM-01089	SAG-L2800 Williamston Meter Proving Station Facility	Webberville - Mid-MI Facility	This Facility will allow a testing environment for gas transmission measurement technology to comply with API-1164, which requires any new protocol, application, or software proposed to be added to the SCADA network should be run in a test-bed or development environment to evaluate the potential for impairing the performance of the SCADA system. Further, the Transportation Security Administration (“TSA”) requires the management of software/credentials on measurement devices and a physical testing laboratory with functional versions of all equipment subject to hardware/firmware upgrades to enable testing/validation of firmware in a controlled/non-production environment. The Company currently does not have a test environment for transmission meters or gas quality and analytical equipment	Conceptual scope has been completed. Planning to move forward on the project on Engineering Design in Q3 upon authorization from the commission.	The Company has complied with API 1164 by testing proposed equipment in parallel with existing systems prior to installation. While workable, this approach introduces operational and cybersecurity risks that would be mitigated by using a dedicated non production test environment. A controlled facility allows new equipment to be validated before being placed into service, and equipment that does not meet requirements to be screened out without affecting live operations. Third party costs for parallel new product testing are approximately $21,500 per product test (as previously stated). The annual total varies with the number of tests performed and the need for temporary test setups. The dollars allocated to the project will fund construction of a dedicated facility that provides the infrastructure to assemble, integrate, and test transmission measurement and gas analytics equipment (gas chromatographs, H2O analyzers, H2S analyzers, and O2 analyzers). This includes general building construction, workspace for equipment fabrication/integration and storage, laboratory space for analytical testing, and a controlled environment for live gas testing of new measurement technologies.	The project will reduce reliance on third party contractors for constructing and testing measurement equipment, enabling use of internal labor and subject matter expertise. It will improve quality control, reduce rework, and standardize construction and testing processes. A dedicated test environment reduces the risk of installing unvalidated equipment in parallel with in service assets and supports robust test to fail and cybersecurity integrity testing without impacting the production environment. It also enables internal troubleshooting, testing, and validation of meters and measurement equipment, lowering long term costs. In addition, constructing enclosures and Gas Analysis equipment internally rather than relying on third party integrators provides a meaningful long term cost advantage. Internal builds are typically completed at roughly half the cost of comparable third party structures, and those savings increase when multiple units are required in future years. The facility also supports additional efficiencies by reducing the need for external testing and laboratory services. These avoided contractor costs, lower integration expenses, and improved internal capabilities contribute to lower future capital and operating costs, providing long term economic benefit to customers.
GM-01133	LAN-Williamston CG Gas Chrom Inst	Williamston City Gate	Improve measurement accuracy by installing a Chromatograph at this site	The engineering design was completed at the end of February. Contractor scope of work is ready to go to bid. Construction is planned to start in Q3.	Not requested	Not requested
GM-95001	JXN-Transducer Repl Program	Various	Improve measurement accuracy. Capital replacement of measurement transducers that are in disrepair or beyond lifecycle	This is for capital transducer replacements that are emergent. There is no design phase for this project. Project orders are opened when measurement transducers are needed to be replaced on a site-by-site basis.	Not requested	Not requested
B-GM-00042	SCADA Gas Quality Hydraulic modeling	Jackson HQ	Improve measurement accuracy. Adding a system that will model gas compositional data and achieve higher data integrity by sending data to various sites within the system. This will alleviate the need to install gas chromatographs at every site. It will not completely eliminate the need for Gas Chromatographs. The chromatograph site selection will continue to target priority sites	Project planning and scoping is still underway. This is expected to move forward to IT project team in Q3 of this year to get in depth scoping and resources	Money will be spent to add functionality/additional software to the gas SCADA system by taking inputs of gas quality in the sytem, building a live gas model of the system, and application of modeled gas quality to sites where there is no gas analysis.	At custody transfer sites, high volume stations, and stations with limited gas quality data, gas analysis/gas chromatography is installed. Other operators have been installing analysis equipment at all points of distribution and every measurement site. Currently, the Company takes a system average and applies that to sites with no chromatography data. The LAUF can be negatively impacted by assuming a system average vs having online analysis at each site or a more acurate representative or modeled data. This project plans to deliver more representative gas quality data at each site without having to install live analysis at every site. The alternative to the project is having 100+ gas chromatograph projects to have live data at each site.

B-GM-00043	Northville CS Line 1200 A Meter and Chromatograph Install	Northville Compressor Station	Improve measurement accuracy. Orifice meters are beyond their reasonable lifespan. The meters need to be updated with Ultrasonic meters. The meter supports are also crumbling.	Engineering is underway with a final design expected by June of this year with construction starting around Q3 of this year.	A cost/benefit analysis has not been performed. Money will be spent to install new Ultrasonic meters and removal of the older orifice meters. This site has orifice meters that have reached the end of their useful life. Orifice meters are acceptable forms of measurement but not optimal given their age. Operationally, the plates are requried to be changed out by operations more periodically. When there are swings in the weather and gas usage is fluxuating, the plates are required to be changed out more frequently. There are a number of orifices at similar age that have been inoperable where plates have not been able to be removed. This is a site that is nearing that timeframe where there will be challenges. This is part of being a proactive steward of the asset and moving to a less maintenance intensive measurement device (Ultrasonic meter measurment)	See previous column
B-GM-00045	Eurkeka CG Meter Replacement	Eureka City Gate	Improve measurement accuracy. Orifice meters are beyond their reasonable lifespan. The meters need to be updated with Ultrasonic meters.	Preliminary assessment. Finalizing project scope and starting engineering will be around June of this year.	A cost/benefit analysis has not been performed. The asset has reached the end of it's useful life. This site has an orifice meter. Orifice meters are acceptable forms of measurement but not optimal given their age. Operationally, the plates are requried to be changed out by operations more periodically. When there are swings in the weather and gas usage is fluxuating, the plates are required to be changed out more frequently. There are a number of orifices at similar age that have been inoperable where plates have not been able to be removed. This is a site that is nearing that timeframe where there will be challenges. This is part of being a proactive steward of the asset and moving to a less maintenance intensive measurement device (Ultrasonic meter measurment)	This is at a city gate in which having accurate measurement will impact the amount of odorant injected. The meter at this site is nearing the end of it's useful life. This project is proactively upgrading metering before failure.
B-GM-00047	Winterfield 12 Gas Chromatograph Installation	Winterfield 12	No chromatograph at a custody transfer site. This will improve measurement accuracy by installing a chromatograph	Project planning and scoping is still underway. The project is expected to start engineering around Q3 of this year.	A cost/benefit analysis has not been performed. On line chromatography provides real time energy content and gas compressibility values for the gas. Our program goal is to have real time or representative energy content for every site in order to help in our effort of reducing LAUF. Site selection for real time data is based on high volume stations, custody transfer locations, and areas where there is not good information on the system. All of these sites selected will help provide real time data at these particular measurement sites and representative gas quality to other near by sites. The plan going forward is to utilize gas chromatography installation projects in conjunction with "B-GM-0042" to build representative gas quality throughout the system.	Project benefit explained in previous column.

B-GM-00049	Charlotte CG Meter Replacement	Charlotte City Gate	Improve measurement accuracy. Orifice meters are beyond their reasonable lifespan. The meters need to be updated with Ultrasonic meters.	Project planning and scoping is underway with engineering expected to start toward the end Q2 or beginning of Q3. Kickoff will be based on when a designer becomes available.	A cost/benefit analysis has not been performed. The asset has reached the end of it's useful life. This site has an orifice meter. Orifice meters are acceptable forms of measurement but not optimal given their age. Operationally, the plates are requried to be changed out by operations more periodically. When there are swings in the weather and gas usage is fluxuating, the plates are required to be changed out more frequently. There are a number of orifices at similar age that have been inoperable where plates have not been able to be removed. This is a site that is nearing that timeframe where there will be challenges. This is part of being a proactive steward of the asset and moving to a less maintenance intensive measurement device (Ultrasonic meter measurment)	This is at a city gate in which having accurate measurement will impact the amount of odorant injected. The meter at this site is nearing the end of it's useful life. This project is proactively upgrading metering before failure.
B-GM-00051	WPC LN 1800 Meter Repl	White Pigeon Compressor Station	Improve measurement accuracy. Orifice meters are beyond their reasonable lifespan. The meters need to be updated with Ultrasonic meters.	Project planning and scoping is underway with engineering expected to start around the end of Q2.	A cost/benefit analysis has not been performed. Money will be spent to install new Ultrasonic meters and removal of the older orifice meters. This site has orifice meters that have reached the end of their useful life. Orifice meters are acceptable forms of measurement but not optimal given their age. Operationally, the plates are requried to be changed out by operations more periodically. When there are swings in the weather and gas usage is fluxuating, the plates are required to be changed out more frequently. There are a number of orifices at similar age that have been inoperable where plates have not been able to be removed. This is a site that is nearing that timeframe where there will be challenges. This is part of being a proactive steward of the asset and moving to a less maintenance intensive measurement device (Ultrasonic meter measurment)	See previous column
B-GM-00053	Jackson Park Rd CG Gas Chromatograph Installation	Jackson Park RD City Gate	Improve measurement accuracy by installing a Chromatograph at this site	Project planning and scoping is underway with engineering expected to start in Q3.	A cost/benefit analysis has not been performed. On line chromatography provides real time energy content and gas compressibility values for the gas. Our program goal is to have real time or representative energy content for every site in order to help in our effort of reducing LAUF. Site selection for real time data is based on high volume stations, custody transfer locations, and areas where there is not good information on the system. All of these sites selected will help provide real time data at these particular measurement sites and representative gas quality to other near by sites. The plan going forward is to utilize gas chromatography installation projects in conjunction with "B-GM-0042" to build representative gas quality throughout the system.	Project benefit explained in previous column.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Deliverability Base Field Measurement Program

Case No. U-21981
WP-MPG-3
Page 3 of 4

Project ID	Project	Location	Project Reason	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
GM-01089	SAG-L2800 Williamston Meter Proving Station Facility	Webberville - Mid-MI Facility	This Facility will allow a testing environment for gas transmission measurement technology to comply with API-1164, which requires any new protocol, application, or software proposed to be added to the SCADA network should be run in a test-bed or development environment to evaluate the potential for impairing the performance of the SCADA system. Further, the Transportation Security Administration ("TSA") requires the management of software/credentials on measurement devices and a physical testing laboratory with functional versions of all equipment subject to hardware/firmware upgrades to enable testing/validation of firmware in a controlled/non-production environment. The Company currently does not have a test environment for transmission meters or gas quality and analytical equipment	35,636	49,970		14,113,679		11,303,887	Y
GM-01127	STC-Coolidge CG Chromatograph Inst	Coolidge City Gate	Improve measurement accuracy by installing a Chromatograph at this site	0	9,788					Y
GM-01133	LAN-Williamston CG Gas Chrom Inst	Williamston City Gate	Improve measurement accuracy by installing a Chromatograph at this site	0	504,182	1,072,962		936,497	136,465	Y
GM-95000	JXN-FGU Meter Program	Marion Winterfield Storage Field	Improve measurement accuracy	9,502	0					Y
GM-95001	JXN-Transducer Repl Program	Various	Improve measurement accuracy. Capital replacement of measurement transducers that are in disrepair or beyond lifecycle	-75,732	0	449,926	453,968	374,938	453,294	Y
GM-95004	Metering & Transmitter Repl Program	Various	Improve measurement accuracy. Capital replacement of measurement transducers that are in disrepair or beyond lifecycle	199,235	281,881					Y
GM-95208	Field Measurement		Closeout Entry	0	-13,104					Y
GM-95309	JXN-Measurement Capital Tools	Various	Improve measurement accuracy. Capital replacement of measurement transducers that are in disrepair or beyond lifecycle	552,306	717,530	375,223	378,594	312,686	378,032	Y
B-GM-00041	Rose Center Meter Replacement	Rose Center City Gate	Upgrading is the only option to ensure safe and reliable operating conditions. When an asset is beyond it's lifecycle, the meter will be required to be upgraded to ensure accurate system LAUF measurement. This will also ensure proper odorization based on the flow rate.		238,800		865,743		721,453	Y
B-GM-00042	SCADA Gas Quality Hydraulic modeling	Jackson HQ	Improve measurement accuracy. Adding a system that will model gas compositional data and achieve higher data integrity by sending data to various sites within the system. This will alleviate the need to install gas chromatographs at every site. It will not completely eliminate the need for Gas Chromatographs. The chromatograph site selection will continue to target priority sites			3,079,029		2,052,686	1,026,343	Y

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-21981
Consumers Energy Company WP-MPG-3
Deliverability Base Field Measurement Program Page 4 of 4

Project ID	Project	Location	Project Reason	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
B-GM-00043	Northville CS Line 1200 A Meter and Chromatograph Install	Northville Compressor Station	Improve measurement accuracy. Orifice meters are beyond their reasonable lifespan. The meters need to be updated with Ultrasonic meters. The meter supports are also crumbling.			4,882,267		4,243,578	638,689	Y
B-GM-00045	Eurkeka CG Meter Replacement	Eureka City Gate	Improve measurement accuracy. Orifice meters are beyond their reasonable lifespan. The meters need to be updated with Ultrasonic meters.			335,357	865,743	223,571	977,529	Y
B-GM-00047	Winterfield 12 Gas Chromatograph Installation	Winterfield 12	No chromatograph at a custody transfer site. This will improve measurement accuracy by installing a chromatograph			421,900	1,082,130	421,900	944,437	Y
B-GM-00048	Ovid CG Gas Chromatograph Installation	Ovid City Gate	Improve measurement accuracy by installing a Chromatograph at this site				425,715	0	425,715	Y
B-GM-00049	Charlotte CG Meter Replacement	Charlotte City Gate	Improve measurement accuracy. Orifice meters are beyond their reasonable lifespan. The meters need to be updated with Ultrasonic meters.				866,177	0	866,177	Y
B-GM-00050	Goodison CG Meter Replacement	Goodison City Gate	Improve measurement accuracy. Orifice meters are beyond their reasonable lifespan. The meters need to be updated with Ultrasonic meters.			858,436		858,436	0	Y
B-GM-00051	WPC LN 1800 Meter Repl	White Pigeon Compressor Station	Improve measurement accuracy. Orifice meters are beyond their reasonable lifespan. The meters need to be updated with Ultrasonic meters.				4,325,599	0	4,325,599	Y
B-GM-00052	WPC LN 1200B Meter Repl	White Pigeon Compressor Station	Improve measurement accuracy. Orifice meters are beyond their reasonable lifespan. The meters need to be updated with Ultrasonic meters.				338,392	0	281,993	Y
B-GM-00053	Jackson Park Rd CG Gas Chromatograph Installation	Jackson Park RD City Gate	Improve measurement accuracy by installing a Chromatograph at this site			421,900	944,437	421,900	669,049	Y
B-GM-00054	Howell CG Gas Chromatograph Installation	Howell City Gate	Improve measurement accuracy by installing a Chromatograph at this site				425,715	0	425,715	Y
B-GM-00057	Romeo Plank RD 1900 USM Install	Romeo Plank RD Valve Site	Improve measurement accuracy - Installation of interstage transmission meters to validate LAUF				340,212	0	283,510	Y
B-GM-00219	MCV Dow Meter Repl	MCV Dow Station	The meter is beyond its lifespan. It will need to be replaced with an Ultrasonic meter				865,743	0	865,743	Y
B-GM-00221	Clarkston LN 2700USM Install	Ckarkston Junction	Improve measurement accuracy - Installation of interstage transmission meters to validate LAUF				340,212	0	283,510	Y
B-GM-00223	Technician Van	Jackson HQ	Measurement Technicians need 2 vans for their personnel. Renting vans costs $3000-$4000/month in O&M budget.				364,013	0	364,013	Y
				5,704,408	**9,150,336**	**11,897,000**	**26,996,070**	**9,846,192**	**25,371,151**	

Business cases have not been conducted on most of these projects as field measurement projects are associated with remote gas measurement equipment monitoring, gas volume calculations, gas transmission metering, Transport Metering Stations (“TMS”), Interstate Interconnection sites, gas quality improvement and processing, gas sampling systems, and other ancillary equipment. These investments directly impact the Company’s ability to conform to the MPSC technical standard requirements concerning natural gas quality, measurement accuracy, and Lost and Unaccounted For (“LAUF”) gas. The Williamston Meter Proving Station Facility business case is included in the Company's Attachment #156 Top 25 cost projects.

U21981-AG-CE-0308
Page **1** of **3**

Question:

88. Refer to WP-MPG-4 on the Pipeline Program. For each of the following projects: GL-03047, GL-03302, GL-03316, GL-03600, GL-03789, GL-03805, B-GL-00259, GL-03640, B-GL-00262, B-GL-00263, B-GL-00264, B-GL-00268, B-GL-00272, BGL-00273, B-GL-00280, B-GL-00623, and B-GL-00625, please:

a. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

b. Explain what recurring problems the Company is experiencing with each project, what repairs have been made previously and why additional repairs cannot be made, and why replacement is necessary.

Response:

Project ID	Project	a. Current Project Phase	a. Next Phase Start
GL-03047	KZO-1200A,B MndnLeon 4in Tap Vlvs Repl	Engineering Designs are completed	Construction phase beginning summer 2026
GL-03302	OVS- 1100 Dorr CG Vlv Repl	Engineering Designs are completed	Construction phase beginning summer 2027
GL-03316	SAG-100A/100B Shepherd CG Dual Tap Repl	Project Planning and Scoping	Engineering Design phase beginning fall 2026
GL-03600	Line 2700 - 31 Mile Rd VS 2710 and 2712 Repl and Sep Ret	Engineering Design are currently at 30%	Construction phase beginning summer 2026
GL-03789	Line 1800 M Ave 1824 and Dual Tap Repl	Engineering Designs are currently at 60%	Construction phase beginning summer 2026
GL-03805	Line 100B - Farwell Mainline Inst	Engineering Design are currently at 30%	Construction phase beginning summer 2026
B-GL-00259	Line 1200A - Chelsea to Hellner Valve Spacing VS INST (Valve Site Installation d	Engineering Design are currently at 90%	Construction phase beginning summer 2026
GL-03640	Line 700/100B - St Louis VS Site Upgrade (Vlv 701-26 Repl, 701X20S Act 115-26N	Engineering Designs are currently at 30%	Construction phase beginning summer 2026

	8GSV2 and Drain Vlv Repl)		
B-GL-00262	FDM 1200B Hanover Horton CG Vlv 1252B Repl and RCV	Engineering Design are currently at 30%	Construction phase beginning summer 2026
B-GL-00263	Line 100A SAG Muskegon River CS Vlv 101x16 Repl, drain valve	Construction	Project will be complete by summer 2026
B-GL-00264	Line 100B - Mission Rd Vlv INST (Valve Site Installation due to valve spacing §1	Engineering Design are currently at 30%	Construction phase beginning summer 2026
B-GL-00268	Line 1800 - Schoolcraft CG - New 8" dual tap valves & piping	Project Planning and Scoping	Engineering Design phase beginning fall 2026
B-GL-00272	Emergent 2027 replacement due to MAOP Revision (Class Location Change	Refer to response to U21981-SA-CE-189 for details on these projects.	
B-GL-00273	Line XX - 2027 VS INST (Valve Site Installation due to valve spacing	Refer to response to U21981-SA-CE-189 for details on these projects	
B-GL-00280	SAG - Line 2100 Carpenter Rd. VS Valves 2114E, 2114, 8GSV2, 8" BDV Repl	Engineering Design are currently at 30%	Construction phase beginning summer 2026
B-GL-00623	Line 1200A V-drive Vlvs 1242A Repl and 1242A1 BDV Inst	Engineering Design are currently at final approval	Construction phase beginning summer 2026
B-GL-00625	ANR Otisville Interconnect Valve 2117 Retirement	Project planning and Scoping	Engineering and design phase beginning summer 2026

b. For projects GL-03047, GL-03302, GL-03316, GL-03600, GL-03789, GL-03640, B-GL-00262, B-GL-00263, B-GL-00268, B-GL-00280, and B-GL-00623 are experiencing sealing and/or operability problems. Onsite repairs were attempted on these valves. Onsite repair options include flushing the valve with new grease, replacing grease fittings, and resetting the stops. Repairs to internal valve components cannot be done in-house because the company does not possess an API-6D monogram to recertify the valves once they have been modified. A replacement project was created once it was determined the repairs were unsuccessful. Replacement of these problem valves is necessary to ensure full operability and isolation in case of emergency. Projects GL-03805, B-GL-00259, B-GL-00264 and B-GL-00625 are not projects due to recurring issues, refer to WP-MPG-4 for project reason. For projects B-GL-00272 and B-GL-00273 please refer to response to U21981-SA-CE-189 for details on these projects.

Witness: Jordan L Waggener
Date: March 27, 2026

Consumers Energy Company — Case No. U-21981
Projected Capital Expenditures for the Capacity/Deliverability Program — WP-MPG-4
Deliverability Base Pipeline Program — Page 2 of 6

Project ID	Project	Location	Project Reason	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
GL-02855	SAG-250 Mt Plsnt VS Vlv 251-16 Repl	Mt Pleasant	Project from prior years (2022) final reconciliation	0	7,476					Y
GL-02859	KZO-1200A V Drive VS Vlv 1242W Actu Repl	Homer	Project from prior years (2021) final reconciliation	125	0					Y
GL-02946	SAG-2100 Brown Rd 2122SBD Repl	Vassar Township	Project from prior years (2021) final reconciliation	5,255	0					Y
GL-03014	SAG-100A Valve Spacing VS INST	Mt Pleasant	Project completed in 2022, P2P Commissioning in 2023 Valve spacing study has indicated a new sectionalizing block valve is needed between Airport and Herrick VS on Line 100A. (49 CFR 192.179)	-55,771	0					Y
GL-03022	FDM-1200A/B Blue Ridge VS Inst	Clarklake	Project from prior years (2022) final reconciliation	-3,263	0					Y
GL-03024	FDM-1100 Lansing CG Arpt Rd Vlv Repl	Lansing	Project from prior years (2022) final reconciliation	-3,894	0					Y
GL-03038	KZO-1200A Vlv 1207, 1208A Repl	White Pigeon	Valve 1207 is identified as inoperable. Long-term compliance with 49 CFR 192.745(b) requires replacement of the valve. Valve 1208A is an isolation valve needed in order to replace valve 1207, but it is known to leak by. 1208C has also been reported as inoperable.	24,054	-12,279					Y
GL-03046	KZO-1200B Vlv 1256B Repl	Jackson	Project from prior years (2022) final reconciliation	74,848	0					Y
GL-03047	KZO-1200A,B MndnLeon 4in Tap Vlvs Repl	Mendon	Replacement of 1223A, 4" tap valves and associated piping fro	0	5,620	1,671,591		1,354,414	317,177	Y
GL-03056	SAG 300 Zilwaukee Jct 314-12 BVD Repl	Saginaw	The blowdown valves at Zilwaukee have been recommeded for replacement by operations. The blowdown valves have been identified as leaking by.	23,910	171					Y
GL-03113	SAG LN300 Midland CG Vlv 307-12N Repl	Midland	During the monthly valve alignment with operations, it has been indicated that Valve 307-12N cannot operate and needs replacement	51,410	-9,735					Y
GL-03114	NVL-LN1400 Highland CG Dual Tap Vlv Repl	Highland	Replacement of two 4" tap valves, two 4" check valves, and associated piping at Highland City Gate in support of CG rebuild and in order to improve gas deliverability.	15,248	24,356					Y
GL-03115	FDM-400-1 Vlv Spacing VS Inst	Fenton	Valve spacing study has indicated a new sectionalizing block valve is needed between Lutz and Fenton VS on Line 400. (49 CFR 192.179)	-42,960	0					Y
GL-03116	SAG-Atlas VS Vlv 1912 Repl	Grand Blanc	Project from prior years (2022) final reconciliation	41	0					Y
GL-03119	NVL 1400-1 Vlv Spacing VS INST	Milford	Valve spacing study has indicated a new sectionalizing block valve is needed between Highland and Pontiac Trail on Line 1400. (49 CFR 192.179)	240,367	41,724					Y
GL-03164	NVL-1400 ClrkstJnct Vlv 1410S Repl	Holly	Replace 24" mainline launcher/receiver Valve 1410S at Clarkston Junction, Line 1400. Valve 1410S has been determined to be inoperable, both with actuation and manually. Long-term compliance with 49 CFR 192.745(b) requires replacement of the valve. Short-term and medium-term negative impacts to inspection on Line 1400.	9,360	-55,429					Y
GL-03178	KZO-1300 B Ave 1320 Repl	Plainwell	Replacement of inoperable valve 1320 at B Ave.	285,338	2,307					Y
GL-03179	KZO-1300 Nazareth Rd CG Dual Tap Inst	Kalamazoo	Project from prior years (2022) final reconciliation	-28,569	0					Y
GL-03187	JXN-LN 2800 Vlv 2816 Repl	Ann Arbor	Replace 18" mainline sectionalizing Miller Valve Site, Line 2800. Valve 2816 has significant sealing issues and has caused isolation problems during planned outages.	98,418	-5,976					Y
GL-03188	STC-Ln 600 Joslyn Rd VS Dual Tap Inst	Lake Orion	Replacement of mainline valve and two 10" tap valves and associated piping at Orion City Gate in support of CG rebuild and in order to improve gas deliverability. Tap valves have been identified as problem valves and are difficult to operate.	1,442,665	31,339					Y
GL-03196	JXN-Del Base Pipe	N/A	Project from prior years final reconciliation	0	-85,878					Y
GL-03198	NVL-LN 2800 Vlv 2818 Repl	South Lyon	Replace 18" mainline sectionalizing Sutton Rd Valve Site, Line 2800. Valve 2818 has significant sealing issues and has caused isolation problems during planned outages.	33,350	6,691					Y
GL-03263	Ln1100 - Dorr to Mid Cal Vlv Inst	Dorr	Valve spacing study has indicated a new sectionalizing block valve is needed between Dorr and Middleville Caledonia VS on Line 1100. (49 CFR 192.179)	-117,433	0					Y

Consumers Energy Company — Case No. U-21981
Projected Capital Expenditures for the Capacity/Deliverability Program — WP-MPG-4
Deliverability Base Pipeline Program — Page 3 of 6

Project ID	Project	Location	Project Reason	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
GL-03266	STC 1500 Vlv 1528 Repl Macomb VS	Macomb	26" mainline sectionalizing Valve 1528 is inoperable in the ope	0	1,063,547					Y
GL-03289	STC- 1500 Valve Spacing VS Inst	New Baltimore	Valve spacing study has indicated a new sectionalizing block valve is needed between St Clair and Macomb on Line 1500. (49 CFR 192.179)	66,767	727,294	1,663,066		1,347,506	315,560	Y
GL-03290	NVL- 1400 Valve 1420N Repl	Northville	Replace 24" mainline launcher/receiver Valve 1420N at Northville Compressor Station, Line 1400. Valve 1420N has been determined to be inoperable, both with actuation and manually. Long-term compliance with 49 CFR 192.745(b) requires replacement of the valve. Short-term and medium-term negative impacts to inspection on Line 1400.	3,737	0					Y
GL-03296	SAG-250 Mt. Pleasant CG Vlv Repl	Mt Pleasant	Two gas supply valves and one drain valve have been recommeded for replacement by operations. These valves have been identified as leaking by, and need to be replaced to allow for integrity inspections.	-777	0					Y
GL-03297	SAG-100A Airport Rd 110-22N Act Repl	Mt Pleasant	Valve 110-22 was discovered to leak by during a 2022 Line 100A outage and needs to be replaced. No isolation at this point requires a 100A outage in this area to extend onto Line 100C. Operator on 110-22N does not operate. Replace Actuator on valve.	799,725	12,300					Y
GL-03298	SAG-2100 Akron CG Vlv 2123 Act Repl	Akron	Valve 2114E and the actuator on Valve 2123 have been recommeded for replacement by operations. Valve 2114E has been identified as leaking by, and the actuator on valve 2123 has been identified as inoperable.	9,619	0					Y
GL-03299	SAG-250 Pine Rvr to Zilwaukee VS Vlv Ins	Freeland	Valve spacing study has indicated a new sectionalizing block valve is needed between Pine River and Zilwaukee on Line 250. (49 CFR 192.179)	-12,824	7,501					Y
GL-03300	NVL-2800 S Lyon Vlv Repl	South Lyon	Replacement of one 18" mainline valve, two 16" tap valves and associated piping at S Lyons-Whitmore Lake City Gate in support of CG rebuild and in order to improve gas deliverability.	88,608	0					Y
GL-03302	OVS- 1100 Dorr CG Vlv Repl	Dorr	Replacement of one 24" mainline valve, two 4" tap valves and associated piping at Dorr City Gate in support of CG rebuild and in order to improve gas deliverability.	12,548	14,830		1,183,816		959,192	Y
GL-03311	SAG-100C Valve Spacing VS	Mt Pleasant	Valve spacing study has indicated a new sectionalizing block valve is needed between Airport and Herrick on Line 100C. (49 CFR 192.179)	48,941	0					Y
GL-03313	FDM-1100 Clintonia VS Vlv 1148 Repl	Portland	Within the Problem Valve Database, valves 1148 at Clintonia VS has been identified as inoperable and is recommeded for replacement by operations. Valve 1148E has been identified as leaking by, and needs to be replaced.	0	1,663,103	212,324		172,037	40,288	Y
GL-03315	FDM-2200 Howell-Vector-Hland Vls Sp Inst	Howell	Valve spacing study has indicated a new sectionalizing block valve is needed between Howell and Vector Hartland on Line 2200. (49 CFR 192.179)	1,816,153	23,932					Y
GL-03316	SAG-100A/100B Shepherd CG Dual Tap Repl	Shepherd	Replacement of two 4" tap valves and two 4" check valves, and associated piping at Shepherd City Gate in support of CG rebuild and in order to improve gas deliverability.				938,681		760,570	Y
GL-03317	SAG-1900 Leonard Lkville Vlv & Dual Tap	Leonard	Replacement of one 26" mainline valve, two 12" tap valves and associated piping at Leonard-Lakeville City Gate in support of CG rebuild and in order to improve gas deliverability.	427,267	2,254,276					Y
GL-03319	SAG 500 2800 GR BLANC VLVS 506-26 8GSV8	Grand Blanc	Valve 506-26 has been identified as a difficult valve to isolate with. Both valve 506-26 and 8GSV2 recommended for replacement by operations.	49,641	1,658,859					Y
GL-03320	STC-1600 Cooldige CG Vlv Repl	Royal Oak	Valve 1632 at Coolidge CG has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced to allow for isolation.	467,294	10,322					Y

Consumers Energy Company
Projected Capital Expenditures for the Capacity/Deliverability Program
Deliverability Base Pipeline Program

Case No. U-21981
WP-MPG-4
Page 4 of 6

Project ID	**Project**	**Location**	**Project Reason**	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
GL-03323	FDM-400 Perry Morrice Dual Tap Vlv Inst	Morrice	Perry-Morrice is a critical facility to improve the resiliency of. This site cannot take an outage at anytime in the year, and the load in fall, winter and spring is too high to reasonably supply temporary gas with a CNG or even LNG trailer. Installation of one 24" mainline valve, two 4" tap valves and associated piping at Perry Morrice City Gate in order to improve gas deliverability.	176,818	2,522,843					Y
GL-03336	SAG 100A Lk George Loc Pipe Repl	Flint	Class location change on Line 500 that results in 326' of pipe needing to be replaced west of Jennings Rd crossing. (49 CFR 192.611)	-92,197	0					Y
GL-03337	JXN 1200A HH CG/Moscow Rd VS 1252A Repl	Lake George	Class location change on Line 100A that results in 4466' of pipe needing to be replaced from Aurthur Rd crossing to south of Cedar Rd. (49 CFR 192.611) Compliance date of Dec 2024	2,699,924	-119,737					Y
GL-03412	FDM-3200 20" New VS Inst	Jackson	Valve spacing study has indicated a new sectionalizing block valve is needed between Lansing Ave and M-106 VS on Line 3200. (49 CFR 192.179)	3,036,545	43,869					Y
GL-03437	SAG-500 Ovid VS Vlv & Act Repl	Ovid	501T6E, 501X20S and 501X16S have been determined to have sealing issues and leak by. Short-term and medium-term negative impacts to outage execution and pipeline emergency response on Line 100A, Line 500, and Ovid City Gate.	1,858,720	46,357					Y
GL-03443	SAG-300 Zilwaukee JCT 2EQV6, 6GSV7 Repl	Zilwaukee	Within the Problem Valve Database, valves 2EQV6 and 6GSV7 at Zilwaukee have been recommended for replacement by operations. These valve have been identified as leaking by, and need to be replaced.	239,385	10,341					Y
GL-03456/BGL-	SAG-300 Muskegon River CS 301-T12 Repl	Marion	Within the Problem Valve Database, Valve 301-T12 has been recommeded for replacement by operations. It has been identified as leaking by.	67,196	674,560					Y
GL-03457/BGL-	SAG-300 Coleman Beav LR Drain Vlv Repl	Coleman	Within the Problem Valve Database, the drain valve at Coleman Beaverton has been recommended for replacement by operations. One of the Drain Valves on the Launcher/Receiver at Coleman Beaverton Valve Site has been identified as causing issues during the integrity inspections.	0	89,776					Y
GL-03473	FDM-400 Bancroft Vlv and Dual Tap Repl	Morrice	Within the Problem Valve Database, valve 402S-24 has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.	63,967	1,166,019					Y
GL-03476	OVS-1800 Plainwell VS Drain Vlv Repl	Plainwell	Replacement of leaking drain valve at Plainwell VS.	31,461	-26					Y
GL-03482	Shelby CG Vlv 1522 Repl	Shelby Twp	Within the Problem Valve Database, valve 1522 at Shelby VS has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.	3,584	1,217,767					Y
GL-03488	NVL-1600 W Wayne CG Vlv Repl	Farmington Hills	Replace Valves 1621 and 1623, valves have issues sealing and leak by.	47,837	227,074					Y
GL-03489	SAG 700 Thomas Twp VS Vlv 705-26 Repl	Thomas Twp	Within the Problem Valve Database, valve 705-26 at Thomas Twp VS has been recommeded for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.	322,506	787,586					Y
GL-03541/BGL-	FDM-1100 Laingsburg CG Vlv 1162 Rmvl	Laingsburg	Valve 1162 has been reported by operations as not sealing. This valve is redundant and can be cut out and replaced with a pup piece. Removal of the bypass installed with meter run project.	0	2,500,074					Y
GL-03600	Line 2700 - 31 Mile Rd VS 2710 and 2712 Repl and Sep Ret	Ray	Within the Problem Valve Database, valves 2710 and 2712 at 31 Mile VS has been recommeded for replacement by operations. These valves have been identified as leaking by, and needs to be replaced. Valve 1712S has been identified as inoperable. Retirement of the unused seperator		0	2,419,958	114,978	1,960,782	552,338	Y

Consumers Energy Company
Projected Capital Expenditures for the Capacity/Deliverability Program
Deliverability Base Pipeline Program

Case No. U-21981
WP-MPG-4
Page 5 of 6

Project ID	**Project**	**Location**	**Project Reason**	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
GL-03604/ B-GL-00245	SAG-500 Torrey Rd VS Vlv 504-26 Repl	Grand Blanc	Valve 504-26 has been identified as a difficult valve to isolate with. Recommended for replacement by operations. Replace mainline valve, tap valves and adjacent piping in conjunction with city gate rebuild.	152,592	929,652					Y
GL-03634	SAG-2060 Flint CG Branch Rd Vlv 2060 Rep	Flint	Replacement of leaking 26" mainline valve at Flint Branch Rd.	0	244,250	800,370		648,503	151,867	Y
GL-03641/B-GL-00247	SAG-2800 Bridgeport Vlv & Drain Vlv Repl	Bridgeport	Within the Problem Valve Database, a LR drain valve haS been recommeded for replacement by operations. This valve has been identified as leaking by.	0	14,285				0	Y
GL-03789	Line 1800 M Ave 1824 and Dual Tap Repl	Kalamazoo	Operations has reported Valve 1824 as severely leaking by, and cannot be used for isolation. Replace mainline valve and dual taps into CG.			1,402,760		1,136,592	266,168	Y
GL-03805	Line 100B - Farwell Mainline Inst	Farwell	Valve spacing study has indicated a new sectionalizing block valve is needed at Farwell VS on Line 100B. (49 CFR 192.179)			1,657,267		1,342,808	314,459	Y
B-GL-00259	Line 1200A - Chelsea to Hellner Valve Spacing VS INST (Valve Site Installation d	TBD	Valve spacing study has indicated a new sectionalizing block valve is needed between Chelsea and Hellner on Line 1200A. (49 CFR 192.179)			1,920,449		1,556,052	364,397	Y
GL-03640	Line 700/100B - St Louis VS Site Upgrade (Vlv 701-26 Repl, 701X20S Act 115-26N 8GSV2 and Drain Vlv Repl)	St Louis	Valves 701-26 and 8GSV2 need to be replaced on the L700 at St Louis VS, as both are leaking by. Project is to replace both valves, and address piping that does not have TVC pressure test documentation, and needs to be reconfirmed via 192.624. Project will also install actuator on Valve 701-20S, and install two new crossover valves on the 16" connection to L100A to allow for a double block to be achieved at the site. Project will also replace 115-26N and the L100B L-R drain valve at St Louis, which are both leaking by.			3,344,962		2,710,270	634,692	Y
B-GL-00262	FDM 1200B Hanover Horton CG Vlv 1252B Repl and RCV	Horton	Within the Problem Valve Database, valve 1252B at Hanover Horton has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.			1,858,988		1,506,253	352,735	Y
B-GL-00263	Line 100A SAG Muskegon River CS Vlv 101x16 Repl, drain valve	Marion	Within the Problem Valve Database, valve 101x16 at Muskegon River CS has been recommended for replacement by operations. This valve have been identified as leaking by, and needs to be replaced.			1,457,405		1,180,869	276,536	Y
B-GL-00264	Line 100B - Mission Rd Vlv INST (Valve Site Installation due to valve spacing §1	Mt Pleasant	Valve spacing study has indicated a new sectionalizing block valve is needed between Mt Pleasant and Herrick on Line 100B. (49 CFR 192.179)			885,527		717,502	168,025	Y
B-GL-00268	Line 1800 - Schoolcraft CG - New 8" dual tap valves & piping	Schoolcraft	Replacement of two 8" tap valves, installation of two 8" check valves, and associated piping at Schoolcraft City Gate in support of CG rebuild and in order to improve gas deliverability.				852,035	0	690,365	Y
B-GL-00271	Emergent Valve Replacements in 2027 due to inoperability	TBD	Emergent Valve Replacement projects due to inoperability (2027)				13,551,001	0	10,979,756	Y

Consumers Energy Company — Case No. U-21981
Projected Capital Expenditures for the Capacity/Deliverability Program — WP-MPG-4
Deliverability Base Pipeline Program — Page 6 of 6

Project ID	**Project**	**Location**	**Project Reason**	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
B-GL-00272	Emergent 2027 replacement due to MAOP Revision (Class Location Change	TBD	Anticipated piping replacement due to potential MAOP revision identified during forthcoming 2026 Class Location Change study (49 CFR 192.611).				3,115,305	0	2,524,189	Y
B-GL-00273	Line XX - 2027 VS INST (Valve Site Installation due to valve spacing	TBD	Emergent sectionalizing block valve installation identified by the 2026 valve spacing study. (49 CFR 192.179)				3,115,305	0	2,524,189	Y
B-GL-00276	Line 1200B Lutes Valve 1226B Cut out	Coldwater	Within the Problem Valve Database, valve 1226B is inoperable, but redundant. Cut out the valve and replace with a pup piece.			308,696		250,122	58,574	Y
B-GL-00277	Line 2080 Thetford VS Drain Valve Repl	Mt Morris	Within the Problem Valve Database, the drain valve at Thetford VS has been recommeded for replacement by operations. This valve has been identified as inoperable, and needs to be replaced.			20,066		16,258	3,807	Y
B-GL-00278	Line 1600 Novi Wixom Valve 1616 Repl	Novi	Within the Problem Valve Database, valve 1616 at Novi Wixom has been recommeded for replacement by operations. This valve has been identified as leaking by, and needs to be replaced.			871,672		706,276	165,396	Y
B-GL-00280	SAG - Line 2100 Carpenter Rd. VS Valves 2114E, 2114, 8GSV2, 8" BDV Repl	Davison	Within the Problem Valve Database, valve 2114, 2114E, 8GSV2 and an 8" BDV have been identified to leak by, Short term and medium-term negative impacts to inspection on Line 2100.			2,083,700		1,688,327	395,373	Y
B-GL-00460	Line 1100 Mid Cal 8GSV7, 8GSV8 and New mainline Inst	Middleville	Replace 8GSV7 as it leaks by, bring 8GSV8 above grade, replace split tee, install a new mainline valve next to 1122W to reduce liquids getting trapped from pig runs, relocate equalizer line.				696,056	0	563,983	Y
B-GL-00623	Line 1200A V-drive Vlvs 1242A Repl and 1242A1 BDV Inst	Homer	Operations has reported valve 1242A at V-Drive as leaking by, and cannot be used for isolation. A blowdown is needed at Valve 1242A1 to be able to blow down that section of piping.			1,315,910		1,066,222	249,688	Y
B-GL-00624	Line 100A Summerton & Remus 420' Class Location Change Pipe Repl	Mt Pleasant	Class location change on Line 100A that results in 420' of pipe needing to be replaced. (49 CFR 192.611)			592,159		479,800	112,360	Y
B-GL-00625	ANR Otisville Interconnect Valve 2117 Retirement	Mt Morris	As of March 2022, this interconnect is no longer in use, retire and remove the tap off of Line 2100 and valve 2117 and replace with straight pipe.				1,119,597	0	907,158	Y
TOTAL				**18,843,674**	**22,843,114**	**24,486,871**	**24,686,774**	**19,840,591**	**24,648,843**	

Business cases have not been conducted on projects. Projects in this program are in accordance with Michigan Gas Safety Standards as explained in my direct testimony.

U21981-AG-CE-0309
Page **1** of **1**

Question:

89. Refer to WP-MPG-6 on City Gate Projects. For each of the following projects: GM-00863, GM-01019, GM-01102, GM-01103, GM-01104, GM-01122, GM-01123, GM-01132, GM-01141, GM-01158, GM-00319, GM-00320, GM-00321, GM-00322, B-GL-00472, and B-GL-00473, please:

a. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

b. Explain what recurring problems the Company is experiencing with each project and whether the device or equipment is still functioning well. Explain what reaching the end of life means and when it was reached or will be reached, and why it must be replaced now and not later.

Response:

a. Please refer to attachment U21981-AG-CE-309-WAGGENER_ATT_1 for the current project status as well as the estimated date for the start of the next project phase.

b. Regarding the recurring problems at each project and whether the device or equipment is still functioning well please refer to attachment U21981-AG-CE-309-WAGGENER_ATT_1.

Regarding end of life - Of the projects listed above, the six city gates listed below were identified as at the end of their design life in WP-MPG-6. Each of these have or will reach 50 years in-service in the year noted.

GM-01102 (2006), GM-01103 (2016), GM-01104 (2030), GM-01122 (2023), GM-01123 (2011), GM-00320 (2019), and B-GL-00473 (2015).

The Company designs city gates for an expected lifespan of approximately 50 years, striving to extend the life of these facilities without compromising reliability and safety. Some city gates operate successfully beyond 50 years while some require replacement earlier than 50 years. Many factors are considered when selecting sites for a rebuild. These factors include, but are not limited to, the obsolescence of existing equipment; the overall condition of the valves, pipe, building, heaters, and separators; absence of equipment* required to meet the Company's definition of a modern city gate

*Modern city gates have a bath heater, a filter/separator, a SCADA Pack RTU, and Emergency Shutdown valves as the primary overpressure protection on all outlet(s).

Witness: Jordan L Waggener
Date: March 27, 2026

U21981-AG-CE-309-WAGGENER_ATT_1
Capacity/Deliverability Program - City Gate Projects

Case No. U-21981
JLWaggener
March 2026

Project ID	Project Description	Current Phase	Problem with the site	Necessity for timing	Est date for next ph
GM-00863	NVL-Novi-Wixom CG ESD, F-S Inst	Engineering Design	The city gate lacks our standard Emergency Shutdown valve for overpressure protection a modern filter/separator, or a modern SCADA Pack.	Mitigating downstream MAOP risk by protecting against liquids and protecting against regulator failures. Mitigating the risk of non-communication if the obsolete SCADA RTU failed.	4/14/2026
GM-01019	STC-Dixie-Waterford CG Vlv Repl	Engineering Design	The city gate lacks our standard Emergency Shutdown valve for overpressure protection.	Mitigating downstream MAOP risk by protecting against regulator failures	5/4/2026
GM-01102	NVL-S Lyon-Whitmore Lk CG Rbld	Construction	The city gate lacks our standard Emergency Shutdown valve for overpressure protection or a modern SCADA Pack. The site is 70 years old and has an odorizer pump that is at the end of its life (30+ years).	Mitigating downstream MAOP risk by protecting against liquids and protecting against regulator failures. Mitigating the risk of non-communication if the obsolete SCADA RTU failed. Mitigating the risk that the 30+ year old odorant pump fails and causes major disruption to the community.	8/14/2026
GM-01103	KZO-Mendon-Leonidas CG Rbld	Construction	The city gate lacks our standard Emergency Shutdown valve for overpressure protection a modern filter/separator, or a modern SCADA Pack. Most of the equipment at the site was installed in 1960.	Mitigating downstream MAOP risk by protecting against liquids and protecting against regulator failures. Mitigating the risk of non-communication if the obsolete SCADA RTU failed.	9/30/2026
GM-01104	KZO-Climax CG Rbld	Construction	The city gate lacks our standard Emergency Shutdown valve for overpressure protection, a modern filter/separator, or a modern SCADA Pack. Most of the equipment at the site was installed in 1980.	Mitigating downstream MAOP risk by protecting against liquids and protecting against regulator failures. Mitigating the risk of non-communication if the obsolete SCADA RTU failed.	9/30/2026
GM-01122	SAG-Flint Irish CG Rbld	Construction	The city gate lacks our standard Emergency Shutdown valve for overpressure protection, a modern filter/separator, or a modern SCADA Pack. Most of the equipment at the site was installed in 1973.	Mitigating downstream MAOP risk by protecting against liquids and protecting against regulator failures. Mitigating the risk of non-communication if the obsolete SCADA RTU failed.	9/28/2026
GM-01123	Spring Arbor CG Rbld	Construction	The city gate lacks our standard Emergency Shutdown valve for overpressure protection, a modern filter/separator, or a modern SCADA Pack. Most of the equipment at the site was installed in 1961.	Mitigating downstream MAOP risk by protecting against liquids and protecting against regulator failures. Mitigating the risk of non-communication if the obsolete SCADA RTU failed.	9/30/2026
GM-01132	NVL-Compressor Station Meter Repl	Engineering Design	Orifice meter at a major transmission measurement interchange. Removing obsolete RTU and replacing with modern.	Improved measurement accuracy. Mitigating the risk of non-communication if the obsolete SCADA RTU failed.	6/15/2026
GM-01141	STC-Goodison CG Partial Rbld	Engineering Design	Load growth has made the heater and odorizer become undersized. The city gate lacks our standard Emergency Shutdown valve for overpressure protection and a modern filter/separator.	To mititgate the risk of equipment freeze-off or frost ball development. To mititgate the risk of under-odorization during peak day event. Mitigating downstream MAOP risk by protecting against liquids and protecting against regulator failures.	6/1/2026

U21981-AG-CE-309-WAGGENER_ATT_1
Capacity/Deliverability Program - City Gate Projects

Case No. U-21981
JLWaggener
March 2026

Project ID	Project Description	Current Phase	Problem with the site	Necessity for timing	Est date for next phase
GM-01158	SAG-Shepherd CG RTU Modem Repl	Engineering Design	The city gate lacks our standard Emergency Shutdown valve for overpressure protection, a modern filter/separator, or a modern SCADA Pack. Most of the equipment at the site was installed in 1959.	Mitigating downstream MAOP risk by protecting against liquids and protecting against regulator failures. Mitigating the risk of non-communication if the obsolete SCADA RTU failed.	11/30/2026
B-GL-00319	2027 MUSKEGON RIVER COMPRESSOR STATION RTU UPGRADE	Pre-Engineering/Design	Multiple transmission RTUs on the site are obsolete equipment and require upgrade to ensure vendor support.	Mitigating the risk of non-communication if the obsolete SCADA RTU failed.	10/1/2026
B-GL-00320	2027 Schoolcraft CG & Odorizer	Pre-Engineering/Design	The city gate lacks our standard Emergency Shutdown valve for overpressure protection, a modern filter/separator, or a modern SCADA Pack. Most of the equipment at the site was installed in 1969.	Mitigating downstream MAOP risk by protecting against liquids and protecting against regulator failures. Mitigating the risk of non-communication if the obsolete SCADA RTU failed.	6/1/2026
B-GL-00321	2027 Sheldon ESD & liquid siphon	Engineering Design	The city gate lacks our standard Emergency Shutdown valve for overpressure protection.	Mitigating downstream MAOP risk by protecting against regulator failures	12/10/2026
B-GL-00322	2027 Mid-Cal ESD	Engineering Design	The city gate lacks our standard Emergency Shutdown valve for overpressure protection.	Mitigating downstream MAOP risk by protecting against regulator failures	6/10/2026
B-GL-00472	Newburgh CG ESD & MAOP Gap	Engineering Design	The city gate lacks our standard Emergency Shutdown valve for overpressure protection.	Mitigating downstream MAOP risk by protecting against regulator failures	9/12/2026
B-GL-00473	Charlotte City Gate Rebuild	Pre-Engineering/Design	The city gate lacks our standard Emergency Shutdown valve for overpressure protection, or a modern filter/separator. Most of the equipment at the site was installed in 1965.	Mitigating downstream MAOP risk by protecting against liquids and protecting against regulator failures.	6/17/2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity/Deliverability Program - City Gate Projects

Case No. U-21981
WP-MPG-6
Page 1 of 3

Project ID	**Project Description**	**Order**	**Location**	**Reason for Project**	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
GL-03398	MAR-Bear Lk-Excelsior PL Inst	42841793	Kalkaska	Pipeline installation in order to retire a City Gate	4,282,320	-43,104					Y
GL-03609	FDM-Charlotte CG DLC Optr Repl	44054225	Charlotte	Emergent replacement of measurement isolation valve	0	4,599					Y
GL-03637	KZO-Climax CG 4in Vlv Repl	44103422	Climax	Carry over from prior years	0	101					Y
GL-03647	STC-Metamora CG Vlv H3 Repl	44295429	Metamora	Emergent Replacement of Failed Heater Bypass Valve	0	18,845					Y
GM-00206	NVL-Newburgh CG (2) Htr Reliters Repl	21219721	Livonia	Closeout/Carry over	-61	0					Y
GM-00378	FDM-Bancroft CG Htr Fuel Train Repl	28702531	Morrice	Heater fuel train replacement to support ongoing use of the gas heater	983	0					Y
GM-00380	NVL-Sheldon Rd CG Htr Fuel Train Repl	28702534	Plymouth	Heater fuel train replacement to support ongoing use of the gas heater	458	0					Y
GM-00423	STC-Pontiac Adams CG Noise, Safety Inst	27456692	Auburn Hills	Carry over from prior years	-22,273	0					Y
GM-00437	NVL-Walled Lk CG Sta Reg Rbld	35542047	Walled Lake	Carry over from prior years	0	-1,003					Y
GM-00501	STC-Orion CG Reg Repl	30624217	Auburn Hills	Replace out of date regulators	-3,072	0					Y
GM-00514	STC-Greenfield CG Rbld	31336816	Royal Oak	Planned 2022 rebuild due to aged facility	119,429	0					Y
GM-00584	NVL-Highland CG- Reg Repl	33161884	Highland	Final Reconciliation	1,721	0					Y
GM-00626	FDM-Mosherville CG Bldg Repl	33601753	Hanover	Closeout/Carry over	77	0					Y
GM-00632	MAR-Forward CG Foundation Repl	33602885	McBain	Final Reconciliation	368	0					Y
GM-00648	STC-Mt Clemens CG Lghting Upgr	34025757	Mt Clemens	Carry over from prior years	0	487					Y
GM-00649	STC-Leonard-Lakeville CG Lghting Upgr	34025981	Leonard	Carry over from prior years	0	320					Y
GM-00683	KZO-Schoolcraft CG Reg Run Repl	34599458	Schoolcraft	Final Reconciliation	1,019	0					Y
GM-00762	SAG-Hemlock CG F-S Inst	36007472	Saginaw	Carry over from prior years	0	5					Y
GM-00781	SAG-Akron CG Vlv Repl	36177798	Akron	Carry over from prior years	0	823					Y
GM-00782	NVL-Salem CG Htr Repl	36177847	Northville	Carry over from prior years	1,620	0					Y
GM-00789	SAG-Mt Pleasant CG Rbld	36251277	Mt Pleasant	Planned 2021 rebuild due to aged facility	32,960	0					Y
GM-00793	STC-Mt Clemons CG Htr Repl	39347373	Clinton Twp	City Gate Heater Replacement	30,062	39,343					Y
GM-00794	KZO-M Ave CG Rbld	40116346	Oshtemo	Planned 2022 rebuild due to aged facility	138,402	62					Y
GM-00803	KZO-Marshall-Lansing CG Rbld	36453069	Marshall	Planned 2021 rebuild due to aged facility	-3,708	21,005					Y
GM-00828	OVS-Mid-Cal CG Civil Upgrade	36810576	Middleville	CG Upgrade	0	8,466					Y
GM-00863	NVL-Novi-Wixom CG ESD, F-S Inst	38925689	Novi	Filter Seperator Install	128,691	367,055	7,073,267	299,876	6,261,356	1,075,438	Y
GM-00867	FDM-Lansing CG-Airport Rd Rbld	39140340	Lansing	Planned 2022 rebuild due to aged facility	206,885	0					Y
GM-00898	MAR-Bear Lk Twp CG Rbld	38520942	Kalkaska	Planned 2022 rebuild due to aged facility	-47,180	60,233					Y
GM-00899	SAG-Akron CG Rbld	38622661	Akron	Planned 2023 rebuild due to aged facility	4,287	137,432					Y
GM-00900	JXN-Napoleon-Brooklyn CG Rbld	38737525	Napoleon	Planned 2022 rebuild due to aged facility	0	450					Y
GM-00901	STC-Rochester CG Rbld	38515215	Rochester	Planned 2022 rebuild due to aged facility	3,319	125,806					Y
GM-00902	KZO-Kzo CG-Nazareth Rd Rbld	38862469	Kalamazoo	Planned 2022 rebuild due to aged facility	112,215	0					Y
GM-00909	STC-Lahser CG Rep Repl	38741773	Beverly Hills	Carry over from prior year project	597	0					Y
GM-00921	STC-Leonard-Lakeville CG Rep Repl	39328182	Leonard	Carry over from prior year project	319,307	-3,901					Y
GM-00924	STC-Holly Cg Valve Repl	39440410	Holly	Closeout/Carry over	0	502					Y
GM-00936	MAR-Excelsior Twp CG Ret-Vlv Inst	41338270	Kalkaska	Planned 2024 Project	188,361	2,026					Y
GM-00941	OVS-Dorr CG Rbld	39997759	Dorr	Planned 2024 rebuild, 1965 original build	2,496,970	184					Y
GM-00942	KZO- Galesburg CG Rbld	40213320	Kalamazoo	Planned 2024 rebuild, 60+ year old facility at the end of its designed life.	4,470,219	27,941					Y

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-21981
Consumers Energy Company WP-MPG-6
Capacity/Deliverability Program - City Gate Projects Page 1 of 3

Project ID	**Project Description**	**Order**	**Location**	**Reason for Project**	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
GM-00943	STC-Orion CG Rbld	39924024	Lake Orion	2024 construction project, 1955 Build	12,637,190	213,078					Y
GM-00944	JXN-Park Rd CG ESD Inst	41700070	Jackson	closed ESD valves for enhanced overpressure protection.	714,204	3,037					Y
GM-00951	JXN-PEPL-Blissfield CG Rbld	40187839	Riga	Planned 2024 rebuild, Installation of new city gate to serve our existing customers. Resolution to MPSC to own, operate and maintain the overpressure protection device which protects our distribution system.	7,171,118	-448,990					Y
GM-00957	JXN-Reg Trailer 2 Build	40191455	Various	Planned 2023 to support temporary regulation for future construction	7,211	0					Y
GM-00958	JXN-Reg Trailer 3 Build	40191453	Various	Planned 2023 to support temporary regulation for future construction	-1,221	0					Y
GM-00966	KZO-Climax CG Valve Repl	40563617	Climax	Planned 2022 rebuild of failed valves	156	0					Y
GM-00976	ALM-St. Louis VS RTU, Bldg Rep	40019478	St Louis	RTU-Elect Upgrade and safety related constructions associated with sinking building	46,961	0					Y
GM-00979	STC-Pontiac Wlton CG ESD Inst	40645212	Auburn Hills	Planned 2023 Rebuild to modernize overpressure protection	5,018	7,527					Y
GM-00994	STC-Leonard-Lakeville City Gate Rbld	41317268	Leonard	Planned 2024 Rebuild, 1970 build	7,525,000	42,260					Y
GM-00996	FDM-Bancroft CG Rbld	41332319	Morrice	Planned 2025 Rebuild, 1962 Build	2,180,723	5,467,425					Y
GM-00997	STC-Lasher CG ESD Vlv Inst	41332540	Beverly Hills	Planned 2025 Project, Installation of fail closed ESD valves for enhanced overpressure protection.	514,911	892,525					Y
GM-01004	FDM-Dexter CG Reg Repl	41424130	Dexter	Planned 2024 replace obsolete regulator	565	0					Y
GM-01006	OVS-Mid-Cal CG Vlv Repl	41564527	Middleville	Carry over from prior year project	245	0					Y
GM-01019	STC-Dixie-Waterford CG Vlv Repl	41858919	Clarkston	2026 construction project	121,657	-706	1,168,641	48,839	1,020,613	190,680	Y
GM-01020	SAG-Flint CG-Branch Rd Vlv Repl	42865404	Flint	2024 valve replacement of failing valve	38,499	0					Y
GM-01021	FDM-Hanover Horton CG Valve Repl	41930157	Hanover	2024 valve replacement of failing valve	5,965	0					Y
GM-01052	JXN-Jxn Hart Rd CG Rbld	42496744	Jackson	2025 construction project 1968 Asset at the end of its designed life.	1,614,922	5,923,239	300,158		262,138	38,020	Y
GM-01054	FDM-Hanover Horton CG Rbld	42650854	Horton	2025 construction project 1963 Asset at the end of its designed life.	783,910	5,904,752					Y
GM-01055	SAG-Flint Torrey Rd CG Rebl	42653954	Flint	Planned 2025 rebuild, 1963 Asset at the end of its designed life.	1,698,708	7,317,567					Y
GM-01056	NVL-Highland CG, Odorizer Rbld	42707627	Highland	2025 construction project 1962 Asset at the end of its designed life.	1,124,159	6,888,255					Y
GM-01061	FDM-Laingsburg CG ESD Vlv Inst	42824337	Laingsburg	Planned 2025 Modernization of overpressure protection	746,794	5,788					Y
GM-01078	STC-Macomb CG ESD Repl	43248849	Macomb	2025 construction project Modernization of overpressure protection	51,181	850,189					Y
GM-01088	STC-Holly CG Vlv H3 Repl	43519371	Holly	Replacement of failing valve	16,461	-3,146					Y
GM-01090	FDM-Stockbridge CG Htr Coil Repl	43633042	Stockbridge	Replacement of Heater Coil to optimize heater perf	7,411	3,648					Y
GM-01091	FDM-Pleasant Lk CG Htr Coil Repl	43633047	Manchester	Replacement of Heater Coil to optimize heater perf	8,038	3,535					Y
GM-01102	NVL-S Lyon-Whitmore Lk CG Rbld	43798101	South Lyon	life.	16,108	1,339,117	7,597,842	282,216	6,676,891	1,168,959	Y
GM-01103	KZO-Mendon-Leonidas CG Rbld	43887578	Bronson	life.	1,000	1,003,837	7,218,516	268,126	6,343,544	1,110,598	Y
GM-01104	KZO-Climax CG Rbld	43887787	Climax	life.	0	862,824	8,521,782	316,535	7,488,839	1,311,111	Y
GM-01105	NVL-Farmington Hills CG Vlv A Repl	43887576	Farmington Hills	Replacement of Failed inlet valve	13,220	209,969					Y
GM-01122	SAG-Flint Irish CG Rbld	44202377	Flint	Rebuild 1973 asset at the end of its designed life.	0	1,149,377	8,342,376	309,871	7,331,179	1,283,508	Y
GM-01123	Spring Arbor CG Rbld	44209831	Spring Arbor	Rebuild 1961 Asset at the end of its designed life.	0	524,425	7,804,159	289,880	6,858,200	1,200,701	Y

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CECo Workpaper WP-MPG-6

Case No: U-21981
Exhibit: AG-26
April 15, 2026
Page 6 of 7

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-21981
Consumers Energy Company WP-MPG-6
Capacity/Deliverability Program - City Gate Projects Page 2 of 3

Project ID	**Project Description**	**Order**	**Location**	**Reason for Project**	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
GM-01129	SAG-Coleman-Beaverton CG RTU Repl	44484229	Coleman	Replacement of obsolet sixnet device & heater relighter moderinzation	0	81,954	295,520	22,983	258,272	57,320	Y
GM-01132	NVL-Compressor Station Meter Repl	44544893	Northville	Replacement of obsolet sixnet device and consolidation of multiple RTU systems	0	1,623,360	1,837,906	68,268	1,615,130	282,769	Y
GM-01141	STC-Goodison CG Partial Rbld	44658225	Rochester Hills	Addition of ESD valve, odorizer and heater replacement		350,000	3,446,074	142,799	3,028,368	544,847	Y
GM-01142	Grand Ledge RTU & BMS	TBD	Grand Ledge	Replacement of obsolet sixnet device	0	50,000					Y
GM-01150	NVL-Livingston Rd VS, CG RTU Upgrd	44720641	Highland	Replacement of obsolet sixnet device	0	52,041	278,409	24,132	243,144	56,341	Y
GM-01152	GRV-Dixie Waterford CG ESD, RTU Upgr	44720275	Clarkston	Modernization of over pressure protection and electrical equipment	0	47,643					Y
GM-01157	SAG-Karn Partial Rbld		Essexville	Replacement of the existing pressure regulating control valves due to operational issues and equipment obsolescence. New regulators will reliably control pressure, reducing overpressure event likelihood. New regulators will retire the existing constant bleed regulators which will reduce LAUF and methane emissions	0	1,000,000					Y
GM-01158	SAG-Shepherd CG RTU Modem Repl	44831895	Shephard	life	0	388	800,055	9,845,627	705,780	8,692,789	Y
B-GL-00045	Overisel Compression RTU Upgrade		Overisel	Rebuild of obsolete RTUs at site			327,201		285,756	41,445	Y
B-GL-00208	City Gates Emergent		Various	Funding for minor emergent capital assets		304,063					Y
B-GL-00311	2026 Emergent		Various	Funding for minor emergent capital assets			528,782	31,215	461,803	94,240	Y
B-GL-00314	2026 GRAND LEDGE CG (G-11) RTU & BMS		Grand Ledge	Replace obsolete RTU with modern SCADApack			402,924	22,983	351,887	71,109	Y
B-GL-00315	2026 MIDLAND CG (M-7) RTU & BMS		Midland	Replace obsolete RTU with modern SCADApack			22,761	0	19,878	2,883	Y
B-GL-00316	2026 NORTH LYON CG RTU & BMS		Lyon Twp	Replace obsolete RTU with modern SCADApack			402,924	22,983	351,887	71,109	Y
B-GL-00318	2027 31 Mile Rd. VS		Ray Twp.	Replace obsolete RTU with modern SCADApack			75,130	427,774	65,613	383,106	Y
B-GL-00319	2027 MUSKEGON RIVER COMPRESSOR STATION RTU UPGRAI		Marion	Replace obsolete RTU with modern SCADApack			129,214	1,810,291	112,847	1,607,229	Y
B-GL-00320	2027 Schoolcraft CG & Odorizer		Schoolcraft	life.			776,685	9,845,627	686,305	8,688,894	Y
B-GL-00321	2027 Sheldon ESD & liquid siphon		Plymouth	Installation of ESD valve and liquid siphon			42,073	1,209,511	36,743	1,061,635	Y
B-GL-00322	2027 Mid-Cal ESD		Middleville	Installation of ESD valve			42,073	1,209,511	36,743	1,061,635	Y
B-GL-00323	2027 DCP MATTHEWS RD RTU		Spring Arbor	Replace obsolete RTU with modern SCADApack			71,134	427,774	62,124	382,599	Y
B-GL-00324	2027 DUTTON RD VS RTU		Rochester Hills	Replace obsolete RTU with modern SCADApack			71,134	427,774	62,124	382,599	Y
B-GL-00325	2027 Evon Rd. Valve Site RTU		Spaulding Twp	Replace obsolete RTU with modern SCADApack			71,134	427,774	62,124	382,599	Y
B-GL-00326	2027 MIDDLEVILLE CG (M-6) RTU		Middleville	Replace obsolete RTU with modern SCADApack			71,134	427,774	62,124	382,599	Y
B-GL-00328	2027 VALVE SITE/STORAGE RTU & ELECTRICAL		Various	Emergent funds for RTU replacement			450,778	3,767,291	393,679	3,347,199	Y
B-GL-00329	2027 BMS Retrofits		Various	Modernization of heater relighters to provide consistant and reliable heating of gas		216,380		166,754		145,637	Y
B-GL-00330	2028 RTU Upgrade		Various	Replace obsolete RTU with modern SCADApack				75,836		66,230	Y
B-GL-00331	2028 Holly CG & Odorizer		Holly	life.				985,869		860,992	Y

Project ID	**Project Description**	**Order**	**Location**	**Reason for Project**	2024 Actual	2025 Projection	2026 Projection	2027 Projection	10 Months Ending 10/31/2026 Projection	12 Months Ending 10/31/2027 Projection	Internal Approval Y/N
B-GL-00332	2028 Kalamazoo Palmer PEPL/CE & Odorizer		Kalamazoo	life.				530,852		463,611	Y
B-GL-00333	2028 ESD		Various	Retrofit of existing city gate with ESD valve for overpressure protection				75,836		66,230	Y
B-GL-00334	2028 Cohoctah Rebuild		Cohoctah	life.				900,932		791,729	Y
B-GL-00335	2028 Dexter CG ESD Install		Dexter	Retrofit of existing city gate with ESD valve for overpressure protection				106,170		92,722	Y
B-GL-00336	2028 Fenton ESD		Fenton	Retrofit of existing city gate with ESD valve for overpressure protection				212,341		185,444	Y
B-GL-00469	RTU Emergent		Various	Emergent funds for RTU replacement		312,175	292,261	772,723	305,835	665,485	Y
B-GL-00470	Ray Compressor RTU		Ray Twp.	Replace obsolete RTU with modern SCADApack				319,114		278,693	Y
B-GL-00472	Newburgh CG ESD & MAOP Gap		Northville	Retrofit of existing city gate with ESD valve for overpressure protection			52,591	3,111,438	45,929	2,723,984	Y
B-GL-00473	Charlotte City Gate Rebuild		Charlotte	life.			210,378	8,146,310	183,722	7,185,535	Y
GM-95011	FDM-Tecumseh- RTU Upgrade	36364845	Tecumseh	Replace obsolete SCADApacks	0	-12,608					Y
GM-95011	KZO Comstock-RTU Upgrade	36400241	Comstock	Replace obsolete SCADApacks	-2,710						Y
GM-95011	FDM Williamston CG -RTU Upgrade	36889754	Williamston	Replace obsolete SCADApacks	6,061						Y
GM-95011	STC- SCADA Trailer Instal	38257732	Mobile Unit	Updating temporary SCADA trailers to allow for continued temporary support during outages	6,531						Y
GM-95011	NVL- SCADA Trailer Instal	38263722	Mobile Unit	Updating temporary SCADA trailers to allow for continued temporary support during outages	8,197						Y
GM-95011	STC-Shelby CG RTU¯Replacement and Elec	38496556	Shelby Twp	Replace obsolete RTU with modern SCADApack	7,914						Y
GM-95014	BUCKEYE 36 TMS (B 7) RTU Install *CNCL*	39064697		Replace obsolete RTU with modern SCADApack	0	-27,223					Y
GM-95014	EUREKA (E1) RTU Install	39065151	Elsie	Replace obsolete RTU with modern SCADApack	-7,142						Y
GM-95014	HEMLOCK CG (H 8) RTU Install	39065271	Saginaw	Replace obsolete RTU with modern SCADApack	-7,448						Y
GM-95014	KALAMAZOO RIVER (K 5) RTU Install	39065277	Kalamazoo	Replace obsolete RTU with modern SCADApack	2,259						Y
GM-95014	MOSHERVILLE (M 14) RTU Install	39065461	Hanover	Replace obsolete RTU with modern SCADApack	-10,651						Y
GM-95014	Dexter (D-5) RTU Install	39065749	Dexter	Replace obsolete RTU with modern SCADApack	-8,564						Y
GM-95021	NVL Charlotte-RTU Upgrade	40546639	Charlotte	Replace obsolete RTU with modern SCADApack	5,334						Y
GM-95021	STC Chrysler Tech Ctr-RTU Upgrade	40546782	Auburn Hills	Replace obsolete RTU with modern SCADApack	19,532						Y
GM-95021	NVL Livingston Rd-RTU Upgrade	40546783	Highland	Replace obsolete RTU with modern SCADApack	550						Y
GM-95021	SAG North Star Ashley-RTU Upgrade	40546787	Ashley	Replace obsolete RTU with modern SCADApack	11,371						Y
GM-95021	STC Squirrel Rd VS-RTU Upgrade	40546788	Lake Orion	Replace obsolete RTU with modern SCADApack	11,333						Y
GM-95021	NVL West Maple VS-RTU Upgrade	40546794	Milford	Replace obsolete RTU with modern SCADApack	8,061						Y
GM-95030	W-4_Woodbury_BMS Retrofit_M_Emergent	41826871	Lake Odessa	Modernization of heater relighters to provide consistant and reliable heating of gas	10,638						Y
GM-95030	W-2_West Wayne_BMS Retrofit_M_Emerge	41826872	Farmington Hills	Modernization of heater relighters to provide consistant and reliable heating of gas	-6,084						Y
GM-95030	W-1_Walled Lake_BMS Retrofit_M_Emerger	41826873	Walled Lake	Modernization of heater relighters to provide consistant and reliable heating of gas	13,753						Y
GM-95030	M-8_Mt Clemons_BMS Retrofit_M_Emergen	41826876	Clinton Twp	Modernization of heater relighters to provide consistant and reliable heating of gas	27,302						Y
GM-95030	R-2_Rochester CG_BMS Retrofit_Emergent	41928404	Rochester	Modernization of heater relighters to provide consistant and reliable heating of gas	7,845						Y
GM-95030	H-7_Howell CG_BMS Retrofit_M_Emergent	42333611	Howell	Modernization of heater relighters to provide consistant and reliable heating of gas	46,030						Y
GM-95032	C-4_Climax CG_BMS Retrofit_Emergent	42565011	Climax CG	Modernization of heater relighters to provide consistant and reliable heating of gas	151,860	6,104					Y
GM-95032	K-2_Kalamazoo-Naz_BMS Retrofit_Emergen	42565013	Kalamazoo	Modernization of heater relighters to provide consistant and reliable heating of gas	51,895						Y
GM-95032	W-3_Williamston CG_BMS Retrofit_Emerger	42565015	Williamston	Modernization of heater relighters to provide consistant and reliable heating of gas	55,495						Y

U21981-AG-CE-0302
Page **1** of **1**

Question:

82. Refer to Exhibit A-12 (MPG-2), Schedule B-5.3, sponsored by Mr. Griffin. Please expand this schedule to include actual amounts for 2023 and 2025 and forecasted amounts for 2026 and 2027 for lines 1-4 and provide it in Excel.

Response:

See attachment U21981-AG-CE-0302-WAGGENER_ATT_1 for the requested information.

Witness: Jordan L Waggener
Date: March 25, 2026

U21981-AG-CE-302-WAGGENER

~~Schedule: B-5.3~~

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures Transmission & Distribution Plant
($000)

Case No.:	U-21981
Exhibit No.:	~~A-12 (MPG-2)~~
Schedule:	~~B-5.3~~
Page:	1 of 1
Witness:	JLWaggener
Date:	March 2026

	(a)		(b)				(c)	(d)	(e)	(f)
		Actual	**Historical Year**	**Preliminary Actuals**	**Forecasted**	**Forecasted**	**Projected Bridge Period**			**Projected Test Year**
Line No	**Description**	**12 Mos Ended 12/31/2023**	**12 Mos Ended 12/31/2024**	**12 Mos Ended 12/31/2025**	**12 Mos Ending 12/31/2026**	**12 Mos Ending 12/31/2027**	**12 Mos Ending 12/31/2025**	**10 Mos Ending 10/31/2026**	**22 Mos Ending 10/31/2026**	**12 Mos Ending 10/31/2027**
1	Asset Relocation	6,168	17,019	20,517	26,417	8,495	24,867	24,656	49,523	9,690
2	Regulatory Compliance	36,139	33,968	34,225	25,905	49,213	29,561	22,609	52,170	46,471
3	Capacity/Deliverability	308,275	266,547	138,319	156,230	159,855	144,184	138,386	282,570	170,902
4	Total Capital	350,582	317,534	193,061	208,552	217,563	198,611	185,651	384,262	227,064

			Projected						
			10 Mos Ending 10/31/2025				**12 Mos Ending 10/31/2026**	**12 Mos Ending 10/31/2027**	**34 Mos Ending 10/31/2027**
5	Asset Relocation		19,065				30,458	9,690	59,213
6	Regulatory Compliance		28,772				23,398	46,471	98,641
7	Capacity/Deliverability		133,630				148,940	170,902	453,472
8	Total Capital		181,467				202,795	227,064	611,326

U21981-AG-CE-0318
Page **1** of **2**

Question:

98. Refer to pages 30-31 of Mr. Joyce's direct testimony on the sale of the Northville storage field gas dehydration/liquid handling project. Please:

a. Explain whether the Northville storage field is intended to be used to meet peak gas demand during the coldest months or to supplement gas purchases during the winter months to meet normal gas demand.

b. Provide the total cost of the dehydration project from inception to completion. If the total cost changed from Case U-21806, provide the increase or decrease and explain why.

c. It appears that the Company is now also proposing a well rehabilitation program for the wells at this field. If yes, explain why and whether this rehabilitation was disclosed in Case No. U-21806, by whom, and where in testimony.

d. Provide the actual moisture content per LB/MMCF experienced during each withdrawal in each year 2018 through 2025 in Excel.

e. Provide the number of days that gas withdrawals occurred during each year in 2021 through 2025.

f. Provide the volume of gas withdrawn on each occasion in 2021 through 2025 and as a percentage of total field capacity in Excel.

g. Provide the volume of gas withdrawn on each occasion in 2021 through 2025 as a percentage of the total gas supply in the pipeline system fed partially from the Northville storage field.

h. If the gas dehydration unit had been in place during the 2023-2024, 2024-2025, and 2025-2026 winter seasons, provide the number of times and volume of gas that the Company would have withdrawn from the field to meet peak demand during each of the three winters.

Response:

a. The Northville storage fields are designated as peaker storage fields and as such are intended to be used to meet peak demand on the coldest days. Having the storage capability of the Northville fields available during winter purchase planning also allows for minimized gas purchase requirements for all weather conditions.

b. Please reference attachment U21981-AG-CE-0318-Joyce_ATT_1. The increase of approximately $3M is due to the higher than budgeted construction contractor cost after the bidding process.

c. No. Lines 16-17 on page 30 of my direct testimony "A breakdown of well rehabilitation work scope is included in Exhibit A-100 (TKJ-5)", is a reference to an overview of the well rehab program. It has been in progress since 2017 including work completed at the Northville storage fields and is described on pages 34 through 37.

d. Please reference attachment U21981-AG-CE-0318-Joyce_ATT_2.

e. Please reference attachment U21981-AG-CE-0318-Joyce_ATT_3.

f. Please reference attachment U21981-AG-CE-0318-Joyce_ATT_3.

g. Please reference attachment U21981-AG-CE-0318-Joyce_ATT_3.

h. The 2023-2024, 2024-2025, and 2025-2026 winter seasons did not have weather reach a level where dispatch of the Northville fields was necessary. Due to the lack of gas dehydration equipment at Northville, these storage fields are placed last on the dispatch priority. Meaning, they would only be called on if all other supply was insufficient to meet customer demand. If dehydration equipment had been available, the Company would have cycled some level of gas from the Northville fields to support system operations, flow testing, and validation of storage field performance. Based on historical usage and past flow testing, estimated volumes for this flow would be 150 MMcf from Northville Reef, 150 MMcf from Lyon 29, and 50 MMcf from Lyon 34. Gas dehydration is needed for reliable supply and higher utilization from the Northville storage fields and to minimize downstream customer and asset integrity impacts due to high moisture content in the gas from the Northville storage fields.

Witness: TIMOTHY K JOYCE
Date: April 2, 2026

MICHIGAN PUBLIC SERVICE COMMISSION **U21981-AG-CE-0318-Joyce_ATT_1** Case No. U-21981

Consumers Energy Company

Gas Compression & Storage

Northville Lyon 29/34 Liquid Handling Actuals and Projected Spend ($000)

For Gas Rate Case

		Actuals								Projected	
Project Definition		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
GS-00365	NVL- Lyon 29-34 Liquid Handling	91	(89)	-	-	1,149	1,191	6,122	12,893	18,905	135
Total Project Cost											40,396

MICHIGAN PUBLIC SERVICE CO **U21981-AG-CE-0318-Joyce_ATT_2** Case No. U-21981

Consumers Energy Company

Gas Compression & Storage

Northville Lyon 29/34 Liquid Handling actual moisture content per LB/MMCF experienced during each withdrawal in each year 2018 through 2025

For Gas Rate Case

	Test Date	Moisture Range
Lyon 29 Field	January 2019	7 to 9
Lyon 29-1	March 2020	1.9 to 7.8
Lyon 29-2	March 2020	4.9 to 8.2
Lyon 29-3	March 2020	5 to 7.9
Lyon 34 Field	January 2019	10 to 12
Lyon 2-34	March 2020	9 to 12
Lyon 3-34	March 2020	11 to 14
Lyon 4-34	March 2020	8 to 17
Northville Reef Field	January 2019	7 to 14
N-211	March 2020	5.7 to 6.8
N-301A	March 2020	6.7 to 7.3
N-302A	March 2020	8 to 13
N-303	March 2021	2 to 56*

MICHIGAN PUBLIC SERVICE CO

U21981-AG-CE-0318-Joyce_ATT_3

Case No. U-21981

Consumers Energy Company

Gas Compression & Storage

Northville Lyon 29/34 Liquid Handling gas withdrawal data from 2021 through 2025.

For Gas Rate Case

Year	Field	Number of days that gas withdrawals occurred	Volume withdrawn, as a percent of total field capacity	Volume withdrawn, as a percent of total system send out	Withdrawal Volume (MMscf)	Notes	Total Field Capacity (MMscf)	Total system send out (MMscf)
2021	Lyon 29	0	0.00%	0.00%	0		2179.59	290,731
	Lyon 34	0	0.00%	0.00%	0		1358	290,731
	Northville Reef	1	2.00%	0.01%	24.6	Flow testing of new well N-303	1220	290,731
2022	Lyon 29	1	5.60%	0.04%	121.7	Flowed for ~12 hours before high moisture	2179.59	308,734
	Lyon 34	0	0.00%	0.00%	0	Flowed for <15 minutes due to valve	1358	308,734
	Northville Reef	1	0.30%	0.00%	3.9	Flowed for ~2 hours before high moisture	1220	308,734
2023	Lyon 29	0	0.00%	0.00%	0		2179.59	296,564
	Lyon 34	0	0.00%	0.00%	0		1358	296,564
	Northville Reef	0	0.00%	0.00%	0		1220	296,564
2024	Lyon 29	0	0.00%	0.00%	0		2179.59	277,138
	Lyon 34	0	0.00%	0.00%	0		1358	277,138
	Northville Reef	0	0.00%	0.00%	0		1220	277,138
2025	Lyon 29	0	0.00%	0.00%	0		2179.59	299,714
	Lyon 34	0	0.00%	0.00%	0		1358	299,714
	Northville Reef	0	0.00%	0.00%	0		1220	299,714

U21806-AG-CE-0506
Page **1** of **2**

Question:

168. Refer to page 33 and 34 of Mr. Joyce's direct testimony on the Lyon 29/34 project. Please:

a. Provide the cost of the project by year from inception to completion.

b. Provide a copy of the analysis performed by the Company to justify undertaking this project.

c. Explain what alternatives were evaluated, and what financial benefits will result from completion of the project. Provide a copy of the cost/benefit analysis performed in Excel with formulas intact and all assumptions explained.

d. Provide the phases of project development with timeline and related cost and the phase that the project is currently in.

e. Explain what has changed since the Company proposed this project in Case No. U-21490. Provide any updates to the responses to the Attorney General's discovery requests in that case for this project.

f. Provide the actual moisture content per LB/MMCF experienced during each withdrawal in each year 2018 through 2024 in Excel.

g. Provide the number of days that gas withdrawals occurred during each year in 2021 through 2024.

h. Provide the volume of gas withdrawn on each occasion in 2021 through 2024 and as a percent of total field capacity.

i. Provide the volume of gas withdrawn on each occasion in 2021 through 2024 as a percent of the total gas supply in pipeline system fed partially from the Northville storage field.

Response:

a. Please reference U21806-AG-CE-0506-Joyce_ATT_1 for cost information the project.

b. Please reference U21806-AG-CE-0506-Joyce_ATT_2 for a copy of the analysis performed by the Company to justify undertaking this project.

c. Please reference U21806-AG-CE-0506-Joyce_ATT_2 for overview of the alternatives that were evaluated.

d. Timeline for the Lyon 29-34 project is as follows: engineering and equipment procurement in 2023 and 2024, construction in 2025 and 2026, and in-service in 2026, and project close-out in 2027.

e. Detailed engineering, construction and material procurement has progressed with construction scheduled to begin in 2025 and conclude in 2026.

U21490-AG-CE-0315 – Updates provided in the responses to this question.
U21490-AG-CE-0316 -Updates provided in the response to U21806-AG-CE-507
U21490-AG-CE-0476 – No updates
U21490-AG-CE-0477 – No updates
U21490-AG-CE-0478 – No updates

f. Please reference U21806-AG-CE-0506-Joyce_ATT_3 for the actual moisture content per LB/MMCF experienced during each withdrawal in each year 2018 through 2024.

g. Please reference U21806-AG-CE-0506-Joyce_ATT_4 for the number of days that gas withdrawals occurred during each year in 2021 through 2024.

h. Please reference U21806-AG-CE-0506-Joyce_ATT_4 for the volume of gas withdrawn on each occasion in 2021 through 2024 and as a percent of total field capacity.

i. Please reference U21806-AG-CE-0506-Joyce_ATT_4 for the volume of gas withdrawn on each occasion in 2021 through 2024 as a percent of the total gas supply in pipeline system fed partially from the Northville storage field.

Witness: Timothy K. Joyce
Date: March 17, 2025

MICHIGAN PUBLIC SERVICE COMMISSION **U21806-AG-CE-0506-Joyce_ATT_1** Case No. U-21806

Consumers Energy Company

Gas Compression & Storage

Northville Lyon 29/34 Liquid Handling Actuals and Projected Spend ($000)

For Gas Rate Case

		Actuals							Projected		
Project Definition		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
GS-00365	NVL- Lyon 29-34 Liquid Handling	91	(89)	-	-	1,149	1,191	6,122	28,835	72	0

Total $37,371

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CECo Response AG-CE-0319

Case No: U-21981
Exhibit: AG-29
April 15, 2026
Page 1 of 1

U21981-AG-CE-0319
Page **1** of **1**

Question:

99. Refer to Table 7 on page 33 of Mr. Joyce's direct testimony on new well drilling projects. Please:

a. Expand the table to include the same information for wells drilled in 2022 and 2023, update the 2025 information to actual, show the cost of individual wells for each field for each year, and provide the expanded information and updated table in Excel.

b. For each well in the expanded table in subpart (a), identify the type of well drilled or to be drilled, i.e., new well, rework/re-entry, etc.

Response:

Drill Year	Location	Field	New Well ID	Projected Cost	Preliminary Actual Cost	Well Type
2022	St. Clair	Lenox	L-201	-	$8,271,841	New
2023	Marion	Winterfield	W-994	$3,338,861	$3,440,149	Re-entry
	Marion	Cranberry	C-995	$6,300,178	$6,225,368	New
	Marion	Cranberry	C-996	$5,251,591	$5,101,952	New
2024	Overisel	Overisel	O-305	$10,083,691	$9,812,582	New
	Marion	Cranberry	C-994	$6,438,192	$6,172,558	New
2025	Marion	Winterfield	W-1004, W-1005, W-1006	$19,232,931	$9,433,899	New
	Marion	Cranberry	C-1103	$7,384,944	$5,010,719	New
2026	St. Clair	Puttygut	P-301, P-302	$13,250,462	-	New
	St. Clair	Four Corners	FC-201	$4,796,996	-	Re-entry
	Ray	Ray	R-510,R-511	$13,250,462	-	New
2027	Marion	Winterfield	W-1007, W-1008, W-1009	$17,682,671	-	New
	Marion	Winterfield	W-996, W-998	$7,744,697	-	Re-entries
	Overisel	Overisel	O-306	$6,528,734	-	New

Witness: TIMOTHY K JOYCE
Date: March 30, 2026

Question:

104. Refer to WP-TKJ-4 showing compression capital projects. For the following projects: GC-00630, GC-00775, GC-00784, 00801, GC-00124, GC-00706, GC-00790, GC-00204, GC-00774, B- GC-00136, GC-00785, GC-00829, GC-00839, GC-00876, B- GC-00153, GC-00885, B- GC-00048, and B- GC-00154, please identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Response:

Project Number	Project Description	Project Status	Next Phase Start Date
GC-00630	MRC-P2 Cooling Wtr System Inst	Construction	Completed Q4 2026
GC-00775	NVL-U1&2 Eng Ctrl Repl	Construction	Completed Q4 2026
GC-00784	NVL-Garrett RV Repl	Engineering Design	Contractor Bids Requested Q3 2026
GC-00801	NVL-Plt1 JW Repl	Engineering Design	Contractor Bids Requested Q4 2026
GC-00124	OVC-Station Cntrls Upgrade	Contractor Bids Requested	Construction Q2 2026
GC-00706	OVC-Fuel Gas Reg Repl	Contractor Bids Requested	Construction Q2 2026
GC-00790	OVC-Plt1 NOX Red	Contractor Bids Requested	Construction Q4 2026
GC-00204	RAY-Valves 540 & 542 Repl	Contractor Bids Requested	Construction Q2 2026
GC-00774	RAY-Plt3 PG-Comp Vlv Repl	Engineering Design	Contractor Bids Requested Q2 2026
B-GC-00136	STC-PLT1-Unit 1-2 Solar Turbine Replacement	Contractor Bids Requested	Construction Q2 2026
GC-00785	STC-Plt134 Blow Down VS Repl	Project Planning or Scoping	Conceptual Design Q4 2026
GC-00829	STC-Common 800 S Vlv Repl	Engineering Design	Contractor Bids Requested Q2 2026
GC-00839	STC-PLT4-TO Reboiler Bldg Upgrade	Engineering Design	Contractor Bids Requested Q4 2026
GC-00876	STC-Common Scrubbers	Conceptual Design	Engineering Design Q3 2026

B-GC-00153	WPC Plt3 Aux Building Expansion	Project Planning/Scoping	Conceptual Design Q4 2026
GC-00885	WPC-P2 Turbine Inst	Project Planning/Scoping	Conceptual Design Q4 2026
B-GC-00048	Reliability Program	Preliminary Assessment	Project Planning or Scoping Q2 2026
B-GC-00154	JXN_Methane Reduction Program	Preliminary Assessment	Project Planning or Scoping Q2 2026

Witness: TIMOTHY K JOYCE
Date: April 1, 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

CECo Workpaper WP-TKJ-4

Case No: U-21981
Exhibit: AG-30
April 15, 2026
Page 3 of 5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Compression Capital Detail (2025-2027)
For Gas Rate Case - December 2025
($000)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
										Projected Bridge Year	Projected Test Year	Projected			
Line No.	Site	Title	Internal Approval	Has a Business Case	2025 7+5 Fcst	2026	2027	12 Mos Ending 12/31/2025	10 Mos Ending 10/31/2026	22 Mos Ending 10/31/2026	12 Mos Ending 10/31/2027	10 Mos ending in 10/31/25	12 Mos. Ending 10/31/26	12 Mos Ending 10/31/2027	34 Mos ending 10/31/27
1	Freedom	GC-05000: FDM-Freedom Plant 3	Yes	Yes	9	0	0	9	0	9	0	9	0	0	9
2		TOTAL FREEDOM UPGRADE			9	0	0	9	0	9	0	9	0	0	9
3															
4	Site	Title			2025 7+5 Fcst	2026	2027								
5	Freedom	GC-00488: FDM-Compression Capital Tools	Yes	No	7	0	0	7	0	7	0	7	0	0	7
6	Freedom	GC-00816: FDM-Plt3 Comp eRCM Repl	Yes	Yes	15	0	0	15	0	15	0	15	0	0	15
7	Freedom	GC-00843: FDM-Plt 3 GC O2 Detector Inst	Yes	Yes	0	51	0	0	44	44	7	0	44	7	51
8	Freedom	GC-00871: FDM-Comp Bldg Heat Trace Inst	Yes	Yes	0	276	0	0	241	241	36	0	241	36	276
9	Freedom	GC-00872: FDM-P3 Stair Inst	Yes	Yes	3	0	0	3	0	3	0	3	0	0	3
10	Freedom	GC-00873: FDM-Plt3 Unit 3-3 JW Pump Repl	Yes	Yes	31	0	0	31	0	31	0	31	0	0	31
11	Freedom	GC-00874: FDM-Plt3 Unit 3-2 JW Pump Repl	Yes	Yes	41	0	0	41	0	41	0	32	9	0	41
12	Freedom	GC-00875: FDM-UPS Batt Repl	Yes	Yes	0	76	0	0	66	66	10	0	66	10	76
13	Freedom	GC-00928: FDM-Unit 3-2 Air Start Repl	Yes	Yes	0	0	0	0	0	0	0	0	0	0	0
14		TOTAL FREEDOM			97	403	0	97	350	447	52	88	359	52	499
15															
16	Site	Title			2025 7+5 Fcst	2026	2027								
17		B-GC-00152: MRCS - Plt-2 Compressor Bldg Window Repl	Yes	Yes	0	1,961	0	0	1,706	1,706	255	0	1,706	255	1,961
18	Muskegon River	GC-00426: MRC-Plnt 2 Lean TEG Repl	Yes	Yes	34	0	0	34	0	34	0	34	0	0	34
19	Muskegon River	GC-00463: MRC-SCP Inst	Yes	Yes	0	0	501	0	0	0	436	0	0	436	436
20	Muskegon River	GC-00485: MRC-Compression Capital Tools	Yes	No	20	0	0	20	0	20	0	20	0	0	20
21	Muskegon River	GC-00597: MRC-Plt 2 Jet Installation	Yes	Yes	0	0	0	0	0	0	0	0	0	0	0
22	Muskegon River	GC-00630: MRC-P2 Cooling Wtr System Inst	Yes	Yes	16,622	1,798	0	16,622	1,704	18,327	94	13,871	4,456	94	18,421
23	Muskegon River	GC-00639: MRC-Plnt 2 Firegate Vlvs Repl	Yes	Yes	(0)	0	0	(0)	0	(0)	0	(0)	0	0	(0)
24	Muskegon River	GC-00647: MRC-Plt 3 FireGate Vlv(s) Rmvl	Yes	Yes	16	0	0	16	0	16	0	16	0	0	16
25	Muskegon River	GC-00655: MRC-Plt-2 119,120,219 Vlv Repl	Yes	Yes	0	360	704	0	314	314	659	0	314	659	973
26	Muskegon River	GC-00656: MRC-Plt-2 113, 115, Vlv Repl	Yes	Yes	0	360	453	0	314	314	441	0	314	441	754
27	Muskegon River	GC-00670: MRC-P2 Dehy Inlet Vlv(s) Repl	Yes	Yes	0	309	459	0	269	269	439	0	269	439	708
28	Muskegon River	GC-00676: MRC-Plt 2 Air Comp Inst	Yes	Yes	0	0	0	0	0	0	0	0	0	0	0
29	Muskegon River	GC-00688: MRC-Plt2 IR Equipment Rmvl	Yes	Yes	(20)	0	0	(20)	0	(20)	0	(20)	0	0	(20)
30	Muskegon River	GC-00693: MRC-Plt 2 Asphalt Repl	Yes	Yes	0	621	615	0	540	540	615	0	540	615	1,156
31	Muskegon River	GC-00749: MRC-Plt2 Containment Liner Repl	Yes	Yes	(11)	0	0	(11)	0	(11)	0	(11)	0	0	(11)
32	Muskegon River	GC-00813: MRC-Plt2 FG Heater Repl	Yes	Yes	0	357	460	0	311	311	446	0	311	446	757
33	Muskegon River	GC-00842: MRC-Plt2 H10 Rbld	Yes	Yes	0	509	13,102	0	443	443	11,465	0	443	11,465	11,908
34	Muskegon River	GC-00850: MRC-Plt2 DeHy Upgrd	Yes	Yes	0	0	1,002	0	0	0	872	0	0	872	872
35	Muskegon River	GC-00852: MRC-Dehy Twr Gas Outlet DPT Repl	Yes	Yes	56	0	0	56	0	56	0	56	0	0	56
36	Muskegon River	GC-00878: MRC-H12 Turbo Repl	Yes	Yes	0	280	0	0	243	243	36	0	243	36	280
37	Muskegon River	GC-00923: MRC-Small Vlv & Lvl Trans Repl	Yes	Yes	0	108	0	0	94	94	14	0	94	14	108
38	Muskegon River	GC-00941: MRC-Station Vent Point Monitoring Inst	Yes	Yes	0	388	0	0	338	338	51	0	338	51	388
39	Muskegon River	GC-00945: MRC-Pump Transmitter Gas Detector Repl	Yes	Yes	14	0	0	14	0	14	0	14	0	0	14
40	Muskegon River	GC-00961: MRC-Plt2 Aux Bld Htr Upgrade	Yes	Yes	48	0	0	48	0	48	0	28	20	0	48
41		TOTAL MUSKEGON RIVER			16,779	7,052	17,295	16,779	6,275	23,054	15,823	14,007	9,046	15,823	38,877
42															
43	Site	Title			2025 7+5 Fcst	2026	2027								
44	Northville	GC-00445: NVL-Air Comp #2 Repl	Yes	Yes	0	526	1,515	0	458	458	1,386	0	458	1,386	1,844
45	Northville	GC-00487: NVL-Compression Capital Tools	Yes	No	0	0	0	0	0	0	0	0	0	0	0
46	Northville	GC-00638: NVL-Fire Gate Valve Repl	Yes	Yes	1	0	0	1	0	1	0	1	0	0	1
47	Northville	GC-00775: NVL-U1&2 Eng Ctrl Repl	Yes	Yes	3,156	4,397	980	3,156	3,463	6,618	1,868	1,804	4,814	1,868	8,487
48	Northville	GC-00784: NVL-Garrett RV Repl	Yes	Yes	213	1,927	700	213	1,189	1,402	1,406	127	1,275	1,406	2,808
49	Northville	GC-00788: NVL-Comp Air Sys Upgrd	Yes	Yes	0	526	2,019	0	458	458	1,825	0	458	1,825	2,283
50	Northville	GC-00801: NVL-Plt1 JW Repl	Yes	Yes	1,467	2,999	1,430	1,467	2,055	3,522	2,271	830	2,692	2,271	5,793
51	Northville	GC-00833: NVL-Plt1 Process Gas Vlv Act Repl	Yes	Yes	0	766	0	0	666	666	100	0	666	100	766
52	Northville	GC-00847: NVL-GC O2 Det inst	Yes	Yes	0	51	0	0	44	44	7	0	44	7	51
53	Northville	GC-00893: NVL-Plt1 Mkt Gas Cooler Repl	Yes	Yes	0	0	494	0	0	0	429	0	0	429	429
54	Northville	GC-00911: NVL-GV501/GV5182W Act Repl	Yes	Yes	51	0	0	51	0	51	0	51	0	0	51
55	Northville	GC-00920: NVL-Stn Vent Pt Monitor Inst	Yes	Yes	0	0	90	0	0	0	78	0	0	78	78
56	Northville	GC-00924: NVL-RV25 Heat Trace Inst	Yes	Yes	2	0	0	2	0	2	0	2	0	0	2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Compression Capital Detail (2025-2027)
For Gas Rate Case - December 2025
($000)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
										Projected Bridge Year	**Projected Test Year**	**Projected**			
Line No.	**Site**	**Title**	**Internal Approval**	**Has a Business Case**	**2025 7+5 Fcst**	**2026**	**2027**	**12 Mos Ending 12/31/2025**	**10 Mos Ending 10/31/2026**	**22 Mos Ending 10/31/2026**	**12 Mos Ending 10/31/2027**	**10 Mos ending in 10/31/25**	**12 Mos. Ending 10/31/26**	**12 Mos Ending 10/31/2027**	**34 Mos ending 10/31/27**
58															
59	**Site**	**Title**			**2025 7+5 Fcst**	**2026**	**2027**								
60	Overisel	B-GC-00134: OVS-Plt_1-Eng_Ign_Sys-Repl	Yes	Yes	0	280	0	0	243	243	36	0	243	36	280
61	Overisel	B-GC-00135: OVCS-Plt_1-Fld_Htr_Fuel_Gas-PSV104046-Repl	Yes	Yes	0	206	54	0	179	179	74	0	179	74	253
62	Overisel	GC-00124: OVC-Station Cntrls Upgrade	Yes	Yes	4,674	5,845	450	4,674	5,417	10,091	876	3,735	6,356	876	10,967
63	Overisel	GC-00484: OVC-Compression Capital Tools	Yes	No	20	0	0	20	0	20	0	20	0	0	20
64	Overisel	GC-00706: OVC-Fuel Gas Reg Repl	Yes	Yes	318	3,848	100	318	3,533	3,851	413	223	3,629	413	4,264
65	Overisel	GC-00759: OVC-Unitized Cooling Inst	Yes	Yes	2,704	299	0	2,704	229	2,933	70	2,839	94	70	3,003
66	Overisel	GC-00763: OVC-Sep Access Platform Repl	Yes	Yes	0	0	0	0	0	0	0	0	0	0	0
67	Overisel	GC-00780: OVC-Plt1 FG401 Vlv Repl	Yes	Yes	192	920	0	192	846	1,039	74	175	864	74	1,112
68	Overisel	GC-00790: OVC-Plt1 NOX Red	Yes	Yes	7,481	10,391	5,100	7,481	9,513	16,994	5,681	5,226	11,768	5,681	22,675
69	Overisel	GC-00795: OVC-Plt1 U2 Ex Manifold Repl	Yes	Yes	382	0	0	382	0	382	0	379	4	0	382
70	Overisel	GC-00799: OVC- U2 Turbo Rebuild	Yes	Yes	(0)	0	0	(0)	0	(0)	0	(0)	0	0	(0)
71	Overisel	GC-00803: OVC-Plt1 PG Field Reg Repl	Yes	Yes	0	0	744	0	0	0	647	0	0	647	647
72	Overisel	GC-00837: OVC-Plt1 Lube Oil Ext Inst	Yes	Yes	405	1,301	6,101	405	1,131	1,536	5,908	254	1,282	5,908	7,444
73	Overisel	GC-00844: OVC-Plt1 Aux Bldg RIM	Yes	Yes	(7)	0	0	(7)	0	(7)	0	(7)	0	0	(7)
74	Overisel	GC-00886: OVC-Plt1 Salem Fld Htr Repl	Yes	Yes	0	0	745	0	0	0	648	0	0	648	648
75	Overisel	GC-00902: OVC-Plt1 EM Gen Mon Press Reg Repl	Yes	No	0	0	0	0	0	0	0	0	0	0	0
76	Overisel	GC-00921: OVC-Plt1 Dehy-Twr 2 2-PDIT Repl	Yes	Yes	(2)	0	0	(2)	0	(2)	0	(2)	0	0	(2)
77	Overisel	GC-00949: OVC-Plt1 DeHy Elec Hoist	Yes	Yes	0	511	0	0	444	444	66	0	444	66	511
78	Overisel	GC-00963: OVC-Plt1 Compressor Barring Jack Repl	Yes	Yes	0	218	0	0	189	189	28	0	189	28	218
79	Overisel	GC-10375: JXN-Unit Monitoring Program	Yes	Yes	1	0	0	1	0	1	0	1	0	0	1
80		TOTAL OVERISEL			16,169	23,817	13,293	16,169	21,725	37,894	14,522	12,843	25,052	14,522	52,416
81															
82	**Site**	**Title**			**2025 7+5 Fcst**	**2026**	**2027**								
83	Ray	GC-00204: RAY-Valves 540 & 542 Repl	Yes	Yes	262	2,398	100	262	2,223	2,485	273	207	2,278	273	2,758
84	Ray	GC-00397: RAY-Plant 1&2 Emer Gen Rmvl	Yes	Yes	2,428	50	0	2,428	50	2,478	0	2,428	50	0	2,478
85	Ray	GC-00483: RAY-Compression Capital Tools	Yes	No	20	100	0	20	90	110	10	20	90	10	120
86	Ray	GC-00580: RAY-Tnk Cntmnt Liner Repl 25,26,27,28,29	Yes	No	(145)	0	0	(145)	0	(145)	0	(145)	0	0	(145)
87	Ray	GC-00657: RAY-Emergent Capital Expense (2019)	Yes	No	(1)	0	0	(1)	0	(1)	0	(1)	0	0	(1)
88	Ray	GC-00677: RAY-Plnt 2 Blowdown Long Term Solution	Yes	Yes	(8)	0	0	(8)	0	(8)	0	(8)	0	0	(8)
89	Ray	GC-00736: RAY–Stn Compressed Air Sys Upgrd	Yes	Yes	1,812	0	0	1,812	0	1,812	0	1,700	113	0	1,812
90	Ray	GC-00742: RAY-P1 Dehy Bypass Ctrl Vlv Repl	Yes	Yes	8	0	0	8	0	8	0	8	0	0	8
91	Ray	GC-00774: RAY-Plt3 PG-Comp Vlv Repl	Yes	Yes	505	4,101	200	505	3,831	4,336	452	274	4,062	452	4,788
92	Ray	GC-00776: RAY-Plt1&2 Pipe Supt Repl	Yes	Yes	781	859	0	781	747	1,528	112	250	1,278	112	1,640
93	Ray	GC-00779: RAY-Plt1 Flow Ctrl Vlv Repl	Yes	Yes	65	30	0	65	22	86	8	52	34	8	94
94	Ray	GC-00787: RAY-Plt3 Still Clmn 3way Vlv Repl	Yes	Yes	60	30	0	60	22	81	8	45	36	8	89
95	Ray	GC-00789: RAY-UPS Batt Repl	Yes	Yes	0	0	0	0	0	0	0	0	0	0	0
96	Ray	GC-00792: RAY-Plt3 FG Rec Vlv Op Repl	Yes	Yes	8	0	0	8	0	8	0	8	0	0	8
97	Ray	GC-00860: RAY-DeHy Sys OP Pro	Yes	Yes	0	249	739	0	217	217	675	0	217	675	892
98	Ray	GC-00862: RAY-Meter Run Repl	Yes	Yes	0	494	4,517	0	430	430	3,994	0	430	3,994	4,424
99	Ray	GC-00864: RAY-Unit 3-4 Turbo Rbld	Yes	Yes	0	280	0	0	243	243	36	0	243	36	280
100	Ray	GC-00865: RAY-Unit 3-1 Starter Repl	Yes	Yes	11	0	0	11	0	11	0	11	0	0	11
101	Ray	GC-00899: RAY-Tank 08 Retire	Yes	Yes	0	763	252	0	664	664	318	0	664	318	982
102	Ray	GC-00904: RAY-P2 Scrub S-4 Relief Vlv Repl	Yes	Yes	0	106	0	0	93	93	14	0	93	14	106
103	Ray	GC-00905: RAY-P1 Scrub S-3 Relief Vlv Repl	Yes	Yes	0	91	0	0	79	79	12	0	79	12	91
104	Ray	GC-00919: RAY-Plt1.2 BD Sys ReDesign	Yes	Yes	0	177	854	0	154	154	766	0	154	766	920
105	Ray	GC-00933: RAY-Unit 3-5 Eng Insul Repl	Yes	Yes	57	0	0	57	0	57	0	57	0	0	57
106	Ray	GC-00936: RAY-U3-4 ENGINE INSULATION REPL	Yes	Yes	61	0	0	61	0	61	0	61	0	0	61
107	Ray	GC-00937: RAY-U3-3 ENGINE INSULATION REPL	Yes	Yes	0	71	0	0	61	61	9	0	61	9	71
108	Ray	GC-00938: RAY-U3-1 ENGINE INSULATION REPL	Yes	Yes	69	0	0	69	0	69	0	69	0	0	69
109	Ray	GC-00942: RAY-Replace RV-37	Yes	Yes	0	99	0	0	86	86	13	0	86	13	99
110	Ray	GC-00943: RAY-Sta Fence Line EM Inst	Yes	Yes	202	0	0	202	0	202	0	162	40	0	202
111	Ray	GC-00950: RAY-PLC Redundant Pwr Inst	Yes	Yes	0	182	0	0	158	158	24	0	158	24	182
112	Ray	GC-00953: RAY-UNIT 3-2 ENGINE INSULATION REPL	Yes	Yes	0	85	0	0	74	74	11	0	74	11	85
113	Ray	GC-00954: RAY-Repl Failed Transmitters JE	Yes	Yes	15	0	0	15	0	15	0	15	0	0	15
114	Ray	GC-00955: RAY-Repl Failed Transmitters	Yes	Yes	50	0	0	50	0	50	0	0	50	0	50
115	Ray	GC-00956: RAY- Vent Pt Monitoring Inst	Yes	Yes	0	0	749	0	0	0	652	0	0	652	652
116		RAY TOTAL			6,259	10,163	7,411	6,259	9,244	15,502	7,386	5,212	10,290	7,386	22,889
117															

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Compression Capital Detail (2025-2027)
For Gas Rate Case - December 2025
($000)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
										Projected Bridge Year	Projected Test Year	Projected			
Line No.	Site	Title	Internal Approval	Has a Business Case	2025 7+5 Fcst	2026	2027	12 Mos Ending 12/31/2025	10 Mos Ending 10/31/2026	22 Mos Ending 10/31/2026	12 Mos Ending 10/31/2027	10 Mos ending in 10/31/25	12 Mos. Ending 10/31/26	12 Mos Ending 10/31/2027	34 Mos ending 10/31/27
118	Site	Title			2025 7+5 Fcst	2026	2027								
119	St. Clair	B-GC-00136: STC-PLT1-Unit 1-2 Solar Turbine Replacement	Yes	Yes	0	1,214	285	0	1,056	1,056	406	0	1,056	406	1,462
120	St. Clair	B-GC-00158: STC FG Heater HMI Replacement	Yes	Yes	4	0	0	4	0	4	0	4	0	0	4
121	St. Clair	GC-00651: STC-1-1,1-2 Aftercooler Repl	Yes	Yes	5,102	50	0	5,102	50	5,152	0	5,077	75	0	5,152
122	St. Clair	GC-00768: STC-Plt3 Lube Oil	Yes	Yes	0	469	0	0	408	408	61	0	408	61	469
123	St. Clair	GC-00770: STC-Plt1 FG Piping Fltr	Yes	Yes	1,767	50	0	1,767	48	1,815	2	1,737	78	2	1,817
124	St. Clair	GC-00785: STC-Plt134 Blow Down VS Repl	Yes	Yes	0	494	3,518	0	430	430	3,125	0	430	3,125	3,555
125	St. Clair	GC-00786: STC-3,4 Left Bank Turbo Repl	Yes	Yes	1	0	0	1	0	1	0	1	0	0	1
126	St. Clair	GC-00829: STC-Common 800 S Vlv Repl	Yes	Yes	416	3,499	300	416	3,143	3,560	640	264	3,295	640	4,199
127	St. Clair	GC-00836: STC-Fuel Gas Vent Vlv Repl	Yes	Yes	22	0	0	22	0	22	0	22	0	0	22
128	St. Clair	GC-00839: STC-PLT4-TO Reboiler Bldg Upgrade	Yes	Yes	1,339	4,049	301	1,339	3,511	4,850	839	1,013	3,836	839	5,688
129	St. Clair	GC-00851: STC-UPS Batteries	Yes	Yes	0	0	0	0	0	0	0	0	0	0	0
130	St. Clair	GC-00876: STC-Common Scrubbers	Yes	Yes	0	247	1,490	0	215	215	1,329	0	215	1,329	1,544
131	St. Clair	GC-00906: STC-P1 Exhaust Duct Repl	Yes	Yes	0	535	0	0	465	466	70	0	465	70	535
132	St. Clair	GC-00932: STC-PLT3 Compressor Lube oil Pumps Repl	Yes	Yes	55	0	0	55	0	55	0	30	25	0	55
133	St. Clair	GC-00935: STC-Plt3 Compressor Lube Oil Accumulator	Yes	Yes	0	87	0	0	76	76	11	0	76	11	87
134		ST CLAIR TOTAL			8,706	10,694	5,895	8,706	9,403	18,109	6,481	8,149	9,960	6,481	24,590
135															
136	Site	Title			2025 7+5 Fcst	2026	2027								
137	White Pigeon	B-GC-00153: WPC Plt3 Aux Building Expansion	Yes	Yes	0	0	1,897	0	0	0	1,651	0	0	1,651	1,651
138	White Pigeon	GC-00486: WPC-Compression Capital Tools	Yes	No	19	0	0	19	0	19	0	19	0	0	19
139	White Pigeon	GC-00642: WPC-P1 Containment Liners Repl	Yes	Yes	(0)	0	0	(0)	0	(0)	0	(0)	0	0	(0)
140	White Pigeon	GC-00757: WPC-Solar Inst	Yes	Yes	1,442	1,039	0	1,442	963	2,405	77	586	1,819	77	2,482
141	White Pigeon	GC-00817: WPC-Inst O2 Sensing Equip GAB	Yes	Yes	0	51	0	0	44	44	7	0	44	7	51
142	White Pigeon	GC-00885: WPC-P2 Turbine Inst	Yes	Yes	0	2,036	15,071	0	1,771	1,771	13,377	0	1,771	13,377	15,148
143	White Pigeon	GC-00910: WPC-P3 Load Cell Repl	Yes	Yes	0	66	0	0	57	57	9	0	57	9	66
144	White Pigeon	GC-00913: WPC-Plt3 Tk Lvl Tm Repl	Yes	Yes	0	0	0	0	0	0	0	0	0	0	0
145	White Pigeon	GC-00916: WPC-PLC Redundant Pwr Inst	Yes	Yes	0	177	0	0	154	154	23	0	154	23	177
146	White Pigeon	GC-00917: WPC-Plt3 UPS Batt Repl	Yes	Yes	65	0	0	65	0	65	0	65	0	0	65
147	White Pigeon	GC-00918: WPC-Plt3 FG Recov Vlv Act Repl	Yes	Yes	(0)	0	0	(0)	0	(0)	0	(0)	0	0	(0)
148	White Pigeon	GC-00934: WPC-Plt3-25 Relief HT Insul Inst	Yes	Yes	106	86	0	106	75	181	11	106	75	11	192
149	White Pigeon	GC-00960: WPC-Plt1.2 Air Comp AC Repl	Yes	Yes	37	0	0	37	0	37	0	37	0	0	37
150	White Pigeon	GC-00962: WPC-Plt3 Vent Pt Monitoring Inst	Yes	Yes	0	0	100	0	0	0	87	0	0	87	87
151	White Pigeon	GC-00967: WPC-Plt1 & Plt2 Air Comp Check Valve Rep	Yes	Yes	84	0	0	84	0	84	0	84	0	0	84
152	White Pigeon	GC-00968: WPC-Unit 2-2 Fuel Line Spool Repl	Yes	Yes	9	0	0	9	0	9	0	9	0	0	9
153	White Pigeon	B-GC-00032: JXN - Operations Capital Tools	Yes	No	0	221	436	0	193	193	408	0	193	408	601
154	White Pigeon	B-GC-00033: JXN - Small Valves and Instrumentation	Yes	No	0	178	352	0	155	155	329	0	155	329	484
155	White Pigeon	B-GC-00045: JXN - Comp Engineer Analyzers	Yes	Yes	0	51	51	0	45	45	51	0	45	51	95
156	White Pigeon	B-GC-00048: Reliability Program	Yes	No	0	0	1,008	0	0	0	877	0	0	877	877
157	White Pigeon	B-GC-00049: System Safety Program	Yes	No	0	0	756	0	0	0	658	0	0	658	658
158	White Pigeon	B-GC-00050: Compliance & MSEA Program	Yes	Yes	0	0	756	0	0	0	658	0	0	658	658
159	White Pigeon	B-GC-00154: JXN_Methane Reduction Program	Yes	No	0	0	1,021	0	0	0	888	0	0	888	888
160		WHITE PIGEON TOTAL			1,763	3,904	21,448	1,763	3,455	5,219	19,109	907	4,312	19,109	24,328
161															
162	Site	Title			2025 7+5 Fcst	2026	2027								
163	Huron	B-GC-00133: HUR - PLC Redundant Power Installation	Yes	Yes	0	221	0	0	192	192	29	0	192	29	221
164	Huron	GC-00927: HUR-Inst Backup Gen	Yes	Yes	0	159	638	0	138	138	576	0	138	576	714
165		HURON TOTAL			0	379	638	0	330	330	605	0	330	605	935
166															
167		TOTAL FREEDOM UPGRADE			9	0	0	9	0	9	0	9	0	0	9
168		OTHER COMPRESSION PORTFOLIO - excludes Freedom upgrade			54,663	67,604	73,209	54,663	59,115	113,778	73,350	44,021	69,756	73,350	187,128
169		TOTAL COMPRESSION PORTFOLIO			54,672	67,604	73,209	54,672	59,115	113,787	73,350	44,031	69,756	73,350	187,137

U21981-AG-CE-0325
Page **1** of **1**

Question:

105. Refer to WP-TKJ-5 showing storage capital projects. For the following projects: GS-00543, GS-00465, GS-00468, GS-00504, GS-00505, GS-00505, GS-00506, GS-00509, GS-00510. GS-00515, GS-00520, and GS-00537, please identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Engineering Design, Contractor Bids Requested, Construction, Completed) and the date when the next phase will start.

Response:

Project Number	Project Description	Project Status	Next Phase Start Date
GS-00543	RAY-Liquid Blocker Vlvs 16" Inst	Project Planning	Engineering Design 2027
GS-00465	STC-4Corners Fac Upgrd	Preconstruction (Contractor Mobilization)	Construction begins 4/13/26
GS-00468	STC-Swan Crk Fac Upgrd	Preconstruction (Contractor Mobilization)	Construction begins 4/13/26
GS-00504	OVS-Sal 16in ML 1 Repl	Preliminary Design Engineering	Detailed Engineering begins Summer 2026.
GS-00505	OVS-Sal 8in ML 3 Repl	Preconstruction	Construction begins 3/31/26
GS-00506	OVS-Sal 16in ML 2 Repl	Detailed Engineering wrapping up now.	Construction begins August 2026.
GS-00509	OVS-Sal Lat 2N Repl	Engineering Design	Bid construction in early 2027.
GS-00510	OVS-Sal Lat 2W Repl	Engineering Design	Bid construction in early 2027.
GS-00515	OVS-Over 16in ML Repl	In detailed engineering	Bid construction in early 2027.
GS-00520	OVS-Sal Lat 2 Repl	Engineering Design	Bid construction in early 2027.
GS-00537	OVS-12in ML Repl	In detailed engineering	Bid construction in early 2027.

Witness: TIMOTHY K JOYCE
Date: April 2, 2026

U21981-SA-CE-317
Requested By: Kevin P. Spence (KPS-1 - 1)
Respondent: TIMOTHY K JOYCE
Date of Response: 3/6/2026
Page **1** of **2**

Question:

1. Referring generally to the direct testimony of Company witnesses; please:
a. Identify all prospective pipeline projects for which the Company anticipates filing Act 9 Applications with the Commission that have associated expenses included in the Company's filing in this proceeding.
b. For each prospective pipeline project identified in part "a" of this request, identify the Company exhibit, page, and line number, reflecting the associated expenses included in the Company's filing in this proceeding. If the identified Company exhibit(s) do not have a singular line item depicting the associated expenses for each prospective pipeline project identified in part "a" of this request, revise the Company exhibit(s) to include breakout line items for each prospective pipeline project.
c. For each prospective pipeline project identified in part "a" of this request, identify:
i. The associated capital expenditures that the Company anticipates for the filing of an Act 9 Application (including, but not limited to, design, testimony, exhibits, etc.) for 2024, 2025, the 10 months ending October 31, 2026, and the 12 months ending October 31, 2027.
ii. The associated capital expenditures that the Company anticipates for the post-filing activities (including, but not limited to, material procurement, construction, testing, etc.) for 2024, 2025, the 10 months ending October 31, 2026, and the 12 months ending October 31, 2027.

Response:

a. Storage pipelines projects for which the Company anticipates filing Act 9 applications with the Commission that have projected expenses included in the Company's filing:

Year	Location	Project Name	Project Type	Projected Cost	Length (ft)	Act 9 Required	Anticipated File Date
2026	Overisel	Salem ML 2	Replacement	$3,769,984	4,013	Yes	March 2026
2027	Overisel	Overisel ML -16"	Replacement	$18,825,938	13,707	Yes	July 2026
	Overisel	Salem Lateral 2N	Replacement	$9,290,370	12,004	Yes	July 2026
	Overisel	Overisel ML – 12"	Replacement	$8,116,226	10,450	Yes	July 2026

b. Please reference direct testimony of Company witness Timothy K. Joyce page 39, Table 8 for the projected storage pipeline projects. Projects and projected expenses are included in WP-TKJ-5, lines 85-112.

U21981-SA-CE-317
Requested By: Kevin P. Spence (KPS-1 - 1)
Respondent: TIMOTHY K JOYCE
Date of Response: 3/6/2026
Page **2** of **2**

c. i. The Company does not track separately the costs related to the preparation of the Certificate of Necessity to Construct and Operate (Act 9) for the storage pipeline replacement projects. Employee time spent on preparing the Act 9's would be included as part of the employee's normal business operations and will go into O&M cost centers and/or the Administrative and General (A&G) or Engineering and Supervision (E&S) allocations depending upon the employee's department.

ii. The capital expenditures anticipated for the material procurement, construction and testing are outlined in Exhibit A-12 (TKJ-4), Schedule b-5.5, page 2, line 17. The costs are further shown on my workpaper WP-TKJ-5, lines 85-112.

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
										Projected Bridge Year	Projected Test Year	Projected			
Line No.	Site	Title	Internal Approval	Has a Business Case	2025 7+5 Fcst	2026	2027	12 Mos Ending 12/31/2025	10 Mos Ending 10/31/2026	22 Mos Ending 10/31/2026	12 Mos Ending 10/31/2027	10 Mos ending in 10/31/2025	12 Mos. Ending 10/31/2026	12 Mos Ending 10/31/2027	34 Mos ending 10/31/2027
53	Site	Title			2025 7+5 Fcst	2026	2027								
54	Overisel	GS-00230: OVS-Salem Reg & Pipe Rmvl	Yes	Yes	60	143	0	60	143	203	0	60	143	0	203
55	Overisel	GS-00422: OVS-Salem Scrubber Brine Tanks	Yes	Yes	151	0	0	151	0	151	0	151	0	0	151
56	Overisel	GS-00455: OVS-O142 Disposal Well	Yes	Yes	(4)	0	0	(4)	0	(4)	0	(4)	0	0	(4)
57	Overisel	GS-00456: OVS-Tnk Repl Goodman 04	Yes	Yes	30	0	0	30	0	30	0	30	0	0	30
58	Overisel	GS-00461: OVS Salem Scrub Sep Repl	Yes	Yes	1,117	5,187	58	1,117	4,360	5,477	885	411	5,066	885	6,362
59		TOTAL OVERISEL			1,353	5,330	58	1,353	4,503	5,857	885	647	5,210	885	6,742
60															
61	Site	Title			2025 7+5 Fcst	2026	2027								
62	Ray	GS-00445: RAY-N MainLine Repl	Yes	Yes	2	0	0	2	0	2	0	2	0	0	2
63	Ray	GS-00543: RAY-Liquid Blocker Vlvs 16" Inst	Yes	Yes	0	0	1,405	0	0	0	1,317	0	0	1,317	1,317
64	Ray	GS-00544: RAY-Storage Vlv 2407 Repl	Yes	Yes	0	0	976	0	0	0	916	0	0	916	916
65	Ray	GS-00454: Ray 24In Repl & Relocate LRs	Yes	Yes	6,672	2,809	52	6,672	2,794	9,466	67	6,544	2,922	67	9,533
66		TOTAL RAY			6,674	2,809	2,434	6,674	2,794	9,468	2,300	6,546	2,922	2,300	11,768
67															
68	Site	Title			2025 7+5 Fcst	2026	2027								
69	St. Clair	GS-00400: STC-BD Well-139 Rbld	Yes	Yes	55	0	0	55	0	55	0	55	0	0	55
70	St. Clair	GS-00459: STC-Blockgate R-102/R-201 Act Repl	Yes	Yes	0	0	0	0	0	0	0	0	0	0	0
71	St. Clair	GS-00465: STC-4Corners Fac Upgrd	Yes	Yes	1,477	3,930	52	1,477	3,756	5,232	227	342	4,890	227	5,459
72	St. Clair	GS-00466: STC-4Corners LR Repl	Yes	Yes	(108)	0	0	(108)	0	(108)	0	(108)	0	0	(108)
73	St. Clair	GS-00467: STC-PtyGut Proc Equip Add	Yes	Yes	2	0	0	2	0	2	0	2	0	0	2
74	St. Clair	GS-00468: STC-Swan Crk Fac Upgrd	Yes	Yes	1,552	3,930	52	1,552	3,755	5,307	227	406	4,901	227	5,534
75	St. Clair	GS-00469: STC-Swan Crk LR Repl	Yes	Yes	117	0	0	117	0	117	0	117	0	0	117
76	St. Clair	GS-00530: STC-FC.SC Lvl Ctrl Repl	Yes	Yes	2	0	0	2	0	2	0	2	0	0	2
77	St. Clair	GS-00536: BD 139 Driveway Upgrade	Yes	Yes	81	185	0	81	185	266	0	76	191	0	266
78	St. Clair	GS-00539: STC-Puttygut Meter Run WT Issues	Yes	Yes	1,414	0	0	1,414	0	1,414	0	1,285	129	0	1,414
79	St. Clair	GS-00550: STC-Lennox 16in ML Rupt Mit 2Vlv	Yes	Yes	0	144	12	0	135	135	21	0	135	21	155
80	St. Clair	GS-00551: STC-Ira 20in ML Rupt Mit 4Vlv	Yes	Yes	0	240	39	0	225	225	54	0	225	54	279
81	St. Clair	GS-10238: STC- Puttygut Observation Well Hookup	Yes	Yes	36	0	0	36	0	36	0	36	0	0	36
82	St. Clair	GS-00317: STC-Wellhead Protection (2016)	Yes	Yes	(164)	0	0	(164)	0	(164)	0	(164)	0	0	(164)
83		TOTAL ST CLAIR			4,465	8,429	155	4,465	8,056	12,521	528	2,050	10,471	528	13,049
84															
85	Site	Title			2025 7+5 Fcst	2026	2027								
86	Marion	GS-00437: MAR-Cranberry Lat 64E Repl	Yes	Yes	1	0	0	1	0	1	0	1	0	0	1
87	Marion	GS-00491: MAR-Win 22in ML Ret	Yes	Yes	91	0	0	91	0	91	0	68	24	0	91
88	Marion	GS-00493: MAR-Cran Lat 61W Repl	Yes	Yes	592	0	0	592	0	592	0	592	0	0	592
89	Marion	GS-00495: MAR-Win Lat 52SB Repl	Yes	Yes	3,479	32	0	3,479	32	3,511	0	3,100	411	0	3,511
90	Marion	GS-00519: MAR-W-986 & W-987 Line & Riser Repls	Yes	Yes	13	0	0	13	0	13	0	13	0	0	13
91	Marion	GS-00548: Marion Storage L/R EQ Lines Install	Yes	Yes	15	0	0	15	0	15	0	15	0	0	15
92	Marion	GS-00556: 2028 Cranberry Lateral 67SE Inst	Yes	Yes	0	0	63	0	0	0	54	0	0	54	54
93	Northville	GS-00431: NVL-LY29-34 Vlv Repl	Yes	Yes	32	0	0	32	0	32	0	32	0	0	32
94	Overisel	B-GS-00061: Overisel Lateral 5 (Replacement)	Yes	Yes	0	63	633	0	53	53	547	0	53	547	600
95	Overisel	GS-00382: OVS-OVS NW Field Retirement	Yes	Yes	1,818	0	0	1,818	0	1,818	0	1,818	0	0	1,818
96	Overisel	GS-00385: OVS-Lat 2 8in Pipe Repl	Yes	Yes	142	0	0	142	0	142	0	124	18	0	142
97	Overisel	GS-00504: OVS-Sal 16in ML 1 Repl	Yes	Yes	15	63	6,639	15	53	68	6,242	15	53	6,242	6,310
98	Overisel	GS-00505: OVS-Sal 8in ML 3 Repl	Yes	Yes	0	2,891	54	0	2,714	2,714	232	0	2,714	232	2,946
99	Overisel	GS-00506: OVS-Sal 16in ML 2 Repl	Yes	Yes	0	3,716	54	0	3,488	3,488	282	0	3,488	282	3,770
100	Overisel	GS-00509: OVS-Sal Lat 2N Repl	Yes	Yes	(1)	73	9,165	(1)	73	72	9,165	(1)	73	9,165	9,237
101	Overisel	GS-00510: OVS-Sal Lat 2W Repl	Yes	Yes	(1)	63	2,396	(1)	63	62	2,396	(1)	63	2,396	2,458

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
										Projected Bridge Year	**Projected Test Year**	**Projected**			
84															
85	**Site**	**Title**			**2025 7+5 Fcst**	**2026**	**2027**								
86	Marion	GS-00437: MAR-Cranberry Lat 64E Repl	Yes	Yes	1	0	0	1	0	1	0	1	0	0	1
87	Marion	GS-00491: MAR-Win 22in ML Ret	Yes	Yes	91	0	0	91	0	91	0	68	24	0	91
88	Marion	GS-00493: MAR-Cran Lat 61W Repl	Yes	Yes	592	0	0	592	0	592	0	592	0	0	592
89	Marion	GS-00495: MAR-Win Lat 52SB Repl	Yes	Yes	3,479	32	0	3,479	32	3,511	0	3,100	411	0	3,511
90	Marion	GS-00519: MAR-W-986 & W-987 Line & Riser Repls	Yes	Yes	13	0	0	13	0	13	0	13	0	0	13
91	Marion	GS-00548: Marion Storage L/R EQ Lines Install	Yes	Yes	15	0	0	15	0	15	0	15	0	0	15
92	Marion	GS-00556: 2028 Cranberry Lateral 67SE Inst	Yes	Yes	0	0	63	0	0	0	54	0	0	54	54
93	Northville	GS-00431: NVL-LY29-34 Vlv Repl	Yes	Yes	32	0	0	32	0	32	0	32	0	0	32
94	Overisel	B-GS-00061: Overisel Lateral 5 (Replacement)	Yes	Yes	0	63	633	0	53	53	547	0	53	547	600
95	Overisel	GS-00382: OVS-OVS NW Field Retirement	Yes	Yes	1,818	0	0	1,818	0	1,818	0	1,818	0	0	1,818
96	Overisel	GS-00385: OVS-Lat 2 8in Pipe Repl	Yes	Yes	142	0	0	142	0	142	0	124	18	0	142
97	Overisel	GS-00504: OVS-Sal 16in ML 1 Repl	Yes	Yes	15	63	6,639	15	53	68	6,242	15	53	6,242	6,310
98	Overisel	GS-00505: OVS-Sal 8in ML 3 Repl	Yes	Yes	0	2,891	54	0	2,714	2,714	232	0	2,714	232	2,946
99	Overisel	GS-00506: OVS-Sal 16in ML 2 Repl	Yes	Yes	0	3,716	54	0	3,488	3,488	282	0	3,488	282	3,770
100	Overisel	GS-00509: OVS-Sal Lat 2N Repl	Yes	Yes	(1)	73	9,165	(1)	73	72	9,165	(1)	73	9,165	9,237
101	Overisel	GS-00510: OVS-Sal Lat 2W Repl	Yes	Yes	(1)	63	2,396	(1)	63	62	2,396	(1)	63	2,396	2,458
102	Overisel	GS-00514: OVS-Lat3 10in Pipe Repl	Yes	Yes	9,966	83	0	9,966	83	10,049	0	9,439	610	0	10,049
103	Overisel	GS-00515: OVS-Over 16in ML Repl	Yes	Yes	0	1,003	17,107	0	989	989	16,458	0	989	16,458	17,447
104	Overisel	GS-00520: OVS-Sal Lat 2 Repl	Yes	Yes	8	137	14,557	8	137	145	14,528	8	137	14,528	14,673
105	Overisel	GS-00537: OVS-12in ML Repl	Yes	Yes	0	528	7,389	0	522	522	7,043	0	522	7,043	7,565
106	Overisel	GS-00547: OVS-Lat 1 Rmvl	Yes	Yes	0	63	617	0	53	53	531	0	53	531	585
107	Overisel	GS-00557: OVS Lat 4 Replacement Project	Yes	Yes	0	0	127	0	0	0	108	0	0	108	108
108	Ray	B-GS-00062: Ray ML West - resilience replacement	Yes	Yes	0	0	63	0	0	0	54	0	0	54	54
109	St. Clair	GS-00432: STC-Ira VlvOp 440 Repl	Yes	Yes	18	0	0	18	0	18	0	18	0	0	18
110	St. Clair	GS-00464: STC-PtyGut ML 16E Repl	Yes	Yes	26	0	0	26	0	26	0	26	0	0	26
111	St. Clair	GS-00489: STC-Hessen Field Repl	Yes	Yes	21,271	347	0	21,271	347	21,618	0	19,042	2,576	0	21,618
112		TOTAL PIPELINE REPLACMENT			37,486	9,060	58,863	37,486	8,606	46,092	57,639	34,310	11,783	57,639	103,731
113															

U21981-AG-CE-0320
Page **1** of **1**

Question:

100. Refer to Exhibit A-12, Schedule B-5.5, page 1, sponsored by Mr. Joyce. Please expanded this schedule to include actual information for lines 1-10 for 2023 and 2025 and forecasted information for 2026 and 2027 and provide it in Excel.

Response:

Please reference attachment U21981-AG-CE-320-Joyce_ATT_1.

Witness: TIMOTHY K JOYCE
Date: April 1, 2026

U21981-AG-CE-320_Joyce_ATT_1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Gas Compression and Gas Storage
($000)

Case No.: U-21981
Exhibit No.: A-12 (TKJ-4)
Schedule: B-5.5
Page: 6 of 6
Witness: TKJoyce
Date: ~~December 2025~~

	(a)		(b)		(c)	(d)	(e)	(f)
		Historical Year	**Historical Year**	**Preliminary Actuals**	**Projected Bridge Year**			**Projected Test Year**
Line No	**Description**	**11 Mos Ended 12/31/2023**	**12 Mos Ended 12/31/2024**	**12 Mos Ended 12/31/2025**	**12 Mos Ending 12/31/2025**	**10 Mos Ending 10/31/2026**	**22 Mos Ending 10/31/2026**	**12 Mos Ending 10/31/2027**
16	**Well Rehabilitation**	**31,031**	**26,981**	**23,546**	**24,086**	**3,833**	**27,919**	**712**
5%	Labor	1,668	1,140	1,457	1,157	184	1,342	34
10%	Capitalized E&S	4,588	2,725	2,141	2,313	368	2,681	68
1%	Materials	589	381	218	354	56	410	10
77%	Contractor	21,722	20,557	18,067	18,517	2,947	21,464	547
0%	Non-Labor Overhead	24	11	31	19	3	22	1
7%	Non-Labor Other	2,442	2,167	1,633	1,726	275	2,001	51
	Contingency				0	0	0	0
17	**Storage Pipeline Replacement**	**3,550**	**13,835**	**35,285**	**37,486**	**8,606**	**46,092**	**57,639**
4%	Labor	439	651	1,006	1,639	376	2,016	2,521
9%	Capitalized E&S	518	1,375	3,212	3,445	791	4,236	5,297
19%	Materials	824	2,294	4,097	7,041	1,616	8,657	10,826
57%	Contractor	1,480	8,131	23,614	21,277	4,885	26,162	32,716
0%	Non-Labor Overhead	14	26	39	49	11	61	76
11%	Non-Labor Other	275	1,357	3,317	4,034	926	4,961	6,203
	Contingency				0	0	0	0
18	**Well Data Acquisition**	**239**	**62**	**1,518**	**1,650**	**2,018**	**3,667**	**5,133**
28%	Labor	76	20	88	469	573	1,042	1,458
5%	Capitalized E&S	33	3	158	90	111	201	281
5%	Materials	71	0	1,093	84	103	186	261
19%	Contractor	23	6	58	307	375	682	955
0%	Non-Labor Overhead	0	0	0	0	0	0	0
42%	Non-Labor Other	35	32	120	700	856	1,556	2,178
	Contingency				0	0	0	0
19	**Riverside Field Retirement**	**12,449**	**24,256**	**2,763**	**22,348**	**0**	**22,348**	**0**
8%	Labor	831	1,935	1,564	1,800	0	1,800	0
23%	Capitalized E&S	3,203	5,692	(9,836)	5,106	0	5,106	0
8%	Materials	2,436	1,679	1,752	1,788	0	1,788	0
41%	Contractor	3,791	9,955	10,458	9,168	0	9,168	0
1%	Non-Labor Overhead	16	106	156	119	0	119	0
20%	Non-Labor Other	2,172	4,889	(1,330)	4,366	0	4,366	0
	Contingency				0	0	0	0
20	**Safety Valve Installation**	**0**	**2,557**	**1,853**	**1,824**	**1,807**	**3,631**	**0**
6%	Labor	0	117	248	106	105	211	0
11%	Capitalized E&S	0	292	177	204	202	406	0
7%	Materials	0	187	60	125	124	249	0
69%	Contractor	0	1,785	1,224	1,256	1,245	2,501	0
0%	Non-Labor Overhead	0	6	5	4	4	8	0
7%	Non-Labor Other	0	170	139	128	127	256	0
	Contingency				0	0	0	0
21	**Total Capital**	**113,046**	**167,776**	**161,744**	**196,595**	**153,756**	**350,351**	**187,169**
	Labor	6,594	8,327	9,385	10,402	8,831	19,233	13,640
	Capitalized E&S	17,847	20,209	4,880	21,425	14,435	35,859	17,295
	Materials	13,891	14,972	21,212	23,521	18,765	42,286	26,888
	Contractor	65,117	106,583	112,512	119,082	95,492	214,574	107,248
	Non-Labor Overhead	98	247	374	323	199	522	222
	Non-Labor Other	9,499	17,437	13,380	21,843	16,034	37,877	21,875
	Contingency	0	0	0	0	0	0	0

Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2024 amounts are the actual amounts. The cost component projections for 2025 and beyond are based upon the 2024-2025 18 month (Jan 2024 - Jun 2025) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop these cost projections.

U21981-AG-CE-0292
Page **1** of **1**

Question:

72. Refer to the Tracking and Traceability IT project on page 80 of Mr. Warriner's direct testimony. Please:

a. Provide a copy of the cost/benefit analysis showing that this project is economically beneficial with calculation in Excel.

b. Provide the current phase of development of the project.

c. Identify whether the detailed requirements phase of the project has been completed or when it will start and be completed.

Response:

a. Refer to Attachment No. U21981-AG-CE-0292_Baker_ATT_1, for the cost/benefit analysis for the project with the financial analysis in Excel with formulas intact. Refer to Exhibit A-22 (SHB-7), page 118, for the assumptions and data.

b. The Tracking and Traceability project is in the Investment Planning phase.

c. The Company has not completed the detailed requirements phase for the Tracking and Traceability project. The Company developed high-level requirements on 6/7/2023, which allowed it to finalize the six scope-of-work items identified on page 81, lines 17 through 27, of Company witness Lincoln D. Warriner's direct testimony. The Company has deferred the project to start in March 2027, to allow for PHMSA-2014-2016-0098 (Plastic Pipe Rule) requirements to be finalized and the project to be appropriately sequenced with other ongoing work. Therefore, the Company should adjust its capital expenditures by $2,772,025 for the projected Bridge Period Ending 10/31/2026 and $1,767,377 for the projected Test Year, and it should adjust O&M expenses by $169,773 for the projected Test Year.

Witness: Stacy H. Baker
Date: April 1, 2026

Tracking & Traceability

Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Year Counter	1	2	3	4	5	6	7	8
Life Flag	1	1	1	1	1	1	1	0
Remaining Expense Flag	0	0	1	1	1	1	1	1

FINANCIAL IMPACT MODEL

Assumptions

Factor/Variable	Value
PreTax Rate of Return	8.643%
Property Tax Factor	2.452%
Insurance Factor	0.080%
Discount Rate	7.500%

	NPVRR Benefit	NPVRR Cost	B/C Ratio
Overall	0	16,825,247	-1.000
Remaining	2,444,299	15,363,649	-0.841

COSTS

			2025	2026	2027	2028	2029	2030	2031	2032
CAPITAL + COR			0	3,326,430	7,277,830	4,260,690	0	0	0	0
CAPITAL + COR *Escalated*			0	3,389,632	7,557,015	4,508,193	0	0	0	0
Total Investment			0	3,389,632	10,946,647	15,454,840	15,454,840	15,454,840	15,454,840	0
Beginning Rate Base			0	3,389,632	10,381,708	12,813,560	9,610,170	6,406,780	3,203,390	0
Depreciation			0	(564,939)	(2,076,342)	(3,203,390)	(3,203,390)	(3,203,390)	(3,203,390)	0
Ending Rate Base			0	2,824,693	8,305,367	9,610,170	6,406,780	3,203,390	0	0
Average Rate Base			0	3,107,163	9,343,537	11,211,865	8,008,475	4,805,085	1,601,695	0
O&M			0	755,390	753,250	320,000	320,000	320,000	320,000	0
O&M *Escalated*			0	769,742	782,145	338,589	345,022	351,577	358,257	0
Other Costs			0	0	0	0	0	0	0	0
Other Costs *Escalated*			0	0	0	0	0	0	0	0
NPVRR OVERALL COSTS										
	NPV	**Total**								
Return Costs	$2,442,743	3,291,066	0	268,552	807,562	969,041	692,172	415,303	138,434	0
Depreciation Costs	$10,796,814	15,454,840	0	564,939	2,076,342	3,203,390	3,203,390	3,203,390	3,203,390	0
Property Tax	$1,309,667	1,867,336	0	83,114	268,412	378,953	378,953	378,953	378,953	0
Insurance	$42,730	60,925	0	2,712	8,757	12,364	12,364	12,364	12,364	0
O&M	$2,233,293	2,945,333	0	769,742	782,145	338,589	345,022	351,577	358,257	0
Other	$0	0	0	0	0	0	0	0	0	0
Total	$16,825,247	$23,619,500	$0	$1,689,059	$3,943,218	$4,902,337	$4,631,901	$4,361,587	$4,091,398	$0
NPVRR REMAINING COSTS										
Return Costs	$2,210,356	3,022,514	0	0	807,562	969,041	692,172	415,303	138,434	0
Depreciation Costs	$10,307,954	14,889,901	0	0	2,076,342	3,203,390	3,203,390	3,203,390	3,203,390	0
Property Tax	$1,237,746	1,784,222	0	0	268,412	378,953	378,953	378,953	378,953	0
Insurance	$40,383	58,213	0	0	8,757	12,364	12,364	12,364	12,364	0
O&M	$1,567,210	2,175,591	0	0	782,145	338,589	345,022	351,577	358,257	0
Other	$0	0	0	0	0	0	0	0	0	0
Total	$15,363,649	$21,930,441	$0	$0	$3,943,218	$4,902,337	$4,631,901	$4,361,587	$4,091,398	$0

BENEFITS

			2025	2026	2027	2028	2029	2030	2031	2032
CAPITAL + COR			0	0	0	0	0	0	0	0
CAPITAL + COR *Escalated*			0	0	0	0	0	0	0	0
Total Investment			0	0	0	0	0	0	0	0
Beginning Rate Base			0	0	0	0	0	0	0	0
Depreciation			0	0	0	0	0	0	0	0
Ending Rate Base			0	0	0	0	0	0	0	0
Average Rate Base			0	0	0	0	0	0	0	0
Total O&M			0	0	0	0	0	0	0	0
Total O&M *Escalated*			0	0	0	0	0	0	0	0
Other			0	0	0	0	0	0	0	0
Other *Escalated*			0	0	0	0	0	0	0	0
NPVRR OVERALL BENEFITS										
	NPV	**Total**								
Return	$0	0	0	0	0	0	0	0	0	0
Depreciation	$0	0	0	0	0	0	0	0	0	0
Property Tax	$0	0	0	0	0	0	0	0	0	0
Insurance	$0	0	0	0	0	0	0	0	0	0
O&M	$0	0	0	0	0	0	0	0	0	0
Other	$0	0	0	0	0	0	0	0	0	0
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NPVRR REMAINING BENEFITS										
Return	$0	0	0	0	0	0	0	0	0	0
Depreciation	$0	0	0	0	0	0	0	0	0	0
Property Tax	$0	0	0	0	0	0	0	0	0	0
Insurance	$0	0	0	0	0	0	0	0	0	0
O&M	$0	0	0	0	0	0	0	0	0	0
Other	$0	0	0	0	0	0	0	0	0	0
Avoided Writeoff	$2,444,299	2,824,693	0	2,824,693	0	0	0	0	0	0
Total	$2,444,299	$2,824,693	$0	$2,824,693	$0	$0	$0	$0	$0	$0

U21981-AG-CE-0404
Page **1** of **1**

Question:

182. Refer to page 117 of Ms. Baker's direct testimony on the Forward Web Proxy Services project. Please:
a. Provide the capex included in this rate case for this project for 2025 and the 10 months ending September 2026 adjusted for ROM.
b. Confirm that these services are currently provided by a third party and the previous problems with poor service encountered with the third party have been mostly resolved. If not confirming, provide evidence otherwise.
c. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Detailed Requirements definition, Implementation, Completed), the phases already completed, and the date when the next phase will start.

Response:

a. As provided in Exhibit A-20 (SHB-5), line 334, columns f and g, the Forward Web Proxy Services project has a projected scheduled start date of January 2027 and a projected end date of January 2028. Accordingly, no capital expenditures for this project are included in this case for 2025 or the 10 months ending September 2026.

b. Service issues have been resolved; however, the Company's current third-party forward web proxy service, under the existing licensing agreement, does not provide data loss prevention (DLP) functionality. This project is needed to implement DLP as a core function of the web proxy service so that the Company can detect and prevent the unauthorized transmission of sensitive or regulated information (including customer data, intellectual property, and operational system information) to unapproved external destinations. The planned solution will inspect content, evaluate contextual indicators, and enforce Company policies to identify and block high-risk activity before data leaves the Company's environment and to support auditable compliance with applicable information governance and regulatory obligations.

c. The project is currently in the Investment Planning phase.

Witness: Stacy H. Baker
Date: April 7, 2026

U21981-AG-CE-0401
Page **1** of **1**

Question:

179. Refer to lines 13-28 on page 114 of Ms. Baker's direct testimony on the OT Datacenter Migration project. Please:

a. Provide the capex included in this rate case for this project for 2025 and the 10 months ending September 2026 adjusted for ROM.

b. Identify the phase of development that the project is currently in (i.e., Preliminary Assessment, Project Planning or Scoping, Conceptual Design, Detailed Requirements definition, Implementation, Completed), the phases already completed, and the date when the next phase will start.

Response:

a. As provided in Exhibit A-20 (SHB-5), lines 242 and 311, columns f and g, the Operational Technology (OT) Datacenter Migration project has a projected start date of June 2026 and a projected end date of December 2027. Accordingly, no capital expenditures are projected for this project in this case for 2025. Your request references the 10 months ending September 2026. Assuming you intended the 10 months ending October 2026 based on the periods in this case, the table below provides the gas allocation capital expenditures for the 10 months ending October 2026.

	Gas Allocation	
	10 Months Ending 10/31/2026	
Cost Category	**Capital**	**ROM Adjusted Capital**
Labor	$63,954	$51,163
Software	$89,822	$71,858
Material	$900,020	$720,016
Contractor Costs	$89,822	$71,858
Non-Labor Other	$ 91,838	$ 73,470
Total	**$ 1,235,456**	**$ 988,365**

b. The OT Datacenter Migration Project is in the Investment Planning phase and is planned to be completed in June 2026. The Define phase is planned to complete in September 2026.

Witness: Stacy H. Baker
Date: April 7, 2026

U21981-AG-CE-0402
Page **1** of **2**

Question:

180. Refer to page 116 of Ms. Baker's direct testimony on the OT Datacenter Migration project. Please:

a. Provide the previous cost estimate to replace the climate control equipment and what changed to increase or decrease that cost to the latest cost estimate presented in this case.

b. Confirm that the aging climate control equipment still works. If not confirming, explain what is not working and why it cannot be repaired.

c. Explain what the ARP-OT Support Common and Support Electric entails. If the Company is raising this item for the first time in this rate case, explain what has changed for it to be an issue now.

Response:

a. The Company initially provided the cost estimate of $5,082,728 for addressing the aging climate control equipment and continuing water infiltration issues at the current location in my rebuttal testimony in electric Case No. U-21870, page 35, lines 6 through 14. Of this amount, the projected cost to replace the aging climate control equipment, including labor, was $4,965,728. The remaining $117,000 is to remediate the water infiltration issue, which requires removing architectural concrete and replacing the waterproof membrane. This estimate has not changed and the same amounts provided in my direct testimony in this case, page 116, lines 5 through 13.

b. The aging climate control equipment has eleven air conditioning units in service, and the units operate; however, the Company considers them end of life and the units have experienced compressor failures that have required investment to repair or replace. The Company replaced two units in 2023. The Company would continue to incur costs to repair or replace the remaining units in phases due to their age. Repairing the units does not address the risk associated with the datacenter location in the basement of the Parnall building near the building's main water pipe, as discussed in my direct testimony on page 116, lines 10–13.

c. The tables below provide a breakdown of the units and associated costs for the ARP-OT Support Common and the ARP-OT Support Electric projects. This is not the first time this information has been provided. The avoided costs in the ARP-OT Support Common and ARP-OT Support Electric were initially provided in my rebuttal testimony in electric Case No. U-21870, in the table at the top of page 36, and there has been no change.

ARP-OT Support Common				
Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total Company 2027 Capital**	**Total Company 2027 O&M**
Hypervisors Nutanix DC	$125,000	6	$750,000	$0
Physical Servers	$16,000	2	$32,000	$0
Software, labor, contractor and overhead and other costs			$27,200	$83,440
Total			**$809,200**	**$83,440**

ARP-OT Support Electric				
Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total Company 2027 Capital**	**Total Company 2027 O&M**
Hypervisors Nutanix DC	$125,000	6	$750,000	$0
Physical Servers	$16,000	3	$48,000	$0
Software, labor, contractor and overhead and other costs			$30,600	$87,120
Total			**$828,600**	**$87,120**

Witness: Stacy H. Baker
Date: April 7, 2026

U21806-AG-CE-0621
Page **1** of **1**

Question:

239. Refer to lines 30-40 on page 100 of Ms. Baker's direct testimony on the OT Datacenter Migration. Please:

a. Provide the cost of this project by year from inception to completion for total company and, for the portion applicable to the gas business for both capital expenditures and O&M expense, separately. Provide this information in Excel.

b. Identify what the dollars will be spent on for this project by year.

c. Explain why this project needs to be completed at this time and whether it can be delayed to a later year.

d. Provide the current phase of development of the project.

Response:

a. Refer to Attachment No. U21806-AG-CE-0621_ATT 1 for the Total Company and gas allocation capital expenditures and O&M expense for the Operational Technology (OT) Datacenter Migration project in Excel.

b. Refer to part a response for categorial spend by year.

c. The OT Datacenter Migration project must be completed and cannot be delayed to a later year due to the state of the current datacenter and the associated risks. The current datacenter would require extensive work to modernize and would not address the risks discussed in my direct testimony starting on page 100, line 40 through page 101, line 6.

   i. There is risk with the current datacenter due to the proximity of water pipes. If the main water piping bursts, the data center equipment would become wet, causing damage and failure. This could disrupt the monitoring of the critical OT systems, such as SCADA.

   ii. The Company has had on-going issues with water infiltration into the basement from rain. The data center has a raised floor and has had standing water under the floor. Facilities have been repaired several times, and it is still an ongoing issue.

   iii. Additionally, the climate conditioners in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns. The failure of HVAC caused the temperature in the data center to rise causing the equipment to begin shutting down. This would cause the equipment to be damaged and fail causing potential disruption to the monitoring of the critical OT systems.

   The Company utilizes this datacenter to operate critical control and monitoring of gas compression and natural gas pipeline. The datacenter migration would ensure these critical systems are highly available for safe and reliable natural gas and electric delivery.

d. The project is in the Investment Planning phase.

Witness: Stacy H. Baker
Date: 3/21/2015

MICHIGAN PUBLIC SERVICE COMMISSION Attachment: U21806-AG-CE-0621_ATT 1

Consumers Energy Company Witness: SHBaker

Operational Technology (OT) Datacenter Migration Date: March 2025

	Total Company		**Gas Allocation**	
Cost Category	**Capital**	**O&M**	**Capital**	**O&M**
	2026			
Software	500,000	-	157,150	-
Material	5,010,000	-	1,574,643	-
Labor	300,000	300,000	94,290	111,620
Contractor Costs	500,000	545,000	157,150	202,777
Non-Labor Overhead	56,000	59,150	17,601	22,008
Non-Labor Other	511,220	1,406,621	160,676	523,363
Total 2026	**6,877,220**	**2,310,771**	**2,161,510**	**859,768**
	2027			
Software	-	-	-	-
Material	-	-	-	-
Labor	200,000	350,000	62,860	129,199
Contractor Costs	500,000	540,000	157,150	199,335
Non-Labor Overhead	49,000	62,300	15,401	22,997
Non-Labor Other	123,400	-	38,785	-
Total 2027	**872,400**	**952,300**	**274,195**	**351,531**
	Total			
Software	500,000	-	157,150	-
Material	5,010,000	-	1,574,643	-
Labor	500,000	650,000	157,150	240,819
Contractor Costs	1,000,000	1,085,000	314,300	402,112
Non-Labor Overhead	105,000	121,450	33,002	45,005
Non-Labor Other	634,620	1,406,621	199,461	523,363
Total Project	**7,749,620**	**3,263,071**	**2,435,706**	**1,211,299**

U21981-AG-CE-0396
Page **1** of **1**

Question:

174. Refer to pages 13-14 of Mr. Guinn's direct testimony on Emergent Repairs. Please provide the capital expenditures for known emergent repair projects for the 10 months ending October 2026 and for the 12 months ending October 2027.

Response:

As noted on page 14 of my direct testimony, capital expenditures for emergent repair projects are unknowable in advance.

Witness: Quentin A. Guinn
Date: March 27, 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Exhibit AG-37
Case No. U-21981
April 15, 2026

Adjustments to Capital Expenditures, Working Capital, and Rate Base
Projected Test Year Ending October 2027
($000)

Line	Description (a)	2025 & Prior (b)	10 M/E Oct 2026 (c)	12 M/E Oct 2027 (d)	Total (e)	Rate Base Reduction (f)	Depreciation Rate [2] (g)	Reduction in Depreciation Expense (h)	Property taxes [3] Rate (i)	Property taxes [3] Adjustment (j)
1	**Distribution Plant:**									
2	Large New Business projects		12,000		12,000	12,000	2.53%	304	$ 0.0139316	84
3	Asset Relocation			8,661.0	8,661	4,331	2.53%	110	$ 0.0139316	60
4	Meters Subprogram		6,259	6,171	12,430	9,345	2.53%	236	$ 0.0139316	87
5	MAOP Projects		44,106	90,705	134,811	89,459	2.53%	2,263	$ 0.0139316	939
6	Capacity and Deliverability		723	11,431	12,154	6,439	2.53%	163	$ 0.0139316	85
7	Material Condition/EIRP			72,459	72,459	36,230	2.53%	917	$ 0.0139316	505
8	Material Condition Non-Modeled		13,784	9,924	23,708	18,746	2.53%	474	$ 0.0139316	165
9	Material Condition - Renewals			24,693	24,693	12,347	2.53%	312	$ 0.0139316	172
10	VSR Program		16,174	32,110	48,284	32,229	2.53%	815	$ 0.0139316	336
11	Compliance & Controls Projects-AMD		3,280	4,773	8,053	5,667	2.53%	143	$ 0.0139316	56
12	Tools			3,600	3,600	1,800	2.53%	46	$ 0.0139316	25
13	Underspent amount for 2025	4,561			4,561	4,561	2.53%	115	$ 0.0139316	32
14	**Transmission Plant**									
15	Asset Relocation		4,835	5,897	10,732	7,784	2.29%	178	$ 0.0139316	75
16	Pipeline Integrity-Transmission			11,488	11,488	5,744	2.29%	132	$ 0.0139316	80
17	TOD Pipeline Integrity		5,348	11,013	16,361	10,855	2.29%	249	$ 0.0139316	114
18	TED-I Projects		1,054	15,662	16,716	8,885	2.29%	203	$ 0.0139316	116
19	Deliverability Field Measurement		7,365	20,752	28,117	17,741	2.29%	406	$ 0.0139316	196
20	Deliverability Base Pipeline		6,277	19,856	26,133	16,205	2.29%	371	$ 0.0139316	182
21	T&S City Gate Stations		1,377	20,829	22,206	11,792	2.29%	270	$ 0.0139316	155
22	Underspent amount for 2025	5,550			5,550	5,550	2.29%	127	$ 0.0139316	39
23	**Gas Storage & Compression**									
24	Northville - Lyon 29/34 Dehydration Facility		3,025		3,025	3,025	2.48%	75	$ 0.0139316	21
25	Storage New Wells		9,870		9,870	9,870	2.48%	245	$ 0.0139316	69
26	Compression Projects		9,171	25,763	34,934	22,053	2.48%	547	$ 0.0139316	243
27	Gas Storage & Pipeline Projects		5,325	57,431	62,756	34,041	2.48%	844	$ 0.0139316	437
28	Gas Compression & Storage 2025 Underspent	34,851			34,851	34,851	2.48%	864	$ 0.0139316	243
29	**Information Technology**									
30	Facilities Tracking and Traceability system		2,772	5,295	8,067	5,420	20.00%	1,084	$ 0.0139316	56
31	ARP-FDAM		1,274	989	2,263	1,769	20.00%	354	$ 0.0139316	16
32	Forward Web Proxy Services			1,008	1,008	504	20.00%	101		-
33	OT Data Center Migration		988	953	1,941	1,465	20.00%	293	$ 0.0139316	14
34	**Facilities Operation**									
35	Emergent Repair Projects		712	450	1,162	937	1.56%	15	$ 0.0139316	8
36	**Total**	**$ 44,962**	**$ 155,719**	**$ 461,913**	**$ 662,594**	**$ 431,638**		**$ 12,256**		**$ 4,608**
37										
38	**Working Capital Adjustments**					93,200				
39										
40	**Total Rate Base Reduction**					**$ 524,838**				

Source: (1) AG witness Coppola Direct Testimony and related exhibits.

(2) Depreciation rates from Company workpaper WP-HLR-24 for 2026 rates.

(3) The property tax adjustment is calculated based on 50% of the disallowed capital expenditures x the property tax rate calculated by the Company on line 16 of Exhibit A-125 (BJV-1), page 1.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-38
April 15, 2026
Page 1 of 2

Working Capital - Summary

Line	Description (a)		Millions Of Dollars (b)	Note or Ref. (c)
1	Test Year Working Capital Per Company		$ 1,383.1	1
	Attorney General Changes			
2	Cash Balance		(13.3)	2
3	Gas Stored Underground - lower gas prices		(12.3)	3
4	Accounts Payable - 23.86% of Gas Storage Change		2.9	4
5	Riverside Storage Regulatory Asset		(9.7)	5
6	Accrued Taxes		(45.9)	6
7	SAP S4 HANA ERP Project		(14.9)	7
8	**Total Change**	(Sum of L2 to L6)	**$ (93.2)**	
9	**AG Revised Working Capital Level**	(L1 + L7)	**$ 1,289.9**	
10	**Change in Working Capital**	**(L8 less L1)**	**$ (93.2)**	

---

1 Per Company Exhibit A-12, Schedule B4

2 Determined As Follows From DR AG-CE-238 Attachment 2

Avg. Cash at Dec 2022	$ 11.4
Avg. Cash at Dec 2023	8.7
Avg. Cash at Dec 2024	16.8
Three Year Average	$ 12.3
Cash Balance per Company	25.6
Reduction in Cash (To Line 2 Above)	$ (13.3)

3 Adjustment to reflect Company's revised balance of $424.6 million per SA-CE-057 (NBQ-1-1) vs. $438.9 million from Exh. A-12, Schedule B4

4 Lower Accounts Payable Due to lower gas prices

5 Removal of Increase included in Exhibit A-12, Sched. B4 in Column (m) due to sale of asset

6 Adjustment to reflect the historic test year level of Accrued Taxes.

7 Adjustment to actual expense trend.

MICHIGAN PUBLIC SERVICE COMMISSION Case No.: U-21981
Consumers Energy Company WP-HLR- 30
Adjustment to Accrued Taxes
For the Projected 12-Month Period Ending October 31, 2027

Line No	(a) Description	(b) Source	(c) Amount
1	Accrued Taxes - June 2025 13-Month Average Balance	WP-HLR-23, Line 27, Col. (f.2)	$ 218,058,689
	Exclude Historical Accrued Income Taxes:		
2	Accrued Federal Income Tax Payable	WP-HLR-23, SAP Acct 2300000	28,500,882
3	Accrued Income Tax Payable - APB 28	WP-HLR-23, SAP Acct 2300500	5,822,007
4	Accrued State Income Tax	WP-HLR-23, SAP Acct 2301000	9,022,792
5	Accrued SBT Tax	WP-HLR-23, SAP Acct 2301200	-
6	Accrued Franchise Tax	WP-HLR-23, SAP Acct 2301400	(123)
7	Accrued State Income Tax Payable - APB 28	WP-HLR-23, SAP Acct 2301500	1,980,796
8	Accrued Local Income Tax Payable	WP-HLR-23, SAP Acct 2301600	159,273
9	Accrued Local Income Tax Payable - APB 28	WP-HLR-23, SAP Acct 2301700	65,820
10	Total Historical Accrued Income Taxes	Sum of Lines 2 through 9	45,551,448
11	Historical Accrued Taxes, Net of Income Taxes	Line 1 - Line 10	172,507,242
	Include Projected Accrued Income Taxes:		
12	Accrued Federal Income Tax - October 2027 13-Month Average Balance	WP-HLR- 31	64,254
13	Accrued State Income Tax - October 2027 13-Month Average Balance	WP-HLR- 31	(415,342)
14	Accrued Local Income Tax - October 2027 13-Month Average Balance	WP-HLR- 31	(3,136)
15	Projected Accrued Income Taxes - October 2027 13-Month Average Balance	Sum of Lines 12 through 14	(354,223)
16	Projected Accrued Taxes - October 2027 13-Month Average Balance	Line 11 + Line 15	172,153,019
17	Accrued Tax Adjustment	Line 16 - Line 1	(45,905,671)

Exhibit AG-39

CONFIDENTIAL

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-40
Date: April 15, 2026
Page 1 of 2

Recommended Capital Structure & Cost Rates for Projected Year Ending October 2027 (Millions of Dollars)

Line	Description (a)	Note	Consumers Energy - Capital Structure Capital Balances (b)	% Permanent Capital (c)	% Total Capital (d)	Cost Rate* (e)	Total Cost (d) x (e) (f)	Conversion Factors** (g)	Pre-Tax Wtd. Cost (f) x (g) (h)
1	Long Term Debt	(A)	$ 14,554	49.87%	42.58%	4.51%	1.92%	1.0000	1.92%
2	Preferred Stock		37	0.13%	0.11%	4.50%	0.00%	1.3381	0.01%
3	Common Equity	(A)	14,591	50.00%	42.69%	9.70%	4.14%	1.3381	5.54%
4	Total Permanent Capital	(B)	29,182	100.00%	85.38%		6.07%		7.47%
5	Short Term Debt	(B)	162		0.47%	4.87%	0.02%	1.0000	0.02%
6	Deferred Income Taxes	(B)	4,669		13.66%	0.00%	0.00%	1.0000	0.00%
7	JDITC								
8	Long Term Debt		83		0.24%	4.51%	0.01%	1.0000	0.01%
9	Preferred Stock		-		0.00%	0.00%	0.00%	1.3381	0.00%
10	Common Equity		83		0.24%	9.70%	0.02%	1.3381	0.03%
11	Total JDITC		166						
12	**Total Capitalization & Cost Rates**		$ 34,179		100.00%		**6.12%**		**7.53%**

Notes

* The Cost of Long Term Debt is from page 2 of this exhibit and the Cost of Common Equity is set forth on Exhibit AG-41. Costs on lines 5 and 6 are from Exhibit A-14, Sched. D1.

** See Company Exhibit A-13, Schedule C2.

(A) Reflects the permanent capital of Consumers Energy per Exhibit A-14, Sched. D1, with equal amounts of Common Equity and Long-term debt/Preferred Stock.

(B) Capital balances per Company Exhibit A-14, Schedule D1.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-40
Date: April 15, 2026

Cost of Long-Term Debt - Dollars in Millions

		Projected Test Year Ending October 2027		
Line	Description or Caption	Long-Term Debt Outstanding	Interest Expense	Cost Rate Col. (c) / (b)
	(a)	(b)	(c)	(d)
1	Exhibit A-14 (MRB-1), Schedule D1 (line 2) Long-Term Debt Cost	$ 14,334	$ 649	4.53%
2	Less: 2027 New Debt Issues #3 and #4 - Lines 47 and 48 of Exhibit A-14, Schedule D2	(496)	(31)	6.28% *
3	Add: 2027 New Debt Issues at lower Cost*	496	29	5.84% *
4	AG's Revised Cost of Long-Term Debt**	**$ 14,334**	**$ 647**	**4.51%**

---

* Reflects the cost rate on line 2 of 6.28% (4.84% U.S. Treasury Rate + Spread of 1.44%) adjusted for a lower 30-Year Treasury rate of 4.40% vs. the Company 30-year U.S. Treasury projection of 4.84% for a 44 pb difference.

** Columns Ib) and (c) equal the sum of Lines 1, 2 and 3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-41
Date: April 15, 2026
Page 1 of 1

Summary of Cost of Common Equity Analysis

Line	Description (a)	Relative Weighting (b)	Consumers Energy Proxy Rates (c)	Note (d)
1	Discounted Cash Flow Approach (DCF)	50.00%	9.57%	1
2	Capital Asset Pricing Model Approach (CAPM)	25.00%	10.15%	2
3	Utility Equity Risk Premium Approach	25.00%	9.45%	3
4	**Calc. Cost of Common Equity (Sum of Col. (b) x (c) for Lines 1, 2 and 3)**		**9.68%**	
5	Calculated ROE rounded up		0.02%	
6	**Cost of Common Equtiy per AG Case (L4 + L5)**		**9.70%**	

Note 1 See Exhibit AG-42
Note 2 See Exhibit AG-43
Note 3 See Exhibit AG-44

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-42
Date: April 15, 2026
Page 1 of 1

Discounted Cash Flow (DCF) Application
(See Equation Below)

						EPS Growth Rate***			
Line	**Company**	**Ticker**	**Average 30 Day High Low Price***	**Projected 2026/27 Ann. Dividend****	**Dividend Yield Col. (d)/(c)**	**Value Line**	**S&P Capital IQ**	**Average of Col. (f) & (g)**	**DCF ROE for Each Co. Col. (e) + (h)**
	(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**
	Proxy Group								
1	Atmos Energy	ATO	$ 173.36	4.06	2.34%	7.00%	7.22%	7.11%	9.45%
2	Chesapeake Utilities	CPK	130.45	2.86	2.19%	7.60%	N/A	7.60%	9.79%
3	NiSource	NI	44.78	1.22	2.72%	7.50%	N/M	7.50%	10.22%
4	New Jersey Resources	NJR	51.15	1.95	3.81%	5.00%	N/A	5.00%	8.81%
5	Northwest Natural Holdings	NWN	48.24	1.97	4.08%	6.00%	5.75%	5.88%	9.96%
6	One Gas	OGS	81.97	2.73	3.33%	6.00%	5.94%	5.97%	9.30%
7	WEC Energy Group	WEC	112.16	3.85	3.43%	6.00%	N/A	6.00%	9.43%
9	Average				***3.13%***	***6.44%***	***6.30%***	***6.44%***	***9.57%***
10	High								10.22%
11	Low								8.81%

---

* Average of High and Low prices for the 30 trading days (per Yahoo) from January 15, 2026 to February 28, 2026

** Value Line Projected Dividends for 2026 and 2027 (weighted 75% and 25% respectively) published February 20, 2026 and for WEC Energy on March 6, 2026

*** Value Line Growth data as of February 20 and March 6, 2026. S&P Capital IQ data per Company Exhibit A-14 (AEB-1) Schedule D5 page 4 of 26, column 6

N/A Data not available

N/M Growth rates at 8% or higher are unrealistic for gas distributors, reflecting a temporary rebound in earnings and not a long-term growth rate.

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-43
Date: April 15, 2026
Page 1 of 1

(See Equation Below)

Line	**Company & Ticker**		**% Common Equity**	**Current Beta (B)**	**Risk Premium (R_p)**	**Beta x Risk Premium Col. (c) x (d)**	**Risk Free Rate (R_f)**	**K_e or CAPM ROE for Each Co. Cols. (e) + (f)**
	(a)		(b)	(c)	(d)	(e)	(f)	(g)
	Proxy Group							
1	Atmos Energy	ATO	60.1%	0.80	7.45%	5.96%	4.40%	10.36%
2	Chesapeake Utilities	CPK	52.5%	0.75	7.45%	5.59%	4.40%	9.99%
3	NiSource	NI	34.7%	0.85	7.45%	6.33%	4.40%	10.73%
4	New Jersey Resources	NJR	42.9%	0.75	7.45%	5.59%	4.40%	9.99%
5	Northwest Natural Holdings	NWN	38.9%	0.80	7.45%	5.96%	4.40%	10.36%
6	One Gas	OGS	56.4%	0.75	7.45%	5.59%	4.40%	9.99%
7	WEC Energy Group	WEC	40.1%	0.70	7.45%	5.22%	4.40%	9.62%
9	**Average**		**46.5%**	**0.77**	**7.45%**	**5.75%**	**4.40%**	***10.15%***
10	High							10.73%
11	Low							9.62%

Sources

Column (b) Per SEC Filings: Average for the four quarters ended December 2025

Column (c) From the Value Line Investment Survey published February 20 and March 6, 2026.

Column (d) Reflects the average returns of Large Stocks (12.29%) vs Long Term Gov't Bond Income Returns (4.84%) for the period 1926 to 2024 per the Ibbotson Clasic Year Book (through 2022) and "slick charts" for 2023 and 2024

Column (f) Per Blue Chip Forecast V ol. 44, No. 6 of June 2, 2025 Utilized by the Company in Exhibit A-14 (AEB-1), Sch. D5, page 8

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy- Gas Rate Case

Case No. U-21981
Exhibit AG-44
Date: April 15, 2026
Page 1 of 1

Utility Equity Risk Premium Approach

Line	Description (a)	Rate Developed (b)	Note (c)
1	Number of Companies in proxy group with credit ratings of A/BBB	7	1
2	Consumers Energy Credit Rating	A	
3	Projected "A" rated Bonds New Issue Rate	5.59%	2
4	Historical Spread - Gas Util. Common Stocks vs. "A" Rated Utility Bonds	3.86%	3
5	Sub Total - Rate for "A" rated companies (lines 3 + 4)	**9.45%**	

Note:

1 Atmos, OneGas, New Jersey Natural Gas and Chesapeake Utilities are "A" rated. All other peer companies are "BBB" rated.

2 Based on analysis of new 30 Year issues for 2024 (see workpapers)

"A" Rated Spread to 30 Yr. Treasuries 2024 (AG workpapers)	1.19%	
Assumed 30 Year US Treasury Bond Rate (from CAPM Analysis)	4.40%	
Projected "A" rated 30 Year bonds	**5.59%**	***To Line 3 above***

3 Per AG Workpapers

MICHIGAN PUBLIC SERVICE COMMISSION **Case No. U-21981**
Consumers Energy - Gas Rate Case **Exhibit AG-45**
Date: April 15, 2026
Peer Group Non-Utility or Non Regulated Operations **Page 1 of 1**

Line	Company & Ticker		Percent Common Equity*	Current Beta (*B*)	Utility Business	Non Utility & Non Reg. Business		Measurement Criteria	SEC Filing Information SEC Form	Period Ending	Page
	(a)		(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)
	Proxy Group										
1	Atmos Energy	ATO	60.1%	0.80	***62.3%***	***37.7%***	A	Net Income	10-K	Sep. 25	26
2	Chesapeake Utilities	CPK	52.5%	0.75	***86.7%***	***13.3%***	B	Op. Income	10-K	Dec. 25	33
3	NiSource	NI	34.7%	0.85	***100.0%***	***0.0%***		Net Income	10-K	Dec. 25	70 & 82
4	New Jersey Resources	NJR	42.9%	0.75	***64.0%***	***36.0%***	C	Net Income	10-K	Sep. 25	35
5	Northwest Natural Hldgs.	NWN	38.9%	0.80	***95.3%***	***4.7%***	D	Op. Income	10-K	Dec. 25	47 & 82
6	One Gas	OGS	56.4%	0.75	***100.0%***	***0.0%***		Revenues	10-K	Dec. 25	7
7	WEC Energy Group	WEC	40.1%	0.70	***85.2%***	***14.8%***	E	Assets	10-K	Dec. 25	148
8	**Average**		**46.5%**	**0.77**	***84.8%***	***15.2%***					

---

* Reflects Average Capitalization for the four quarters ended December 2025

A Pipeline and Storage

B Non Utility is primarily Propane Distribution

C Primarily Clean Energy Ventures and Energy Services

D Renewable Energy, Storage and Pipelines

E Non-Utility Energy Infrastructure

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-46
Date: April 15, 2026
Page 1 of 1

Market to Book Equity Ratios

Line	Company & Ticker		Dec. 31, 2025 Mkt. Price p/ Sh.	December 31, 2025 Book Value of Common Equity ($Mil.)	Shares Outstanding (Millions)	Book Value Per Sh.	Market to Book Ratio
	(a)		(b)	(c)	(d)	(e)	(f)
	Proxy Group						
1	Atmos Energy	ATO	167.63	14,283.0	165.4	86.35	1.9
2	Chesapeake Utilities	CPK	124.76	1,598.5	23.9	66.88	1.9
3	NiSource	NI	41.76	9,450.1	478.4	19.75	2.1
4	New Jersey Resources	NJR	46.12	2,472.3	100.8	24.53	1.9
5	Northwest Natural Hldgs.	NWN	46.77	1,475.0	41.6	35.46	1.3
6	One Gas	OGS	77.25	3,440.1	62.7	54.87	1.4
7	WEC Energy Group	WEC	105.46	13,613.6	325.5	41.82	2.5
8	**Average**						**1.9**

Col. (b) Closing Price Per Yahoo
Col. (c) Per SEC Filings
Col. (d) Per SEC Filings
Col. (e) Equals Col. (c) divided by Col. (d)
Col. (f) Equals Col. (b) divided by Col. (e)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-47
Date: April 15, 2026

Gas Regulatory Decisions - Authorized ROE's under 9.9% - 12 Mo. Periods Ended September 2024 and 2025

Line	Gas Company*	Order Date & Jurisdiction*			ROE Rate from Order* 2023-24	2024-25	Parent Company	Foreign, Prvt, Domestic	Long Term Debt Issued Since Rate Order**			
1	Piedmont Natural Gas	Oct	5	SC	9.30%		Duke Energy	D	$150M	4.85%	3/5 Yr	(Nov 2023)
2	Chattanooga Gas	Oct	6	TN	9.80%		Southern Co.	D	$400M	5.70%	10 Yr	(Feb 2024)
3	New Youk State Elec. & Gas	Oct	12	NY	9.20%		Avangrid	D	$680M	Var. Rates	Var. Mat.	(Dec 2023)
4	Rochester Gas & Electric	Oct	12	NY	9.20%		Avangrid	D	$680M	Var. Rates	Var. Mat.	(Dec 2023)
5	Northwestern Energy	Oct	25	MT	9.55%		NorthWestern Energy	D				
6	Minnesota Energy Rescs	Oct	26	MN	9.65%		WEC Energy	D				
7	Avista	Oct	26	OR	9.50%		Avista	D				
8	Duke Energy Onio	Nov	1	OH	9.60%		Duke Energy	D	$150M	4.85%	3/5 Yr	(Nov 2023)
9	Madison Gas & Electric	Nov	3	WI	9.70%		MGE Corp	D				
10	Questar Gas	Nov	7	WY	9.65%		Dominion Energy	D	$1.0 Bil	5/5.35%	10/30 Yr.	(Feb 2024)
11	Northern States Power	Nov	9	FL	9.80%		Xcel Energy	D				
12	Wisconsin Power & Light	Nov	9	WI	9.80%		Alliant Energy	D				
13	Ameren Illinois	Nov	16	IL	9.44%		Ameren	D	$700M	4.38%	5 Yr	(Dec 2023)
14	North Shore Gas	Nov	16	IL	9.38%		WEC Energy	D	$20M	5.82%	5 Yr	(Dec 2023)
15	Northern Illinois Gas	Nov	16	IL	9.51%		Southern Co.	D	$400M	5.70%	10 Yr	(Feb 2024)
16	Peoples Gas Light & Coke	Nov	16	IL	9.38%		WEC Energy	D				
17	Piedmont Natural Gas	Dec	4	TN	9.80%		Duke Energy	D	$150M	4.85%	3/5 Yr	(Nov 2023)
18	Baltimore Gas & Electric	Dec	14	MD	9.45%		Exelon	D	$1.7 B	5.2/5.4/5.6	5/10/20 Yrs	(Feb 2024)
19	Washington Gas Light	Dec	14	MD	9.50%		AltaGas BB Rated	F	900 M	7.20%	30 Yr.	(Sep 2024)
20	Washington Gas Light	Dec	15	MD	9.65%		AltaGas BB Rated	F	900 M	7.20%	30 Yr.	(Sep 2024)
21	Mountaineer Gas	Dec	21	WV	9.75%		UGI	D				
22	Black Hills Wyoming Gas	Jan	17	WY	9.85%		Black Hills	D	$450 M	6.00%	10 Yr.	(May 2024)
23	Texas Gas Service	Jan	31	TX	9.70%		One Gas	D	$250 M	5.10%	5 Yr	(Aug 2024)
24	Black Hills Colorado	Mar	24	CO	9.30%		Black Hills	D	$450 M	6.00%	10 Yr.	(May 2024)
25	Southwest Gas - North	Apr	8	NV	9.50%		Southwest Gas	D				
26	Southwest Gas - South	Apr	8	NV	9.50%		Southwest Gas	D				
27	Northeast Ohio Nat. Gas	Apr	17	OH	9.75%		First Energy	D	$800 M	4.88%	15 Yr.	(Aug 2024)
28	CenterPoint Energy	Jun	26	TX	9.80%		CenterPoint Energy	D	$800 M	6.90%	31 Yr.	(Aug 2024)
29	Fitchburg Gas & Elec.	Jun	28	MA	9.40%		Unitil	D				
30	Central Hudson Gas & Elec.	Jul	18	NY	9.50%		Fortis	F				
31	New Mexico Gas	Jul	25	NM	9.38%		Emera	F				
32	Northern Indiana Pub. Serv.	Jul	31	IN	9.75%		NiSource	D	$500 M	6.37%	30 Yr.	(Sep 2024)
33	KeySpan Gas East	Aug	15	NY	9.35%		National Grid P. C.	F				
34	Brooklyn Union Gas	Aug	15	NY	9.35%		National Grid P. C.	F				
35	Interstate Power & Light	Sep	17	IA	9.65%		Alliant Energy	D				
36	Sierra Pacific Power	Sep	18	NV	9.45%		Berkshire Hathaway	PVT				
37	Michigan Gas Utilities	Sep	26	MI	9.86%		WEC Energy	D	$25 M	4.8%/5.2%	5 & 10 Yr.	(Oct 2024)
					9.56%							

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-47
Date: April 15, 2026
Page 2 of 3

Gas Regulatory Decisions - Authorized ROE's under 9.9% - 12 Mo. Periods Ended September 2024 and 2025

		Order Date &			ROE Rate from Order*		Parent	Foreign,Prvt,				
Line	**Gas Company***	**Jurisdiction***			**2023-24**	**2024-25**	**Company**	**Domestic**	**Long Term Debt Issued Since Rate Order****			
1	Black Hills Arkansas	Oct	25	AR		9.85%	Black Hills	D				
2	Public Service Elec. & Gas	Oct	26	NJ		9.60%	Pub. Serv. Enterprises G	D	$1.0 B	4.9%/5.5%	5 & 10 Yr.	(Mar 2025)
3	Northwest Natural Gas	Oct	26	OR		9.40%	Northwest Natural Hold	D	$325 M	7.00%	30 Yr.	(Mar 2025)
4	Public Service of Colorado	Nov	1	CO		9.35%	Xcel Energy	D	$1.1 B	4.8%/5.2%	5 & 10 Yr.	(Mar 2025)
5	DTE Gas	Nov	7	MI		9.80%	DTE Energy	D	$1.1 B	5.20%	5 Yr	(Feb 2025)
6	Connecticut Nat. Gas	Nov	9	CT		9.15%	Avangrid	D				
7	Sthrn. Connecticut Nat. Gas	Nov	9	CT		9.15%	Avangrid	D				
8	Texas Gas Service	Nov	16	TX		9.70%	One Gas	D				
9	Elizabethtown Gas	Nov	16	NJ		9.60%	JP Morgan Infrast via S J	PVT				
10	New Jersey Natural Gas	Nov	16	NJ		9.60%	N J Resources	D				
11	Summitt Utilities	Nov	16	AR		9.85%	Kinder Morgan Ptns.	D				
12	National Fuel Gas	Dec	4	NY		9.70%	National Fuel Gas	D	$1.0 BM67:	5.5%/5.9%	5 & 10 Yr.	(Feb 2025)
13	Wisconsin Gas	Dec	14	WI		9.80%	WEC Energy	D	$300 M	4.55%	5 Yr	(Dec 2024)
14	Wisconsin Public Svc.	Dec	14	WI		9.80%	WEC Energy	D	$300 M	4.55%	5 Yr	(Dec 2024)
15	Avista Washington	Dec	15	WA		9.80%	Avista	D				
16	Columbia Gas	Dec	21	KY		9.75%	NiSource	D	$1.0 B	5.75%	30 Yr	(Nov 2025)
17	Piedmont Natural Gas	Jan	7	NC		9.80%	Duke Energy	D	$1.0 B	4.95%/5.7%	10 Yr & 30 Y	(Sep 2025)
18	Northern States Por - MN	Feb	13	MN		9.60%	Exel	D				
19	Cascade Natural Gas	Feb	24	WA		9.50%	MDU Resources	D				
20	Orange & Rockland	Mar	20	NY		9.75%	Consolidated Edison	D				
21	Southwest Gas	Mar	27	AZ		9.84%	Sowthwest Gas Holding	D				
22	Columbia Gas of MD	Apr	22	MD		9.80%	NiSource	D	$1.0 B	5.75%	30 Yr	(Nov 2025)
23	Atmos TX	May	13	TX		9.80%	Atmos	D	$600M	5.45%	30 Yr	(Sep 2025)
24	Columbia Gas VA	May	15	VA		9.75%	NiSource	D	$1.0 B	5.75%	30 Yr	(Nov 2025)
25	Avista OR	May	23	OR		9.50%	Avista	D				
26	Corning Natural Gas	Jun	12	NY		9.50%	Argo Infrastructure Ptns	PVT				
27	Atmos TX	Jun	17	TX		9.80%	Atmos	D	$600M	5.45%	30 Yr	(Sep 2025)
28	Chesapeake Util	Jun	18	DE		9.60%	Chesapeake Utilities	D				
29	East Ohio Gas	Jun	26	OH		9.79%	Enbridge	PVT				
30	Delta Natural Gas	July	1	KY		9.75%	Essential Utilities	D				
31	Atmos - KY	Aug	11	Ky		9.75%	Atmos	D	$600M	5.45%	30 Yr	(Sep 2025)
32	Central Hudson Gas & Electric	Aug	14	NY		9.50%	Fortis	F				
33	Niagra Mohawk	Aug	14	NY		9.50%	National Grid	F				
34	Libefrty Utilities	Aug	26	NH		9.30%	Algonquin	F				
35	Avista	Aug	29	ID		9.60%	Avista	D				
36	Consumers Energy	Sep	30	MI		9.80%	CMS Energy	D				
						9.64%						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-47
Date: April 15, 2026

Gas Regulatory Decisions - Summary of All Authorized ROEs

			No. of Companies		ROEs Awarded		
			12 Mo. Ended Sept.		12 Mo. Ended June of		
	State	Company /Description	2024	2025	2024	2025	
1	Average ROEs - Companies Under 9.9%		37	36	9.56%	9.64%	
2	California	Southern California Gas	1	1	10.50%	10.08%	Wildfire Risk
3	Florida	Peoples Gas System	1		10.15%		Hurricane Risk
4	Alaska	ENSTAR Natural Gas	1		11.88%		Isolated Utility; 150K customers
5	Virginia	Roanoake Gas Company		1		9.90%	Small Company; 63K Customers
6	Indiana	Ohio Valley Gas		1		10.00%	Small Company; 30K Customers
7	Other Jurisdictions						
8	Illinois	Liberty Utilities		1		9.90%	378K Gas Customers (Ill. & NE US)
9	North Dakota	MDU Resources		1		9.90%	Small Operation
10	North Dakota	NSP Minnesota		1		9.90%	Small Operation***
11	Washington	Pudget Sound Gas		1		9.90%	
12	**Cases at 9.9% + with ROEs Stated**		**3**	**7**	**10.84%**	**9.94%**	
13	**Average of All ROEs Awarded**		**40**	**43**	**9.66%**	**9.69%**	

* All ROE data from Regulatory Research Associates & excludes Limited Issue Rider cases

** Customer size information is from SEC documents and Company web sites

*** NSP Minnesota includes certain minor gas operations located in N. Dakota

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company - Gas Rate Case

Case No. U-21981
Exhibit AG-48
Date: April 15, 2026
Page 1 of 2

Rating Agency Cash Flow Ratios
(With ROE at 9.70% and a 50% Common Equity Ratio)

		2024 Adjusted Moody's Cash Flow Ratio ($ Millions)			
Line	Caption	Cash From Operations Pre-Wkg. Cap.	Debt	Ratio (e) / (f)	Note
	(a)	(b)	(c)	(d)	
1	**2024 Actual Ratio Results**	$ 2,344	$ 12,346	**19.0%**	1
2	Increase Common Equity (to 50% vs 49.9%)	1	(12)		2
3	Increase ROE by 0.87% (to 9.70% vs 8.83%)	99			3
4	**2024 Pro Forma w/50% Common Equity, 9.70% ROE**	$ 2,444	$ 12,334	**19.8%**	L 1 + L 2 + L 3
5	**Ratings Downgrade Risk**			***Below 18%***	4

Notes

1 From page 1 of Moody's May 29, 2025 report on Consumers Energy (Exhibit AG-51 with DR AG-CE-0227)

2 As noted below under "Avg. 2024 Capitalization", the Company's Common Equity ratio was 49.95% in 2024. Adjusting to 50% shifts
$12 million to common equity from long-term debt (0.05% x $22.8 billion = $12 million).
Higher Common Equity of $12 million x the Company's earned ROE of 8.83% = $1.0 million in higher Net Income.

3 Increasing the ROE from 8.83% (actual) to 9.70% (a 0.97% change) produces a $99 million increase in total Company earnings (0.87% x $11.4 billion = $99 million).
Note: Consumers 2024 Net Income of $ 1,007 million (p. 100, form 10-K) / $11.4 billion (below) = an 8.83% ROE.

4 From page 2 of Moody's May 29, 2025 report on Consumers Energy (see DR AG-CE-0227)

Average 2024 Capitalization ($ Millions)	**Actual 2024**		**Rebalancing**	**2024 Rebalanced**	
(from Case U-21981 Ex. A-14 (MRB-2) Sch. D1a, pg.1)	**Amount**	**% Capital**	**Adjustmts.**	**Amount**	**% Capital**
Long-Term Debt	$ 11,392	49.9%	$ (12)	$ 11,380	49.8%
Preferred Stock	37	0.2%		37	0.2%
Common Equity	11,405	49.9%	12	11,417	50.0%
Total	$ 22,834	100.0%		$ 22,834	100.0%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company - Gas Rate Case

Case No. U-21981
Exhibit AG-48
Date: April 15, 2026
Page 2 of 2

2022 Rating Agency Cash Flow Ratios
Impact of Lower Gas in Storage

		2022 Adjusted Moody's Cash Flow Ratio ($ Millions)			
Line	**Caption**	**Cash From Operations Pre-Wkg. Cap.**	**Debt**	**Pro Forma Ratio (e) / (f)**	**Note**
	(a)	**(b)**	**(c)**	**(d)**	
1	**2022 Actual Ratio Results**	$ 2,096	$ 10,472	**20.0%**	1
	Pro Forma Adjustment - Lower Gas in Storage				
2	Lower Debt Financing - Gas in Storage		(378)		2
3	Lower Interest Expenbse	11			3
4	**2022 Pro Forma results with lower Gas in Storage**	$ 2,107	$ 10,094	**20.9%**	L 1 + L 2 + L 3
5	**Improvement in Ratio Results**			***0.9%***	L 4 less L 1

Notes

1 From page 1 of Moody's May 29, 2025 report on Consumers Energy (see AG-CE-0400)

2 Per CMS/Consumers Energy 2022 Form 10-K, Gas in Storage increased from $462 million (Dec 2021) to $840 million (Dec 2022) which is a $378 million difference.

3 Equals $378 million capital difference x avg. debt rate from case U-21308 of 4.7% x after tax rate of 64%.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Gas Rate Case

Case No. U-21981
Exhibit AG-49
Date: April 15, 2026
Page 1 of 1

Most Recent Ordered ROEs of Peer Group

Line	Company & Ticker (a)		Most Recent Authorized ROE*	State	Date	Relevant Gas Utility Units
	Proxy Group					
1	Atmos Energy	ATO	9.80%	TX	Jun-25	Atmos Energy - Texas
2	Chesapeake	CPK	9.60%	DE	Jun-25	Chesapeake Delaware
3	NiSource	NI	9.75%	KY	May-25	Columbia Gas of Kentucky
4	New Jersey Resources	NJR	9.60%	NJ	Nov-24	New Jersey Natural Gas
5	Northwest Natural Holdings	NWN	9.40%	OR	Oct-24	Northwest Natural Gas
6	One Gas	OGS	9.70%	TX	Nov-24	Texas Gas Service
7	WEC Energy Group	WEC	9.80%	WI	Dec-24	Wisc Elec., Wisc. Gas, WPSC
8	**Average of seven companies**		**9.66%**			

---

* Regulatory Research Associates

U21981-AG-CE-0227
Page **1** of **1**

Question:

7. Please provide a copy of all S&P and Moody's rating agency reports covering Consumers Energy and CMS Energy issued since the beginning of 2024.

a. Confirm that as the parent company of Consumers Energy, CMS Energy's ability to inject capital into Consumers Energy depends on the ability of CMS Energy to raise debt and equity capital.

b. Identify by report and page number, where any of the credit rating agencies since 2024 have identified in the credit reports of CMS Energy and Consumers Energy that the debt level at CMS Energy is a concern that could affect the credit rating of Consumers Energy.

Response:

> **Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that information regarding CMS Energy is irrelevant to this matter as CMS Energy is not a party to this case. Subject to the Company's objection, and without waiving that objection, Consumers Energy responds as follows:**

Please find the requested ratings agency credit opinions for Consumers Energy attached.

a. As discussed on page 8, lines 2-9 of Ms. Bulkley's Direct Testimony, the stand-alone principle of ratemaking requires that regulated rates should be based on the risks and benefits of the regulated utility, not its investors, parent or affiliates. Consistent with this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, Ms. Bulkley evaluated the investor-required return for Consumers Energy's natural gas utility operations in Michigan. Therefore, the fact that Consumers is affiliated with CMS Energy is not an appropriate consideration in this base rate case.

b. Please see the response to part a.

Witness: Ann E. Bulkley
Date: March 30, 2026

S&P Global
Ratings

RatingsDirect®

Consumers Energy Co.

September 15, 2025202x

Primary Contact

Ruchi Agrawal
Toronto
14372252983
ruchi.agrawal
@spglobal.com

Secondary Contact

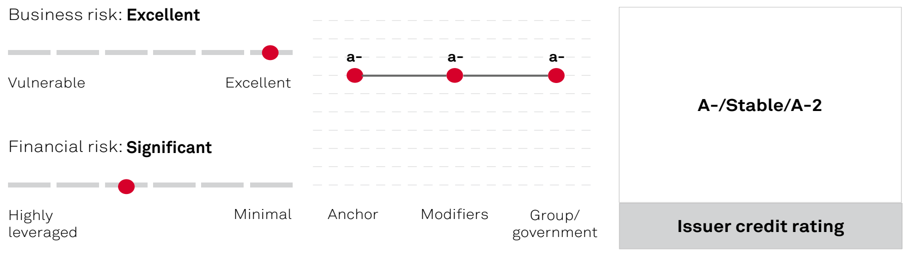
Obioma Ugboaja, CFA
New York
1-212-438-7406
obie.ugboaja
@spglobal.com

Research Contributor

Pradeep arul Pragash
CRISIL Global Analytical Center,
an S&P Global Ratings affiliate
Chennai

This report does not constitute a rating action.

Ratings Score Snapshot



Credit Highlights

Overview

Key strengths	Key risks
Monopolistic vertically integrated electric utility and gas distribution utility operations.	Lack of operating diversity that makes the company largely depend on Michigan regulators to sustain its credit quality.
Favorable regulatory construct in Michigan.	A 2024 third-party audit that indicated below-average system reliability as measured by system and customer average interruption indices.
Large customer base of 1.9 million electric and 1.8 million gas customers.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.
Insulated subsidiary of its parent, CMS Energy Corp., allowing us to rate it one notch above the parent.	Susceptibility to adverse weather events, including winter and convective storms.
	Exposure to cyclical commercial and industrial customers, which account for 45%-50% of electric utility revenues and 20%-25% of gas utility revenues.

We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk. We believe Michigan's regulatory construct is above average compared with peers because of the benefit of a streamlined 10-month rate case process. Other constructive rate mechanisms include the use of forward test-years, power supply cost rider adjustments, and natural gas cost rider adjustments. These mechanisms help the company earn its allowed return on equity (ROE) and minimize regulatory lag.

CE is currently seeking rate increases in both electric and gas businesses. In June 2025 CE filed for a $460 million electric rate increase, based on a 10.25% ROE (previously approved 9.9%) and an equity layer of 42.94% (previously approved 41.73%). Separately, CE is seeking a $217 million rate increase in its gas business. This is premised on a ROE of 10.25% (previously approved 9.9%) and an equity layer of 42.58% (previously approved 41.48%).

We continue to monitor related developments. We will also continue to monitor the company's performance in light of a 2024 third-party audit which indicated a below-average system reliability assessment for CE as measured by system and customer average interruption indices.

Table 1

Consumers Energy Co. rate-case details

	Electric rate case		Gas rate case	
	Present case: Requested by CE 6/2/2025	**Previous case: Authorized by MPSC 3/21/2025**	**Present case: CE revised request 6/25/2025**	**Previous case: Authorized by MPSC 7/23/2024**
Rate change amount (mil. $; excluding deferrals)	438.8	153.8	217.1	35.0
Return on equity (%)	10.25	9.90	10.25	9.90
Common equity to total capital (%)	42.94	41.73	42.58	41.48

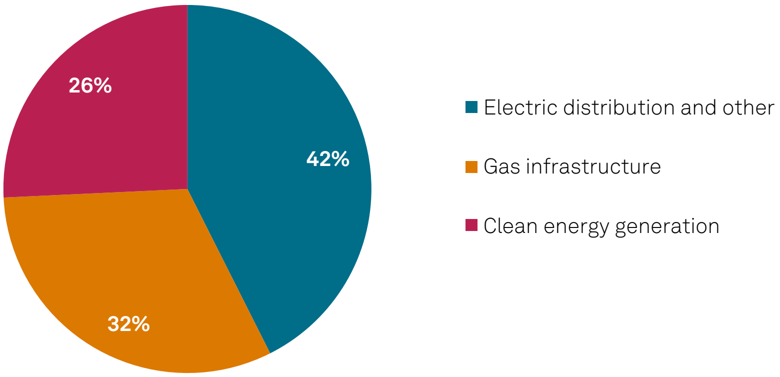
MPSC--Michigan Public Service Commission. N.A.--Not available. Sources: Company, S&P Capital IQ Pro.

The company's elevated capital spending plan prioritizes infrastructure upgrades and its energy transition plans. Over the next five years, CE plans to invest $20 billion to maintain and upgrade its electric distribution systems and gas infrastructure, as well as reduce its carbon emissions. This includes $8.5 billion for electric distribution upgrades--such as strengthening circuits, replacing poles, and connecting clean energy sources--and $6.3 billion for gas infrastructure improvements to enhance safety, sustain deliverability, and cut methane emissions. Additionally, $5.2 billion will fund clean generation investments in wind, solar, and hydroelectric resources.

The company also intends to reduce its carbon exposure in line with its Integrated Resource Plan (IRP), which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 and a goal to retire CE's owned coal-fired generation plants in 2025. However, on June 1, 2025, the US Department of Energy (DOE) ordered CE to extend the retirement of its coal fired J.H. Campbell power plant by 90 days. Furthermore, the company's IRP targets a gradual reduction in its gas-fired generation dependence after 2025. The company has also announced a net-zero greenhouse gas emissions target by 2050 and a zero-methane emissions target by 2030 for its gas distribution system.

Chart 1

CE's five-year investment plan (2025-2029)



Source: Company fillings.

A portion of CE's service territory has a relatively high wildfire risk classification from the Federal Emergency Management Agency (FEMA). This area is contiguous and has a population of 10,000-15,000 people, 7,000-9,000 housing units (about 40%-60% occupied), and median home values of $100,000-$150,000, according to 2024 U.S. census data. Part of the company's capital spending plan is focused on smart electric systems and anticipates pursuing further undergrounding pilots, with the potential to underground up to 400 miles of electric lines per year, starting in 2027, to address some of its climate-related risks.

While CE has not been found culpable for any wildfires in its service territory and is not currently party to any material litigation, we will continue to monitor the company's ability to effectively manage its risks associated with adverse weather events.

We expect CE's credit measures to remain within the significant financial risk profile category. Throughout our base-case scenario, we expect funds from operations (FFO) to debt of 17%-20%.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of 17%-20%.

Downside scenario

We could lower our rating on CE if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or
- We lower our rating on parent CMS Energy.

Exhibit: AG-50
Case No.: U-21981
Date: April 15, 2026
Page 5 of 16

Upside scenario

Although less likely, we could raise our rating on CE if:

- We raise our rating on CMS Energy; and
- CE's stand-alone financial measures improve, reflecting FFO to debt consistently above 20%.

Our Base-Case Scenario

Assumptions

- Consistent rate case filings and use of existing regulatory mechanisms;
- Elevated capital spending over the forecast period averaging $4 billion annually;
- Annual dividends averaging $1 billion-$1.2 billion annually;
- Equity infusion by the parent to maintain the company's capital structure;
- All debt maturities refinanced; and
- Continued negative discretionary cash flow financed in a balanced manner to support the regulated capital structure.

Key metrics

Period ending	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. $)	2022a	2023a	2024a	2025e	2026f	2027f
Adjusted ratios						
Debt/EBITDA (x)	4.6	4.6	4.6	4-5	4-5	4-5
FFO/debt (%)	18.7	17.6	17.9	17-19	18-20	18-20
FFO cash interest coverage (x)	7.0	5.4	5.5	5-6	5-6	5-6

a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas customers in Michigan. CE's electric business operates as a vertically integrated utility that generates, distributes, and sells electricity. The electric utility sources 25%-30% of its generation from purchased power, rather than from its own plants. The company also sells, stores, and transports natural gas. It is based in Jackson, Mich. CE contributes to about 95% of CMS' EBITDA.

Exhibit: AG-50
Case No.: U-21981
Date: April 15, 2026
Page 6 of 16

Peer Comparison

Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Wisconsin Power & Light Co.	Wisconsin Electric Power Co.	Consolidated Edison Co. of New York Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2024-12-31	2024-12-31	2024-12-31	2024-12-31	2024-12-31
Mil.	$	$	$	$	$
Revenue	7,076	6,166	1,845	3,980	14,129
EBITDA	2,692	3,078	870	1,859	4,748
Funds from operations (FFO)	2,218	2,840	712	1,219	3,564
Interest	551	696	176	275	1,207
Cash interest paid	493	469	172	576	1,121
Operating cash flow (OCF)	2,365	2,725	752	1,369	3,304
Capital expenditure	2,854	3,604	819	1,546	4,398
Free operating cash flow (FOCF)	(489)	(879)	(67)	(177)	(1,094)
Discretionary cash flow (DCF)	(1,605)	(1,655)	(263)	(417)	(2,167)
Cash and short-term investments	44	11	51	0	1,254
Gross available cash	44	11	51	0	1,254
Debt	12,403	13,266	4,025	6,163	25,253
Equity	11,413	11,154	4,101	5,492	19,971
EBITDA margin (%)	38.0	49.9	47.2	46.7	33.6
Return on capital (%)	6.9	7.3	6.8	11.7	6.2
EBITDA interest coverage (x)	4.9	4.4	4.9	6.8	3.9
FFO cash interest coverage (x)	5.5	7.1	5.1	3.1	4.2
Debt/EBITDA (x)	4.6	4.3	4.6	3.3	5.3
FFO/debt (%)	17.9	21.4	17.7	19.8	14.1
OCF/debt (%)	19.1	20.5	18.7	22.2	13.1
FOCF/debt (%)	(3.9)	(6.6)	(1.7)	(2.9)	(4.3)
DCF/debt (%)	(12.9)	(12.5)	(6.5)	(6.8)	(8.6)

Business Risk

Our assessment of CE's business risk profile reflects the company's monopolistic electric and natural gas utility operations and effective management of regulatory risk. The MPSC regulates

CE, and we view the regulatory environment in Michigan as above average compared with peers. This is demonstrated through the company's use of forward-looking test years and a streamlined 10-month rate case process. Furthermore, CE benefits from other constructive rate mechanisms, such as the power supply cost recovery adjustment rider, and the gas cost recovery adjustment rider.

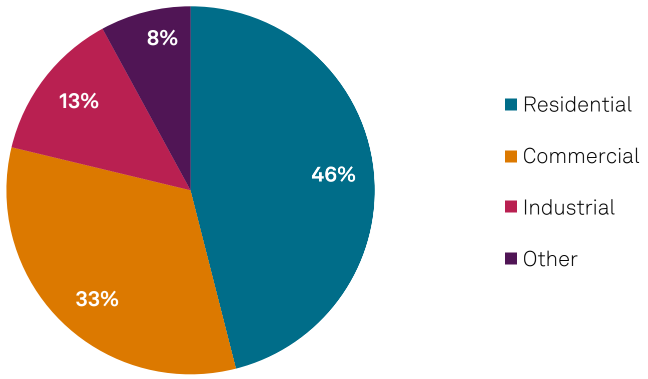
In 2023, the state passed a law that allows electric utilities in the state to earn a return equal to their pre-tax weighted average cost of capital on payments made under new purchased-power agreements. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag.

The company actively manages its gas supply to reduce price volatility and support its gas system operations by injecting natural gas into storage during the summer months for use during the winter months. During 2024, 47% of the natural gas supplied to all customers during the winter months came from storage. Additionally, CE's large customer base of about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan bolsters the company's business risk profile.

That said, the company’s service territory is susceptible to localized storms and adverse weather conditions. It is also exposed to cyclical commercial and industrial customers for its electric operations, which contribute about 45%-50% of the company’s electric revenues. Furthermore a 2024 third-party audit indicated below-average system reliability assessment for CE as measured by system and customer average interruption indices, which we will continue to monitor.

Chart 2

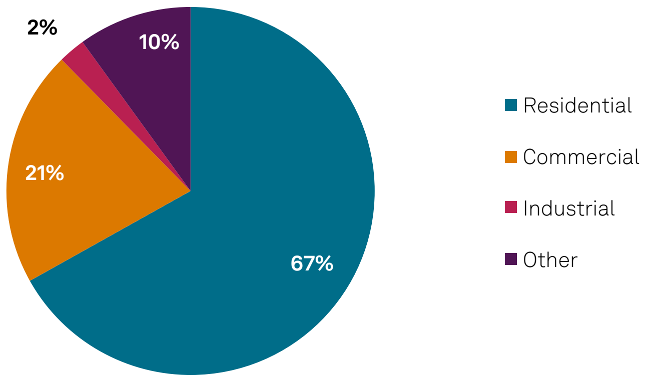
CE's 2024 electrical revenue by customer class



Source: Company fillings.

Chart 3

CE's 2024 gas revenue by customer class



Source: Company fillings.

Financial Risk

We assess CE's financial measures using our medial volatility table, reflecting the company's lower risk regulated electric and gas utility operations and its effective management of regulatory risk. Under our base-case scenario, we expect:

- Elevated capital spending averaging about $4.0 billion annually over the forecast period;
- Dividends averaging $1.0 billion-$1.2 billion annually;
- Equity infusion by the parent to maintain the company's capital structure;
- Continued use of existing regulatory mechanisms;
- Negative discretionary cash flow; and
- The refinancing of all debt maturities.

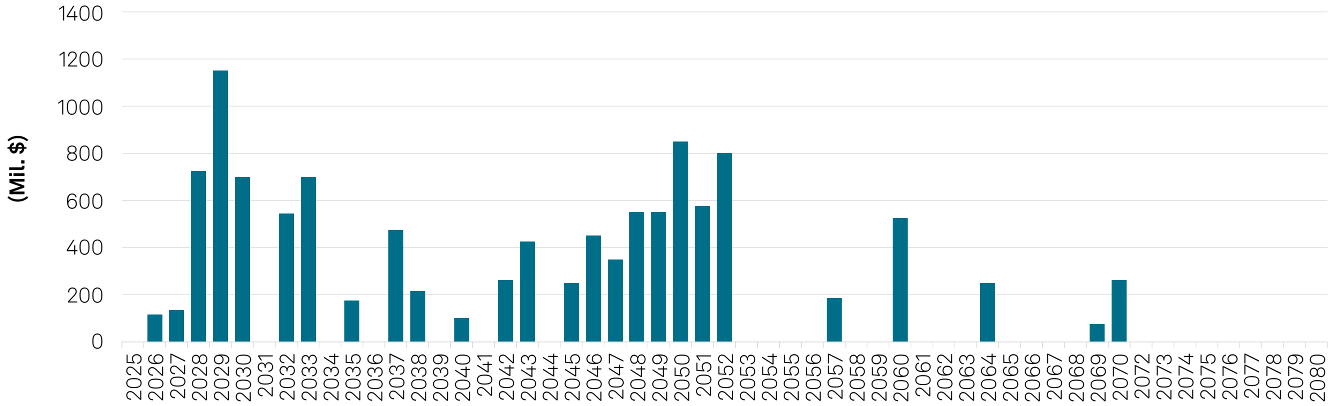
As such, we anticipate financial measures to be consistent with the middle of the range for the significant financial risk category. Specifically, we forecast FFO to debt of 17%-20%.

Debt maturities

Chart 4

CE's debt maturities

First mortgage bonds as of December 2024



Source: Company fillings.

Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024
Reporting period	2019a	2020a	2021a	2022a	2023a	2024a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,341	6,155	6,987	8,117	7,129	7,076
EBITDA	2,252	2,392	2,406	2,397	2,485	2,692
Funds from operations (FFO)	1,823	1,968	2,040	2,057	2,000	2,218
Interest expense	335	393	381	375	496	551
Cash interest paid	296	373	376	343	454	493
Operating cash flow (OCF)	1,688	1,265	2,013	984	2,415	2,365
Capital expenditure	2,191	2,254	2,136	2,275	2,279	2,854
Free operating cash flow (FOCF)	(502)	(989)	(124)	(1,291)	136	(489)
Discretionary cash flow (DCF)	(1,094)	(1,628)	(847)	(2,061)	(560)	(1,605)
Cash and short-term investments	11	20	22	43	35	44
Gross available cash	11	20	22	43	35	44
Debt	8,238	9,113	9,415	11,024	11,371	12,403

Consumers Energy Co.--Financial Summary

Common equity	7,737	8,556	9,261	10,137	10,782	11,413
Adjusted ratios						
EBITDA margin (%)	35.5	38.9	34.4	29.5	34.9	38.0
Return on capital (%)	7.7	7.5	6.9	6.3	6.2	6.9
EBITDA interest coverage (x)	6.7	6.1	6.3	6.4	5.0	4.9
FFO cash interest coverage (x)	7.2	6.3	6.4	7.0	5.4	5.5
Debt/EBITDA (x)	3.7	3.8	3.9	4.6	4.6	4.6
FFO/debt (%)	22.1	21.6	21.7	18.7	17.6	17.9
OCF/debt (%)	20.5	13.9	21.4	8.9	21.2	19.1
FOCF/debt (%)	(6.1)	(10.9)	(1.3)	(11.7)	1.2	(3.9)
DCF/debt (%)	(13.3)	(17.9)	(9.0)	(18.7)	(4.9)	(12.9)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2024									
Company reported amounts	12,162	11,431	7,200	2,706	1,515	518	2,692	2,446	797	2,842
Cash taxes paid	-	-	-	-	-	-	19	-	-	-
Cash interest paid	-	-	-	-	-	-	(493)	-	-	-
Lease liabilities	69	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	5	1	1	(1)	4	-	-
Intermediate hybrids (equity)	19	(19)	-	-	-	1	(1)	(1)	(1)	-
Accessible cash and liquid investments	(44)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	13	(13)	(13)	-	(13)
Share-based compensation expense	-	-	-	25	-	-	-	-	-	-

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Securitized stranded costs	(700)	-	(124)	(124)	(37)	(37)	37	(87)	-	-
Power purchase agreements	415	-	-	47	22	22	(22)	25	-	25
Asset-retirement obligations	548	-	-	33	33	33	-	-	-	-
Nonoperating income (expense)	-	-	-	-	55	-	-	-	-	-
Reclassification of interest and dividend cash flows	-	-	-	-	-	-	-	(9)	-	-
Debt: other	(65)	-	-	-	-	-	-	-	-	-
Total adjustments	241	(19)	(124)	(14)	74	33	(474)	(81)	(1)	12
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	12,403	11,413	7,076	2,692	1,589	551	2,218	2,365	796	2,854

Liquidity

We assess CE's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecast consolidated EBITDA declines 10%. We believe the supportive regulatory framework provides manageable cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity.

In addition, CE can absorb high-impact, low-probability events, in our view, as the company maintains about $1.1 billion in committed credit facilities through 2027, and can likely lower its capital spending (averaging $2.8 billion-$3.0 billion annually) during stressful periods, indicating a limited need for refinancing under such conditions. CE can borrow $500 million from parent CMS Energy as per its renewed credit agreement in December 2024.

Furthermore, our assessment reflects the company's prudent risk management and sound relationships with its banking group. Overall, we believe that the company can withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. As on June 30, 2025, CE had about $570 million of debt maturities in the next 12 months, and we

Exhibit: AG-50
Case No.: U-21981
Date: April 15, 2026
Page 12 of 16

expect the company to proactively address these maturities well in advance of their scheduled due dates.

Principal liquidity sources

- Estimated cash FFO of about $2.8 billion;
- Credit facilities of about $1.1 billion; and
- Available cash of about $600 million as on June 30, 2025.

Principal liquidity uses

- Debt maturities of about $570 million over the next 12 months as on June 30, 2025;
- Working capital outflows of about $170 million; and
- Estimated maintenance capital spending of about $3.1 billion; and
- Dividends of about $1 billion.

Covenant Analysis

Requirements

CE's credit agreements contain a covenant for CE to maintain debt to capitalization below 65%.

Compliance expectations

In our base-case scenario, we expect CE to remain compliant with this covenant and have sufficient headroom.

Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of CE. The company's use of fossil fuel generation sources exposes it to heightened energy transition risks. The capacity of its generation portfolio comprises about 35% natural gas, 19% coal, 17% hydroelectric, 17% oil and gas, and 12% wind and solar as of Dec. 31, 2024. The company's accelerated coal retirement plan for its utility partially mitigates this risk. It includes a goal to be coal-free in owned generation in 2025 and have 60% of its utility's capacity portfolio sourced from clean energy resources by 2030 and 100% by 2040.

Furthermore, the company experienced heightened winter and convective storm activity in recent years.

While CE has not been found culpable for any wildfires in its service territory and is not currently party to litigation concerning these matters, a portion of its service territory has a relatively high wildfire risk classification from FEMA. This area is contiguous and has a population of about 10,000-15,000 inhabitants, 7,000-9,000 housing units, of which about 40%-60% are occupied, and median home values of $100,000-$150,000 according to 2024 U.S. Census data. Part of the company's capital spending plan is focused on smart electric systems and anticipates pursuing further undergrounding pilots, with the potential to underground up to 400 miles of electric lines per year starting in 2027. We will continue to monitor the company's ability to effectively manage its risks associated with adverse weather events.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy largely because we view the utility as integral to the group's identity, highly unlikely to be sold and having a strong commitment from management, given the company's emphasis on maintaining the size of the regulated utility operations relative to the nonutility businesses.

Given CE’s stand-alone credit profile, and because CE is operationally separate and maintains sufficient insulating measures, we rate the utility one notch above the GCP. Some of the key insulating measures are:

- CE is a separate and stand-alone legal entity that functions independently (both financially and operationally), files its own rate cases, and is independently regulated by MPSC;
- CE has its own records and books, including stand-alone audited financial statements;
- The utility has its own funding arrangements, including issuing its own long-term debt, and it has a separate committed credit facility to cover its short-term funding needs;
- CE does not comingle funds, assets, or cash flow with parent CMS Energy or its other subsidiaries, and it does not participate in a money pool;
- We believe there is a strong economic basis for CMS Energy to preserve CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE is also a significant portion of CMS Energy, accounting for about 95% of the consolidated company; and
- There are no cross-default provisions between parent CMS Energy and CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

- As on Dec. 31, 2024, CE's capital structure comprised about $12.2 billion of long-term debt, including about $11.4 billion in first-mortgage bonds (FMBs), $700 million of securitized debt (all of which is deconsolidated from our credit metrics), and about $110 million of tax-exempt revenue bonds.

Analytical conclusions

- We rate the company's senior unsecured debt 'A-', in-line with the long-term issuer credit rating on CE as the rated issuances are senior unsecured debt issued by a qualifying investment grade utility as per our criteria.
- We base our 'A-2' short-term rating on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- We assign recovery ratings to FMBs issued by U.S. utilities, which can result in issue ratings being notched above an issuer credit rating on a utility, depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of secured utility bonds that qualify for a recovery rating as defined in our criteria.

- CE's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

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-**
Modifiers	
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, Insulated (no change to SACP)**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, July 7, 2025
- General Criteria: Hybrid Capital: Methodology And Assumptions, Feb. 10, 2025
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, 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: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017

- Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of September 15, 2025)*	
Consumers Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Issuer Credit Ratings History	
30-Oct-2019	A-/Stable/A-2
03-Dec-2014	BBB+/Stable/A-2
11-Sep-2014	BBB/Positive/A-2
Related Entities	
CMS Energy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Junior Subordinated	BBB-
Preferred Stock	BBB-
Senior Unsecured	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

Exhibit: AG-50
Case No.: U-21981
Date: April 15, 2026
Page 16 of 16

Copyright © 2026 by Standard & Poor's Financial Services LLC. All rights reserved.

No content (including ratings, credit-related analyses and data, valuations, model, software or other application or output therefrom) or any part thereof (Content) may be modified, reverse engineered, reproduced or distributed in any form by any means, or stored in a database or retrieval system, without the prior written permission of Standard & Poor's Financial Services LLC or its affiliates (collectively, S&P). The Content shall not be used for any unlawful or unauthorized purposes. S&P and any third-party providers, as well as their directors, officers, shareholders, employees or agents (collectively S&P Parties) do not guarantee the accuracy, completeness, timeliness or availability of the Content. S&P Parties are not responsible for any errors or omissions (negligent or otherwise), regardless of the cause, for the results obtained from the use of the Content, or for the security or maintenance of any data input by the user. The Content is provided on an “as is” basis. S&P PARTIES DISCLAIM ANY AND ALL EXPRESS OR IMPLIED WARRANTIES, INCLUDING, BUT NOT LIMITED TO, ANY WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR USE, FREEDOM FROM BUGS, SOFTWARE ERRORS OR DEFECTS, THAT THE CONTENT'S FUNCTIONING WILL BE UNINTERRUPTED OR THAT THE CONTENT WILL OPERATE WITH ANY SOFTWARE OR HARDWARE CONFIGURATION. In no event shall S&P Parties be liable to any party for any direct, indirect, incidental, exemplary, compensatory, punitive, special or consequential damages, costs, expenses, legal fees, or losses (including, without limitation, lost income or lost profits and opportunity costs or losses caused by negligence) in connection with any use of the Content even if advised of the possibility of such damages.

Some of the Content may have been created with the assistance of an artificial intelligence (AI) tool. Published Content created or processed using AI is composed, reviewed, edited, and approved by S&P personnel.

Credit-related and other analyses, including ratings, and statements in the Content are statements of opinion as of the date they are expressed and not statements of fact. S&P's opinions, analyses and rating acknowledgment decisions (described below) are not recommendations to purchase, hold, or sell any securities or to make any investment decisions, and do not address the suitability of any security. S&P assumes no obligation to update the Content following publication in any form or format. The Content should not be relied on and is not a substitute for the skill, judgment and experience of the user, its management, employees, advisors and/or clients when making investment and other business decisions. S&P does not act as a fiduciary or an investment advisor except where registered as such. While S&P has obtained information from sources it believes to be reliable, S&P does not perform an audit and undertakes no duty of due diligence or independent verification of any information it receives. Rating-related publications may be published for a variety of reasons that are not necessarily dependent on action by rating committees, including, but not limited to, the publication of a periodic update on a credit rating and related analyses.

To the extent that regulatory authorities allow a rating agency to acknowledge in one jurisdiction a rating issued in another jurisdiction for certain regulatory purposes, S&P reserves the right to assign, withdraw or suspend such acknowledgment at any time and in its sole discretion. S&P Parties disclaim any duty whatsoever arising out of the assignment, withdrawal or suspension of an acknowledgment as well as any liability for any damage alleged to have been suffered on account thereof.

S&P keeps certain activities of its business units separate from each other in order to preserve the independence and objectivity of their respective activities. As a result, certain business units of S&P may have information that is not available to other S&P business units. S&P has established policies and procedures to maintain the confidentiality of certain non-public information received in connection with each analytical process.

S&P may receive compensation for its ratings and certain analyses, normally from issuers or underwriters of securities or from obligors. S&P reserves the right to disseminate its opinions and analyses. S&P's public ratings and analyses are made available on its Web sites, www.spglobal.com/ratings (free of charge), and www.ratingsdirect.com (subscription), and may be distributed through other means, including via S&P publications and third-party redistributors. Additional information about our ratings fees is available at www.spglobal.com/usratingsfees.

STANDARD & POOR'S, S&P and RATINGSDIRECT are registered trademarks of Standard & Poor's Financial Services LLC.

U21981-AG-CE-0227
Page **1** of **1**

Question:

7. Please provide a copy of all S&P and Moody's rating agency reports covering Consumers Energy and CMS Energy issued since the beginning of 2024.

a. Confirm that as the parent company of Consumers Energy, CMS Energy's ability to inject capital into Consumers Energy depends on the ability of CMS Energy to raise debt and equity capital.

b. Identify by report and page number, where any of the credit rating agencies since 2024 have identified in the credit reports of CMS Energy and Consumers Energy that the debt level at CMS Energy is a concern that could affect the credit rating of Consumers Energy.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that information regarding CMS Energy is irrelevant to this matter as CMS Energy is not a party to this case. Subject to the Company's objection, and without waiving that objection, Consumers Energy responds as follows:

Please find the requested ratings agency credit opinions for Consumers Energy attached.

a. As discussed on page 8, lines 2-9 of Ms. Bulkley's Direct Testimony, the stand-alone principle of ratemaking requires that regulated rates should be based on the risks and benefits of the regulated utility, not its investors, parent or affiliates. Consistent with this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, Ms. Bulkley evaluated the investor-required return for Consumers Energy's natural gas utility operations in Michigan. Therefore, the fact that Consumers is affiliated with CMS Energy is not an appropriate consideration in this base rate case.

b. Please see the response to part a.

Witness: Ann E. Bulkley
Date: March 30, 2026

MOODY'S
RATINGS

CREDIT OPINION

29 May 2025

Update

Send Your Feedback

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	(P)A3
Type	Senior Unsec. Shelf - Dom Curr
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

Lily Cochran +1.212.553.4795
Ratings Associate
lily.cochran@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

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Consumers Energy Company

Update to credit analysis

Summary

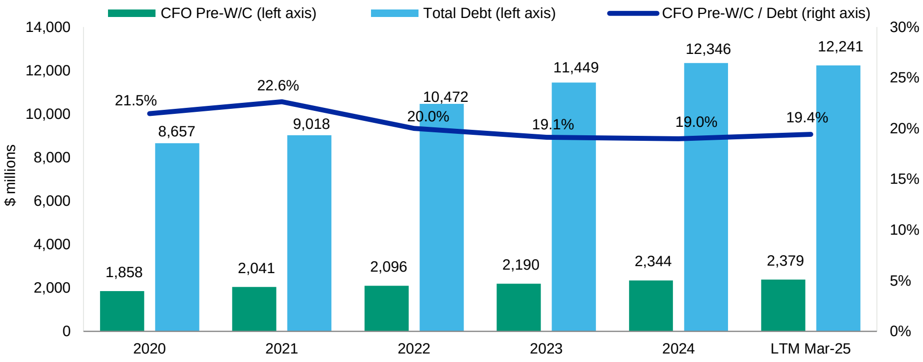
Consumers Energy Company's (Consumers Energy) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in the credit supportive regulatory environment of Michigan. We expect the utility to maintain a relatively stable financial profile with cash flow from operations before changes in working capital (CFO pre-WC) to debt averaging around 19-21%, including an adjustment to exclude securitization debt, over the next 2-3 years.

At the end of the 31 March 2025, Consumers Energy's CFO pre-WC to debt ratio was 20.5%, including the adjustment to exclude securitization bonds. The company will continue to execute its robust capital investment plan and have an active regulatory calendar over this period. Based on the Michigan regulatory framework, we expect the utility to recover its investment costs on a timely basis and to earn an appropriate return on its investments.

Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). However, CMS has made notable progress in reducing the percentage of parent debt in its capital structure in recent years. We now estimate that the percentage of parent debt will remain below 25% of total consolidated debt. All of Consumer Energy's outstanding debt obligations are secured.

Exhibit 1

Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.5%, 20.1% and 20.5% in 2023, 2024 and LTM ending 31 March 2025, respectively.
Source: Moody's Financial Metrics™

Credit strengths

- Credit supportive regulatory environment in Michigan

Exhibit: AG-51
Case No.: U-21981
Date: April 15, 2026
Page 3 of 14

- Transparent and timely cost recovery
- Stable financial profile

Credit challenges

- Robust capital investment plan
- Maintaining regulatory support for these capital investments
- Lack of geographic and regulatory diversity with single state service territory

Rating outlook

The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. The stable outlook also incorporates our view that Consumers Energy will maintain prudent financial policies while managing through its robust investment cycle and that debt levels at the parent will not increase materially.

Factors that could lead to upgrade

A rating upgrade could be considered if credit metrics improve such that CFO pre-WC to debt is above 21% on a sustained basis. In addition, if the Michigan regulatory framework becomes even more formulaic, transparent or timely with its suite of cost recovery mechanisms for Consumers Energy, a rating upgrade could be possible.

Factors that could lead to downgrade

A rating downgrade could be considered if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment or if the company's CFO pre-WC to debt ratio declines below 18% on a sustained basis.

Key indicators

Exhibit 2

Consumers Energy Company

	2020	2021	2022	2023	2024	LTM Mar-25
CFO Pre-W/C + Interest / Interest	6.6x	7.5x	7.1x	5.8x	5.5x	5.5x
CFO Pre-W/C / Debt	21.5%	22.6%	20.0%	19.1%	19.0%	19.4%
CFO Pre-W/C – Dividends / Debt	14.1%	14.6%	12.7%	13.0%	12.5%	12.9%
Debt / Capitalization	44.9%	43.7%	45.1%	45.8%	46.0%	45.3%

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Credit metrics included in the exhibit include securitization bonds. When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.5%, 20.1% and 20.5% in 2023, 2024 and LTM ending 31 March 2025, respectively.
Source: Moody's Financial Metrics™

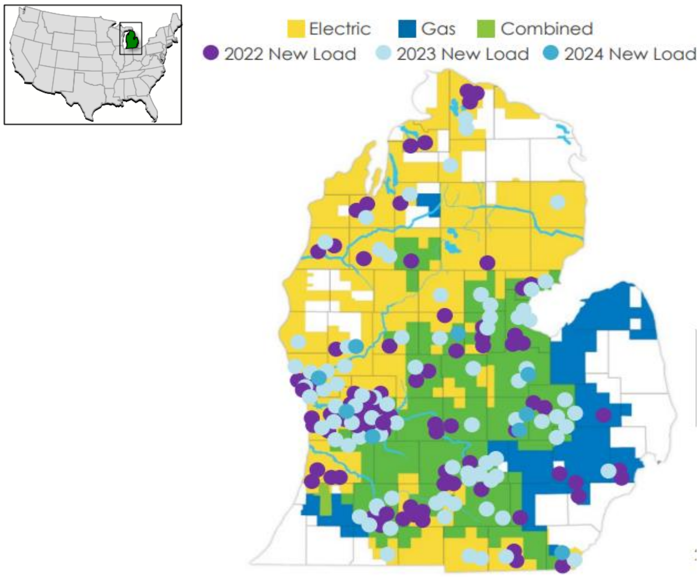
Profile

Consumers Energy is a vertically integrated electric and gas utility serving approximately 1.9 million electric and 1.8 million gas customers in the state of Michigan with an average rate base of $26 billion at the end of 2024. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. The utility is a wholly-owned subsidiary of CMS and, as the primary subsidiary of the parent company, it represents over 95% of CMS's consolidated earnings and cash flows. In addition to Consumers Energy, CMS has a subsidiary called NorthStar Clean Energy, a non-utility domestic independent power producer and marketer.

Exhibit: AG-51
Case No.: U-21981
Date: April 15, 2026
Page 4 of 14

Exhibit 3

Consumers Energy's Service Territory



Source: Company filings

Detailed credit considerations

Consumers Energy Company's ESG credit impact score is CIS-3

We view the regulatory environment in Michigan to be credit supportive. Consumers Energy is regulated by the Michigan Public Service Commission (MPSC) and we view the regulatory framework in Michigan to be more credit supportive than most other states. The state of Michigan has a long history of enacting legislations that are supportive of utility investments in the state. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework has been streamlined, improving both the rate case process and the timeliness of cost recovery. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which had 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 costs, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before the construction of major projects.

The latest energy legislation enacted in Michigan (2023 Energy Law) laid out the state's renewable energy standards. Under the new law, renewable energy standards were raised to 50% by 2030 and 60% by 2035 from the previous 15% by 2021 requirement. It also set a clean energy standard of 80% by 2035 and 100% by 2040. Under the law, zero to low-carbon emitting sources, such as nuclear generation and natural gas generation with carbon capture, are considered clean energy sources. Along with these new standards, the new legislation expanded the authority of the MPSC to oversee their implementation. Consumers Energy filed its Clean Energy Plan in November 2024 and will file an update in 2026. Given the existing regulatory framework in Michigan, we expect the company's collaborative dialogue with both stakeholders and regulator to continue under the new legislation.

In its filing in November 2024, Consumers Energy proposed 9 GW of purchased and owned solar energy resources and up to 2.8 GW of new, competitive bid wind capacity. Under its plan, Consumers Energy will retire all of its coal-fired power plants. While the company was set to retire its last remaining coal-fired power plant, J.H. Campbell power plant, on 1 June 2025, the US Department of Energy (DOE) issued an executive order to extend the retirement of this power plant by 90 days. It is expected that this power plant will be in service through mid-August 2025.

The utility purchased the 1.2 GW natural gas fired power plant called Covert in May 2023 in anticipation of the coal-fired generating capacity retirement. The company also contracted to purchase 400 MW of battery storage capacity to ensure system reliability. As a result of the settlement agreement related to Consumers Energy IRP, the utility is allowed to record approximately $1.3 billion of the remaining book value of these power plants as a regulatory asset and earn a 9% return on equity (ROE) through the remaining life. Instead of securitizing the remaining book value, the settlement will minimize the impact of the accelerated coal retirements on

Exhibit: AG-51
Case No.: U-21981
Date: April 15, 2026
Page 5 of 14

Consumers Energy's credit metrics. We view this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

Consumers Energy Company's ESG credit impact score is CIS-3

Michigan utilities benefit from numerous formulaic rate adjustment mechanisms that provide a high degree of cash flow stability and assurance of recovery. For example, Consumers Energy has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas 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. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/under recoveries, although interim gas inventory buildup could substantially increase the company's working capital financing when gas prices increase sharply.

Gas utilities in the state also benefit from programs designed to assure recovery of needed infrastructure improvements. The company's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including the replacement of 2,700 miles of natural gas distribution and service pipelines with more durable material.

Consumers Energy Company's ESG credit impact score is CIS-3

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. Over the last three years, Consumers Energy experienced downward pressure on its allowed ROE in its rate cases although the company was able to maintain a 9.9% allowed ROE. We expect Consumers Energy to maintain a stable financial profile because there are other offsetting mechanisms such as usage of forward test year to allow the utility to earn appropriate returns and to recover investment costs on a timely basis. However, further deterioration of the allowed ROE is likely to put negative pressure on the company's overall financial profile.

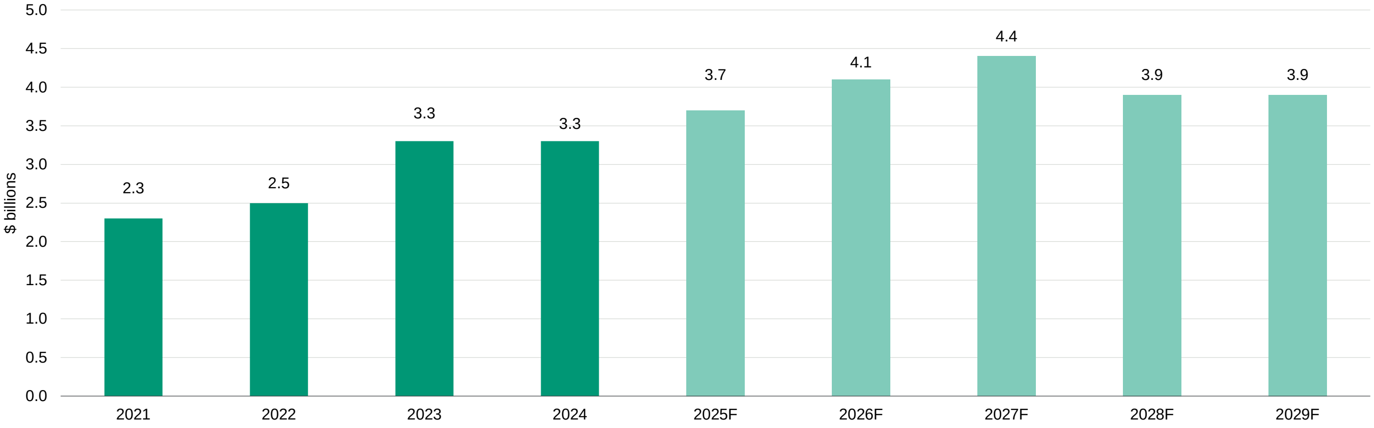
Consumers Energy's latest electric rate case received a final order in March 2025 from the MPSC. The final order authorized an increase of $176 million electric base rates based on a 9.9% return on equity and 50% equity capitalization. The rate increase was also based on a test year ending 28 February 2026 and the total rate base was approximately $14.86 billion. The utility currently has a gas rate case pending before the MPSC. Consumers Energy filed its rate increase request in December 2024. The MPSC staff filed its recommendation, proposing a rate increase of $177 million based on a 9.75% ROE and 50% equity capitalization. Consumers Energy's current allowed ROE and equity capitalization are 9.9% and 50%, respectively. The MPSC must issue a final order before or in October 2025.

Consumers Energy Company's ESG credit impact score is CIS-3

Consumers Energy's capital spending continues to be robust. The company increased its five-year capital expenditure plan through 2029 to $20 billion, approximately $3 billion higher than the previous plan. Consumers Energy will invest approximately $6.3 billion primarily to maintain and upgrade its gas utility infrastructure; $8.5 billion related to its electric distribution and other infrastructure; and $5.2 billion related to clean energy generation. These investments should enhance the company's reliability and safety as well as help it execute its decarbonization plan.

Exhibit 4

Consumers Energy's elevated capital program will extend at least through 2029

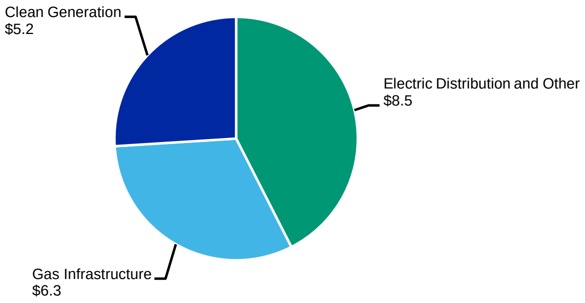


Source: Company filings

Through this period, Consumers Energy plans to keep rate increases modest, which should help to maintain regulatory support for investment cost recovery. Funding for these investments will be provided by internally generated cash flow, the issuance of debt at Consumers Energy and equity contributions from CMS. We expect Consumers Energy's near-term credit metric to be somewhat pressured given the level of expected investment expenditure and the timing of the cost recovery. Over the next 12-18 months, its CFO pre-WC to debt ratio could range 18%-19% including securitization bonds. Excluding the securitization bonds, we expect the metric to range 19% - 20%. At the end of 2024 and as of 31 March 2025, Consumers Energy produced a CFO pre-WC to debt ratio of 20.1% and 20.5%, respectively, excluding securitization debt.

Exhibit 5

Planned Capital Expenditures 2025 - 2029 ($ billions)

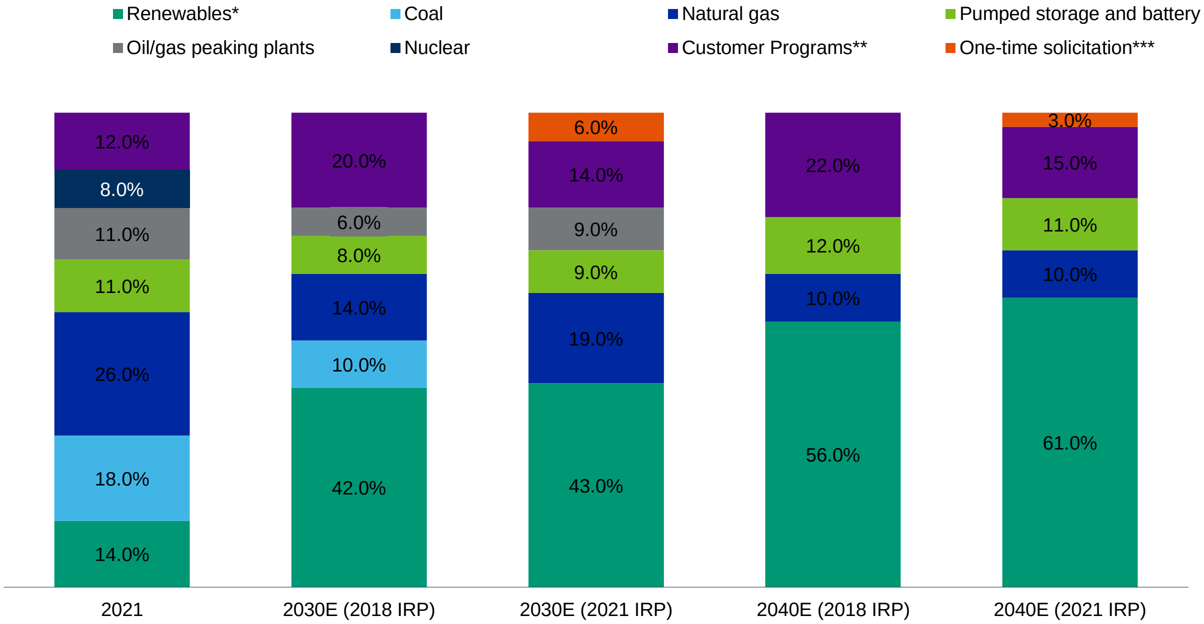


Source: Company filings

Through 2040, Consumers Energy will add up to 8 GW of solar power, which is 2 GW more than what was approved in the company's 2018 IRP. As a result, by 2040, 60% of Consumers Energy's generation capacity will be from renewable sources. In order to replace the retiring coal capacity, the utility acquired the Covert natural gas-fired power plant for approximately $815 million in 2023. It issued requests for proposals (RFP) for two purchased power agreements (PPA) for 500 MW of dispatchable generation and 200 MW of clean energy sources. Under the financial compensation mechanism (FCM), Consumers Energy is allowed earn a return on the PPAs. Pre-tax weighted average cost of capital is approximately 9%. This mechanism allows the utility to earn returns without incurring additional construction risks, a credit positive.

Exhibit 6

Based on the latest IRP settlement, more than 60% of Consumers Energy's generation sources will be renewables by 2040



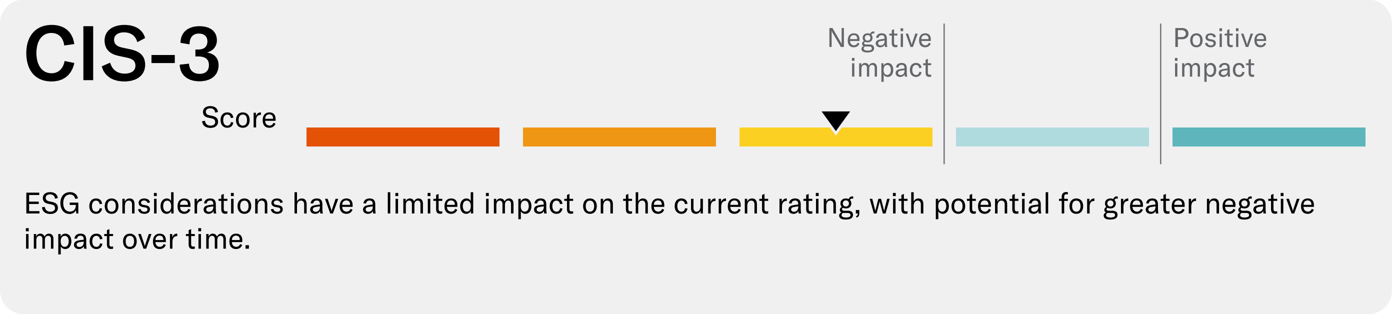
*Does not include renewable RECs.
**Includes energy waste reduction, demand response, and conservation voltage reduction program.
***One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.
Source: Company filings

ESG considerations

Consumers Energy Company's ESG credit impact score is CIS-3

Exhibit 7

ESG credit impact score



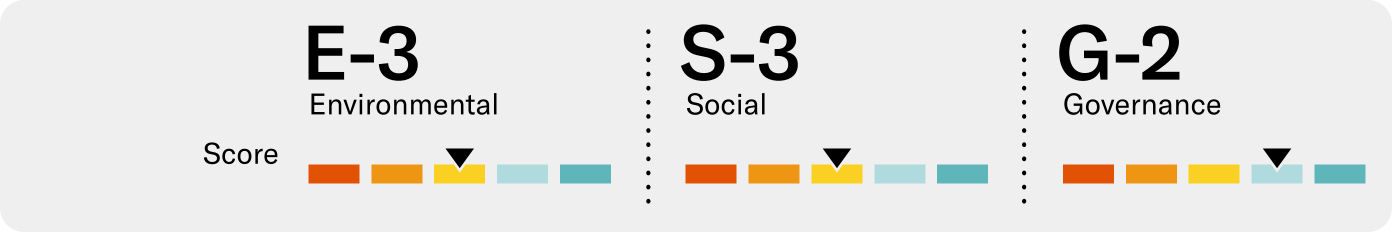
ESG considerations have a limited impact on the current rating, with potential for greater negative impact over time.

Source: Moody's Ratings

Consumers Energy's **CIS-3** indicates that ESG considerations have limited impact on the current credit rating with greater potential for negative impact over time. It reflects some exposure to physical climate risk due to increasing frequency and severity of storm activities. It also incorporates social risks stemming from inherent risk associated with regulated utilities and governance risk that is not a material driver.

Exhibit 8

ESG issuer profile scores



Source: Moody's Ratings

Environmental

Consumers Energy's **E-3** issuer profile score reflects some exposure to physical climate risk, which highlights the increasing severity and frequency of extreme storm activities. It also incorporates some exposure to carbon transition risk associated with its gas utility operations and gas-fired power plants.

Social

Consumers Energy's **S-3** issuer profile score is primarily related to its customer and regulatory relations as well as demographic and societal trends. The utility's regulatory environment, as well as its interaction with the MPSC, are important in considering the utility's social risk. Also, the safety and reliability of its operations are important social considerations.

Governance

Consumers Energy's **G-2** issuer profile score reflects our view that its governance does not pose a particular risk and is not a material driver in the company's overall credit profile. It also incorporates its position as a subsidiary of CMS whose corporate governance considerations including financial policy and risk management influence Consumers Energy.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumers Energy's external liquidity sources include a $1.1 billion secured revolving credit facility expiring in December 2027 and, as of 31 March 2025, net availability was $1.075 billion with $25 million of letters of credit outstanding. Consumers Energy also maintains a $250 million secured credit facility terminating in November 2025 and had $178 million available as of 31 March 2025. Both facilities are secured by first mortgage bonds. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's $500 million commercial paper program. At 31 March 2025, the company had no commercial paper notes outstanding under the program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at 65%. At 31 March 2025, its debt to capital ratio was 50%.

These facilities includes sustainability linked pricing metrics, which permits pricing adjustments for meeting targets related to sustainability. Targets include renewable generation and diverse supplier spend, highlighting its commitment to shifting its exposure to a greater renewable content and to supplier diversity.

The utility's continuing capital expenditure program and dividend policy will result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent.

For the period ended 31 March 2025, Consumers Energy generated approximately $2.5 billion of cash from operations, invested $3.03 billion and distributed $801 million of dividends to CMS, resulting in negative free cash flow of approximately $1.33 billion. Given its robust investment plan, we expect Consumers Energy to maintain its negative free cash flow position over the 12-18 months.

In May 2025, Consumers issued $500 million 4.5% first mortgage bonds due 2031 and $625 million first mortgage bonds due 2035.

Exhibit: AG-51
Case No.: U-21981
Date: April 15, 2026
Page 9 of 14

Methodology and scorecard

We use our global Regulated Electric and Gas Utilities rating methodology as the primary methodology for analyzing Consumers Energy Company.

Exhibit 9

Rating factors

Consumers Energy Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2025		Moody's 12-18 Month Forward View	
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	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.8x	A	5.5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	19.1%	Baa	19% - 20%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	12.6%	Baa	12% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	45.7%	Baa	45% - 46%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned				A3

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Source: Moody's Financial Metrics™ and Moody's Ratings forecasts

Appendix

Exhibit 10

Peer comparison

Consumers Energy Company

	Consumers Energy Company			DTE Electric Company			Northern States Power Company (Minnesota)			Wisconsin Electric Power Company			DTE Gas Company		
	(P)A3 Stable			(P)A2 Stable			A2 Stable			A2 Stable			A3 Stable		
(in $ millions)	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25
Revenue	7,166	7,200	7,451	5,804	6,277	6,265	6,043	5,767	5,888	4,045	3,980	4,120	1726	1783	1946
CFO Pre-W/C	2,190	2,344	2,379	2,565	2,969	2,915	2,261	2,171	2,090	992	1,231	1,269	638	538	625
Total Debt	11,449	12,346	12,241	12,523	13,611	13,425	7,692	8,436	8,355	6,596	7,050	6,899	2642	2883	2861
CFO Pre-W/C + Interest / Interest	5.8x	5.5x	5.5x	6.7x	6.4x	6.1x	7.8x	6.8x	6.5x	3.1x	3.5x	3.6x	7.2x	5.5x	6.1x
CFO Pre-W/C / Debt	19.1%	19.0%	19.4%	20.5%	21.8%	21.7%	29.4%	25.7%	25.0%	15.0%	17.5%	18.4%	24.1%	18.7%	21.8%
CFO Pre-W/C – Dividends / Debt	13.0%	12.5%	12.9%	12.5%	16.1%	15.8%	21.0%	19.9%	19.6%	9.4%	14.1%	14.9%	16.9%	11.4%	14.4%
Debt / Capitalization	45.8%	46.0%	45.3%	48.4%	48.4%	48.2%	43.0%	42.3%	41.5%	50.0%	49.6%	47.7%	42.3%	42.2%	40.8%

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Source: Moody's Financial Metrics™

Exhibit 11

Moody's–adjusted cash flow reconciliation

Consumers Energy Company

(in $ millions)	2020	2021	2022	2023	2024	LTM Mar-25
FFO	**1,993.9**	**2,054.1**	**2,124.9**	**2,064.8**	**2,204.9**	**2,276.9**
+/- Other	(136.0)	(13.0)	(29.0)	125.0	139.0	102.0
CFO Pre-WC	**1,857.9**	**2,041.1**	**2,095.9**	**2,189.8**	**2,343.9**	**2,378.9**
+/- ΔWC	25.0	(53.0)	(1,098.0)	243.0	105.0	122.0
CFO	**1,882.9**	**1,988.1**	**997.9**	**2,432.8**	**2,448.9**	**2,500.9**
- Div	638.0	723.0	770.0	696.0	796.0	802.0
- Capex	2,183.9	2,066.1	2,255.9	2,259.8	2,850.9	3,035.9
FCF	**(939.0)**	**(801.0)**	**(2,028.0)**	**(523.0)**	**(1,198.0)**	**(1,337.0)**
(CFO Pre-W/C) / Debt	21.5%	22.6%	20.0%	19.1%	19.0%	19.4%
(CFO Pre-W/C - Dividends) / Debt	14.1%	14.6%	12.7%	13.0%	12.5%	12.9%
FFO / Debt	23.0%	22.8%	20.3%	18.0%	17.9%	18.6%
RCF / Debt	15.7%	14.8%	12.9%	12.0%	11.4%	12.0%
Revenue	6,189.0	7,021.0	8,151.0	7,166.0	7,200.0	7,451.0
Interest Expense	332.3	315.3	341.9	454.7	524.1	525.0
Net Income	798.3	837.8	883.2	801.7	931.3	1,004.0
Total Assets	25,399.0	27,140.0	29,916.0	31,852.0	34,088.0	34,029.0
Total Liabilities	16,861.5	17,879.5	19,779.5	21,070.5	22,675.5	22,391.5
Total Equity	8,537.5	9,260.5	10,136.5	10,781.5	11,412.5	11,637.5

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Source: Moody's Financial Metrics™

Ratings

Exhibit 12

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
LT IRB/PC	A3
Pref. Stock	Baa1
Commercial Paper	P-2
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Pref. Stock	Ba1

Source: Moody's Ratings

© 2025 Moody's Corporation, Moody's Investors Service, Inc., Moody's Analytics, Inc. and/or their licensors and affiliates (collectively, "MOODY'S"). All rights reserved.

CREDIT RATINGS ISSUED BY MOODY'S CREDIT RATINGS AFFILIATES ARE THEIR CURRENT OPINIONS OF THE RELATIVE FUTURE CREDIT RISK OF ENTITIES, CREDIT COMMITMENTS, OR DEBT OR DEBT-LIKE SECURITIES, AND MATERIALS, PRODUCTS, SERVICES AND INFORMATION PUBLISHED OR OTHERWISE MADE AVAILABLE BY MOODY'S (COLLECTIVELY, "MATERIALS") MAY INCLUDE SUCH CURRENT OPINIONS. MOODY'S DEFINES CREDIT RISK AS THE RISK THAT AN ENTITY MAY NOT MEET ITS CONTRACTUAL FINANCIAL OBLIGATIONS AS THEY COME DUE AND ANY ESTIMATED FINANCIAL LOSS IN THE EVENT OF DEFAULT OR IMPAIRMENT.

SEE APPLICABLE MOODY'S RATING SYMBOLS AND DEFINITIONS PUBLICATION FOR INFORMATION ON THE TYPES OF CONTRACTUAL FINANCIAL OBLIGATIONS ADDRESSED BY MOODY'S CREDIT RATINGS. CREDIT RATINGS DO NOT ADDRESS ANY OTHER RISK, INCLUDING BUT NOT LIMITED TO: LIQUIDITY RISK, MARKET VALUE RISK, OR PRICE VOLATILITY. CREDIT RATINGS, NON-CREDIT ASSESSMENTS ("ASSESSMENTS"), AND OTHER OPINIONS INCLUDED IN MOODY'S MATERIALS ARE NOT STATEMENTS OF CURRENT OR HISTORICAL FACT. MOODY'S MATERIALS MAY ALSO INCLUDE QUANTITATIVE MODEL-BASED ESTIMATES OF CREDIT RISK AND RELATED OPINIONS OR COMMENTARY PUBLISHED BY MOODY'S ANALYTICS, INC. AND/OR ITS AFFILIATES. MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND MATERIALS DO NOT CONSTITUTE OR PROVIDE INVESTMENT OR FINANCIAL ADVICE, AND MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND MATERIALS ARE NOT AND DO NOT PROVIDE RECOMMENDATIONS TO PURCHASE, SELL, OR HOLD PARTICULAR SECURITIES. MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND MATERIALS DO NOT COMMENT ON THE SUITABILITY OF AN INVESTMENT FOR ANY PARTICULAR INVESTOR. MOODY'S ISSUES ITS CREDIT RATINGS, ASSESSMENTS AND OTHER OPINIONS AND PUBLISHES OR OTHERWISE MAKES AVAILABLE ITS MATERIALS WITH THE EXPECTATION AND UNDERSTANDING THAT EACH INVESTOR WILL, WITH DUE CARE, MAKE ITS OWN STUDY AND EVALUATION OF EACH SECURITY THAT IS UNDER CONSIDERATION FOR PURCHASE, HOLDING, OR SALE.

MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS, AND MATERIALS ARE NOT INTENDED FOR USE BY RETAIL INVESTORS AND IT WOULD BE RECKLESS AND INAPPROPRIATE FOR RETAIL INVESTORS TO USE MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS OR MATERIALS WHEN MAKING AN INVESTMENT DECISION. IF IN DOUBT YOU SHOULD CONTACT YOUR FINANCIAL OR OTHER PROFESSIONAL ADVISER.

ALL INFORMATION CONTAINED HEREIN IS PROTECTED BY LAW, INCLUDING BUT NOT LIMITED TO, COPYRIGHT LAW, AND NONE OF SUCH INFORMATION MAY BE COPIED OR OTHERWISE REPRODUCED, REPACKAGED, FURTHER TRANSMITTED, TRANSFERRED, DISSEMINATED, REDISTRIBUTED OR RESOLD, OR STORED FOR SUBSEQUENT USE FOR ANY SUCH PURPOSE, IN WHOLE OR IN PART, IN ANY FORM OR MANNER OR BY ANY MEANS WHATSOEVER, BY ANY PERSON WITHOUT MOODY'S PRIOR WRITTEN CONSENT. FOR CLARITY, NO INFORMATION CONTAINED HEREIN MAY BE USED TO DEVELOP, IMPROVE, TRAIN OR RETRAIN ANY SOFTWARE PROGRAM OR DATABASE, INCLUDING, BUT NOT LIMITED TO, FOR ANY ARTIFICIAL INTELLIGENCE, MACHINE LEARNING OR NATURAL LANGUAGE PROCESSING SOFTWARE, ALGORITHM, METHODOLOGY AND/OR MODEL.

MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND MATERIALS ARE NOT INTENDED FOR USE BY ANY PERSON AS A BENCHMARK AS THAT TERM IS DEFINED FOR REGULATORY PURPOSES AND MUST NOT BE USED IN ANY WAY THAT COULD RESULT IN THEM BEING CONSIDERED A BENCHMARK.

All information contained herein is obtained by MOODY'S from sources believed by it to be accurate and reliable. Because of the possibility of human or mechanical error as well as other factors, however, all information contained herein is provided "AS IS" without warranty of any kind. MOODY'S adopts all necessary measures so that the information it uses in assigning a credit rating is of sufficient quality and from sources MOODY'S considers to be reliable including, when appropriate, independent third-party sources. However, MOODY'S is not an auditor and cannot in every instance independently verify or validate information received in the credit rating process or in preparing its Materials.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability to any person or entity for any indirect, special, consequential, or incidental losses or damages whatsoever arising from or in connection with the information contained herein or the use of or inability to use any such information, even if MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers is advised in advance of the possibility of such losses or damages, including but not limited to: (a) any loss of present or prospective profits or (b) any loss or damage arising where the relevant financial instrument is not the subject of a particular credit rating assigned by MOODY'S.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability for any direct or compensatory losses or damages caused to any person or entity, including but not limited to by any negligence (but excluding fraud, willful misconduct or any other type of liability that, for the avoidance of doubt, by law cannot be excluded) on the part of, or any contingency within or beyond the control of, MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers, arising from or in connection with the information contained herein or the use of or inability to use any such information.

NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY CREDIT RATING, ASSESSMENT, OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER.

Moody's Investors Service, Inc., a wholly-owned credit rating agency subsidiary of Moody's Corporation ("MCO"), hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by Moody's Investors Service, Inc. have, prior to assignment of any credit rating, agreed to pay Moody's Investors Service, Inc. for credit ratings opinions and services rendered by it. MCO and all MCO entities that issue ratings under the "Moody's Ratings" brand name ("Moody's Ratings"), also maintain policies and procedures to address the independence of Moody's Ratings' credit ratings and credit rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold credit ratings from Moody's Investors Service, Inc. and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually at ir.moodys.com under the heading "Investor Relations — Corporate Governance — Charter and Governance Documents - Director and Shareholder Affiliation Policy."

Moody's SF Japan K.K., Moody's Local AR Agente de Calificación de Riesgo S.A., Moody's Local BR Agência de Classificação de Risco LTDA, Moody's Local MX S.A. de C.V, I.C.V., Moody's Local PE Clasificadora de Riesgo S.A., and Moody's Local PA Calificadora de Riesgo S.A. (collectively, the "Moody's Non-NRSRO CRAs") are all indirectly wholly-owned credit rating agency subsidiaries of MCO. None of the Moody's Non-NRSRO CRAs is a Nationally Recognized Statistical Rating Organization.

Additional terms for Australia only: Any publication into Australia of this document is pursuant to the Australian Financial Services License of MOODY'S affiliate, Moody's Investors Service Pty Limited ABN 61 003 399 657AFSL 336969 and/or Moody's Analytics Australia Pty Ltd ABN 94 105 136 972 AFSL 383569 (as applicable). This document is intended to be provided only to "wholesale clients" within the meaning of section 761G of the Corporations Act 2001. By continuing to access this document from within Australia, you represent to MOODY'S that you are, or are accessing the document as a representative of, a "wholesale client" and that neither you nor the entity you represent will directly or indirectly disseminate this document or its contents to "retail clients" within the meaning of section 761G of the Corporations Act 2001. MOODY'S credit rating is an opinion as to the creditworthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors.

Additional terms for India only: Moody's credit ratings, Assessments, other opinions and Materials are not intended to be and shall not be relied upon or used by any users located in India in relation to securities listed or proposed to be listed on Indian stock exchanges.

Additional terms with respect to Second Party Opinions and Net Zero Assessments (as defined in Moody's Ratings Rating Symbols and Definitions): Please note that neither a Second Party Opinion ("SPO") nor a Net Zero Assessment ("NZA") is a "credit rating". The issuance of SPOs and NZAs is not a regulated activity in many jurisdictions, including Singapore. JAPAN: In Japan, development and provision of SPOs and NZAs fall under the category of "Ancillary Businesses", not "Credit Rating Business", and are not subject to the regulations applicable to "Credit Rating Business" under the Financial Instruments and Exchange Act of Japan and its relevant regulation. PRC: Any SPO: (1) does not constitute a PRC Green Bond Assessment as defined under any relevant PRC laws or regulations; (2) cannot be included in any registration statement, offering circular, prospectus or any other documents submitted to the PRC regulatory authorities or otherwise used to satisfy any PRC regulatory disclosure requirement; and (3) cannot be used within the PRC for any regulatory purpose or for any other purpose which is not permitted under relevant PRC laws or regulations. For the purposes of this disclaimer, "PRC" refers to the mainland of the People's Republic of China, excluding Hong Kong, Macau and Taiwan.

Exhibit: AG-51
Case No.: U-21981
Date: April 15, 2026
Page 13 of 14

REPORT NUMBER 1444764

Exhibit: AG-51
Case No.: U-21981
Date: April 15, 2026
Page 14 of 14

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

U21981-AG-CE-0227
Page **1** of **1**

Question:

7. Please provide a copy of all S&P and Moody's rating agency reports covering Consumers Energy and CMS Energy issued since the beginning of 2024.

a. Confirm that as the parent company of Consumers Energy, CMS Energy's ability to inject capital into Consumers Energy depends on the ability of CMS Energy to raise debt and equity capital.

b. Identify by report and page number, where any of the credit rating agencies since 2024 have identified in the credit reports of CMS Energy and Consumers Energy that the debt level at CMS Energy is a concern that could affect the credit rating of Consumers Energy.

Response:

> **Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that information regarding CMS Energy is irrelevant to this matter as CMS Energy is not a party to this case. Subject to the Company's objection, and without waiving that objection, Consumers Energy responds as follows:**

Please find the requested ratings agency credit opinions for Consumers Energy attached.

a. As discussed on page 8, lines 2-9 of Ms. Bulkley's Direct Testimony, the stand-alone principle of ratemaking requires that regulated rates should be based on the risks and benefits of the regulated utility, not its investors, parent or affiliates. Consistent with this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, Ms. Bulkley evaluated the investor-required return for Consumers Energy's natural gas utility operations in Michigan. Therefore, the fact that Consumers is affiliated with CMS Energy is not an appropriate consideration in this base rate case.

b. Please see the response to part a.

Witness: Ann E. Bulkley
Date: March 30, 2026

CREDIT OPINION

23 March 2026

Update

Send Your Feedback

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	Baa2
Type	Pref. Stock - Dom Curr
Outlook	Negative

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 *VP-Sr Credit Officer* jairo.chung@moodys.com	+1.212.553.5123
Dean Moschitto *Ratings Associate* dean.moschitto@moodys.com	+1.212.553.4149
Laura Barrientos *Associate Managing Director* laura.barrientos@moodys.com	+1.212.553.1637
Jim Hempstead *MD - Gbl Proj and Infra Fin* james.hempstead@moodys.com	+1.212.553.4318

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Consumers Energy Company

Update to credit following outlook change to negative

Summary

Consumers Energy Company's (Consumers Energy, A1 senior secured negative) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in a generally credit supportive Michigan regulatory environment. The utility plans to invest approximately $24 billion over the next five years to support its load growth as well as to meet Michigan's clean energy goal by retiring coal-fired power plants and adding new natural gas-fired power plants and renewable sources. Although we view the regulatory environment in Michigan to be credit supportive, the significant step up in the company's capital investment plan without contemporaneous cost recovery through higher equity capital structure and more timely cash recovery mechanisms for large projects, will constrain the company's ability to produce credit metrics that are appropriate for its credit rating.

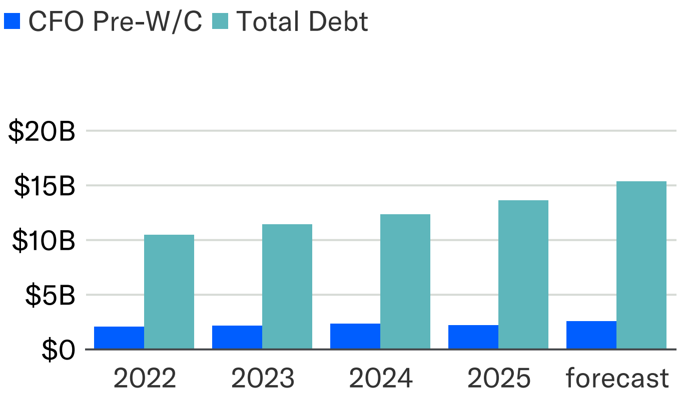
In 2025, Consumers Energy's cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio was 16.8%, excluding securitization bonds, lower than its 18% downgrade threshold primarily due to extreme storms in its service territory. Importantly, a constructive outcome on its pending rate case proceeding as well as supportive regulatory decisions on the company's capital investments will be critical to the company's ability to improve its financial profile.

Recent development

On 19 March, we changed the rating outlook of Consumers Energy to negative from stable. We affirmed its ratings, including the A1 first mortgage bond rating and Prime-2 commercial paper rating. At the same time, we affirmed the ratings of its parent company CMS Energy Corporation (CMS) and maintained its stable rating outlook.

Exhibit 1

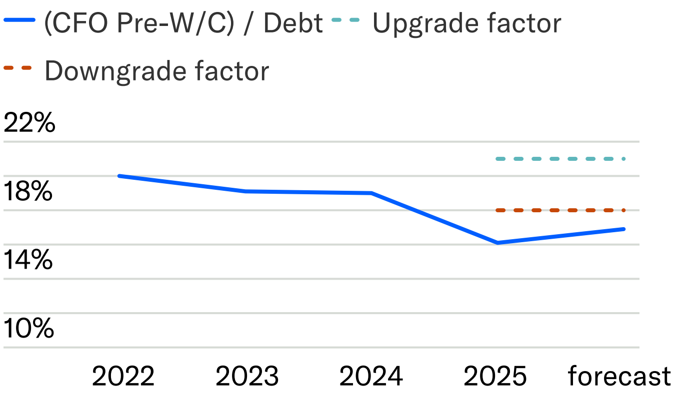
CFO Pre-W/C and Total Debt



All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Forecast reflects 2 year average of 2026F and 2027F.
Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Exhibit 2

Consumers' metric is likely to remain pressured below 18%



All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Forecast reflects 2 year average of 2026F and 2027F.
When adjusting for the impact of securitization debt, Consumers Energy's CFO pre-W/C to debt ratio would be 20.5%, 20.1% and 16.8% in 2023, 2024 and 2025, respectively.
Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Credit strengths

- Generally credit supportive regulatory environment in Michigan
- Several timely cost recovery mechanisms including future test years applied during rate cases

Credit challenges

- Significantly higher capital investment plan will require additional debt issuance
- Maintaining regulatory support for these capital investments
- Lack of geographic and regulatory diversity with single state service territory

Rating outlook

The negative outlook for Consumers reflects our expectation that the company's elevated investment plan will continue to pressure its credit metrics including CFO pre-WC to debt below 18%, excluding the impact of securitization debt, without appropriate regulatory support.

Factors that could lead to an upgrade

Given the negative outlook, a rating upgrade for Consumers is not likely in the near term. The outlook could be changed to stable if Consumers' financial profile improves, including a ratio of CFO pre-WC to debt expected to be sustained well above 18%. A constructive outcome on its pending rate case and future regulatory decisions will be important to preserve the company's credit quality and an outlook change back to stable.

Factors that could lead to a downgrade

A rating downgrade of Consumers would be considered if the company's CFO pre-WC to debt ratio remains below 18% on a sustained basis; or if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment, including a less constructive outcome of its pending rate case or future regulatory decisions.

Key indicators

Exhibit 3

Consumers Energy Company

	2022	2023	2024	2025	2026F	2027F
(CFO Pre-W/C + Interest) / Interest Expense	7.1x	5.8x	5.5x	4.8x	5.0x – 5.5x	4.9x – 5.3x
(CFO Pre-W/C) / Debt	20.0%	19.1%	19.0%	16.1%	17.0% - 18.0%	17.0% - 18.0%
(CFO Pre-W/C – Dividends) / Debt	12.7%	13.0%	12.5%	9.5%	10.0% - 11.0%	10.0% - 11.0%
Debt / Book Capitalization	45.1%	45.8%	46.0%	46.4%	44.0% - 48.0%	44.0% - 48.0%

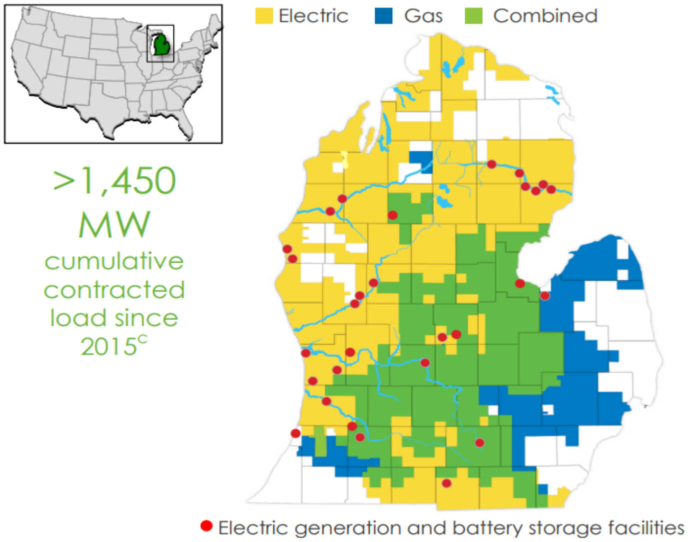
All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Credit metrics included in the exhibit include securitization bonds. When adjusting for the impact of securitization debt, Consumers Energy's CFO pre-W/C to debt ratio would be 20.5%, 20.1% and 16.8% in 2023, 2024 and 2025, respectively
Source: Moody's Financial Metrics™

Profile

Consumers Energy is a vertically integrated electric and gas utility serving approximately 1.9 million electric and 1.8 million gas customers in the state of Michigan with an average rate base of $28 billion at the end of 2025. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. The utility is the primary subsidiary of CMS as it represents over 95% of CMS's consolidated earnings and cash flows. In addition to Consumers Energy, CMS has a subsidiary called NorthStar Clean Energy, a non-utility domestic independent power producer and marketer.

Exhibit 4

Consumers Energy's Service Territory



MW addition figure as of 31 December 2025
Source: Company filings

Exhibit: AG-52
Case No.: U-21981
Date: April 15, 2026
Page 5 of 14

Detailed credit considerations

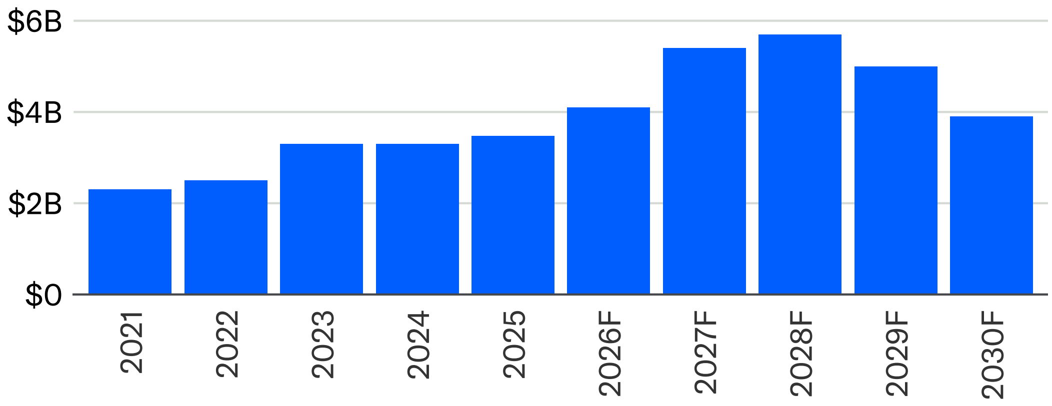
Weakened metrics to remain pressured due to heightened capital investment plan

Consumers Energy's latest investment plan over the next five years is approximately $24 billion, which is approximately $4 billion higher than its previous plan. About 72% of the investments are earmarked for its electric utility, with about even split between generation and distribution investments. Consumers Energy will invest approximately $6.7 billion primarily to maintain and upgrade its gas utility infrastructure; $8.6 billion related to its electric distribution and other infrastructure; and $8.8 billion related to clean energy generation.

The preview of Consumers Energy's upcoming Integrated Resource Plan (IRP), which will be filed in June, included the company's “all-of-the-above” approach with over 13 GW of new power generation capacity. This included expanded renewable investments, including solar, wind and battery storage as well as two new natural gas-fired power plants with total capacity of around 1.5 GW. Based on the investment plan previewed by the company, we expect that Consumers Energy's credit metrics will remain pressured, including its CFO pre-WC to debt ratio sustained below the current threshold for a potential downgrade of 18%. Importantly, a constructive outcome on its pending rate case proceeding as well as supportive regulatory decisions on the company's capital investments will be critical to the company's ability to improve its financial profile. In 2025, Consumer's ratio of CFO pre-WC to debt was approximately 16.8%, excluding the impact of securitization debt. Primarily, the weakness was due to extreme storms in it service territory during the year.

Exhibit 5

Consumers Energy's elevated capital program will extend at least through 2030

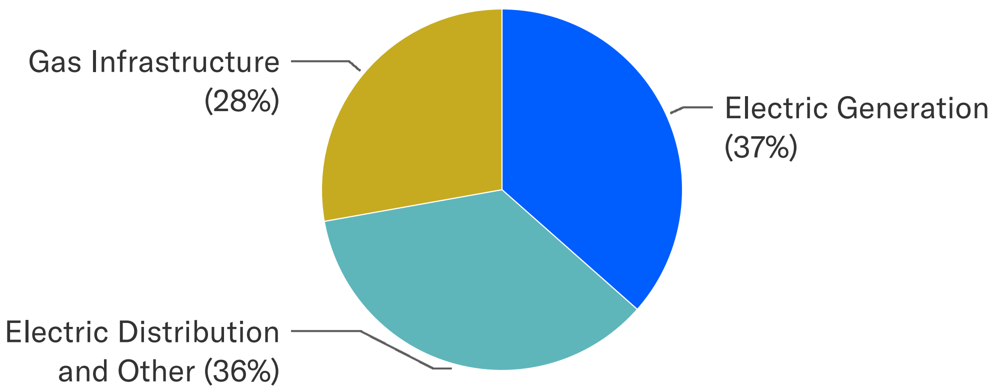


Source: Company filings

Funding for these investments will be provided by internally generated cash flow, the issuance of debt at Consumers Energy and equity contributions from CMS. We expect CMS to increase it equity issuance to support the utility's higher capital expenditure. For example, CMS issued $1 billion of junior subordinated notes in 2025. The company's current financing plan includes approximately $700 million of equity issuance compared to $525 million issued in 2025.

Exhibit 6

Planned Capital Expenditures 2026 - 2030 totals around $24 billion



Total may be higher than 100% due to rounding.
Source: Company filings

Generally supportive regulatory environment

Consumers Energy is regulated by the Michigan Public Service Commission (MPSC) and we view the regulatory framework in Michigan to be more credit supportive than most other states. The state of Michigan has a long history of enacting legislations that are supportive of utility investments in the state. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework has been streamlined, improving both the rate case process and the timeliness of cost recovery. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which had 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 costs, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before the construction of major projects.

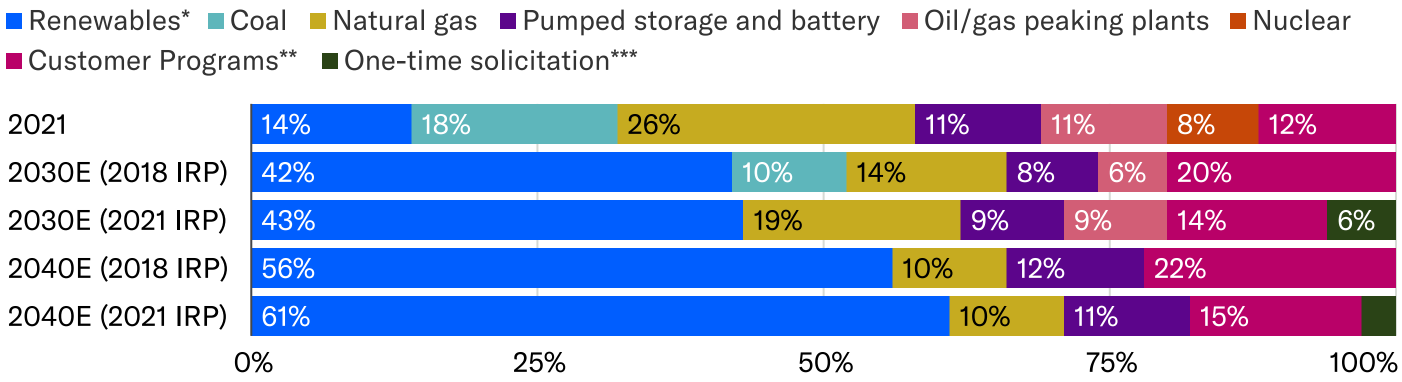
The latest energy legislation enacted in Michigan (2023 Energy Law) laid out the state's renewable energy standards. Under the new law, renewable energy standards were raised to 50% by 2030 and 60% by 2035 from the previous 15% by 2021 requirement. It also set a clean energy standard of 80% by 2035 and 100% by 2040. Under the law, zero to low-carbon emitting sources, such as nuclear generation and natural gas generation with carbon capture, are considered clean energy sources. Along with these new standards, the new legislation expanded the authority of the MPSC to oversee their implementation. Consumers Energy updated its Renewable Energy Plan, which was approved by the MPSC in September 2025.

Consumers Energy will file its next IRP in June. It is subject to the approval of the MPSC and we expect a constructive outcome similar to the last IRP's approval. As a result of the settlement agreement related to Consumers Energy's last IRP, the utility is allowed to record approximately $1.3 billion of the remaining book value of the coal-fired power plants that are anticipated to retire as a regulatory asset and earn a 9% return on equity (ROE) through the remaining life. Instead of securitizing the remaining book value, the settlement minimized the impact of the accelerated coal retirements on Consumers Energy's credit metrics. We viewed this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

In September 2025, the MPSC approved Consumers Energy's latest Renewable Energy Plan, which enables the company to achieve 60% renewable energy by 2035 and 100% clean energy by 2040. Through 2040, Consumers Energy will add up to 8 GW of solar power, which is 3 GW more than what was approved in the company's 2018 IRP. Consumers Energy will grow its solar portfolio to 9 GW and wind portfolio to 4 GW. To backfill the retirement of its Karn 1 and 2 coal units, the utility acquired the Covert natural gas-fired power plant for approximately $815 million in 2023. Under the financial compensation mechanism (FCM), Consumers Energy is allowed earn a return on the PPAs. Pre-tax weighted average cost of capital is approximately 9%. This mechanism allows the utility to earn returns without incurring additional construction risks since building new generation isn't the only way the utility could earn a return, a credit positive. Under the current plan, approximately half of Consumers Energy's renewable generation will be owned and the remaining requirement met through PPAs.

Exhibit 7

Based on the latest IRP settlement, more than 60% of Consumers Energy's generation sources will be renewables by 2040



*Does not include renewable RECs.
**Includes energy waste reduction, demand response, and conservation voltage reduction program.
***One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.
Source: Company filings

Timeliness of cost recovery based on a prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous rate adjustment mechanisms that typically provide cash flow stability and assurance of recovery. For example, Consumers Energy has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas 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. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability. The GCR mechanism may be adjusted monthly within a capped range to minimize over or under recoveries although interim gas inventory buildup could substantially increase the company's working capital financing when gas prices increase sharply.

Gas utilities in the state also benefit from programs designed to assure recovery of needed infrastructure improvements. The company's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including the replacement of 2,700 miles of natural gas distribution and service pipelines with more durable material.

Active rate case cadence likely to continue

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. Although there was some pressure, due to customer affordability concerns in the state, to lower the allowed ROE level over the last three years, the MPSC has maintained a 9.9% allowed ROE for electric. For its gas utility operations, the allowed ROE is 9.8%. However, further deterioration of the allowed ROE is likely to put negative pressure on the company's overall financial profile.

Consumers Energy currently has both electric and gas rate cases pending. In June 2025, Consumers Energy filed its latest electric rate case. Its revised requested increase of $423 million is based on a 10.25% ROE for the test year ending 30 April 2027. The MPSC must issue its final order either before or in April 2026. The final order for its previous electric rate case was received in March 2025. The final order authorized an increase of $154 million, including the approval of a $22 million surcharge related to distribution investments in prior years, in electric base rate revenue based on a 9.9% allowed ROE. The rate increase was also based on a test year ending February 2026 and the total rate base was approximately $14.86 billion.

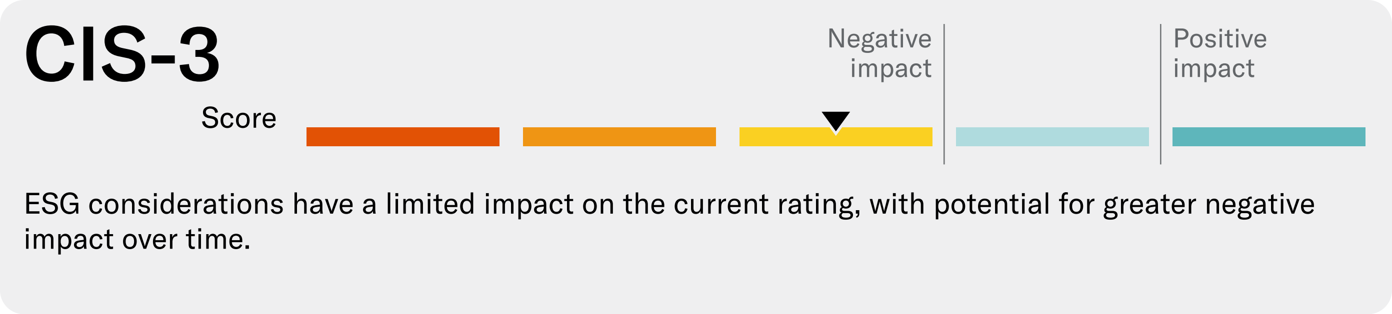
The company filed its gas rate case in December 2025, requesting an annual rate revenue increase of $240 million based on a 10.25% allowed ROE for the projected period ending 31 October 2027. The final order must be issued either before or in October 2026.

ESG considerations

Consumers Energy Company's ESG credit impact score is CIS-3

Exhibit 8

ESG credit impact score



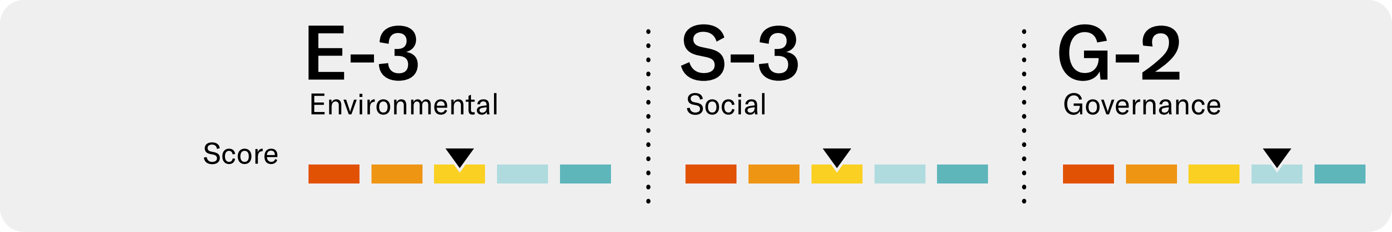
ESG considerations have a limited impact on the current rating, with potential for greater negative impact over time.

Source: Moody's Ratings

Consumers Energy's **CIS-3** indicates that ESG considerations have limited impact on the current credit rating with greater potential for negative impact over time. It reflects some exposure to physical climate risk due to increasing frequency and severity of storm activities. It also incorporates social risks stemming from inherent risk associated with regulated utilities.

Exhibit 9

ESG issuer profile scores



Source: Moody's Ratings

Environmental

Consumers Energy's **E-3** issuer profile score reflects some exposure to physical climate risk, which highlights the increasing severity and frequency of extreme storm activities. It also incorporates exposure to carbon transition risk associated with its gas utility operations and gas-fired power plants. Based on its latest Renewable Energy Plan, the company is projected to increase its generation mix to be 60% renewable by 2035 and 100% clean energy by 2040.

Social

Consumers Energy's **S-3** issuer profile score is primarily related to its customer and regulatory relations as well as demographic and societal trends. The utility's regulatory environment, as well as its interaction with the MPSC, are important in considering the utility's social risk. Also, the safety and reliability of its operations are important social considerations.

Governance

Consumers Energy's **G-2** issuer profile score reflects our view that its governance does not pose a particular risk.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Exhibit: AG-52
Case No.: U-21981
Date: April 15, 2026
Page 9 of 14

Liquidity analysis

We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumers Energy's external liquidity sources include a $1.1 billion senior secured revolving credit facility expiring in November 2030. As of 31 December 2025, net availability was $1.094 billion with $6 million of letters of credit outstanding. Consumers Energy also maintains a $300 million senior secured credit facility terminating in November 2028 and had $300 million available as of 31 December 2025. Both facilities are secured by first mortgage bonds. In addition, Consumers Energy has a $100 million senior secured letter of credit facility expiring in May 2027 with $100 million letters of credit outstanding at the end of 2025. It also has a $50 million unsecured letter of credit facility expiring in March 2028 with $43 million letters of credit outstanding, and two $100 million unsecured letter of credit facilities with automatic renewal provisions with $97 million and $100 million letters of credit outstanding, respectively, at the end of the same period. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's $500 million commercial paper program. At 31 December 2025, the company had no commercial paper notes outstanding under the program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at 65%. At 31 December 2025, its debt to capital ratio was 51%.

The utility's continuing capital expenditure program and dividend policy will result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent. In addition, Consumers Energy will manage the financing of its capital investment program to maintain its targeted capital structure authorized by its regulators.

For the period ended 31 December 2025, Consumers Energy generated approximately $2.2 billion of cash from operations, invested $3.3 billion and distributed $900 million of dividends to CMS, resulting in negative free cash flow of approximately $2.0 billion. Given its robust investment plan, we expect Consumers Energy to maintain its negative free cash flow position over the 12-18 months.

In May 2025, Consumers issued $500 million 4.5% first mortgage bonds due 2031 and $625 million 5.05% first mortgage bonds due 2035.

Methodology and scorecard

We use our global Regulated Electric and Gas Utilities rating methodology as the primary methodology for analyzing Consumers Energy Company. The scorecard-indicated outcome reflects the implied senior unsecured rating and the actual rating assigned of A1 is Consumers Energy's senior secured rating, which would be two notches higher than its implied senior unsecured rating.

Exhibit 10

Rating factors

Consumers Energy Company

Regulated Electric and Gas Utilities Industry Scorecard	Current FY Dec-25		Moody's 12-18 month forward view	
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	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.3x	A	5.1x - 5.3x	A
b) CFO pre-WC / Debt (3 Year Avg)	18.0%	Baa	17% - 18%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	11.6%	Baa	10% - 11%	Baa
d) Debt / Capitalization (3 Year Avg)	46.1%	Baa	44% - 48%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned				A1

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Appendix

Exhibit 11

Peer comparison

Consumers Energy Company

	Consumers Energy Company			DTE Electric Company			Northern States Power Company (Minnesota)			Wisconsin Electric Power Company		
	A3 Stable			A2 Stable			A2 Stable			A2 Stable		
	FY	FY	FY	FY	FY	FY	FY	FY	FY	FY	FY	FY
(in $ millions)	Dec-23	Dec-24	Dec-25	Dec-23	Dec-24	Dec-25	Dec-23	Dec-24	Dec-25	Dec-23	Dec-24	Dec-25
Revenue	7,166	7,200	8,132	5,804	6,277	6,885	6,043	5,767	6,307	4,045	3,980	4,494
CFO Pre-W/C	2,190	2,344	2,198	2,565	2,969	2,748	2,261	2,171	2,223	992	1,231	1,168
Total Debt	11,449	12,346	13,642	12,523	13,611	14,852	7,692	8,436	9,330	6,596	7,050	8,075
(CFO Pre-W/C + Interest) / Interest Expense	5.8x	5.5x	4.8x	6.7x	6.4x	5.4x	7.8x	6.8x	6.1x	3.1x	3.5x	3.2x
(CFO Pre-W/C) / Debt	19.1%	19.0%	16.1%	20.5%	21.8%	18.5%	29.4%	25.7%	23.8%	15.0%	17.5%	14.5%
(CFO Pre-W/C – Dividends) / Debt	13.0%	12.5%	9.5%	12.5%	16.1%	12.8%	21.0%	19.9%	19.3%	9.4%	14.1%	7.0%
Debt / Book Capitalization	45.8%	46.0%	46.4%	48.4%	48.4%	47.9%	43.0%	42.3%	42.0%	50.0%	49.6%	49.0%

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Source: Moody's Financial Metrics™

Exhibit 12

Moody's–adjusted cash flow reconciliation

Consumers Energy Company

(in $ millions)	2020	2021	2022	2023	2024	2025
FFO	**1,993.9**	**2,054.1**	**2,124.9**	**2,064.8**	**2,204.9**	**2,288.0**
+/- Other	(136.0)	(13.0)	(29.0)	125.0	139.0	(90.0)
CFO Pre-WC	**1,857.9**	**2,041.1**	**2,095.9**	**2,189.8**	**2,343.9**	**2,198.0**
+/- ΔWC	25.0	(53.0)	(1,098.0)	243.0	105.0	32.0
CFO	**1,882.9**	**1,988.1**	**997.9**	**2,432.8**	**2,448.9**	**2,230.0**
- Div	638.0	723.0	770.0	696.0	796.0	899.0
- Capex	2,183.9	2,066.1	2,255.9	2,259.8	2,850.9	3,313.0
FCF	**(939.0)**	**(801.0)**	**(2,028.0)**	**(523.0)**	**(1,198.0)**	**(1,982.0)**
Revenue	6,189.0	7,021.0	8,151.0	7,166.0	7,200.0	8,132.0
Interest Expense	332.3	313.5	341.9	454.7	524.1	575.6
Net Income	798.3	839.3	883.2	801.7	931.3	1,050.9
Total Assets	25,399.0	27,140.0	29,916.0	31,852.0	34,088.0	37,081.0
Total Liabilities	16,861.5	17,879.5	19,779.5	21,070.5	22,675.5	24,529.4
Total Equity	8,537.5	9,260.5	10,136.5	10,781.5	11,412.5	12,551.6

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Source: Moody's Financial Metrics™

Ratings

Exhibit 13

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Negative
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Bkd Senior Secured	A1
LT IRB/PC	A3
Pref. Stock	Baa2
Commercial Paper	P-2
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Pref. Stock	Ba1

Source: Moody's Ratings

CREDIT RATINGS ISSUED BY MOODY'S CREDIT RATINGS AFFILIATES ARE THEIR CURRENT OPINIONS OF THE RELATIVE FUTURE CREDIT RISK OF ENTITIES, CREDIT COMMITMENTS, OR DEBT OR DEBT-LIKE SECURITIES, AND MATERIALS, PRODUCTS, SERVICES AND INFORMATION PUBLISHED OR OTHERWISE MADE AVAILABLE BY MOODY'S (COLLECTIVELY, "MATERIALS") MAY INCLUDE SUCH CURRENT OPINIONS. MOODY'S DEFINES CREDIT RISK AS THE RISK THAT AN ENTITY MAY NOT MEET ITS CONTRACTUAL FINANCIAL OBLIGATIONS AS THEY COME DUE AND ANY ESTIMATED FINANCIAL LOSS IN THE EVENT OF DEFAULT OR IMPAIRMENT. SEE APPLICABLE MOODY'S RATING SYMBOLS AND DEFINITIONS PUBLICATION FOR INFORMATION ON THE TYPES OF CONTRACTUAL FINANCIAL OBLIGATIONS ADDRESSED BY MOODY'S CREDIT RATINGS. CREDIT RATINGS DO NOT ADDRESS ANY OTHER RISK, INCLUDING BUT NOT LIMITED TO: LIQUIDITY RISK, MARKET VALUE RISK, OR PRICE VOLATILITY. CREDIT RATINGS, NON-CREDIT ASSESSMENTS ("ASSESSMENTS"), AND OTHER OPINIONS INCLUDED IN MOODY'S MATERIALS ARE NOT STATEMENTS OF CURRENT OR HISTORICAL FACT. MOODY'S MATERIALS MAY ALSO INCLUDE QUANTITATIVE MODEL-BASED ESTIMATES OF CREDIT RISK AND RELATED OPINIONS OR COMMENTARY PUBLISHED BY MOODY'S ANALYTICS, INC. AND/OR ITS AFFILIATES. MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND MATERIALS DO NOT CONSTITUTE OR PROVIDE LEGAL, COMPLIANCE, INVESTMENT, FINANCIAL OR OTHER PROFESSIONAL ADVICE, AND MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND MATERIALS ARE NOT AND DO NOT PROVIDE RECOMMENDATIONS TO PURCHASE, SELL, OR HOLD PARTICULAR SECURITIES. MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND MATERIALS DO NOT COMMENT ON THE SUITABILITY OF AN INVESTMENT FOR ANY PARTICULAR INVESTOR. MOODY'S ISSUES ITS CREDIT RATINGS, ASSESSMENTS AND OTHER OPINIONS AND PUBLISHES OR OTHERWISE MAKES AVAILABLE ITS MATERIALS WITH THE EXPECTATION AND UNDERSTANDING THAT EACH INVESTOR WILL, WITH DUE CARE, MAKE ITS OWN STUDY AND EVALUATION OF EACH SECURITY THAT IS UNDER CONSIDERATION FOR PURCHASE, HOLDING, OR SALE.

MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS, AND MATERIALS ARE NOT INTENDED FOR USE BY RETAIL INVESTORS AND IT WOULD BE RECKLESS AND INAPPROPRIATE FOR RETAIL INVESTORS TO USE MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS OR MATERIALS WHEN MAKING AN INVESTMENT DECISION. IF IN DOUBT YOU SHOULD CONTACT YOUR FINANCIAL OR OTHER PROFESSIONAL ADVISER.

ALL INFORMATION CONTAINED HEREIN IS PROTECTED BY LAW, INCLUDING BUT NOT LIMITED TO, COPYRIGHT LAW, AND NONE OF SUCH INFORMATION MAY BE COPIED OR OTHERWISE REPRODUCED, REPACKAGED, FURTHER TRANSMITTED, TRANSFERRED, DISSEMINATED, REDISTRIBUTED OR RESOLD, OR STORED FOR SUBSEQUENT USE FOR ANY SUCH PURPOSE, IN WHOLE OR IN PART, IN ANY FORM OR MANNER OR BY ANY MEANS WHATSOEVER, BY ANY PERSON WITHOUT MOODY'S PRIOR WRITTEN CONSENT. FOR CLARITY, NO INFORMATION CONTAINED HEREIN MAY BE USED TO DEVELOP, IMPROVE, TRAIN OR RETRAIN ANY SOFTWARE PROGRAM OR DATABASE, INCLUDING, BUT NOT LIMITED TO, FOR ANY ARTIFICIAL INTELLIGENCE, MACHINE LEARNING OR NATURAL LANGUAGE PROCESSING SOFTWARE, ALGORITHM, METHODOLOGY AND/OR MODEL.

MOODY'S CREDIT RATINGS, ASSESSMENTS, OTHER OPINIONS AND MATERIALS ARE NOT INTENDED FOR USE BY ANY PERSON AS A BENCHMARK AS THAT TERM IS DEFINED FOR REGULATORY PURPOSES AND MUST NOT BE USED IN ANY WAY THAT COULD RESULT IN THEM BEING CONSIDERED A BENCHMARK.

All information contained herein is obtained by MOODY'S from sources believed by it to be accurate and reliable. Because of the possibility of human or mechanical error as well as other factors, however, all information contained herein is provided "AS IS" without warranty of any kind. MOODY'S adopts all necessary measures so that the information it uses in assigning a credit rating or assessment is of sufficient quality and from sources MOODY'S considers to be reliable including, when appropriate, independent third-party sources. However, MOODY'S is not an auditor and cannot in every instance independently verify or validate information received in the credit rating or assessment process or in preparing its Materials.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability to any person or entity for any indirect, special, consequential, or incidental losses or damages whatsoever arising from or in connection with the information contained herein or the use of or inability to use any such information, even if MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers is advised in advance of the possibility of such losses or damages, including but not limited to: (a) any loss of present or prospective profits or (b) any loss or damage arising where the relevant financial instrument is not the subject of a particular credit rating or assessment assigned by MOODY'S.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability for any direct or compensatory losses or damages caused to any person or entity, including but not limited to by any negligence (but excluding fraud, willful misconduct or any other type of liability that, for the avoidance of doubt, by law cannot be excluded) on the part of, or any contingency within or beyond the control of, MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers, arising from or in connection with the information contained herein or the use of or inability to use any such information.

NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY CREDIT RATING, ASSESSMENT, OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER.

Moody's Investors Service, Inc., a wholly-owned credit rating agency subsidiary of Moody's Corporation ("MCO"), hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by Moody's Investors Service, Inc. have, prior to assignment of any credit rating, agreed to pay Moody's Investors Service, Inc. for credit ratings opinions and services rendered by it. MCO and all MCO entities that issue ratings under the "Moody's Ratings" brand name ("Moody's Ratings"), also maintain policies and procedures to address the independence of Moody's Ratings' credit ratings and credit rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold credit ratings from Moody's Investors Service, Inc. and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually at ir.moodys.com under the heading "Investor Relations — Corporate Governance — Charter and Governance Documents - Director and Shareholder Affiliation Policy."

Moody's SF Japan K.K., Moody's Local AR Agente de Calificación de Riesgo S.A., Moody's Local BR Agência de Classificação de Risco LTDA, Moody's Local MX S.A. de C.V, I.C.V., Moody's Local PE Clasificadora de Riesgo S.A., Moody's Local PA Calificadora de Riesgo S.A., Moody's Local CR Calificadora de Riesgo S.A., Moody's Local ES S.A. de CV Clasificadora de Riesgo, Moody's Local RD Sociedad Calificadora de Riesgo S.R.L. and Moody's Local GT S.A.(collectively, the "Moody's Non-NRSRO CRAs") are all indirectly wholly-owned credit rating agency subsidiaries of MCO. None of the Moody's Non-NRSRO CRAs is a Nationally Recognized Statistical Rating Organization.

Additional terms for Australia only: Any publication into Australia of this document is pursuant to the Australian Financial Services License of MOODY'S affiliate, Moody's Investors Service Pty Limited ABN 61 003 399 657AFSL 336969 and/or Moody's Analytics Australia Pty Ltd ABN 94 105 136 972 AFSL 383569 (as applicable). This document is intended to be provided only to "wholesale clients" within the meaning of section 761G of the Corporations Act 2001. By continuing to access this document from within Australia, you represent to MOODY'S that you are, or are accessing the document as a representative of, a "wholesale client" and that neither you nor the entity you represent will directly or indirectly disseminate this document or its contents to "retail clients" within the meaning of section 761G of the Corporations Act 2001. MOODY'S credit rating is an opinion as to the creditworthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors.

Additional terms for India only: Moody's credit ratings, Assessments, other opinions and Materials are not intended to be and shall not be relied upon or used by any users located in India in relation to securities listed or proposed to be listed on Indian stock exchanges.

Additional terms with respect to Second Party Opinions and Net Zero Assessments (as defined in Moody's Ratings Rating Symbols and Definitions): Please note that neither a Second Party Opinion ("SPO") nor a Net Zero Assessment ("NZA") is a "credit rating". The issuance of SPOs and NZAs is not a regulated activity in many jurisdictions, including Singapore. EU: In the European Union, each of Moody's Deutschland GmbH and Moody's France SAS provide services as an external reviewer in accordance with the applicable requirements of the EU Green Bond Regulation. JAPAN: In Japan, development and provision of SPOs and NZAs fall under the category of "Ancillary Businesses", not "Credit Rating Business", and are not subject to the regulations applicable to "Credit Rating Business" under the Financial Instruments and Exchange Act of Japan and its relevant regulation. PRC: Any SPO: (1) does not constitute a PRC Green Bond Assessment as defined under any relevant PRC laws or regulations; (2) cannot be included in any registration statement, offering circular, prospectus or any other documents submitted to the PRC regulatory authorities or otherwise used to satisfy any PRC regulatory disclosure requirement; and (3) cannot be used

Exhibit: AG-52
Case No.: U-21981
Date: April 15, 2026
Page 13 of 14

REPORT NUMBER 1471122

Exhibit: AG-52
Case No.: U-21981
Date: April 15, 2026
Page 14 of 14

Contacts

Jairo Chung *VP-Sr Credit Officer* jairo.chung@moodys.com	+1.212.553.5123	**Dean Moschitto** *Ratings Associate* dean.moschitto@moodys.com	+1.212.553.4149
Laura Barrientos *VP-Sr Credit Officer/MDG* laura.barrientos@moodys.com	+1.212.553.1637	**Jim Hempstead** *MD - Gbl Proj and Infra Fin* james.hempstead@moodys.com	+1.212.553.4318

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

U21981-AG-CE-0223
Page **1** of **1**

Question:

3. Provide a copy of the Blue Chip Forecast and other documents supporting the 30-year U.S. Treasury rates referenced on lines 11-16 on page 26 of witness Bulkley's direct testimony and related footnotes.

Response:

Please see Attachments 1 through 3.

Witness: Ann E. Bulkley
Date: March 30, 2026

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 44, No. 6, June 2, 2025

Wolters Kluwer

Long-Range Survey:

The table below contains results of our semi-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are estimates for the years 2026 through 2031 and averages for the five-year periods 2027-2031 and 2032-2036. Apply these projections cautiously. Few economic, demographic and political forces can be evaluated accurately over such long time spans.

		------------------------ Average For The Year ------------------------						Five-Year Averages	
		2026	2027	2028	2029	2030	2031	2027-2031	2032-2036
1. Federal Funds Rate	**CONSENSUS**	**3.4**	**3.2**	**3.2**	**3.2**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.7	3.5	3.4	3.4	3.4	3.4	3.4	3.4
	Bottom 10 Average	3.1	3.0	2.9	2.9	2.8	2.9	2.9	2.8
2. Prime Rate	**CONSENSUS**	**6.5**	**6.4**	**6.3**	**6.3**	**6.2**	**6.2**	**6.3**	**6.2**
	Top 10 Average	6.7	6.6	6.5	6.6	6.5	6.5	6.5	6.5
	Bottom 10 Average	6.2	6.2	6.0	6.0	5.9	5.9	6.0	5.9
3. SOFR	**CONSENSUS**	**3.4**	**3.3**	**3.2**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.6	3.4	3.3	3.3	3.3	3.3	3.3	3.3
	Bottom 10 Average	3.2	3.2	3.0	2.9	2.9	2.9	3.0	2.8
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.4**	**3.3**	**3.2**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.5	3.4	3.3	3.2	3.2	3.2	3.3	3.3
	Bottom 10 Average	3.3	3.3	3.1	3.0	3.0	3.0	3.1	2.9
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.3**	**3.2**	**3.2**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**
	Top 10 Average	3.6	3.4	3.4	3.4	3.3	3.3	3.4	3.3
	Bottom 10 Average	3.1	2.9	2.9	2.8	2.8	2.8	2.9	2.8
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.3**	**3.2**	**3.2**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	3.6	3.4	3.4	3.3	3.3	3.3	3.3	3.3
	Bottom 10 Average	3.1	3.0	3.0	2.9	2.9	2.9	3.0	2.8
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.3**	**3.3**	**3.3**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**
	Top 10 Average	3.6	3.5	3.4	3.4	3.4	3.4	3.4	3.4
	Bottom 10 Average	3.1	3.1	3.1	3.1	3.0	3.0	3.1	3.0
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.4**	**3.4**	**3.5**	**3.4**	**3.4**	**3.4**	**3.4**	**3.4**
	Top 10 Average	3.7	3.6	3.7	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.1
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**
	Top 10 Average	3.9	3.9	3.9	3.9	3.9	3.9	3.9	4.0
	Bottom 10 Average	3.4	3.5	3.5	3.5	3.4	3.4	3.5	3.4
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**4.0**	**4.1**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**
	Top 10 Average	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
	Bottom 10 Average	3.8	3.9	3.8	3.8	3.8	3.8	3.8	3.8
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.5**	**4.4**	**4.4**	**4.3**	**4.3**	**4.3**	**4.4**	**4.3**
	Top 10 Average	4.7	4.7	4.6	4.6	4.6	4.6	4.6	4.7
	Bottom 10 Average	4.2	4.3	4.1	4.1	4.1	4.1	4.1	4.1
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.2**	**5.2**	**5.2**	**5.1**	**5.1**	**5.1**	**5.1**	**5.1**
	Top 10 Average	5.4	5.5	5.4	5.4	5.4	5.4	5.4	5.4
	Bottom 10 Average	5.0	5.0	4.9	4.9	4.9	4.9	4.9	4.9
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**
	Top 10 Average	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
	Bottom 10 Average	5.8	5.9	5.8	5.8	5.8	5.7	5.8	5.8
14. State & Local Bonds Yield	**CONSENSUS**	**4.3**	**4.3**	**4.3**	**4.2**	**4.2**	**4.2**	**4.3**	**4.1**
	Top 10 Average	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4
	Bottom 10 Average	4.1	4.2	4.1	4.1	4.1	4.1	4.1	3.8
15. Home Mortgage Rate	**CONSENSUS**	**6.2**	**6.2**	**6.1**	**6.0**	**6.0**	**6.0**	**6.1**	**5.9**
	Top 10 Average	6.4	6.4	6.4	6.3	6.3	6.3	6.3	6.3
	Bottom 10 Average	5.9	6.0	5.8	5.8	5.8	5.7	5.8	5.6
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**113.3**	**112.7**	**112.7**	**112.2**	**111.7**	**111.3**	**112.1**	**110.8**
	Top 10 Average	114.2	113.3	113.4	112.9	112.5	112.2	112.8	112.4
	Bottom 10 Average	112.2	111.9	112.0	111.3	110.7	110.3	111.3	109.1
		--------------------- Year-Over-Year, % Change ---------------------						Five-Year Averages	
		2026	2027	2028	2029	2030	2031	2027-2031	2032-2036
B. Real GDP	**CONSENSUS**	**1.5**	**1.9**	**2.0**	**2.0**	**1.9**	**2.0**	**2.0**	**1.9**
	Top 10 Average	1.9	2.1	2.2	2.2	2.2	2.2	2.2	2.1
	Bottom 10 Average	1.1	1.8	1.8	1.8	1.7	1.7	1.8	1.8
C. GDP Chained Price Index	**CONSENSUS**	**2.4**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.6	2.3	2.2	2.2	2.2	2.2	2.2	2.2
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.5**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.9	2.4	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.1
E. PCE Price Index	**CONSENSUS**	**2.4**	**2.0**	**2.0**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**
	Top 10 Average	2.8	2.3	2.2	2.1	2.1	2.1	2.2	2.1
	Bottom 10 Average	2.1	1.8	1.8	1.8	1.7	1.8	1.8	1.8

VLFAlert

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 VLFAlert and thank you for your continued support.

Volatility is Not Risk:

Why the Difference is Critical to Long-Term Results

2017 lulled many equity investors into a comfort zone based on historically low volatility. 2018 has been more volatile—with tighter monetary policy and geopolitical and trade policy uncertainty among the drivers of the increase. But volatility levels in 2018 are actually historically normal—even with the bouts of volatility anticipated ahead of the November mid-term elections. But volatility is not risk. And recognizing the difference can be critical to your long-term investment returns.

Defining Our Terms

Volatility is simply the measure of the up and down movements of the market. For example, since 1950, when the Value Line Funds were first established, the average maximum drawdown in the broad U.S. equity market during midterm election years has been -17%, with weakness tending to be concentrated in the pre-election days. However, the good news is that there has been a consistent tendency historically for post-drawdown rallies, averaging +32% in the subsequent year.[1] Volatility? Yes! Uncertainty? Yes! But volatility is only risk if you act during down times—that is, only if you sell. To which the often-invoked quip may well be the most prudent answer: "Don't just do something, sit there."

Risk, on the other hand, is the probability of a permanent loss. You might think of risk as the possibility of having to lower your quality of life in the future.

> **"Volatility is not synonymous of risk but—for those who truly understand it—of wealth."**
>
> *- Francois Rochon**

Recognizing the Difference

Volatility is independent of risk. Too many investors let an investment's short-term price movements, or perceptions of short-term price movements, drive their buying and selling decisions. Too often volatility is regarded as something to be avoided. But since short-term price moves are unknowable and independent of underlying fundamentals and value, such volatility should not be a determinant.

And ALL investments have risk of some kind, including cash and CDs. One just needs to pick the risks that are best to take based on your individual tolerance level, time horizon and financial needs and goals.

As famed investor and Berkshire Hathaway CEO Warren Buffet wrote:

> "Stock prices will always be far more *volatile* than cash-equivalent holdings. *Over the long term*, however, currency-denominated instruments are *riskier* investments — far riskier investments — than widely-diversified stock portfolios that are bought over time and that are owned in a manner invoking only token fees and commissions. **That lesson has not customarily been taught in business schools, where volatility is almost universally used as a proxy for risk. Though this pedagogic assumption makes for easy teaching, it is dead wrong: Volatility is *far* from synonymous with risk.** Popular formulas that equate the two terms lead students, investors and CEOs astray."[2]

> **"Volatility is our friend. Volatility has nothing to do with risk."**
>
> *- Mohnish Pabrai**

(continued on back)

It's a Matter of Time, Not Timing

Most experienced investors do not fear volatility, only unrecoverable loss. But most losses, as measured by a day, a week, a quarter or a year, are recoverable over time. Declines in principal value have historically been temporary. Of course, there are true risks. A company could go totally out of business. An innovation could transform an industry so profoundly to make a once "blue chip" company a relic. A geopolitical event could happen to negate all assumptions. But these occurrences are rare. For the vast majority of investors, maintaining a long-term perspective is the real key to attaining gains over their investing lifetime. Historically, since World War II, the longer you hold stocks, the narrower the range of returns.[3] In other words, even if volatility is a concern, it decreases the longer you hold stocks. It's the old adage: what matters is time in the market, not market timing.

> **"You can't overlook the volatility, but you don't let it push you around in the market."**
>
> *- Boone Pickens**

solutions designed to meet a broad array of investment goals. Whether you are looking for income or long-term capital appreciation, whether you choose to invest in equities, taxabl or tax-exempt fixed income or a hybrid fund of multiple asset classes, you can rely on the solid fundamentals of Value Line Funds.

Value Line Funds Include:
Equity Funds
Premier Growth Fund
Larger Companies Focused Fund
Mid Cap Focused Fund
Small Cap Opportunities Fund
Hybrid Funds
Asset Allocation Fund
Capital Appreciation Fund
Fixed Income Funds
Tax Exempt Fund
Core Bond Fund

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Exhibit AG-55
Case No. U-21981
Date: April 15, 2026
Page 1 of 1

Line #		$000
1	**Exhibit A-13, Schedule C-5 Per Company**	$ 347,439
2		
3	**Distribution Operations**	
4	Pipelines O&M Expense	(2,529)
5	Leak Repair and Survey	(9,787)
6	Meter Tech & Management System	(645)
7	EIRP Training	(1,357)
8	Field Operations	(2,051)
9	**Transmission & Compression**	
10	Compression Expense	(2,525)
11	Pipeline Integrity Expense	(7,907)
12	**Customer Service**	
13	Customer Contact Center Expense	(1,757)
14	Analytics & Outreach	(720)
15	Business Customer Care	(1,000)
16	**Information Technology**	
17	IT Security Expense	(1,600)
18	IT Operations Expense Savings	(1,420)
19	Disallowed IT Capital Projects - Expense	(1,007)
20	**Corporate Expense**	(6,280)
21	**Health Care Costs**	(870)
22	**Rate Case Expenses**	(367)
23	**Incentive Compensation**	(529)
24	**Total O&M expense Reductions**	$ (42,351)
25		
26	**Adjusted O&M Expense**	$ 305,088

Source: Coppola Direct Testimony.

Question:

109. Refer to Table 9 on page 18 of Mr. Pnacek's direct testimony on the O&M expense for Distribution Pipelines. Please:
a. Expand this table to include 2025 actual information and forecasted information for 2026 and 2027 and provide it in Excel.
b. The division of the labor expense for 2024 and the projected test year under line 2 of Exhibit A-117, page 1, results in an average labor rate of $140 ($7,120,000 / 50,817 hours) for 2024 and $129 ($8,511,000 / 66,100 hours) for the projected test year. Explain why these labor rates are higher than the total of SLR and indirect labor rates in Table 8 for the same periods.

Response:

a) Please see attachment U21981-AG-CE-0329_Pnacek_ATT_1.xlsx
b) The Distribution rates in Table 8 were incorrect. See the updated table below. The SLR and indirect labor rates in Table 8 are used only for union labor. The Labor component in Exhibit A-117 includes more than just union labor, such as Fleet and Lab Service chargebacks.

Table 8 Updated

	Distribution				Service			
	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate	Standard Labor Rates	Indirect Labor Rates	Vehicle Rates	Total Rate
2024	$73.41	$37.44	$29.36	$140.21	$73.80	$97.42	$21.40	$192.62
2025	$75.58	$37.03	$31.74	$144.36	$75.63	$100.59	$22.69	$198.91
2026	$78.96	$39.48	$30.00	$148.44	$78.71	$102.32	$20.46	$201.50
2027	$82.22	$41.11	$35.35	$158.68	$81.96	$106.55	$24.59	$213.10

Witness: JAMES P PNACEK
Date: April 2, 2026

Table 9 p18

Operations & Maintenance – Distribution
Units/Orders, Hours & Dollars

Year (Jan-Dec)	Units/Orders	Hours	Dollars
2021	13,755	59,207	$11,721,014
2022	9,983	47,774	$10,531,290
2023	9,370	40,741	$8,924,773
2024 Actual	19,414	50,817	$11,542,032
2025 Preliminary Actuals	19,885	63,610	$14,063,530
2026 Projected	22,700	66,100	$11,282,000
2026-2027 Test Year	22,700	66,100	$13,797,000
2027 Projected	22,700	66,100	$13,877,000

U21981-AG-CE-0330
Page **1** of **2**

Question:

110. Refer to Table 22 on page 34 of Mr. Pnacek's direct testimony on the O&M expense for Leak Repair and Survey. Please:
a. Expand this table to include 2023 and 2025 actual information and forecasted information for 2026 and 2027 and provide it Excel.
b. Provide the number of units for each line for each year 2023-2024 actual and 2026-2027 forecasted in Excel.
c. Explain why there is an expense for Leak Classification given that this is simply a classification of units that did not get repaired and no work was done, as stated on lines 16-18 of Mr. Pnacek's testimony,
d. Explain what specifically is driving the increase in expense for each line item from 2024 to the projected test year. If driven by additional units, explain why and show how those higher units were determined.

Response:

a) Please see attachment U21981-AG-CE-0330_Pnacek_ATT_1.xlsx
b) Please see attachment U21981-AG-CE-0330_Pnacek_ATT_1.xlsx
c) This statement is a mischaracterization of my testimony. My testimony does not state that no work is done during a classification. Page 35, lines 16 to 18 state: "Classification units are the number of leaks that did/do not get repaired immediately. These leaks go to the backlog. The classification units are driven by historical and projected leaks data and the balancing of workload." This is the definition of a classification unit and not the Leak Classification process.
   Above and below grade leaks on gas facilities require an investigation to determine proper action. Leaks are classified as Immediate Action, Scheduled Action, or Deferred Action leaks. Procedures require continuing to investigate a gas leak until no leak is found, or the (above or below grade) leak is located and classified, or the source is identified as a foreign gas. The investigation and classification actions make up the Leak Classification process and expenses.
d) Refer to page 34, line 10 to page 35, line 4 and page 36, lines 6 to 20 of my direct testimony for specifics that are driving the increase in expenses. The following is a summary of the cost impacts associated with the programs cost drivers from my testimony.
    - The method and technology of leak survey changed through the implementation of mobile AMD. The leak survey scheduling approach changed by going from an

individual asset approach to a Geographic Grid approach. These changes will add efficiencies to program.

- There is an increase in survey units of 637,497 and classification units of 4,992. Leak Survey and Leak Classifications unit increases, and Line Patrols result in an expense increase of $4,025,820.
- The repair units increased by 16,637 units. Increasing the number of units and miles being surveyed results in an increase in the expected number of leaks found during leak survey. The Company plans to maintain a leak backlog at the lowest achievable level. The increase in the number of repairs contributes $9,796,628 to the program increase.

The increase is driven by higher survey units as discussed throughout the Leak Repair and Survey section of my testimony. Additionally, refer to page 39, line 18 and page 40, line 7 which states: "The higher units are based on the Company changing the frequencies associated with the Scheduled leak surveys. The assets with a code required five-year survey, adequately vented non-business districts assets, will now be performed on a three-year basis. The assets currently requiring a three-year code required survey, cathodically unprotected metallic mains and services, will now be performed on an annual basis. These changes will increase public safety and reduce methane emissions."..."The Leak Surveys expense for the test year is forecasted to be higher than the previous two years with approximately 1,150,226 survey units and 23,623 miles of main. This is based on the code-required schedule and the new frequency of the gas facilities to be surveyed. With the increased frequency, the Company will be leak surveying its entire system every three years as opposed to every five years. "

The increase in leak survey units will lead to an increase in the number of leaks found. The number of leaks found will lead to more leaks needing to be classified. More leaks being discovered will require more leaks to be repaired.

Witness: JAMES P PNACEK
Date: April 2, 2026

Table 22 p34 U21981-AG-CE-0330_Pnacek_ATT_1

Leak Repair and Survey

Projection Breakdown by Activity Type

Work Type	**2023 Actual**	**2024 Actual**	**2025 Preliminary Actuals**	**2026 Forecast**	**2026-2027 Test Year**	**2027 Forecast**
Leak Survey & Patrol	$5,339,146	$7,054,883	$6,366,111	$4,558,598	$10,049,705	$10,321,142
Leak Classification	$1,573,968	$1,212,538	$3,124,086	$1,017,680	$2,243,537	$2,304,133
Leak Assessments	$517,381	$468,761	$749,591	$281,061	$619,616	$636,351
Leak Repairs – Meter Stands and Regs	$3,286,805	$5,235,841	$6,821,337	$4,465,387	$9,844,215	$10,110,102
Leak Repairs – Services	$1,553,816	$3,478,992	$4,083,314	$2,967,058	$6,541,059	$6,717,730
Leak Repair – Mains	$2,594,560	$2,415,682	$1,902,888	$2,060,215	$4,541,868	$4,664,541
Total Program	**$14,865,676**	**$19,866,696**	**$23,047,327**	**$15,350,000**	**$33,840,000**	**$34,754,000**

U21981-AG-CE-0330_Pnacek_ATT_1

UNITS

Leak Repair and Survey

Projection Breakdown by Activity Type

Work Type	**2023 Actual**	**2024 Actual**	**2026 Forecast**	**2027 Forecast**
Leak Survey & Patrol	368,287	512,729	1,150,226	1,052,061
Leak Classification	3,981	5,871	9,560	9,560
Leak Assessments	1,705	1,911	3,112	3,112
Leak Repairs – Meter Stands and Regs	10,342	23,975	39,039	39,039
Leak Repairs – Services	1,792	2,340	3,810	3,810
Leak Repair – Mains	293	326	531	531
Total Program	**386,400**	**547,152**	**1,206,278**	**1,108,113**
Expense	**$ 14,865,676**	**$ 19,866,696**	**$ 15,350,000**	**$34,754,000**
Expense per Work Unit	$ 38.47	$ 36.31	$ 12.73	$ 31.36

U21981-AG-CE-0342
Page **1** of **1**

Question:

122. Refer to Table 45 on page 73 of Mr. Pnacek's direct testimony on Meter Tech and Management System Support. Please:
a. Expand this table to include 2023 and 2025 actual information and forecasted information for 2026 and 2027 and provide it in Excel.
b. Explain why the Meters Correctors expense is more than doubling from 2024 to the projected test year and provide supporting evidence.

Response:

a) See attachment U21981-AG-CE-0342_Pnacek_ATT_1.xlsx.
b) Please refer to page 74, line 1 to 14 of my direct testimony for an explanation of why the Meters Correctors expense is more than doubling from 2024 to the projected test year. In 2021, a determination was made relative to stand-alone natural gas meter correctors, which had previously been purchased under the Gas Meters capital program, that the components were considered replacement parts and would be purchased under the O&M program going forward, starting in 2022. In 2022, 2023, and 2024 the Company was able to reduce stand-alone meter corrector inventory purchases by depleting excess inventory holdings and receiving meter correctors at no cost as part of a vendor quality settlement. The increase for the projected year is due to a projected unit usage increase year over year as well as the need to supplement on-hand inventory after years of inventory depletion. 2025 spend levels represent the ramping back up of purchases to a more normal level of equipment demand, with full normalization beginning in 2026. The test year projected program requirement represents normal business expenses with the change in categorization of the gas meter corrector purchases.

Witness: JAMES P PNACEK
Date: April 2, 2026

Table 45, p73 U21981-AG-CE-0342_Pnacek_ATT_1

Meter Tech & Mgmt Sys Support

Projection Breakdown by Activity Type

Work Type	**2023 Actual**	**2024 Actual**	**2025 Preliminary**	**2026 Projected**	**2026-2027 Test Year**	**2027 Projected**
Exempt/Non-Exempt Salaries	$206,101	$145,432	$184,001	$174,670	$191,597	$196,356
OM&C Salaries	$740,763	$847,601	$790,392	$1,018,003	$1,022,220	$1,047,612
Expenses	$338,454	$116,020	$90,184	$139,345	$195,200	$200,049
Gas Smart Meter Pilot					$240,000	$240,000
Meter Correctors (began to purchase as O&M in 2022)	$246,460	$884,697	$2,008,980	$2,203,983	$2,203,983	$2,203,983
Total Program	**$1,531,778**	**$1,993,750**	**$3,073,557**	**$3,536,000**	**$3,853,000**	**$3,888,000**

Question:

128. Refer to Table 66 on page 100 of Mr. Pnacek's direct testimony on EIRP Expense. Please:
a. Expand this table to include 2023 and 2025 actual information and forecasted for 2026 and 2027 and provide it in Excel.
b. Explain why the EIRP Facilities expense line is nearly doubling in the projected test year from 2024 and provide supporting evidence.
c. Explain why the EIRP Labor OMC Training expense line is increasing by $1.1 million in the projected test year from 2024 and provide supporting evidence.
d. Explain why the Company is including costs for training expense in this EIRP area above the training expense in Table 57.
e. Provide the components of the 2024 and projected test year expenses for Labor OM&C Training showing on which items the money is being spent on with related dollars in Excel.
f. Provide the number of employees trained, number of hours, and the number of training sessions conducted in each year 2023-2025 and forecasted for 2026 and 2027.

Response:

a) Please see attachment U21981-AG-CE-0348_Pnacek_ATT_1.xlsx
b) The 2024 actuals reflects maintenance and payments for the three ERIP Company headquarter. Since that time, the Company has moved out of those headquarters and now has a total of nine ERIP Company headquarters. See page 101, line 21 to page 102, line 5 of my direct testimony. The increase reflects increase maintenance and operating cost for these nine headquarters. Please see U21981-AG-CE-0348_Pnacek_ATT_1.xlsx for associated costs.
c) See page 101 line 11 to line 18 of my direct testimony for the explanation. The EIRP workforce continues to experience employees transferring to other operating departments within the Company. Along with this employee movement, hiring and training are planned to allow for appropriate staffing as the Company implements the NGDP. Based on projections, this will result in increased spending compared to 2024. This increase is due to additional training needed for the complexity of the EIRP work plan, and for training new hires to maintain the workforce.

Please see attachment U21981-AG-CE-0348_Pnacek_ATT_1.xlsx for details on the history of employee turnover in the EIRP department. There has been an 83% turnover rate since 2020.

The Company plans to hire a total of 160 OM&C employees for 2026 and 2027. The hiring is necessary to support the increase in the EIRP work plan miles from 135.0 miles of plastic in 2026 to 167.9 miles of plastic in 2027 as shown in the Exhibit A-114 (KAP-6). As previously stated, the Company needs to expend an incremental $1,155,150 for new-hire and step-promotion training, which is necessary to support the forecasted increase in the EIRP Capital work plan.

d) The training in this program is the technical training required to ensure the field employees are fully skilled and qualified to complete the EIRP work. This includes initial training for newly hired employees, as well as more advanced training for higher skilled employees.

e) Please see attachment U21981-AG-CE-0348_Pnacek_ATT_1.xlsx

f) Please see attachment U21981-AG-CE-0348_Pnacek_ATT_1.xlsx. Data is based on best efforts and the best information available to the company and may not reflect an accurate actual to forecast comparison. Total employees trained reflects all instances of employees being trained. Sessions are the number of classes and do not reflect a count of how many days classes occurred.

Witness: JAMES P PNACEK
Date: April 2,2026

Table 66 p100	U21981-AG-CE-0348_Pnacek_ATT_1					
EIRP O&M						
Projection Breakdown by Activity Type						
Work Type	**2023 Actual**	**2024 Actual**	**2025 Preliminary Actuals**	**2026 Projected**	**2026-2027 Test Year**	**2027 Projected**
EIRP Supervision & Admin Sal/Exp	$869,933	$974,098	$971,206	$1,072,729	$1,090,500	$1,103,539
EIRP Tools	$84,056	$34,238	$60,901	$61,904	$63,100	$63,328
EIRP OM&C Expenses (Non-Labor)	$10,059	$5,256	$94,500	$0	$0	$0
EIRP Facilities	$251,148	$182,023	$370,003	$352,705	$353,400	$360,817
EIRP Labor OM&C Training	$2,132,942	$1,846,780	$971,367	$2,585,772	$2,933,000	$3,001,930
Total Program	**$3,348,137**	**$3,042,395**	**$2,467,978**	**$4,073,111**	**$4,440,000**	**$4,529,615**

	2024 Actual	2025 Actual	2026	2027
O&M - 4.10 EIRP O&M				
121820: EIRP Gas Facilities Maintenance	$72,051	$166,532	$185,111	$189,369
121821: EIRP Gas Facilities Operations	$115,229	$203,470	$167,594	$171,449
EIRP Facilities	**$187,280**	**$370,003**	**$352,705**	**$360,817**

U21981-AG-CE-0348_Pnacek_ATT_1

Year	Headcount (year ending) [1]	Headcount change from previous year	Cumulative Headcount loss since 2020	# of Employee Hired	Cumulative Employee's hired since 2020	Number of Employee lost from previous year	Cumulative Employee loss since 2020
2020	**495**						
2021	486	9	9	128	128	137	137
2022	423	63	72	27	155	90	227
2023	414	9	81	23	178	32	259
2024	379	35	**116**	38	**216**	73	**332**
2025	372	7	**123**	15	**231**	22	**354**

Average Number Employees since 2020	428
Employee Turnover Rate	83%

[1] Data for 2020-2025 EIRP Performance reports Attachment 5

Note: Headcount is OM&C only

U21981-AG-CE-0348_Pnacek_ATT_1

U21981-AG-CE-0348_Pnacek_ATT_1

	Total Employees	Number of Hours	Total Session
2023	1065	41,708	71
2024	1084	35,405	67
2025	622	15,576	45
2026	1061	49,295	131
2027	1061	49,295	131

U21981-AG-CE-0345
Page **1** of **1**

Question:

125. Refer to Table 61 on page 93 of Mr. Pnacek's direct testimony on Field Operations Expense. Please expand this table to include 2025 actual information and forecasted information for 2026 and 2027 and provide it in Excel.

Response:

Please see attachment U21981-AG-CE-0345_Pnacek_ATT_1.xlsx

Witness: JAMES P PNACEK
Date: April 2, 2026

Table 61 p93 U21981-AG-CE-0345_Pnacek_ATT_1

Field Operations Expenses

Projection Breakdown by Activity Type

Work Type	2023 Actual	2024 Actual	2025 Preliminary Actuals	2026 Projected	2026-2027 Test Year	2027 Projected
Field Ops OM&C Gas Expenses	$1,752,881	$1,619,018	$1,599,193	$1,296,936	$1,505,078	$1,510,738
Field Ops OT Meals Gas	$287,835	$360,741	$407,122	$282,690	$304,290	$304,290
Pipeline User Fees	$696,966	$830,915	$834,712	$835,008	$851,008	$854,208
Technology and Digital Solutions					$1,800,000	$2,500,000
Permits	$95,831	$111,979	$153,324	$112,446	$112,446	$112,446
Gas Field Mobility Exp	$294,525	$419,321	$410,228	$295,920	$301,596	$302,726
Gas Bonds/Escrow	$334,514	($1,993,180)	$0	$130,000	$130,000	$130,000
Total Program	$3,462,552	$1,348,794	$3,404,579	$2,953,000	$5,004,418	$5,714,409

U21981-AG-CE-0346
Page **1** of **1**

Question:

126. Refer to lines 6-29 on page 94 of Mr. Pnacek's direct testimony on the basis for the increase in Field Operations Expense. Please:
a. Identify over what future periods the $2.4 million in gas bonds will be refunded to the Company. Explain why this amount was credited entirely in 2024 and not amortized over future years.
b. Provide how much of the $550,000 pertains to each item.
c. Provide the cost savings or financial benefits from the $1.250 million to be invested in advanced geospatial systems.

Response:

a) The bonds are generally received within a 12 month period. The $2.4M was moved to the balance sheet in 2024 because that was when it was discovered that these should be receivables rather than expense.
b) The Company plans to spend the $550,000 primarily on Advanced Methane Detection technology. The plan on the specific breakdown of spending is still being developed.
c) The Company is in the process of performing an analysis to determine the cost savings for this investment. This information is currently not available.

Witness: JAMES P PNACEK
Date: April 2, 2026

U21981-AG-CE-0343
Page **1** of **1**

Question:

123. Refer to Table 54 on page 84 of Mr. Pnacek's direct testimony on Compression Expense. Please:
a. Expand this table to include 2023 and 2025 actual information and forecasted information for 2026 and 2027 and provide it in Excel.
b. Explain why the Labor expense is increasing by $1.8 million in the projected test year from 2024 and provide supporting evidence. If the number of employees is increasing, provide the number and explain what they will be working on.

Response:

a) Please see attachment U21981-AG-CE-0343_Pnacek_ATT_1.xlsx.
b) Per page 87, line 10 to 11 of my direct testimony, Crews performed local capital program work in 2024 that is not in the test year plan. This contributes $595,074 to the perceived program labor increase. With less Capital work the O&M program will realize an increase. The Company plans to fill two union position vacancies. The remainder of the increase is due to contractual wages increase and COLA for OM&C and the O&M portion of non-union merit increase. Please see attachment U21981-AG-CE-0343_Pnacek_ATT_1.xlsx.

Witness: JAMES P PNACEK
Date: April 2, 2026

Table 54 p84 U21981-AG-CE-0343_Pnacek_ATT_1

Work Type	**2023 Actual**	**2024 Actual**	**2025 Preliminary Actuals**	**2026 Projected**	**2026-2027 Test Year**	**2027 Projected**
Labor	$10,370,000	$9,419,621	$9,455,331	$9,686,058	$11,262,143	$11,845,608
Material	$1,122,000	$2,998,370	$3,862,302	$3,078,101	$3,578,642	$3,764,377
Contractor	$3,390,000	$2,517,324	$3,453,479	$2,584,249	$3,004,483	$3,160,419
Non-Labor Overheads	$45,000	$49,542	$54,348	$51,336	$59,684	$62,781
Non-Labor Other	$2,953,000	$2,157,139	$2,968,080	$2,200,257	$2,558,048	$2,690,814
Total	**$17,880,000**	**$17,141,996**	**$19,793,540**	**$17,600,000**	**$20,463,000**	**$21,524,000**

U21981-AG-CE-0343_Pnacek_ATT_1

Labor	**2024**	**Test Year**	**Variance**	
Labor	$ 9,419,621	$ 11,262,143	$ 1,842,522	
Labor Impacts				**Comment**
Capital Work			$ 595,074	Working 8,000 less Capital Hours in the Test year
Headcount			$ 316,000	Filling 2 Union vacancies
Union Wage Increase			$ 838,000	3.5% plus COLA
Non-Union Wage Increase			$ 93,448	Annual Merit increase (joint expense)

Question:

78. Refer to Table 1 on page 17 of Mr. Griffin's direct testimony on the inspection miles of the transmission pipelines. Please expand this table to include actual miles for 2022, 2023, and 2025. Explain why forecasted miles for 2025 decreased significantly from 2024.

Response:

The table below expands Table 1 on page 17 of Michael P. Griffin's direct testimony, outlining actual mileage from 2022-2025 and projected 2026-2027 mileage:

PI-Transmission Inspection Mileage (ILI + Transmission DA)					
2022	2023	2024	2025	2026	2027
66.8	266.5	374.6	198.7	297.0	329.7

Multiple factors contributed to the difference in mileage between 2024 and 2025. The number of inspections in the work plan is largely driven by HCA compliance dates in which the Company utilizes a 6-year inspection cycle. The total mileage inspected is determined by the length of the segments scheduled that year. The Company does not have a target mileage per year. The 2025 work plan had lower mileage because there were fewer and shorter segments scheduled for inspection. The Mid-Michigan project also retired segments which would have been up for inspection in 2025.

Witness: Jordan L Waggener
Date: March 26, 2026

U21981-AG-CE-0303
Page **1** of **1**

Question:

83. Refer to Exhibit A-72 (MPG-1), page 1, sponsored by Mr. Griffin. Please:

a. Expand this schedule to include actual amounts for 2025 and forecasted amounts for 2026 and 2027 for lines 1-5 at summary level and provide it in Excel.

b. Explain what Non-Labor Overheads and Non-Labor Other costs are being allocated to O&M expenses in these areas and provide the basis of allocation.

Response:

a. Refer to attachment U21981-AG-CE-303-WAGGENER_ATT_1 for the requested information.

b. Non-Labor Overheads include: non-labor fleet and non-labor lab services. Non-Labor Other includes: non-labor IT, business expenses, fees and regulatory permits

Witness: Jordan L Waggener
Date: April 1, 2026

U21981-AG-CE-303-WAGGENER_ATT_1

MICHIGAN PUBLIC SERVICE COMMISSION U-21981
Consumers Energy Company ~~A-72 (MPG-1)~~
Summary of Actual & Projected O&M Expenses 1 of 1
Regulatory Compliance O&M Expenses JLWaggener
($000) March 2026

		(a)	(b)	(c)			(d)
Line No.		**Description**	**Actual 12-Mos Ended 12/31/2024**	**Preliminary Actual 12-Mos Ended 12/31/2025**	**Forecasted 12-Mos Ending 12/31/2026**	**Forecasted 12-Mos Ending 12/31/2027**	**Projected 12-Mos Ending 10/31/2027**
1		**MAOP Transmission**	**$ 3,025**	**$ 3,007**	**$ 2,218**	**$ 2,266**	**$ 2,654**
	11%	Labor	324	327			284
	4%	Material	125	295			109
	85%	Contractor	2,568	2,318			2,252
	1%	Non-Labor Overheads	33	47			29
	-1%	Non-Labor Other	(25)	19			(21)
2		**Corrosion Control - Transmission**	**1,169**	**1,699**	**2,068**	**2,300**	**2,261**
	13%	Labor	156	279			301
	5%	Material	54	85			105
	76%	Contractor	891	1,264			1,724
	3%	Non-Labor Overheads	36	68			70
	3%	Non-Labor Other	32	4			61
3		**Pipeline Integrity - TOD**	**889**	**729**	**983**	**899**	**913**
	7%	Labor	63	79			65
	9%	Material	80	(9)			82
	81%	Contractor	718	596			737
	2%	Non-Labor Overheads	18	38			19
	1%	Non-Labor Other	10	25			10
4		**Pipeline Integrity - Transmission**	**18,444**	**15,099**	**16,032**	**27,275**	**26,351**
	5%	Labor	867	1,490			1,239
	6%	Material	1,016	285			1,452
	86%	Contractor	15,897	12,861			22,711
	3%	Non-Labor Overheads	546	432			781
	1%	Non-Labor Other	118	31			169
5		**Total**	**$ 23,527**	**$ 20,535**	**$ 21,301**	**$ 32,740**	**$ 32,179**
		Labor	1,409	2,176			1,888
		Material	1,275	656			1,748
		Contractor	20,073	17,038			27,425
		Non-Labor Overheads	634	586			899
		Non-Labor Other	135	79			219

Notes: % breakdown for cost elements is based on 2024 actual
Test Year is based on 2026 and 2027 monthly cashflow

U21981-SA-CE-007
Requested By: Brittney Klocke (BMK-1 - 6)
Respondent: Alex M. Gast
Date of Response: 12/29/2025
Page **1** of **1**

Question:

6. Are calls projected to decrease in the bridge and test years? Why or why not? Has the Company seen calls decrease as more customers move to digital self-service options? If so, how has the call volume decreased each year?

Response:

Yes, calls are projected to continue declining in both the bridge and test years. The decline is driven by continued customer adoption of digital self-service tools and enhancements to IVR and other digital platforms that reduce the need for live-agent support.

Yes, the Company has already observed a steady decline in call volumes as customers increasingly rely on digital channels.

Annual Call Volume Decrease:

- 2023: 2,748,882 calls
- 2024: 2,613,774 calls
- 2025 (Jan–Oct 15): 2,013,774 calls

This reflects:

- A decrease of 135,108 calls from 2023 to 2024, approximately a 5% reduction.
- A further decline of more than 600,000+ calls in 2025 compared to the same period in 2024, representing roughly 23% annualized decrease.

U21981-SA-CE-006
Requested By: Brittney Klocke (BMK-1 - 5)
Respondent: Alex M. Gast
Date of Response: 12/29/2025
Page **1** of **1**

Question:

5. What is the current cost per call to the Contact Center? What is the projected cost per call for 2026 and 2027?

Response:

The current cost per call for the Contact Center is $11.13 year-to-date. Based on projected reductions in call volume, the estimated cost per call is $12.24 for 2026 and $13.46 for 2027.

U21981-SA-CE-011
Requested By: Brittney Klocke (BMK-1 - 10)
Respondent: Alex M. Gast
Date of Response: 12/29/2025
Page **1** of **1**

Question:

10. What are the current staffing levels of the Contact Center, and how are those expected to change in 2026 and 2027?

Response:

The Contact Center currently has a headcount of 211 employees. Based on projected reductions in call volume, staffing is expected to decrease to approximately 185 employees by year-end 2026 and approximately 149 employees by year-end 2027.

U21981-SA-CE-052
Requested By: Brittney M. Klocke (BMK-3 - 1)
Respondent: Alex M. Gast
Date of Response: 1/22/2026
Page **1** of **1**

Question:

1. From audit response SA-CE-011, why are the number of employees in the Contact Center expected to decrease from 211 (currently) to 185 (year end 2026) and 149 (year end 2027)? How will costs for the Contact Center be affected by this reduction in staff? How many external customer service representatives does the Company have in the Contact Center, and how will those numbers be reduced in 2026 and 2027?

Response:

The projected reduction in Contact Center headcount—from 211 currently to 185 by year end 2026 and 149 by year end 2027—is driven by planned efficiency gains tied to automation, enhanced self service capabilities, and workflow optimization. As these initiatives mature, the Company expects fewer manual interventions, which reduces the staffing required to support daily operations.

The primary cost impact will be a reduction in labor expense, which is the largest component of the Contact Center's cost structure. Additional savings are anticipated through lower training, onboarding, and vendor related support costs.

Regarding vendor Customer Service Representatives (CSR), the headcount is flexible and adjusts based on the volume forecasts provided. The Company does not determine the vendor's staffing levels; instead, the Company supplies a projected forecast in advance, and the vendor meets that demand. Forecasted volumes are developed based on current business needs. For context, the current vendor CSR headcount is 69. Future vendor staffing levels for the remainder of 2026 and 2027 will align with the volumes forecasted during those periods.

U21981-AG-CE-0420
Page **1** of **2**

Question:

198. Refer to page 3 of Exhibit A-132 sponsored by Ms. Wiersema on customer service O&M expenses. Please:

a. Expand this schedule to include actual expenses for 2023 and 2025 and forecasted expense for 2026 and 2027 and provide it in Excel.

b. Explain why the labor expense under Analytics & Outreach increases by $0.6 million from 2024 to the projected test year. Provide supporting evidence that the higher expense is necessary.

c. Explain why the labor expense under Customer Contact Center increases by $1.2 million from 2024 to the projected test year. Provide supporting evidence that the higher expense is necessary.

Response:

a. Refer to U21981-AG-CE-0420_ATT1

b. Labor costs in Analytics & Outreach are increasing by a total of $0.6M for the following areas:

1. $199k in new labor costs for Customer Strategy & Transformation leadership (new FTEs)
2. $109k for increased IT labor allocation for IT support
3. $92k for 2 FTEs in Brand that transferred from External Comms. This labor was included with External Comms in the Corporate witness exhibit for the historical year but is now reflected in Brand for the test year.
4. $224k labor variance for Customer Strategy
    - 2024 actuals reflect multiple vacancies throughout the historical year while test year labor is forecasted at full headcount.
    - This team also had a mid-year reorganization in 2024, which combined the Customer Operations Strategy team with the Customer Strategy team to streamline operations. Because this occurred mid-year, only partial labor for these employees are reflected in the historical year.
    - As result, some 2024 labor is reflected in in the Customer Contact Center section of A-132 page 3, while the test year reflects the full labor under the updated structure, including several FTEs added to the team.

c. Labor costs in the Customer Contact Center are increasing by $1.2M due to annual wage and merit increases of 4% per year for Customer Service Representatives (CSR) and 3.2% - 3.5% per year for Exempt and Non-exempt staff. Below is a table reflecting the annual General Wage Increase (GWI) stipulated in the CSR union contract.

U21981-AG-CE-0420
Page **2** of **2**

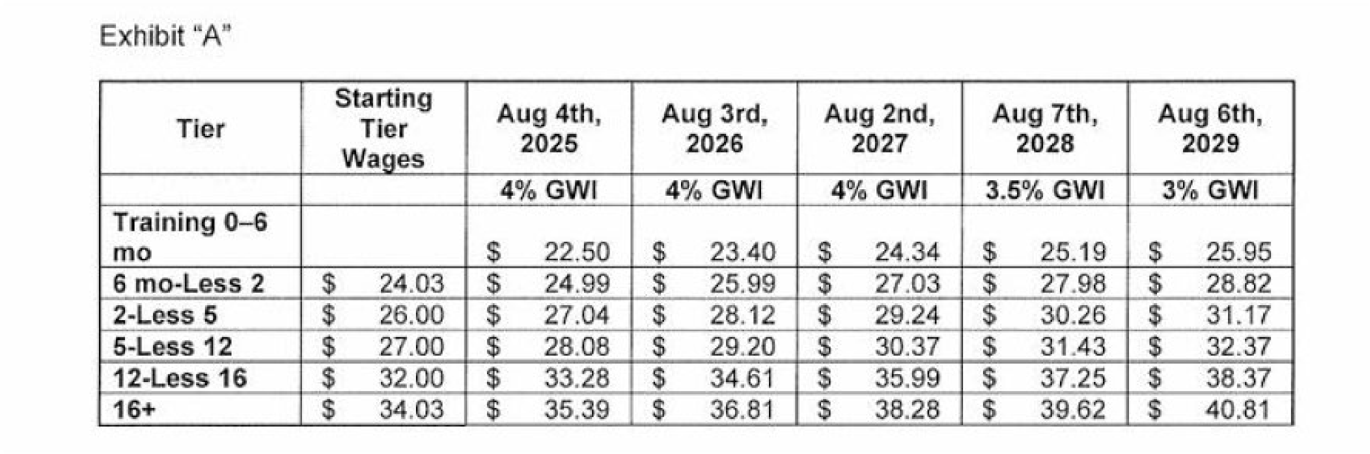


Exhibit "A"

Tier	Starting Tier Wages	Aug 4th, 2025	Aug 3rd, 2026	Aug 2nd, 2027	Aug 7th, 2028	Aug 6th, 2029
		4% GWI	4% GWI	4% GWI	3.5% GWI	3% GWI
Training 0–6 mo		$ 22.50	$ 23.40	$ 24.34	$ 25.19	$ 25.95
6 mo-Less 2	$ 24.03	$ 24.99	$ 25.99	$ 27.03	$ 27.98	$ 28.82
2-Less 5	$ 26.00	$ 27.04	$ 28.12	$ 29.24	$ 30.26	$ 31.17
5-Less 12	$ 27.00	$ 28.08	$ 29.20	$ 30.37	$ 31.43	$ 32.37
12-Less 16	$ 32.00	$ 33.28	$ 34.61	$ 35.99	$ 37.25	$ 38.37
16+	$ 34.03	$ 35.39	$ 36.81	$ 38.28	$ 39.62	$ 40.81

Witness: Alex M Gast
Date: April 7, 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Customer Interactions
($000) U21981-AG-CE-0420_ATT1

Line No.	Description	Actual 12-Mos Ended 12/31/2023	Actual 12-Mos Ended 12/31/2024	Actual 12-Mos Ended 12/31/2025	Projected 12-Mos Ended 12/31/2026	Projected 12-Mos Ended 12/31/2027	Projected 12-Mos Ending 10/31/2027
1	Analytics & Outreach	2,656	1,328	2,094	3,848	3,861	2,905
	Labor	2,065	1,148	1,376	2,697	2,500	1,778
	Material	4	2	1	1	-	-
	Contractor	520	320	623	1,027	1,236	820
	Non-Labor Overhead	-	-	-	1	-	-
	Non-Labor Other	67	(142)	95	122	125	307
2	Business Customer Care	1,826	1,517	2,086	3,642	3,539	2,549
	Labor	1,557	1,364	1,557	2,701	2,698	1,943
	Material	1	1	1	0	-	4
	Contractor	235	108	469	749	319	427
	Non-Labor Overhead	-	-	-	-	-	-
	Non-Labor Other	34	44	59	191	522	174
3	Credit & Assistance	2,270	2,132	2,451	2,461	2,551	2,403
	Labor	1,544	1,535	1,439	1,694	1,828	1,724
	Material	10	48	31	9	48	55
	Contractor	534	476	687	652	583	541
	Non-Labor Overhead	-	-	-	-	-	-
	Non-Labor Other	183	73	294	105	92	83
4	Customer Contact Center	12,998	12,864	13,128	12,428	12,214	13,767
	Labor	10,029	9,251	9,528	9,171	9,025	10,544
	Material	21	14	8	3	(0)	13
	Contractor	2,255	2,998	2,841	2,581	2,500	2,670
	Non-Labor Overhead	-	-	-	-	-	-
	Non-Labor Other	693	600	751	674	690	541
5	Digital Customer Operations	1,884	872	894	2,045	2,057	818
	Labor	555	560	603	1,364	1,495	429
	Material	0	0	0	-	-	0
	Contractor	1,292	251	224	601	483	313
	Non-Labor Overhead	-	-	-	-	-	-
	Non-Labor Other	36	61	66	80	78	76
6	Total Customer Interactions O&M	21,634	18,714	20,653	24,423	24,222	22,441
	Labor	15,749	13,858	14,503	17,628	17,545	16,418
	Material	36	65	41	12	48	72
	Contractor	4,835	4,154	4,844	5,610	5,122	4,771
	Non-Labor Overhead	-	-	-	1	-	-
	Non-Labor Other	1,013	636	1,265	1,172	1,507	1,181

U21981-SA-CE-083
Requested By: Brittney M. Klocke (BMK-4 - 4)
Respondent: Alex M. Gast
Date of Response: 1/26/2026
Page **1** of **2**

Question:

4. The following questions pertain to Company exhibit A-132 (MNW-2), page 3:
a. what is driving the increases in O&M costs for the Analytics & Outreach, Business Customer Care, Credit and Assistance, and Customer Contact Center for the test year?
b. Conversely, what is driving the overall decrease in O&M for the test year for the Digital Customer Operations area?
c. Why are the overall labor costs for the CX&G area projected to increase by over $2.5 million in the test year?
d. Why are the overall contractor and non-labor other costs projected to increase by $617,000 and $545,000 respectively in the test year?

e. is there any overlap between employees and duties performed in any of the areas within the CX&G? If so, how are costs allocated for those employees?

Response:

a. Analytics & Outreach

- $297k in new spend for Customer Strategy & Transformation team
- $356k for new IT allocation
- $335k in new spend for Voice of the Customer CX Enterprise Feedback Management Solution
- $350k increase for Customer Strategy team labor at full headcount, vs vacancies in 2024, as well as staff transferred from Projects & Support team
- $291k for labor & contractor services in the Brand Strategy team due to headcount changes, increased costs for Magnit, Creative Funds, & Meltwater

Business Customer Care

- $1M in new spend for Growth team labor & outside services added to Economic Development team

Credit & Assistance

- $91k increase due to reduced theft investigation bill credits
- $68k increase for Collection Agency Services
- $140k labor increase for full headcount in the Low-Income team and Revenue Recovery Office team that had vacancies in 2024

Customer Contact Center

- $900k increase for CSR labor due to new union contract wage increases & merits

U21981-SA-CE-083
Requested By: Brittney M. Klocke (BMK-4 - 4)
Respondent: Alex M. Gast
Date of Response: 1/26/2026
Page **2** of **2**

b. The overall decrease in O&M for Digital Customer Operations was due organizational changes in the Utility Services team involving staff that moved to Growth (Business Customer Care), Voice of the Customer (Analytics & Outreach).

c. Specific to just overall labor costs, the main drivers are a $900k increase for CSR labor due to new union contract wage increases & merits, $540k increase in Economic Development labor for Growth plus 3.2% merit increases year over year, and $199k for Strategy & Transformation team. The remaining increases are primarily due to cumulative 3.2% merit increases to labor, year over year, across 2025, 2026, and through the test year ending 10/31/2027, as well as forecasting full headcount with no vacancies in the test year (whereas 2024 labor reflected multiple vacant positions).

d. Customer Interactions Contractor costs in the test year increased due to CX Enterprise Feedback Management System for Voice of the Customer, Brand outside service vendors, as well as Customer Strategy & Transformation outside services. Customer Interactions Non-labor Other costs increased in the test primarily due to IT allocations, Growth Site Readiness, and Growth team business expenses.

e. Yes, there is overlap between utility O&M work and product portfolio support for several areas within CX&G. Historically, costs were allocated based on an annual labor study that assessed how labor and associated non-labor was split between utility O&M and product support. Currently, the Company is transitioning to a timesheet-based method to track costs between utility O&M and products.

U21981-SA-CE-138
Requested By: Brittney M. Klocke (BMK-5 - 4)
Respondent: Alex M. Gast
Date of Response: 2/5/2026
Page **1** of **1**

Question:

4. From audit response SA-CE-084 were any of the 6 employees added to the Growth team new to the Company? What are the goals that are expected to be achieved by the Growth team and what benefits will customers receive?

Response:

No, all 6 employees added were existing employees of the Company. The Growth Team's goals are to retain and grow existing customer load, attract and support new strategic load, and deliver disciplined economic development services with clear guardrails so costs are paid by those who benefit. All customers benefit through better system utilization and stronger planning that help spread fixed costs and reduce upward pressure on rates, along with accelerating speed to energization, energy education and advocacy, access to programs (energy efficiency, demand response, and renewables), and the utility services needed to deliver safe, reliable, affordable, clean, and equitable energy across Michigan.

U21981-SA-CE-286
Requested By: Brittney M. Klocke (BMK-9 - 4)
Respondent: Alex M Gast
Date of Response: 2/25/2026
Page **1** of **2**

Question:

4. Please further expand and explain the reply from audit response SA-CE-138 that the Growth team's purpose is to "retain and grow existing customer load, attract and support new strategic load, and deliver disciplined economic development services with clear guardrails so costs are paid by those who benefit." How is the Company planning to use the Growth team to attract and grow its customer load, as well as attract and support new customer load? Please be as detailed as possible about the activities to be performed by employees in this area.

Response:

Growth staff members perform the following activities to support existing business retention and expansion, as well as new business attraction with the objective of driving load growth:

- Business Retention – Employees support existing customers through defined activities that strengthen operational stability and long-term load
- Provide energy solutions aligned with customer operational needs
- Connect customers with energy efficiency and demand response programs to support cost-saving opportunities
- Offer renewable energy options when sustainability goals are a priority
- Connect businesses with state and local economic development tools, resources and organizations to support ongoing needs
- Business Expansion - For customers considering growth, the team provides clear, actionable information to support expansion decisions and position Michigan as the ideal location over other states and countries being examined by the customer
- Develop proposals that outline energy upgrades, associated costs, and timelines to serve expansion needs – at the customer's existing site or prospective sites (assist in identifying prospective sites where applicable)
- Conduct rate analyses to confirm the customer is on the most effective rate given load changes
- Share available energy capacity information at current or prospective sites
- Provide site options within the service territory in partnership with local economic development organizations

U21981-SA-CE-286
Requested By: Brittney M. Klocke (BMK-9 - 4)
Respondent: Alex M Gast
Date of Response: 2/25/2026
Page **2** of **2**

- Business Attraction - The team helps position Michigan, and the Company's service territory, as competitive locations for new investment
- Respond to Michigan Economic Development Corporation RFI's with accurate energy analysis and solutions to serve prospective customer needs
- Respond directly to inquiries from prospective customers and site consultants with accurate energy solutions that meet prospective customer needs
- Provide utility expertise at prospective business site tours, familiarization tours and project meetings to ensure Michigan and the Company's service territory meets customer needs
- Prepare energy assessments for the State's industrial site readiness program
- Support local communities and economic development partners with site readiness activities
- Educate communities on energy processes, impacts, and planning related to new business

U21981-AG-CE-0399
Page **1** of **1**

Question:

177. Refer to lines 18-23 on page 26 of Ms. Baker's direct testimony on IT Operations O&M expense. Please provide a breakdown of the $4.3 million for each item and identify when those expenses will be incurred and why they are incremental to historical levels.

Response:

The $4.3 million increase in IT Operations O&M expenses consists of the following items:

- $3.3 million increase in cloud subscription starting in third quarter 2025 primarily due Digital-Hybrid Cloud and Data Center Migration project and SAP HANA Database Migration projects,

- $0.4 million increase in license and maintenance for IT service management starting in March 2027,

- $0.9 million increase in cloud subscriptions due to the Genesys Cloud Migration project in 2025,

- Offset by $0.2 million decrease for various other subscriptions and license and maintenance agreements starting in 2026,

- $0.6 million increase for contractors to support application development and delivery starting in 2025,

- Offset by $0.3 million decrease in Human Resources and Supply Chain contractors due to efficiencies starting in 2025,

- Offset by $0.2 million decrease in Strategy and Governance resources due to efficiencies starting in 2025,

- Offset by $0.2 million decrease starting in 2026 for insourcing cloud engineering and analytics platform resources starting in 2025 and 2026.

Witness: Stacy H. Baker
Date: April 7, 2026

U21981-AG-CE-0400
Page **1** of **1**

Question:

178. Refer to lines 3-8 on page 27 of Ms. Baker's direct testimony on IT Operations O&M expense. Please:

a. Identify to which applications the $2.6 million applies with related dollars, when those expenses will be incurred, and why they are incremental to historical levels.

b. By transferring data processing to the cloud from internal data processing, does the Company now have excess internal computing capacity? What is the cost savings from the transfer to the cloud and where are they reflected in this rate case?

Response:

a. The $2.6 million increase in Security Operations O&M expenses consists of the following items:

- $1.2 million increase cloud subscription costs starting in third quarter 2025 primarily due Digital-Hybrid Cloud and Data Center Migration project and SAP HANA Database Migration projects,

- $0.4 million increase for network costs that moved to Cyber Security due to reorg beginning in 2025,

- $0.3 million increase for subscription and license and maintenance agreements beginning in 2027 for multi-factor authentication, risk management, and IT service management tools starting in 2026 and 2027,

- $0.4 million increase for Physical Security contractor costs for on-site security starting in 2026,

- $0.3 million increase for Cyber Security contractor costs to support Network Operations center and security engineering starting 2025 and 2026.

b. The Company does not have excess internal computing capacity by transferring applications to the cloud. As applications migrate to the cloud, the Company systematically retires legacy servers that are no longer required and repurposes newer hardware where feasible to support remaining on-premises needs. Refer to my direct testimony on page 18, line 3 through page 20 lines 3, for cost efficiencies and savings related to migrating to migrating to the cloud. Additionally, refer to Audit Response No. U21981-SA-CE-129, part a, for projected annual operational O&M cost savings.

Witness: Stacy H. Baker
Date: April 7, 2026

U21981-SA-CE-129
Requested By: Emma Harris (EH-7 - 12)
Respondent: Stacy H. Baker
Date of Response: 2/3/2026
Page **1** of **2**

Question:

12. Regarding the “Digital-Hybrid Cloud and Data Center Migration” project:
a. Please detail the cost savings the Company expects to see, as a result of this project, due to the reduction in operational costs for running IT services, as mentioned in witness Baker's testimony, page 110, lines 21-22.
b. When did the Company learn about the change in projected costs detailed on page 114, lines 3-12 of witness Baker's testimony.
c. Please explain why the project end date has shifted out a year in this case, with the project now planned to be completed at the end of 2026 instead of 2025 as originally indicated in the previous gas case, U-21806, and the current electric case, U-21870.
d. Please provide a breakdown of the work completed in 2025, shown in Exhibit A-20 (SHB-5), line 158, and explain why the projected costs for 2025 are significantly higher than 2024 and 2026.
i. Please provide a breakdown of all actual project costs for 2025, if this data is known.

Response:

a. The Company projects that due to this project annual operational O&M costs will be reduced for hardware maintenance $520,000 and software licensing & maintenance $900,000.

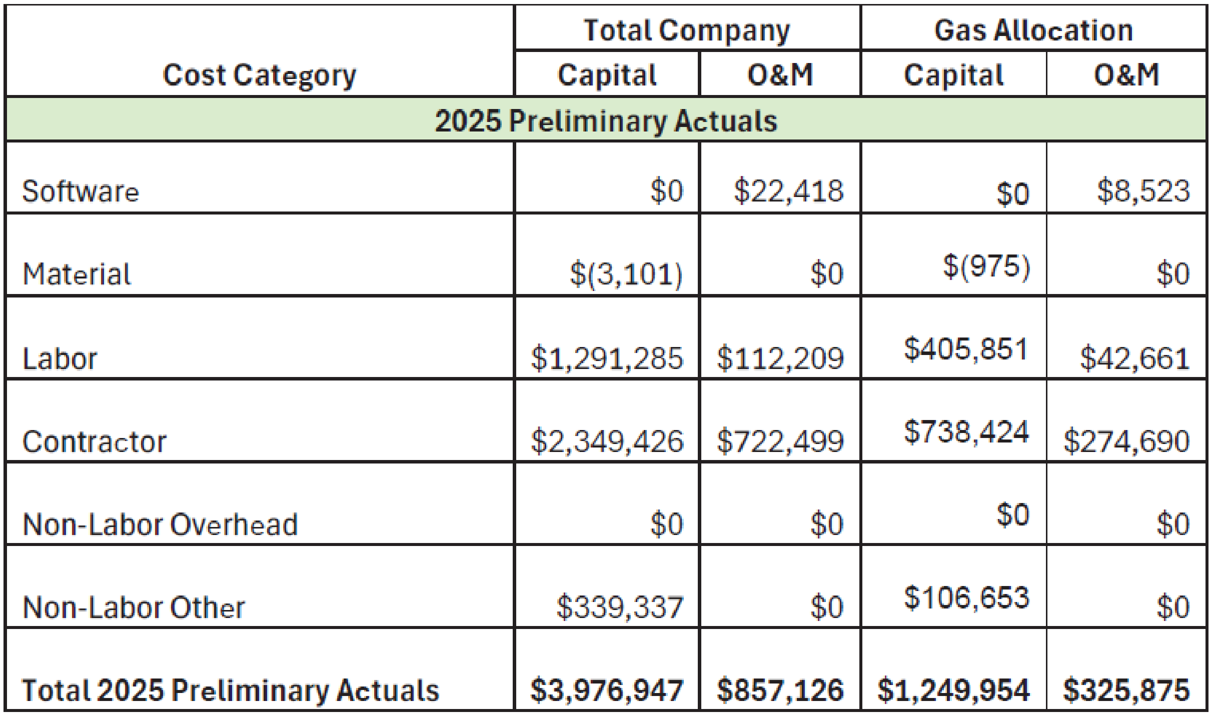
b. The Company learned about the change in projected costs detailed in my direct testimony on page 114, lines 3-12, in April and October of 2025.

c. The Digital Hybrid Cloud and Data Migration project originally scheduled for completion in 2025, will now extend into 2026. This adjustment is due to several application migrations that were not completed within the initial timeline in 2025. As a result, twenty applications remain to be migrated in 2026.

d. The projected costs for 2025 were significantly higher due to 2024 focused on planning and startup activities, establishing infrastructure readiness, and early application migrations. In contrast, 2025 efforts were solely focused on application migrations resulting in an increase in costs as stated on page 114, lines 7 - 12 of witness Baker's testimony. In 2026, only the applications that remained on premise were left to migrate. As a result, the scope of work was much smaller, and the associated costs were lower.

U21981-SA-CE-129
Requested By: Emma Harris (EH-7 - 12)
Respondent: Stacy H. Baker
Date of Response: 2/3/2026
Page **2** of **2**

i. The table below provides a breakdown of the preliminary actual costs for 2025.



Cost Category	Total Company		Gas Allocation	
	Capital	O&M	Capital	O&M
2025 Preliminary Actuals				
Software	$0	$22,418	$0	$8,523
Material	$(3,101)	$0	$(975)	$0
Labor	$1,291,285	$112,209	$405,851	$42,661
Contractor	$2,349,426	$722,499	$738,424	$274,690
Non-Labor Overhead	$0	$0	$0	$0
Non-Labor Other	$339,337	$0	$106,653	$0
Total 2025 Preliminary Actuals	**$3,976,947**	**$857,126**	**$1,249,954**	**$325,875**

U21981-AG-CE-0247
Page **1** of **2**

Question:

27. Refer to pages 4-7 of Mr. Foster's direct testimony on Corporate Service O&M expense. For each area, before allocation of expenses to various businesses, please:

a. Provide the actual expense for each year 2023 to 2025 and forecasted for 2026 and 2027 in Excel. Explain year over year increases of 5% or greater. Explain how the forecast for 2026 and 2027 expenses was determined.

b. Provide the actual number of employees for each year 2023 to 2025 and forecasted for 2026 and 2027 in Excel. Explain year over year increases of 2 employees or greater.

Response:

a. Please see U21981-AG-CE-0247_ATT_1 for the actual and forecasted expenses before allocations. The forecasts for 2026 and 2027 were developed by applying inflation to 2024 historical actuals, consistent with the methodology used to calculate Corporate O&M expenses for the projected test year in this case.

Explanations of year over year increases

- Sustainability & External Affairs
  - 2023 – 24: increase due to consulting expense
  - 2025 – 26: increase due to applying inflation to 2024 historical actuals
- Legal, Ethics, Regulatory, and Risk
  - 2025 – 26: increase due to one-time legal consultant expense in 2024 resulting in an increase to the 2026 forecast; the Company did not seek recovery of the one-time legal consultant O&M expense as shown on Exhibit A-58, line 13.
- People & Culture and Learning and Development
  - 2024 – 25: Increase due to the filling of vacancies and higher gas skills technical training
- Finance and Shared Services
  - 2024-25: Increase due to the filling of vacancies and higher treasury fee credits in 2024.
- General Activities
  - 2025 – 26: increase due to less Capitalized Credits
- Administrative and Other
  - 2023 – 24: increase due to Regulatory Commission expense
  - 2025 – 26: increase due to Regulatory Commission expense in 2024, resulting in an increase to the 2026 forecast.

b. Please see U21981-AG-CE-0247_ATT_2 for the actual and forecasted number of employees.

Change in headcount explanations

- Sustainability & External Affairs
  - 2023 – 24: increase due to filling vacancies
  - 2024 – 25: increase due to External Communication move from Customer Experience to Sustainability & External Affairs
- People & Culture and Learning and Development
  - 2023 – 24: increase due to filling vacancies and an increase in Learning and Development
  - 2025 – 26: increase in Learning and Development, Employee Communications, Benefit Administration, primarily due to filling vacancies; Increase due to SAP S4 project employees returning to the organization.
- Finance and Shared Services
  - 2024 – 25: increase due to filling recent vacancies; Increase in the Finance Transformation & Technology department.

Witness: Matthew J. Foster
Date: April 3, 2026

U21981-AG-CE-0248
Page **1** of **1**

Question:

28. Refer to lines 9-19 on page 7 of Mr. Foster's direct testimony on Corporate Service O&M expense allocations. For each area within Corporate Services, please:

a. Provide the actual expense for each year 2023 to 2025 and forecasted for 2026 and 2027 allocated to the utility gas business, electric utility business, and non-utility businesses in Excel.

b. Provide the allocation factors used to calculate the allocations in subpart (a) if different than the three-factor Mass Formula.

c. Provide the calculations of the three-factor Mass Formula in Excel with all the supporting data for each of the subsidiaries that are included in the formula, including operating revenue, labor, and property, plant and investments for each year 2023 to 2027.

Response:

a. This response is supported by three attachments that collectively provide the requested data.

Please see U21981-AG-CE-0248_Foster_ATT_1 for the actual expense by Corporate Department.

Please see U-21981-AG-CE-0248_Foster_ATT_2 for expenses that are charged to non-utility businesses using the Mass Formula. The Mass Formula activity shown in the attachment encompasses non-Corporate expenses, including benefit expenses.

Please see U-21981-AG-CE-0248_Foster_ATT_3 for the O&M allocation to the gas utility and electric utility.

b. In addition to the three-factor allocation, O&M costs are allocated between the gas and electric businesses using the following methodologies.
    - O&M programs that are utility specific. For example, Gas skills training is 100% Gas O&M.
    - Customer Count: Electric 51%, Gas 49%
    - Capitalization Ratio: Electric 59%, Gas 41%
    - Bank Balances: Electric 68%, Gas 32%

c. Please see U21981-AG-CE-0248_Foster_ATT_4. The attachment includes eight tabs providing the Mass Formula and three-factor allocation sturdies for 2023 – 2026. The 2027 allocation studies have not been performed.

Witness: Matthew J. Foster
Date: April 3, 2026

U-21981-AG-CE-0248_ATT_3
($000)

Description	2023 Gas Actual	2023 Electric Actual	2024 Gas Actual	2024 Electric Actual	2025 Gas Actual	2025 Electric Actual	2026 Gas Rate Case Forecast	2026 Electric Rate Case Forecast	2027 Gas Rate Case Forecast	2027 Electric Rate Case Forecast
Sustainability & External Affairs	$ 2,529	$ 2,755	$ 3,506	$ 5,007	$ 2,559	$ 4,090	$ 3,690	$ 5,271	$ 3,775	$ 5,392
Legal, Ethics, Regulatory, and Risk	8,784	16,752	8,791	14,013	7,059	11,789	9,254	14,751	9,467	15,090
People & Culture and Learning and Development	12,955	11,700	14,774	9,946	14,343	11,055	15,552	10,470	15,910	10,711
Finance and Shared Services	10,410	17,346	10,752	17,246	10,828	18,157	11,318	18,154	11,579	18,571
General Activities	4,139	6,671	(4,509)	(5,665)	(6,754)	(6,441)	(4,746)	(5,963)	(4,855)	(6,100)
Administration & Other-Gas Portion	1,506	2,100	1,623	2,919	1,889	820	1,709	3,073	1,748	3,144

	12-Mo Ending 2025	12-Mo Ending 2026	10-Mo Ending 2027	Compounded Inflation Rate
Annual inflation rates per Company witness Rayl	2.8%	2.4%	2.3%	7.7%
Number of months in the period	12	12	10	
Pro-rated inflation rate	2.8%	2.4%	1.9%	7.3%

U21981-AG-CE-0252
Page **1** of **1**

Question:

32. Refer to Exhibit A-58 sponsored by Mr. Foster. Please explain what is included in General Activities for Labor and Non-Labor and provide the amounts for each year 2023 to 2025. Explain any variances of 10% or greater year over year.

Response:

Please see U-21981-AG-CE-0252_Foster_ATT_1 for General Activities Labor and Non-Labor.

General Activities Labor Explanations

- Voluntary Separation
    - 2023 – 2024: No Voluntary Separation Plan offered in 2024
- Other Separation
    - 2023 – 24: decrease due to less involuntary separations
    - 2024 – 25: decrease due to less involuntary separations
- Billing Credits
    - 2023 – 24: Lower ASP related billing credits
- EICP
    - 2023 – 24: Increased EICP payment

General Activities Non-Labor Explanations

- Senior Officer
    - 2023 – 24: Increase in leadership consulting and training
    - 2024 – 25: Increase in leadership consulting and training
- Capitalized Credits
    - 2023 – 24: Decreased Credits due to lower non-labor to be allocated to Capital
    - 2024 – 25: Increased Credits due to more non-labor to be allocated to Capital
- Billing Credits
    - 2023 – 24: Lower Pension & Benefit and ASP billing credits

Witness: Matthew J. Foster
Date: April 2, 2026

Consumers Energy Company

U21981-AG-CE-0252-Foster_ATT_1

$(000)

General Activities Labor

Line No.	**Description**	**2023**	**2024**	**2025**
1	Voluntary Separation	12,582	-	-
2	Other Separation	871	521	-
3	Senior Officers	700	736	733
4	Capitalized Credits	(13,541)	(12,588)	(12,714)
5	Billing Credits	(937)	(430)	(460)
6	EICP	7,753	8,991	8,654
7	General Activities Labor	$ 7,428	$ (2,770)	$ (3,787)

General Activities Non-Labor

Line No.	**Description**	**2023**	**2024**	**2025**
8	Senior Officers	293	405	861
9	Capitalized Credits	(1,646)	(1,081)	(1,966)
10	Billing Credits	(1,936)	(1,063)	(1,441)
11	General Activities Non-Labor	$ (3,289)	$ (1,739)	$ (2,546)

U21981-AG-CE-0268
Page **1** of **2**

Question:

48. Refer to lines 11-22 on page 23 of Ms. Grob's direct testimony on health care costs. Please provide the incremental healthcare costs savings achieved each year from 2022 to 2025 and forecasted for 2026 and 2027. Describe how those cost savings were achieved.

Response:

a. Amount listed below are gross amounts before electric/gas splits or capitalization.

2022

- Salaried Active Employee Community Blue PPO & Delta Dental premiums increased
- Implemented SaveOn Pharmacy Benefit with a savings of $1.4M.

2023

- Medical Plan Design Changes – Increase deductible and out-of-pocket limits for Community Blue PPO and Express Scripts Prescription Drug Plans – total savings of $508,000.
- Removal of Aetna Dental – only have coverage through Delta Dental. Projected savings of $85K admin fee and $1.4M in network discount savings. Actual negotiated savings on administrative fees were $70K.
- SaveOn Pharmacy Benefit program projected annual savings of $1.7M.

2024

- Negotiated savings on Medical ASO Negotiated Fees resulted in $31K savings.
- RxC / ESI Renewal Savings resulted in $1.9M savings.
- Life Insurance move to MetLife with a projected savings of $510,000 ($390,000 active basic life and $120,000 retiree life.

2025

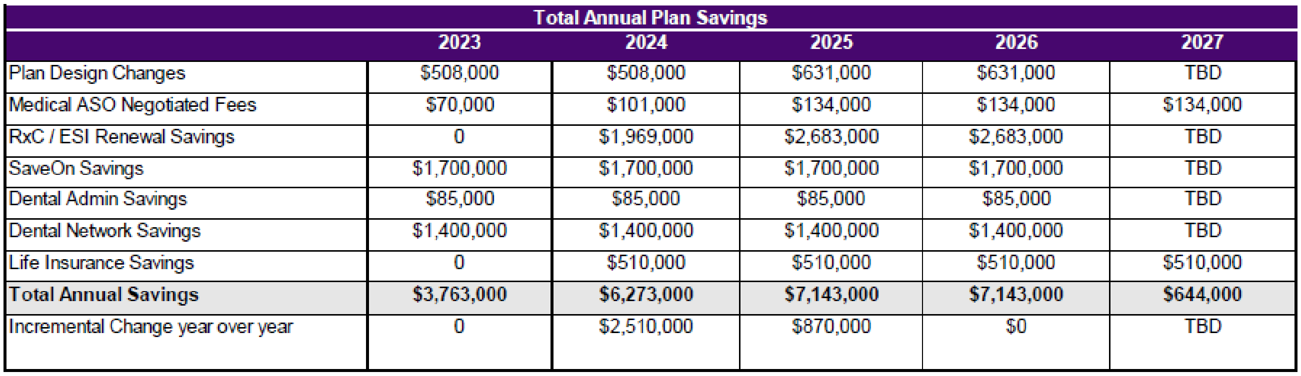
- RxC / ESI Renewal Savings resulted in $.8M savings.

2027

- TBD on most items as items are in contract renewals

Additional details on chart below for years 2023-2027.

U21981-AG-CE-0268
Page **2** of **2**



Total Annual Plan Savings

	2023	2024	2025	2026	2027
Plan Design Changes	$508,000	$508,000	$631,000	$631,000	TBD
Medical ASO Negotiated Fees	$70,000	$101,000	$134,000	$134,000	$134,000
RxC / ESI Renewal Savings	0	$1,969,000	$2,683,000	$2,683,000	TBD
SaveOn Savings	$1,700,000	$1,700,000	$1,700,000	$1,700,000	TBD
Dental Admin Savings	$85,000	$85,000	$85,000	$85,000	TBD
Dental Network Savings	$1,400,000	$1,400,000	$1,400,000	$1,400,000	TBD
Life Insurance Savings	0	$510,000	$510,000	$510,000	$510,000
Total Annual Savings	**$3,763,000**	**$6,273,000**	**$7,143,000**	**$7,143,000**	**$644,000**
Incremental Change year over year	0	$2,510,000	$870,000	$0	TBD

Witness: Kendra K Grob
Date: April 2, 2026

U21981-AG-CE-0264
Page **1** of **1**

Question:

44. For each of the last two completed gas rate cases (U-21806 and U-21490), please provide the following information in Excel:

a. The amount paid to each outside consultant or consulting firm to work on rate case matters and describe what services were provided.

b. The number of hours and labor cost with benefits for Company employees and management working on the rate case from start to completion by department. If actual hours or costs are not tracked or reported, provide a reasonable estimate.

c. The total cost to prepare and complete the rate case from start to completion. If a total actual cost is not tracked or reported, provide a reasonable cost estimate.

Response:

a. There was no outside consulting costs related to Case No. U-21490. Case No U-21806 had $148,847 of consulting costs related to witness Ann Bulkley.
b. This information was not tracked and is not available. Please see the response to U-21981-AG-CE-0265 for the forecasted costs related to the pending gas rate case.
c. This information was not tracked and is not available. Please see the response to U-21981-AG-CE-0265 for the forecasted costs related to the pending gas rate case.

Witness: Heidi J. Myers
Date: April 2, 2026

U21981-AG-CE-0265
Page **1** of **1**

Question:

45. For the current rate case No. U-21981, please provide the following information in Excel:
a. The total amount to be paid to each outside consultant or consulting firm to work on rate case matters and describe what services will be provided. If a total fixed amount is not known, provide the best cost estimate available to completion of the rate case. Explain why Company employees are not able of providing those services.
b. The forecasted number of hours and labor cost with benefits for Company employees and management working on the rate case from start to completion by department. If hours or costs have not been forecasted as part of the Company labor budget, provide a reasonable estimate.

Response:

a. The only consultant in use for the pending gas rate case is Ann Bulkley, who is serving as the return on equity witness. To date, the Company has incurred $17,735 in consulting expense and would anticipate total cost to support this gas rate case to be similar to the cost of supporting the last gas rate case ($148,847). A decision was made when members of the finance organization either retired or left the company to bring in a 3rd party to offer their professional opinion and analysis for purposes of rate cases. At the same time, the Company chose not to replace all the employees that retired or left the company as this work was no longer completed internally. If the Company chose to bring the work back in house, it would need to replace the employees that had left.

b. See Attachment 1.

Witness: Heidi J. Myers
Date: April 2, 2026

U-21981 Forecasted Witness Hours and Cost

	Hours	**Average Hourly Rate with Benefits**	**Cost**
Information Technology	600	68.06	40,837
Gas Operations	4400	68.06	299,469
Capital Structure	75	68.06	5,105
Customer Attachment Program	80	68.06	5,445
EICP/Compensation	115	68.06	7,827
Corporate	350	68.06	23,821
Benefits	100	68.06	6,806
Facilities	95	68.06	6,466
Fleet	250	68.06	17,015
Rates (Revenue Req/Cost/Pricing/Policy/Tariffs)	1725	68.06	117,405
Manufactured Gas Plant	60	68.06	4,084
Sales Forecast	335	68.06	22,800
Tax	100	68.06	6,806
Customer	300	68.06	20,418
Total	8585		$ 584,304

U21981-AG-CE-0414
Page **1** of **1**

Question:

192. Refer to Ms. Conrad's direct testimony on the EICP incentive compensation plan. For each year 2020 to 2025, please provide the target performance for each of the operating measures compared to the actual results for those years in Excel. Identify what percentage of the target performance was achieved.

Response:

See Part III 086 for the target performance for each of the operating measures compared to the actual results for 2020 – 2024. See attachment 1 for 2025.

Witness: Amy M Conrad
Date: April 7, 2026

Non-officer
Annual Incentive Plan

Operational Payout Metrics

Number of goals achieved	0-3	4	5	6	7	8	9
Award %	0%	50%	75%	100%	125%	150%	200%

Operational Payout Metrics

Number of goals achieved	0-3	4	5	6	7	8	9
Award %	0%	50%	75%	100%	125%	150%	200%

Operational Payout Metrics

Number of goals achieved	0-3	4	5	6	7	8	9
Award %	0%	50%	75%	100%	125%	150%	200%

Plan Year	2019				2020				2021			
Metric	**Weighting**	**Target**	**Actual Achieved**	**Actual Payout %**	**Weighting**	**Target**	**Actual Achieved**	**Actual Payout %**	**Weighting**	**Target**	**Actual Achieved**	**Actual Payout %**
Operational	**50%**				**50%**				**50%**			
•**Employee Safety (Incidents or Recordable Incidents Rate)**		54/0.67 or less	105/1.23	Not Met		54/0.67 or less	101/1.22	Not Met		≤ 81	135	Not Met
•**Eliminate Vintage Services**		≥ 9,250	9,635	Met		≥ 9,250	9747	MET		N/A	N/A	N/A
•**Distribution reliability minutes**		≤ 165	233	Not Met		≤ 180	195	Not Met		≤ 180	228	Not Met
•**Generation Customer Value (Fleet Availability)**		≥ 72%	75%	Met		≥ 72%	76%	Met		≥ 76%	76%	Met
•**Customer Experience Index (Forrester Index)**		≥ 71	69	Not Met		≥ 71	76	Met		≥ 78	73	Not Met
•**Employee Empowerment** Index (Employee Empowerment Index, and Maintain top quartile employee engagement)		N/A	N/A	N/A		≥ 57 and 1st quartile employee engagement	≥ 63 and 1st quartile employee engagement	Met		≥ 65 and 1st quartile employee engagement	63 and 1st quartile employee engagement	Not Met
•**Gas Flow Deliverability**		≥ 90%	91%	Met		≥ 92%	94%	Met		≥ 95%	96%	Met
•**Customer On Time Delivery (orders complete within target window)**		≥ 70%	79%	Met		N/A	N/A	N/A		N/A	N/A	N/A
•**Service On Time Delivery (volume/ adherence with target window)**		≥ 65% / ≥ 95%	82%/96%	Met		N/A	N/A	N/A		N/A	N/A	N/A
•**Demand Response**		N/A	N/A	N/A		≥ 469 MW	509 MW	Met		N/A	N/A	N/A
•**Trash to Landfill**		N/A	N/A	N/A		≤ 4,864 TONS	3,794 Tons	Met		N/A	N/A	N/A
•**Cyber Security (phishing click rate)**		≤ 5%	3%	Met		N/A	N/A	N/A		≤ 4%	3%	Met
•**Methane Emmission Reduction** (Reduction of Methane Emissions through replacements of Mains and Services)		N/A	N/A	N/A		N/A	N/A	N/A		≥ 422 MT	447 MT	Met
•**Clean Energy** (Demand Response resources acquired, plus Energy Waste Reduction programs)		N/A	N/A	N/A		N/A	N/A	N/A		≥ 608 MW	733 MW	Met
				50%				63%				38%
Financial												
Earnings Per Share	**35%**	See Officer Annual Incentive		44%	**35%**	See Officer Annual Incentive		47%	**35%**	See Officer Annual Incentive		21%
Operating Cash Flow	**15%**	See Officer Annual Incentive		17%	**15%**	See Officer Annual Incentive		30%	**15%**	See Officer Annual Incentive		18%
				111%				139%				77%

2022 Non-Officer Incentive Compensation Plan Results

Operational Measures	Weighting	50% Threshold	75%	100% Target	125%	150%	175% Max	ACTUAL	Payout %
Employee Safety (Recordable Incidents Rate, High-Risk Injuries[1] & No fatalities[2])	2.50%	a.1.74	a.1.31	**a.1.20**	a.1.15	a.1.10	a.1.03	a.1.17	145%
	2.50%	b. 34	b.32	**b.30**	b.28	b.26	b.24	b.22	
Culture Index (Empowerment, Employee Engagement & DEI)	8.3%	1 index at Target[3]	2 index at Target[3]	**All 3 indexes at Target[3]**	2 indexes at Target &1 Index above Target	1 index at Target & 2 Indexes above Target	3 Indexes above Target	0	0%
Customer Experience (Survey Measuring CXi)	8.3%	69	71	**73**	75	77	79	73	100%
Electric Reliability (SAIDI)	8.3%	190	185	**180**	175	165	152	182	90%
Waste Elimination (Affordability) [4] (O&M Savings through Waste Elimination)	8.3%	$31M	$35M	**$39M**	$43M	$47M	$55M	$58M	175%
Methane Emission (Reduction through replacement of mains and services)	8%	357MT	378MT	**399MT**	420MT	457MT	483MT	448MT	144%
	50%							**TOTAL**	**109%**

Financial	Weighting	25% Threshold	100% Target	200% Maximum	Actual Achieved	Award Payout%
Earnings Per Share	**50%**	$2.71	$2.85	$2.99	$2.89	**160%**

TOTAL EICP Award Payout Level = 135%

1 High-Risk = Recordable or non-recordable injury caused by a release of high energy
2 A fatality = zero payout for employee safety
3 Target = +2 from 2021 actual. Baseline will be reaffirmed in 2022 with move to new survey platform.
4 The Company is not seeking recovery of this measure as it is financial in nature.

2023 Non-Officer Incentive Compensation Plan Results

Operational Measures	Weighting	50% Threshold	75%	100% Target	125%	150%	175% Max	ACTUAL	Payout %
Employee Safety (Recordable Incidents Rate, High-Risk Injuries[1] & No fatalities[2])	2.50%	a.1.65	a.1.28	**a.1.07**	a.0.97	a.0.87	a.0.77	a.1.48	141%
	2.50%	b. 32	b.30	**b.27**	b.25	b.23	b.20	b.10	
Culture Index (Empowerment, Employee Engagement & DEI)	8.3%	1 of 3 indexes at target	2 of 3 indexes at target	**All 3 indexes at target**	2 indexes at target &1 index above target	1 index at target & 2 indexes above target	3 indexes above target	0	0%
Customer Experience (Survey Measuring CXi)	8.3%	66	68	**73**	74	75	80	64	0%
Electric Reliability (SAIDI)	8.3%	185	180	**170**	160	155	150	176	85%
Waste Elimination (Affordability) [3] (O&M Savings through Waste Elimination)	8.3%	$30M	$35M	**$45M**	$50M	$55M	$65M	$79M	175%
Methane Emission (Reduction through replacement of mains and services)	8%	414MT	436MT	**459MT**	485MT	510MT	551MT	533MT	164%
	50%							**TOTAL**	**94%**

Financial	Weighting	25% Threshold	100% Target	200% Maximum	Actual Achieved	Award Payout%
Earnings Per Share	**50%**	$2.95	$3.06	$3.25	$3.11	**140%**

TOTAL EICP Award Payout Level = 117%

---

1 High-Risk = Recordable or non-recordable injury caused by a release of high energy
2 A fatality = zero payout for employee safety
3 The Company is not seeking recovery of this measure as it is financial in nature.

2024 Non-Officer Incentive Compensation Plan Results

Operational Measures	Weighting	50% Threshold	75%	100% Target	125%	150%	175% Max	ACTUAL	Payout %
Employee Safety (Recordable Incidents Rate, High-Risk Injuries[1] & No fatalities[2])	5.83%	a.1.76	a.1.23	**a. 0.96**	a. 0.92	a. 0.86	a. 0.75	1.71	121%
	2.50%	b. 25	b.20	**b.13**	b.12	b.11	b. 10	11	
Culture Index (Empowerment, Employee Engagement & DEI)	8.3%	1 index at Target[3]	2 index at Target[3]	**All 3 indexes at Target[3]**	2 indexes at Target &1 Index above Target	1 index at Target & 2 Indexes above Target	3 Indexes above Target	2 Index at Target	75%
Customer Experience (Survey Measuring CXi)	8.3%	64	67	**69**	71	75	81	64	50%
Electric Reliability (SAIDI)	8.3%	185	180	**170**	160	155	150	155	150%
Waste Elimination (Affordability) [3] (O&M Savings through Waste Elimination)	8.3%	$45M	$55M	**$63M**	$66M	$70M	$74M	$112M	175%
Methane Emission (Reduction through replacement of mains and services)	8.3%	278 MT	290 MT	**302 MT**	335 MT	366 MT	375 MT	472 MT	175%
	50%							**TOTAL**	**124%**

Financial	Weighting	25% Threshold	100% Target	200% Maximum	Actual Achieved	Award Payout%
Earnings Per Share	**50%**	$3.17	**$3.29**	$3.51	$3.34	**136%**

TOTAL EICP Award Payout Level = 130%*

1 High-Risk = Recordable or non-recordable injury caused by a release of high energy
2 A fatality = zero payout for employee safety
3 The Company is not seeking recovery of this measure as it is financial in nature.

*Actual payout was 134% inclusive of a 4% below the line adjustment for non-officers.

2025 Plan Year

Metric	Weighting	50% Threshold	75%	100% Target	125%	150%	175% Max	ACTUAL	Payout %
Employee Safety									
a. Recordable Incidents Rate (30%),	**2.5%**	a.1.24	a.1.12	**a.1.00**	a.0.98	a.0.96	a.0.94	2.34	0%
b. High-Risk Injuries[1] (70%),	**5.8%**	b.20	b.16	**b.12**	b.11	b.10	b.9	9	
c. No fatalities[2]								1	
Culture Index									
a. Employee Engagement (33%),	**8.3%**	a.71	a.72	**a.**73	a.74	a.76	a.78	75	104%
b. Empowerment (33%), &		b.65	b.66	**b.**67	b.68	b.70	b.72	66	
c. Diversity, Equity, & Inclusion (33%)		c.73	c.74	**c.**75	c.76	c.78	c.80	75	
(Overall outcome = avg of each index award)									
Customer Experience [1] (Survey Measuring CXi)	**8.3%**	**64**	**65**	**66**	**68**	**70**	**75**	63	0%
Electric Reliability (SAIDI)	**8.3%**	165 mins	160 mins	155 mins	150 mins	145 mins	140 mins	163 mins	60%
Waste Elimination[3] (O&M Savings through Waste Elimination)	**8.3%**	$44M	$49M	$53M	$58M	$66M	$75M	$102M	175%
Methane Emission Reduction (Reduce fugitive methane emissions associated with gas distribution)	**8.3%**	74 MT	78 MT	82 MT	93 MT	114 MT	135 MT	113 MT	149%
	50%							**TOTAL**	**81%**

1 High-Risk = Recordable or non-recordable injury caused by a release of high energy
2 A fatality = zero payout for employee safety
3 The Company is not seeking recovery of this measure as it is financial in nature.

Financial		Weighting	25% Threshold	100% Target	200% Maximum	Actual Achieved	Award Payout%	Award Payout %
Earnings Per Share		**50%**	$3.41	**$3.54**	$3.76	$3.61	**150%**	**150%**

TOTAL EICP Award Payout Level = 116%

MICHIGAN PUBLIC SERVICE COMMISSION
CONSUMERS ENERGY COMPANY

Exhibit AG-71
Case No. U-21981
April 15, 2026
Page 1 of 1

Computation of Revenue Deficiency for Projected Test Year Ending October 2027

($000)

Line	Description (a)	Company Filed Amount (b)	AG Recommended Adjustments (c)	Revised Amount (d)
1	Rate Base [(1)]	$ 12,488,293	$ (524,838)	$ 11,963,456
2	Rate of Return	6.40%	-0.28%	6.12%
3	Income Required	$ 799,708	$ (67,545)	$ 732,163
4	Adjusted Net Operating Income [(2)]	620,380	41,702	662,082
5	Income Deficiency (Sufficiency)	$ 179,328	$ (109,247)	$ 70,081
6	Revenue Multiplier	1.3381	1.3381	1.3381
7	**Revenue Deficiency (Sufficiency)**	**$ 239,956**	**$ (146,182)**	**$ 93,774**

(1) Rate Base Adjustments Exhibit AG-37.

(2) AG adjustments to Operating Income

			Source
Revenue		$ -	
Lower Forecast of O&M Expenses		42,351	Exhibit AG-55
Property Taxes		4,608	Exhibit AG-37
Depreciation Expense		12,256	Exhibit AG-37
Total		$ 59,215	
Effective Tax Rate (1-1/1.3381)	25.27%		
Taxes		14,961	
Interest Synchronization for cap. Ex. adjustments		(2,551)	AG-71 WP1
Adjusted Net Operating Income		$ 41,702	

PROOF OF SERVICE - U-21981

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 15th day of April 2026.

/s/ Celeste Gill

Celeste R. Gill

Consumers Energy Company:
Spencer Sattler
Gary Gensch, Jr.
Evan Keimach
Bret Totoraitis
Anne Uitvlugt
Michael C. Rampe
Spencer.sattler@cmsenergy.com
Gary.genschjr@cmsenergy.com
Evan.keimach@cmsenergy.com
Bret.totoraitis@cmsenergy.com
Anne.uitvlugt@cmsenergy.com
michael.rampe@cmsenergy.com
Mpsc.filings@cmsenergy.com

Attorney General of Michigan:
Celeste Gill
Gillc1@michigan.gov
ag-enra-spec-lit@michigan.gov

Sebastian Coppola
sebcoppola@corplytics.com

Energy Michigan:
Timothy Lundgren
Laura Chappelle
Haylee Skank
tjlundgren@varnumlaw.com
lachappelle@varnumlaw.com
hnskank@varnumlaw.com

ALJ:
Hon. Lesley Fairrow
Fairrowl1@michigan.gov

MEC/CUB/SC:
Christopher Bzdok
Holly Hillyer
Sean Clark
Natasha Fowles
chris@tropospherelegal.com
holly@tropospherelegal.com
sean@tropospherelegal.com
natasha@tropospherelegal.com

MPSC Staff:
Lori Mayabb
Amit Singh
Alena Clark
Adam Cozort
Nicholas Taylor
Monica Stephens
mayabbl@michigan.gov
singha9@michigan.gov
clarka55@michigan.gov
cozorta1@michigan.gov
taylorn10@michigan.gov
stephensm11@michigan.gov

LBWL/MSU:
Nolan Moody
Cole Lussier
nmoody@dickinsonwright.com
clussier@dickinsonwright.com

ABATE:
Stephen Campbell
Michael Pattwell
Benjamin Holwerda
Lauren Degnan
scampbell@clarkhill.com
mpattwell@clarkhill.com
bholwerda@clarkhill.com
ldegnan@clarkhill.com

LBWL:
Jason D. Hawkins
Jason.hawkins@lbwl.com

RESA:
Jennifer Heston
jheston@potomaclaw.com