

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21806

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

Revised Direct Testimony

And Exhibits

of

Sebastian Coppola

On behalf of

Attorney General Dana Nessel

April-May 23, 2025

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1 **I. Introduction**

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

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

5 **Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.**

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

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

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

- 3 ○ Filed testimony on behalf of the Michigan Attorney General in Michigan Gas
4 Utilities Corporation (MGUC) 2023-2024 GCR reconciliation in case No. U-
5 21274.
- 6 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
7 Company (DTEE) 2023 PSCR reconciliation in case No. U-21260.
- 8 ○ Filed testimony on behalf of the Michigan Attorney General in Consumers
9 Energy Company (CECo) 2023-2024 GCR reconciliation in case No. U-21270.
- 10 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy
11 Gas Company (SEMCO) 2023-2024 GCR plan reconciliation in case No. U-
12 21278.
- 13 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2023
14 PSCR reconciliation in case No. U-21258.
- 15 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2024
16 electric rate case U-21585 on several issues, including operation and
17 maintenance expenses, capital expenditures, cost of capital, and other items.
- 18 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2024
19 electric rate case U-21534 on several issues, including operation and
20 maintenance expenses, capital expenditures, cost of capital, and other items.
- 21 ○ Filed testimony on behalf of the Michigan Attorney General in the Upper
22 Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several
23 issues, including operation and maintenance expenses, capital expenditures, cost
24 of capital, and other items.
- 25 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2024 gas
26 rate case U-21540 on several issues, including operation and maintenance
27 expenses, capital expenditures, cost of capital, and other items.
- 28 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy
29 Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- 30 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas
31 Company (DTE Gas) 2024 gas rate case U-21291 on several issues, including
32 sales, operation and maintenance expenses, capital expenditures, cost of capital,
33 and other items.
- 34 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-
35 2023 GCR reconciliation in case No. U-21065.

- 1 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2023 gas
2 rate case U-21490 on several issues, including sales, operation and maintenance
3 expenses, capital expenditures, cost of capital, and other items.
- 4 ○ Filed testimony on behalf of the Michigan Attorney General in DTM Michigan
5 Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in
6 case No. U-21525.
- 7 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
8 Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- 9 ○ Filed testimony on behalf of the Michigan Attorney General in Michigan Gas
10 Utilities Corporation (MGUC) 2022-2023 GCR reconciliation case No. U-
11 21067.
- 12 ○ Filed testimony on behalf of the Michigan Attorney General in Consumers
13 Energy Company (CECo) 2022 PSCR reconciliation in case No. U-21049.
- 14 ○ Filed testimony on behalf of the Michigan Attorney General in the Indian
15 Michigan Power Company's 2023 electric rate Case U-21461 on several issues,
16 including sales, operation and maintenance expenses, capital expenditures, cost
17 of capital, and other items.
- 18 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas
19 Company (DTE Gas) 2023-2024 GCR plan in case No. U-21271.
- 20 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2023-
21 2024 GCR plan in case No. U-21269.
- 22 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2023
23 electric rate Case U-21389 on several issues, including operation and
24 maintenance expenses, capital expenditures, cost of capital, and other items.
- 25 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy
26 Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- 27 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
28 Company (DTEE) 2023 rate Case U-21297 on several issues, including
29 operation and maintenance expenses, capital expenditures, cost of capital, and
30 other items.
- 31 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-
32 2024 GCR plan in case No. U-21273.
- 33 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas
34 rate Case U-21308 on several issues, including sales revenues, operation and
35 maintenance expenses, capital expenditures, cost of capital, and other items.

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

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

2 A. I have been asked by the Michigan Department of Attorney General to perform an
3 independent analysis of Consumers Energy Company's (CECo or the Company) gas rate
4 case filing in Case No. U-21806. This testimony presents a report of that analysis with
5 related recommendations.

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

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

- 8 1. The level of proposed rate base and capital expenditures
- 9 2. The amount of working capital
- 10 3. The Company's cost of capital
- 11 4. Adjustments to forecasted transportation volumes and related revenues for the
12 projected test year
- 13 5. The level of operations and maintenance expenses
- 14 6. Depreciation and property tax adjustments
- 15 7. Rate design issues
- 16 8. Deferral of certain costs proposed by the Company.

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

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

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

- 3 1. Exhibit AG-1 CMS Energy Investor Presentations
- 4 2. Exhibit AG-2 New Service Connections
- 5 3. Exhibit AG-3 Asset Relocations-Civic
- 6 4. Exhibit AG-4 Asset Relocations-Reimbursable
- 7 5. Exhibit AG-5 Regulatory Compliance MAOP projects
- 8 6. Exhibit AG-6 PHMSA Rule on MAOP
- 9 7. Exhibit AG-7 EIRP Miles Retired, Installed and Costs
- 10 8. Exhibit AG-8 EIRP Large Projects Development Phase
- 11 9. Exhibit AG-9 EIRP Completion Extension
- 12 10. Exhibit AG-10 Material Condition Non-Modeled Projects
- 13 11. Exhibit AG-11 Vintage Services Replacement Program
- 14 12. Exhibit AG-12 LDAR Rule and Advanced Methane Detection
- 15 13. Exhibit AG-13 ECAP Cap Ex Projects
- 16 14. Exhibit AG-14 Utility Network IT Project
- 17 15. Exhibit AG-15 Transmission Pipeline Integrity Projects
- 18 16. Exhibit AG-16 Transmission MAOP Projects
- 19 17. Exhibit AG-17 Transmission Asset Relocation projects
- 20 18. Exhibit AG-18 Transmission Field Measurement Projects
- 21 19. Exhibit AG-19 Transmission Pipeline Deliverability Projects
- 22 20. Exhibit AG-20 Transmission Citygate Stations
- 23 21. Exhibit AG-21 Transmission Remote Closure Valves
- 24 22. Exhibit AG-22 Northville Dehydration Project
- 25 23. Exhibit AG-23 Storage New Well Projects
- 26 24. Exhibit AG-24 Storage and Compression Projects
- 27 25. Exhibit AG-25 Storage and Compression Large Projects
- 28 26. Exhibit AG-26 Storage and Compression 2024 Underspent
- 29 27. Exhibit AG-27 Tracking and Traceability IT Project
- 30 28. Exhibit AG-28 CONF ERP IT Project

- 1 29. Exhibit AG-29 ERP IT Project Features
- 2 30. Exhibit AG-30 IT Servers and Equipment Replacement
- 3 31. Exhibit AG-31 IT Project Forward Web Proxy Services
- 4 32. Exhibit AG-32 IT Projects 2024 Underspent
- 5 33. Exhibit AG-33 Transportation Fleet Purchases
- 6 34. Exhibit AG-34 CONF Revised AG Capex, Rate Base, Depreciation, Property Taxes
- 7 Adjust.
- 8 35. Exhibit AG-35 CONF Working Capital Adjustments Summary
- 9 36. Exhibit AG-36 Working Capital – Cash On Hand Balances
- 10 37. Exhibit AG-37 CONF W/C SAP S/4 Cloud Implementation Costs
- 11 38. Exhibit AG-38 W/C Cloud Computing Amortization Corrected
- 12 39. Exhibit AG-39 W/C Riverside Storage Field Loss Amortization
- 13 40. Exhibit AG-40 W/C Accrued Taxes
- 14 41. Exhibit AG-41 Overall Cost of Capital
- 15 42. Exhibit AG-42 Cost of Common Equity
- 16 43. Exhibit AG-43 Cost of Common Equity-DCF
- 17 44. Exhibit AG-44 Cost of Common Equity-CAPM
- 18 45. Exhibit AG-45 Cost of Common Equity-Risk Premium
- 19 46. Exhibit AG-46 Peer Group Utility and Non-Utility Business Mix
- 20 47. Exhibit AG-47 Market to Book Ratios of Peer Group
- 21 48. Exhibit AG-48 ROE Decisions by Regulatory Commissions
- 22 49. Exhibit AG-49 Cash Flow to Debt Coverage Ratio Recalculation
- 23 50. Exhibit AG-50 Peer Group ROEs
- 24 51. Exhibit AG-51 Rating Agencies Reports
- 25 52. Exhibit AG-52 Value Line Market Volatility Not Risk
- 26 53. Exhibit AG-53 Gas Sales Analysis
- 27 54. Exhibit AG-54 Transportation Revenue Adjustments
- 28 55. Exhibit AG-55 Transportation Volume Decline Not Explained
- 29 56. Exhibit AG-56 CONF Revised O&M Summary Adjustments
- 30 57. Exhibit AG-57 Distribution Pipeline Integrity, Lean Office, AMD
- 31 58. Exhibit AG-58 EIRP Training

- 1 59. Exhibit AG-59 Transmission Corrosion Control and MAOP Expense
2 60. Exhibit AG-60 Customer Service, Analytics and Digital
3 ~~61. Exhibit AG-61 Revised Act 9 Transportation Volume Credits~~
4 ~~62. Exhibit AG-62 Recalculation of Com Use and LAUF Gas Expense~~
5 63. Exhibit AG-63 Voluntary Separation Program Cost Savings
6 ~~64. Exhibit AG-64 Corporate Expenses and General Activities 2021 PTY~~
7 65. Exhibit AG-65 Health Care Cost Savings
8 66. Exhibit AG-66 Incentive Compensation Operating Measures Results
9 67. Revised Exhibit AG-67 AG Revised Revenue Requirement

10 **II. SUMMARY CONCLUSIONS & RECOMMENDATIONS**

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

14 A. The Company filed for a rate increase of \$248 million. The rate increase represents an
15 overall increase in base rates of 16% and an increase in residential base rates also of 17.6%.
16 Including the cost of gas, the average residential gas bill would increase by approximately
17 12%. I have identified several cost disallowances to the Company’s proposed cost levels
18 and capital projects, that I recommend the Commission approve. As a result of these
19 adjustments, I have determined that the Company has a revenue deficiency of ~~\$76.5~~95.6
20 million. It should be noted that the Company reported a revenue sufficiency (surplus) of
21 \$9.4 million in 2023. The Company also achieved a Return on Common Equity of 10.08%
22 in 2023.¹ My conclusions and related adjustments are summarized below:

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

1. I recommend a reduction in capital expenditures of ~~\$563~~\$533 million and a reduction of ~~\$535~~\$514.7 million to rate base for the test year, including a \$154 million adjustment to working capital. This reduces the Company's revenue deficiency by ~~\$42.7~~\$41.1 million.
2. I recommend that the Commission adopt a lower cost of capital rate of 5.97%, a capital structure with 50% equity capital and a return on common equity of 9.75%. These recommendations reduce the Company's revenue deficiency by \$39.2 million.
3. I recommend higher commercial transportation gas deliveries, which increase distribution margin revenue by \$1.8 million.
4. I recommend a lower level of Operations and Maintenance expenses for the test year. This reduces the Company's revenue deficiency by ~~\$73.3~~\$56.4 million.
5. I recommend a lower amount of depreciation expense of ~~\$13.7~~\$13.3 million and lower property tax expense of ~~\$3.9~~\$3.7 million pertaining to the lower capital expenditures and additions to plant discussed above. These adjustments reduce the revenue deficiency by the same amount.
6. I recommend that the Commission retain the residential monthly customer charge remain at \$15.00.
7. I recommend that the Commission retain the General Service GS-1 monthly customer charge at \$18.00.
8. I recommend that the Commission reject several of the accounting cost deferral and premature or unnecessary.

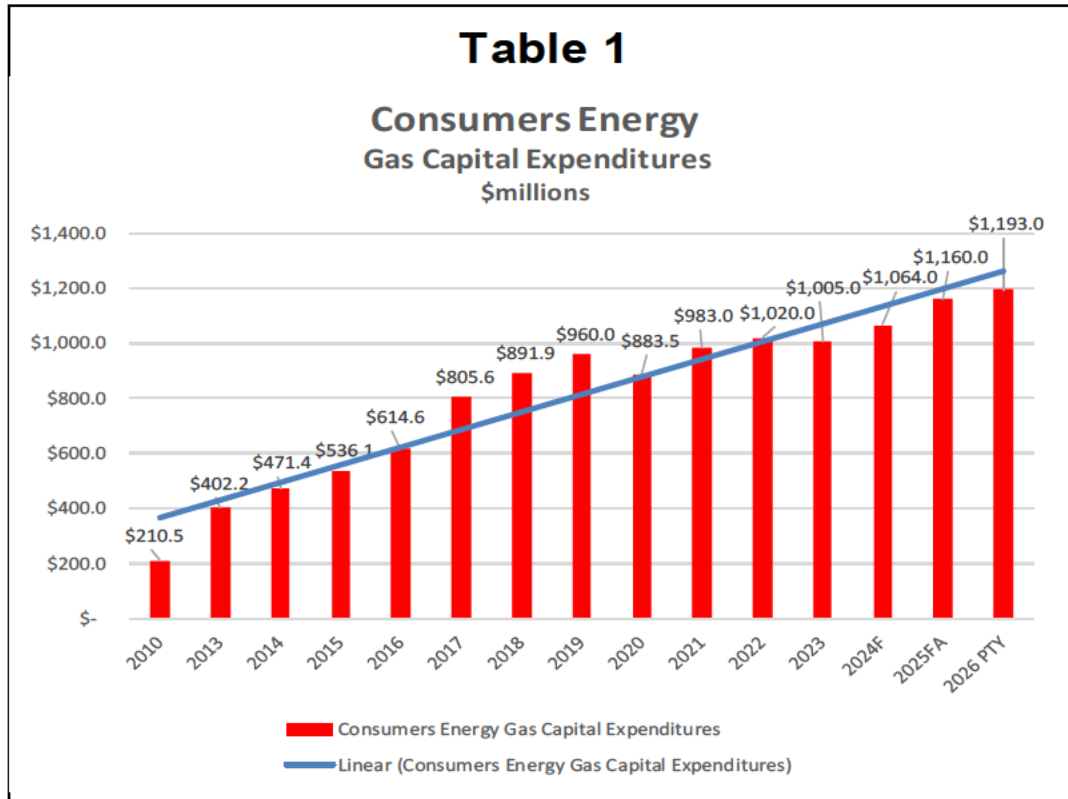
The remainder of my testimony provides further details and support to these summary conclusions and recommendations.

1 **III. LARGE INCREASE IN RATE BASE**
2 **AND CAPITAL EXPENDITURES**

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

6 A. In this general rate case, CECo has proposed capital expenditures of \$1.0 billion for 2023,
7 \$1.1 billion for 2024, \$967 million for the 10 months ending October 2025 (\$1.2 billion
8 annualized), and an additional \$1.2 billion for the 12 months ending October 2026. These
9 increases are in addition to capital expenditures of \$2.9 billion made during the prior three
10 years from 2020 to 2022.² The following chart in Table 1 shows the dramatic increase in
11 capital expenditures over recent years in comparison to more moderate amounts in prior
12 years.

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



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Until 2010, the Company was able to keep capital expenditures around \$200 million annually. By 2022, about twelve years later, the level of capital expenditures has increased five-fold to \$1.0 billion and continues at this high level into 2023 through 2026.

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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 24% to \$11.8 billion over the 2023 historical rate base.

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Table 2 Consumers Energy Gas Rate Base Growth 2010 to Projected 2026 Test Year											
Rate Base Year	2010	2014	2015	2016	2017	2018	2020	2021	2022	2023	2026TY
Docket No.	U-16855	U-17882	U-18124	U-18424	U-20322	U-20650	U-21148	U-21308	U-21490	U-21806	U-21806
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	\$ 11,751.0
Year over Year Change		15%	8%	10%	14%	13%	31%	13%	13%	9%	24%
Cumulative Change over 2010 Rate Base		15%	24%	37%	56%	77%	131%	161%	194%	222%	299%

¹ Historical actual rate base in each docket, except Case No. U-21608 Test Year proposed amount.

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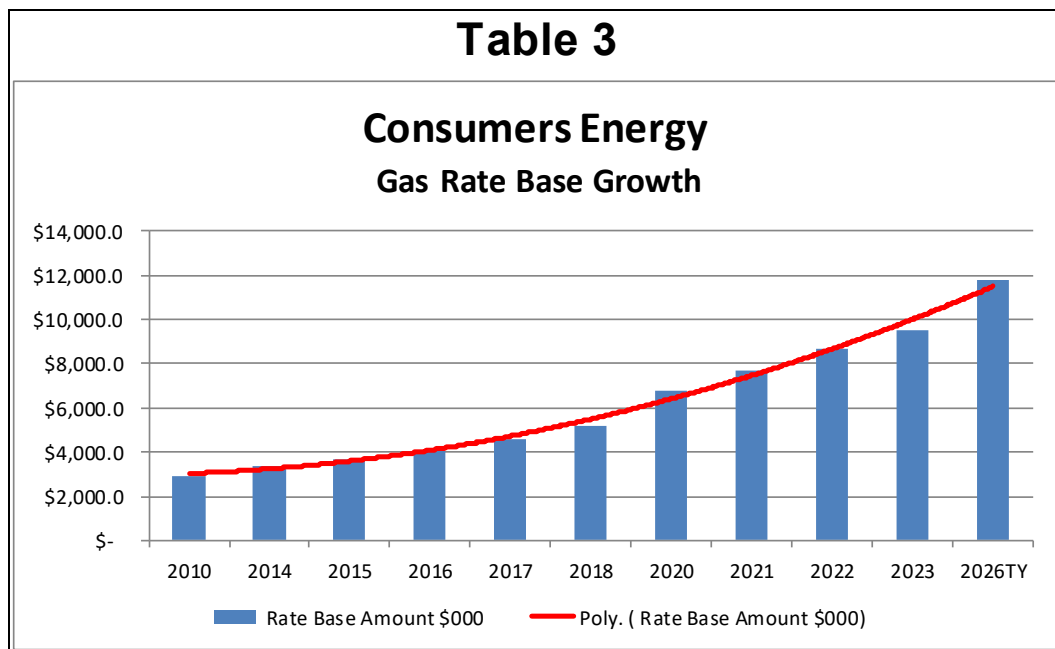
The significant increase in rate base is illustrated by the following chart included in Table

3

3, which shows the exponential trend of increases in recent years.³ The current trend has

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significant negative implications on customer bills as discussed later in my testimony.



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

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

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

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

18 Second and perhaps a bigger driver is that the replacement of aging gas transmission,
19 storage and distribution infrastructure has given the Company an opportunity to accelerate
20 rate base growth to increase earnings growth. For utility companies, earnings growth is
21 directly related to rate base growth. As shown in the tables above, large increases in capital

1 expenditures result in double digit increases in rate base which in turn fuels earnings growth,
2 dividend growth, and stock price appreciation for shareholders.

3 The Company's executive management team, which is largely the same for Consumers
4 Energy and for CMS Energy, has been quite clear and aggressive in communicating to
5 investors and securities analysts its goal of increasing earnings per share at an average
6 annual rate of 6% to 8%. For a utility such as CECo with limited gas sales and revenue
7 growth, the increase in earnings per share comes almost entirely from the increase in capital
8 expenditures and rate base. Exhibit AG-1 includes pertinent sections of a CMS Energy's
9 presentation to investors and securities analysts in March 2025 where Company
10 management communicated its earnings per share, capital expenditures growth goals and
11 achievements. Other recent presentations tell the same story. The presentations point to
12 only gas sales or revenue growth of 1-3%, which does not get anywhere close to propel
13 earnings per share growth of 6% to 8% without higher rate base growth.

14 Even more troubling is management's recent pronouncement forecasting \$20 billion in
15 capital spending over the next 5 years with a large portion of that amount coming from the
16 gas utility. Management has also communicated that capital spending opportunities exist
17 in excess of \$50 billion in the coming years. Exhibit AG-1 shows this forecast along with
18 other supporting information.

19 **Q. HAVE YOU DETERMINED WHAT THE IMPACT ON RESIDENTIAL**
20 **CUSTOMER BILLS COULD BE OVER THE COMING YEARS IF THE**

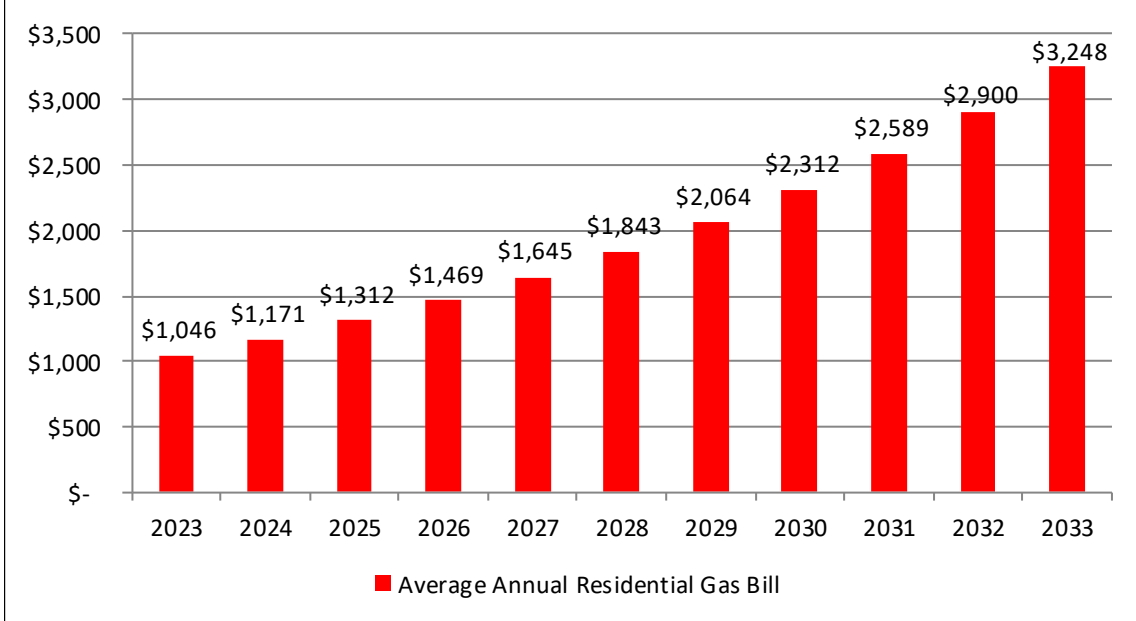
1 **COMMISSION APPROVES THE PROPOSED RATE INCREASE AND THAT**
2 **RATE OF INCREASE CONTINUES INTO FUTURE YEARS?**

3 A. Yes. Based on the 2023 sales revenue filed by the Company in this rate case, the average
4 annual gas bill for residential customers was \$1,046.⁴ As shown in Table 2 above, the
5 Company’s rate base has been growing in double digits and for the past 10 years from 2015
6 through the end of the 2026 projected test year at an average annual rate of 12%. If we
7 assume that the Company will continue the current pace of capital expenditures and annual
8 rate base growth of 12% annually, this growth rate accompanied by increases in operating
9 expenses will more than double the actual 2023 annual gas bill of \$1,046 in 10 years to
10 \$3,248 by 2033. Table 4 below shows the potential increase in the average residential gas
11 bill if the current trend in rate base growth continues, and the price of natural supply remains
12 the same as in 2023. Although gas prices have abated since 2022, with increased demand
13 for natural gas and limited gas supply, they could reach or surpass those prices in future
14 years.

⁴ Exhibit A-16, Schedule F2, shows residential revenue of \$1,631,131,000 for 2023. The Company had 1,559,943 residential customers for the year (Exh. A-5, Schedule E-2}, which calculates to the actual average residential gas bill of \$1,046 for the year.

Table 4

Consumers Energy Average Annual Residential Gas Bill



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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.

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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.

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1 **IV. Review of Capital Expenditures**

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

4 A. Yes. I have analyzed the Company’s forecasted capital expenditures by major department
5 or area, and I have identified reasonable expenditure levels that the Commission should
6 adopt. In projecting adjusted capital expenditures for 2025 and the projected test year
7 where applicable I applied an inflation factor to the historical cost base to reflect
8 inflationary cost pressure that the Company may face in those years. The inflation factors
9 are 2.4% for 2025 and 2.5% for 2026. These rates reflect the increase in the forecasted
10 Consumer Price Index during the 2025-2026 periods as shown in the S&P Global Market
11 Intelligence Forecast provided by the Company.⁵

12 **A. Distribution Plant**

13 In Exhibit A-12 (LDW-1), Schedule B-5.8, the Company forecasted capital expenditures
14 for various Distribution Plant capital programs of \$204.6 million for 2024, \$227.2 million
15 for the 10 months ending October 2025, and \$321.1 million for the 12 months ending
16 October 2026. In comparison, the Company spent \$212.9 million in 2023. In my
17 testimony below, I will discuss certain programs where adjustments to the proposed capital
18 expenditures should be made.

⁵ Exhibit AG-3 includes WP-HLR-33 with the S&P Global Market Intelligence forecast report.

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1. Mains, Services and Meter Stands

As shown in Exhibit A-101 (LDW-2), within the Distribution New Business Program, the Company forecasted capital expenditures for the Mains, Services and Meter Stands subprogram of \$55.3 million for 2024, \$49.6 million for the 10 months ending October 2025, and \$61.7 million for the 12 months ending October 2026. Company witness Lincoln Warriner discusses this subprogram beginning on page of 12 of his direct testimony. The Company also refers to this subprogram as new service connections.

On page 13 of his direct testimony, Mr. Warriner states that the Company forecasted 6,800 new service connections for both 2024 and 2025, and 7,000 new connections for 2026. For the 12 months ending October 2026, Mr. Warriner forecasted 6,964 new services to support his forecasted capital expenditures of \$61,682,000. On page 14 of his testimony, Mr. Warriner outlines the number of new service connections installed in prior years with the most recent year of 2023 reported at 6,870 new connections.

Q. DO YOU AGREE WITH THE COMPANY’S FORECASTED CAPITAL EXPENDITURES FOR THE 2025 BRIDGE PERIOD ENDING OCTOBER 2025 AND THE PROJECTED TEST YEAR?

A. No. In discovery, the Attorney General asked the Company to provide the actual number of new service connections installed in 2024 along with other pertinent data about new housing starts in Michigan that would inform a more accurate forecast of new service connections for 2025 and 2026. In response, the Company reported that the actual number

1 of new service connections for 2024 was 5,950 or nearly 13% lower than the Company's
2 forecast of 6,800 units.⁶ The Company also provided the forecast of new Michigan
3 housing starts compiled by S&P Global Market Intelligence as of February 2025. The
4 report forecasts an increase in Michigan housing starts of 6.3% for 2025 and a decline of
5 7.9% in 2026.⁷ Housing starts and new service connections are sensitive to mortgage
6 interest rates. The general expectation by economists and home buyers has been that
7 mortgage interest rates would decline further in 2025 and in subsequent years. However,
8 persistently high inflation rates and other economic factors have prevented the Federal
9 Reserve Bank from lowering interest rates further with no clear expectation currently of
10 further declines in 2025. Therefore, the Company's forecast that new service connections
11 would rebound to 6,800 units in 2025 and 7,000 units in 2026 from the actual 5,950 units
12 completed in 2024 is no longer realistic.

13 **Q. WHAT IS YOUR FORECAST FOR NEW SERVICE CONNECTIONS FOR 2025**
14 **AND 2026 AND THE RELATED CAPITAL EXPENDITURES?**

15 A. Although the S&P Global forecast of Michigan housing starts shows an increase of 6.3%
16 in 2025 followed by a decline of 7.9% in 2026, over the two-year period there is a net
17 decline of approximately 2% over the level of housing starts in 2024. Instead of
18 forecasting a decline over this timeframe, I have taken a conservative approach and

⁶ Exhibit AG-2 includes DR AG-CE-0340.

⁷ Id. includes DR AG-CE-0341 Partial.

1 forecasted that new service connections for 2025 and 2026 will be similar to the 5,950
2 units reported for 2024.

3 Based on this revised forecast, I calculated that capital expenditures for 2025 would be
4 \$52,658,000 using the Company's forecasted unit cost of \$8,850.⁸ The amount pertaining
5 to the 10-month bridge period ending October 2025 is \$43,882,000 ($\$52,658,000 \times 10/12$).
6 This amount is \$5,714,000 lower than the Company's forecast of \$49,596,000.

7 For 2026, the forecasted capital expenditures are \$53,865,000 (5,950 units x \$9,053). For
8 the 12 months ending October 2026, the forecasted capital expenditures are \$53,664,000.⁹
9 This amount is \$8,018,000 lower than the \$61,682,000 forecasted by the Company.

10 **Q. ON PAGE 15 OF HIS DIRECT TESTIMONY, MR. WARRINER DISCUSSES**
11 **FORECASTS OF HOUSING PERMITS AND U.S. HOUSING STARTS TO**
12 **SUPPORT HIS FORECAST FOR NEW SERVICE CONNECTIONS FOR 2025**
13 **AND 2026. WHAT ARE YOUR OBSERVATIONS?**

14 A. As I have stated in my testimony in previous rate cases on this subject, forecasts of housing
15 permits are not as a reliable predictor of new service connections as housing starts. The
16 forecast of housing permits anticipates a level of new housing construction that is usually
17 issued months ahead of the start of construction while housing starts reflect the near term

⁸ Unit cost from Table 5 on page 19 of Mr. Warriner's direct testimony, (5,950 units x \$8,850 = \$52,658,000).

⁹ ($\$53,865,000 \times 10/12$) + ($\$52,658,000 \times 2/12$) = 53,664,000.

1 start of construction. Therefore, housing starts are a better predictor of the level and timing
2 of new service line installation activity for the forecasted periods.

3 Regarding the Company's use of forecasted U.S. housing starts, this forecast is too far
4 removed from what is likely to occur in Michigan given the significant migration of
5 population to southern and southwestern states and the large increases in new housing in
6 those areas of the country. The forecast of Michigan housing starts I used is more pertinent
7 to the level of housing activity and new service connections that the Company will face in
8 its Michigan service area.

9 **Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANY'S**
10 **FORECASTED CAPITAL EXPENDITURES FOR 2024 FOR NEW SERVICE**
11 **CONNECTIONS?**

12 A. Yes. As stated above, the Company forecasted a higher number of new service
13 connections for 2024 than it actually installed and included higher capital expenditures in
14 this rate case than it actually incurred. The Company forecasted that it would incur capital
15 expenditures of \$55,338,000 for 2024 when it actually incurred only \$52,271,000 for the
16 year.¹⁰ The difference of \$3,067,000 should be removed from the Company's forecasted
17 capital expenditures in this rate case. Customers should not pay for costs the Company
18 did not incur, including the return on investment, depreciation expense, and property taxes
19 that the Company would recover if those costs were not removed from rate base. In prior

¹⁰ DR SA-CE-399 for 2024 actual. Exhibit A-101, page 1, line 1 for the forecasted amount.

1 rate cases, the Commission has ruled that forecasted costs for the bridge period not
2 incurred by the Company should not be included in rate base and in the calculation of new
3 rates. Therefore, I recommend that \$3,067,000 of capital expenditures be removed from
4 the Company's forecasted 2024 capital expenditures.

5 **Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO**
6 **THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR NEW**
7 **SERVICE CONNECTIONS?**

8 A. As discussed above, I recommend that the Commission remove \$3,067,000 for 2024,
9 \$5,714,000 for the 10 months ending October 2025, and \$8,018,000 for the projected test
10 year from the Company's forecasted capital expenditures.

11 **2. Large New Business Projects**

12 As shown in Exhibit A-101 (LDW-2), the Company forecasted capital expenditures for
13 the Large New Business Projects subprogram of ~~\$8.7~~\$9.7 million for 2024, \$3.1 million
14 for the 10 months ending October 2025, and nearly \$5.0 million for the 12 months ending
15 October 2026. Company witness Lincoln Warriner discusses this subprogram beginning
16 on page of 22 of his direct testimony.

17 In response to discovery, the Company provided a list of seven projects that it expected to
18 complete between 2024 and the end of the projected test year. In addition, the Company
19 identified \$4,778,000 of capital expenditures for unspecified large projects that could arise

1 during the projected test year but that are undetermined and not yet known.¹¹ These
2 projects are currently unknown, and the Company has included an amount as simply a
3 placeholder for projects that may or may not occur in the future. The Commission has
4 ruled in prior rate cases that placeholder amounts should not be included in rate base given
5 that they do not pertain to known projects and the large uncertainty of whether those capital
6 expenditures will be incurred by the Company. Therefore, my recommendation is that the
7 \$4,778,000 should be removed from the capital expenditures forecasted by the Company
8 for the projected test year.

9 Regarding the seven identified projects, the Company reported that for two of the projects
10 no contracts have yet been signed with the customers. The first project is with the Lansing
11 BW&L for the Delta Energy Park and the contract is still in progress. The second project
12 is for an industrial site development and no contract has been initiated. The two projects
13 represent capital expenditures of \$2,054,000 for the 10 months ending October 2025 and
14 \$124,000 for the projected test year. Given that the contracts have not yet been finalized,
15 the capital expenditures for the two projects are still very preliminary and uncertain.

16 Given the uncertainty with the two projects, it is premature to include those capital
17 expenditures in rate base in this rate case. If the project costs are not removed the Company
18 would recover the return on investment, depreciation expense, and property taxes it has
19 not actually incurred. If the Company actually incurs the capital spending, it can include
20 those amounts in the next rate case when they are known. Therefore, I recommend that

¹¹ Exhibit AG-2 includes DR AG-CE-0346 with ATT_1.

1 the capital expenditures of \$2,054,000 for the 10 months bridge period and the \$124,000
2 for the projected test year be removed for the Company forecasted capital expenditures.

3 **Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE COMPANY'S**
4 **FORECASTED CAPITAL EXPENDITURES FOR LARGE NEW BUSINESS**
5 **PROJECTS FOR 2024?**

6 A. Yes. As shown in the attachment to DR AG-CE-0346 (Exhibit AG-2), the Company
7 forecasted that it would incur capital expenditures of \$9,709,000 for 2024 when it actually
8 incurred only \$7,761,000 for the year. The difference of \$1,948,000 should be removed
9 from the Company's forecasted capital expenditures in this rate case. Customers should
10 not pay for costs the Company did not incur, including the return on investment,
11 depreciation expense, and property taxes that the Company would otherwise recover if
12 those costs are not removed from rate base.

13 **Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO**
14 **THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR LARGE**
15 **NEW BUSINESS PROJECTS?**

16 A. I recommend that the Commission remove \$1,948,000 for 2024, \$2,054,000 for the 10
17 months ending October 2025, and \$124,000 for the projected test year from the Company's
18 forecasted capital expenditures.

1 **3. Asset Relocation**

2 I am addressing two subprograms under Asset Relocation. As shown in Exhibit A-102
3 (LDW-2), the Company forecasted capital expenditures for the Asset Relocation-Civic
4 Improvement subprogram of \$64.1 million for 2024, \$63.6 million for the 10 months
5 ending October 2025, and \$82.2 million for the 12 months ending October 2026. For the
6 Asset Relocation-Reimbursable subprogram, the Company forecasted capital expenditures
7 of \$22.7 million for 2024, \$12.2 million for the 10 months ending October 2025, and \$16.6
8 million for the 12 months ending October 2026. Company witness Lincoln Warriner
9 discusses these subprograms beginning on page of 25 of his direct testimony.

10 Regarding Civic Improvements, in discovery, the Attorney General and the Commission
11 Staff (Staff) asked the Company to expand the information provided in Mr. Warren’s direct
12 testimony and provide the number of projects and related forecasted capital expenditures
13 for each year 2024 to 2026 along with the basis for developing those forecasts. The
14 Attorney General also requested that the Company provide the actual number of projects
15 and related spending for 2024. In response, the Company provided the actual number of
16 projects for 2019 to 2023 and the forecasted numbers for 2014 to 2026 with related capital
17 expenditures. However, the Company could not provide the actual number of projects and
18 capital spending for 2024 before preparation of this testimony, claiming that the
19 accumulation of this information was still in progress.

1 In response to Staff Audit Request SA-CE-402, the Company also explained that the
2 Company forecasted costs were based on prior years' historical experience with a 3%
3 annual growth rate.

4 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S FORECASTED CAPITAL**
5 **EXPENDITURES FOR ASSET RELOCATION-CIVIC IMPROVEMENT?**

6 A. Based on the analysis below, I found the Company's forecasted capital expenditures for
7 Civic Improvements to be significantly overstated. The forecasted capital spending should
8 reflect the level of work activity that the Company plans to undertake during the respective
9 periods. For this program, the level of activity is reflected in the number of planned
10 projects, the number of feet of distribution main replaced/installed, and the number of
11 services to be relocated. The attachment to SA-CE-402 shows that on average for the three
12 years 2022-2024 the Company completed or planned to complete 154 projects and install
13 or planned to install 201,945 feet of main and 1,787 service lines. In this calculation, I
14 used the Company's forecasted 2024 numbers instead of actual number due to the
15 Company's inability to provide timely actual data.

16 In comparison, for 2025 the Company plans to complete 22 more projects than the 3-year
17 average but install only 145,330 feet of main and 1,689 services. The fewer feet of main
18 and services planned for 2025 represent a reduction of 28% and 5%, respectively from the
19 levels installed on average in the prior three years. Similarly, for 2026, the Company plans
20 to do more projects but still install fewer feet of main and services than the 2022-2024
21 three-year average. The reduction is 18% for mains and 3% for services. However, the

1 Company's forecasted capital spending does not track with the level of work activity
2 planned.

3 **Q. DID YOU CALCULATE AN APPROPRIATE LEVEL OF CAPITAL SPENDING**
4 **FOR 2025 AND 2026 THAT REFLECTS THE LEVEL OF WORK ACTIVITY?**

5 A. Yes. The largest driver of capital spending for relocation projects is the number of feet of
6 main to be relocated and replaced with the number of services to be replaced adding to
7 that cost. Although the Company did not provide the cost split between relocating mains
8 and services, I calculated the cost of relocating and replacing services at \$11,267,000 for
9 2025 and \$12,857,000 for 2026.¹² These amounts are based on the cost per vintage service
10 line replaced by the Company under the Vintage Service Replacement program.¹³ Thus,
11 the cost to relocate and replace services accounts for approximately 16% of the total capital
12 expenditures forecasted by the Company for Civic Improvements for 2025 and 2026.¹⁴

13 As I stated earlier, for 2025 the feet of main to be installed is 28% lower than in the prior
14 three-year average and the number of services is 5% lower. By weighting these
15 percentages by the corresponding capital spending in each cost category, I calculated an
16 overall percentage reduction of 24%.¹⁵ For the three-years 2022-2024, the Company
17 incurred average capital spending for Civic Improvements of \$83,580,000.¹⁶ After

¹² 2025: 1,689 units x \$6,671 unit cost = \$11,267,000. 2026: 1,740 units x \$7,389 unit cost = \$12,857,000.

¹³ Company response to DR AG-CE-0793 Attachment 1.

¹⁴ $\$11,267,000 \div \$70,770,000 = 16\%$. $\$12,857,000 \div \$83,444,000 = 15\%$.

¹⁵ $(-28\% \times 84\%) + (-5\% \times 16\%) = -24.3\%$.

¹⁶ From Tables 9 and 10 of Mr. Warriner's direct testimony at pages 30 and 31. $(2022: \$103,075,000 + 2023: \$83,518,000 - 2024: \$64,148,000) \div 3 = \$83,580,000$

1 adjusting for inflation at 2.4%, the base cost for 2025 is \$85,586,000. Applying the 24%
2 reduction in work activity, decreases the adjusted forecasted capital expenditures for 2025
3 to \$65,045,000.¹⁷ The applicable amount for the 10 months ending October 2025 is
4 \$54,204,000 ($\$65,045,000 \times 10/12$). This amount is \$9,408,000 lower than the
5 \$63,612,000 forecasted by the Company.

6 For 2026, the same approach results in a reduction in overall work activity of 16% from
7 the 2022-2024 three-year period.¹⁸ After applying this percentage reduction to the
8 inflation adjusted three-year average capital expenditures of \$87,726,000, the forecasted
9 capital expenditures for 2026 are \$73,690,000.¹⁹ The amount applicable to the projected
10 test year is \$72,249,000.²⁰ This amount is \$9,913,000 lower than the Company's
11 forecasted amount of \$82,162,000.

12 **Q. DID YOU PERFORM A SIMILAR ASSESSMENT OF THE COMPANY'S**
13 **FORECASTED CAPITAL EXPENDITURES FOR ASSET RELOCATION-**
14 **REIMBURSABLE PROJECTS?**

15 A. Yes, but on a more limited extent due to the inability of the Company to provide forecasted
16 workload activity for 2025 and 2026. In discovery, the Attorney General asked the
17 Company to provide both historical and forecasted work units for 2019 through 2026, as
18 well as work performed for large customer requested relocation projects. In response, the

¹⁷ $\$85,586,000 \times 76\% = \$65,045,000$.

¹⁸ $(-18\% \times 84\%) + (-3\% \times 16\%) = -15.6\%$.

¹⁹ $\$83,580,000 \times 1.024 \times 1.025 = \$87,726,000 \times 84\% = \$73,690,000$.

²⁰ $\$73,690,000 \times 10/12 + \$65,045,000 \times 2/12 = \$72,249,000$.

1 Company provided the historical information through 2024 but stated that it had not
2 developed forecasted work units for 2025 and 2026. In response to additional discovery,
3 the Company also stated that in developing the forecasted capital expenditures for 2024,
4 2025 and 2026, it had applied a 3.5% annual cost escalation rate on the 2023 cost levels
5 and subsequent year to cover for both inflation and workload growth.²¹ This statement is
6 unsupported because no forecasted inflation rates or work activities were disclosed in the
7 discovery response.

8 To arrive at a reasonable capital expenditures forecast for 2025 and 2026, I started with
9 the most recent three years of actual capital expenditures for 2022-2024 and reduced those
10 amounts for the expenditures pertaining to large customer relocations to determine a
11 normalized level. The net result is an historical average spending level of \$14,089,000.²²
12 Adjusted for inflation at 2.4%, the forecasting capital expenditures are \$14,427,000 for
13 2025 and \$12,023,000 for the 10 months ending October 2025. This amount is \$203,000
14 lower than the \$12,226,000 forecasted by the Company.

15 For 2026, I adjusted the three-year historical further for another year of inflation for a total
16 amount of \$14,788,000.²³ The amount pertaining to the projected test year is \$14,728,000.

17 This amount is \$1,919,000 lower than the Company's forecast of \$16,647,000.

²¹ Exhibit AG-4 includes DR AG-CE-0352, 0353, and 0762 with attachments.

²² Attachment to AG-CE-0352 (Exhibit AG-4) total line for 2022, 2023, and 2024, less the amounts for large customer requested relocations, and divided by 3 = \$14,089,000.

²³ \$14,089,000 x 1.024 x 1.025 = \$14,788,000.

1 Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO
2 THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR ASSET
3 RELOCATION?

4 A. I recommend that the Commission remove \$9,611,000 for the 10 months ending October
5 2025, and \$11,832,000 for the projected test year from the Company's forecasted capital
6 expenditures.

7 **4. Regulatory Compliance Program**

8 As shown in Exhibit A-103 (LDW-4), the Company forecasted capital expenditures for
9 the Regulatory Compliance Program of \$45.2 million for 2024, \$91.7 million for the 10
10 months ending October 2025, and \$150.3 million for the 12 months ending October 2026.
11 Included in those amounts are capital expenditures for MAOP projects for large
12 distribution pipelines and related facilities.²⁴ For 2023, the Company incurred capital
13 spending of \$1,607,000 in this area. For future years, the Company forecasted capital
14 expenditures of \$9,295,000 for 2024, \$59,964,000 for the 10 months ending October 2025,
15 and \$115,812,000 for the projected test year. Mr. Warriner discusses the Distribution
16 MAOP program and related regulations beginning on page 46 of his direct testimony.

17 Although the MAOP projects fall within recently issued regulations issued by the Pipeline
18 Hazardous Materials Safety Administration (PHMSA), the genesis of the problem
19 requiring the replacement or remediation of pipelines to re-establish the MAOP is the lack

²⁴ MAOP = Maximum Allowable Operating Pressure for a pipeline or related facilities.

1 of traceable, verifiable, and complete (TVC) records that should have been maintained by
2 the Company. In response to discovery, the Company acknowledged the missing records
3 that prevent it from confirming the appropriate MAOP at which the pipeline should be
4 currently operating.²⁵ Although the PHMSA rules provide for procedures and alternative
5 steps that the Company can undertake short of replacing the pipeline to develop TVC
6 records and to re-establish the MAOP,²⁶ the Company claims that it needs to replace 15
7 distribution pipeline segments, as identified in Table 17 on page 48 of Mr. Warriner’s
8 direct testimony.

9 In discovery, the Attorney General asked the Company to provide a list of MAOP projects
10 where it was able to avoid replacement of the pipeline or pipeline segment and reducing
11 capital expenditures by undertaking the other options to replacement outlined in the
12 PHMSA rule. In response, the Company stated that so far it has not identified any other
13 alternatives to replacement.²⁷ The attachment to the response also shows that for the 15
14 projects contemplated for 2024 through 2026, the Company has chosen only the
15 replacement option at a total cost of \$206.3 million over the three-year period.

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

²⁵ Exhibit AG-5 includes DR AG-CE-0358 with ATT_2.

²⁶ Exhibit AG-6 includes a copy of PHMSA rules.

²⁷ Exhibit AG-5 includes DR AG-CE-0357with ATT_1.

1 A. The reason for replacement of the pipelines under the MAOP projects is the direct result
2 of the Company not having the appropriate records to verify that the pipelines can operate
3 at the designed pressure level and not knowing their material properties and attributes that
4 would assist in that verification. These are basic records that the Company should have in
5 its possession from when the pipeline was installed. The PHMSA rules simply require
6 that the Company check its records to verify it is operating the pipelines and related
7 facilities at the MAOP specific to those facilities. The need to replace the pipelines
8 emanates from the fact that the Company did not maintain the necessary records to perform
9 the required verification.

10 Customers should not pay for the cost to replace pipelines due to the Company's failure to
11 maintain appropriate records irrespective of when the pipeline was initially installed. The
12 Company has the sole responsibility to maintain those records and periodically confirm
13 that it is operating its pipelines at the appropriate allowable pressure. The PHMSA rules
14 enacted in 2019 simply require that pipeline operators do now what they should have been
15 doing all along. Therefore, the cost of replacing the pipeline segments under the MAOP
16 projects should be borne entirely by the utility and not its customers. However, as a
17 reasonable accommodation, given the age of the pipelines being replaced, the Commission
18 could allow the Company to recover 50% of the cost of replacement and split the burden
19 50/50 between the Company and customers.

20 **Q. IN HIS TESTIMONY AND RESPONSES TO DISCOVERY, MR. WARRINER**
21 **STATES THAT LINE 1080 IS NOT BEING REPLACED BUT IS BEING**

1 **SUPPLEMENTED BY A SECOND LINE. DOES THAT PLAN CHANGE YOUR**
2 **ASSESSMENT?**

3 A. No. The reason why the Company needs to supplement Line 1080 with a second line is
4 because Line 1080 can only operate at a limited pressure level due to the inability to
5 pressure test the line given the lack of records to allow it to establish the pipeline design
6 MAOP. By operating the line at a lower pressure based on available records, the Company
7 cannot adequately meet customers' gas demand and now wants to install a second parallel
8 line of 6.7 miles at a cost of \$35 million. Therefore, this project would not exist but for
9 the Company's lack of traceable, verifiable, and complete records for Line 1080.

10 **Q. DID YOU DETERMINE THE AMOUNT OF CAPITAL EXPENDITURES THAT**
11 **THE COMMISSION SHOULD REMOVE FROM THIS RATE CASE**
12 **PERTAINING TO THE DISTRIBUTION MAOP PROJECTS?**

13 A. Yes. In response to DR AG-CE-0358 (Exhibit AG-5), the Company provided an expanded
14 Table 17 from Mr. Warriner's direct testimony that shows each MAOP project with the
15 related capital expenditures by year and for the bridge period and the projected test year.
16 That information has been summarized in the table below and the Company's proposed
17 capital spending corresponds to the forecasted capital expenditures on line 3 of page 1 of
18 Exhibit A-103 (LDW-4).

MAOP Capital Expenditures (000):	Company Proposed Amount	50% Disallowance	Amount Recoverable
2023 Actual	\$ 1,607	\$ 804	\$ 803
2024 Forecast	\$ 9,295	\$ 4,648	\$ 4,647
10 Months Ending October 2025	\$ 59,964	\$ 29,982	\$ 29,982
Projected Test Year	\$ 115,811	\$ 57,906	\$ 57,905

1

2 Based on the discussion above, I recommend that the Commission disallow recovery of
3 50% of the capital expenditures, as calculated in the summary table. This involves
4 disallowance of \$804,000 for 2023, \$4,648,000 for 2024, \$29,982,000 for the 10 months
5 ending October 2025, and \$57,906,000 for the project test year.

6 Later in my testimony, I will address the recovery of O&M expense pertaining to the
7 review of pipeline MAOP records.

8 **Q. HAS THE COMMISSION PREVIOUSLY RULED ON THE RECOVERY OF**
9 **COSTS PERTAINING MAOP PROJECTS?**

10 A. Yes. In Case No. U-21291, which was the DTE Gas Company 2024 rate case, the
11 Commission approved the Attorney General recommendation to disallow 50% of the
12 O&M expense pertaining the review costs of MAOP records included in the projected test
13 year. In reaching its decision, the Commission stated:

14 The Commission respectfully disagrees with the ALJ’s recommendation regarding the
15 MAOP Records Review. The Commission previously addressed DTE Gas’s MAOP
16 Records Review in Case No. U-20940 and determined that the 2019 revisions to
17 federal pipeline safety regulations and the “2011 advisory bulletin are not new record
18 keeping requirements and that DTE Gas was required previously by the MGSS to
19 perform strength tests, including MAOP tests, and to maintain those records for the
20 life of the pipeline.” December 9 order, p. 33. As a result, the Commission instructed

1 that, in future rate cases, “DTE Gas must adequately justify that the required [MAOP]
2 work is a direct result of the new requirements in the regulations and not a result of
3 the company’s historically poor record keeping practices.” Id., pp. 123-124.

4 The Commission acknowledges that DTE Gas provided testimony in this case
5 asserting the need to implement a reconfirmation plan in conformance with the
6 PHMSA revised regulations. See, 4 Tr 620. However, the Commission finds that
7 reconfirmation of MAOP under the pertinent regulations are only required if the
8 records necessary to establish MAOP are not TVC. See, 49 CFR 192.624(a)(1).
9 Therefore, the Commission is not persuaded that DTE Gas’s projected remediation
10 work is not a result of the company’s historically poor recordkeeping practices. The
11 Commission, thus, finds that cost sharing is appropriate for the projected O&M
12 expense for the MAOP Records Review. Accordingly, the Commission declines to
13 adopt the ALJ’s recommendation, and instead adopts the Attorney General’s proposal
14 to remove \$875,000 from DTE Gas’s O&M expense for the projected test year.²⁸

15 In Case No. U-20940, which was the DTE Gas 2021 rate case, the Commission declined
16 to adopt the Attorney General’s recommendation to disallow 50% of the capital
17 expenditures for the Middlebelt deration project that related to MAOP remediation and
18 pipeline replacement. In its order the Commission stated:

19 The Commission finds that recovery of the capital costs related to the Middlebelt
20 deration project should be permitted. The Commission agrees with the ALJ’s findings
21 that the 2019 PHMSA rules and 2011 advisory bulletin are not new record keeping
22 requirements and that DTE Gas was required previously by the MGSS to perform
23 strength tests, including MAOP tests, and to maintain those records for the life of the
24 pipeline. However, the Commission is disinclined to disallow the capital costs
25 associated with this project as they are necessary to reestablish the MAOP of the
26 pipeline and to ensure safe operation. Safety is a core mission of the Commission’s
27 regulation of natural gas operations within the state, and safety has been emphasized
28 by the Commission on numerous occasions. Namely, in DTE Gas’s previous rate case,
29 Case No. U-18999, the company sought recovery of the O&M expenses associated
30 with record remediation in response to the 2019 PHMSA rules, which were pending
31 at the time. While the company did not request recovery of capital expenses and the
32 Commission disallowed the O&M expense because the federal rules were not yet
33 finalized, the Commission spoke to the importance of safety.... Considering the
34 company’s testimony that the Middlebelt deration project was ranked the highest
35 distribution risk and among the highest risks for transmission, the Commission finds
36 that the safety concern justifies cost recovery of the capital expense in this instance.

²⁸ Case No. U-21291, MPSC Order dated November 7, 2024 at page 148.

1 Although I appreciate the Commission concern and the need to take remediation actions
2 when safety issues are involved, the issue here is not whether the work should be done or
3 not done to remedy problems but who should pay for it. In both rate cases, the Commission
4 has clearly concluded that the responsibility to maintain appropriate records falls on the
5 utility. The Commission also concluded that reconfirmation of MAOP under the pertinent
6 regulations are only required if the records necessary to establish MAOP are not TVC.

7 The Commission determined that the utility's projected remediation work was the result of
8 the company's historically poor recordkeeping practices and that cost sharing for the
9 projected O&M expense for the MAOP Records Review was appropriate. By logical
10 extension, the capital expenditures to replace or remediate various pipeline segments and
11 related facilities should also be accorded the same cost sharing treatment between the
12 Company and customers. The only difference is that one is an operating expense and the
13 other is a capital expenditure. However, the cost sharing treatment should be the same.

14 Therefore, I recommend that the Commission adopt my recommendation to allow the
15 Company to recover only 50% of the proposed capital expenditures for MAOP remediation
16 or replacement and disallow the remaining expenditures, as I have outlined above.

17 **Q. IS THERE ANOTHER REASON TO ALLOW THE COMPANY TO ONLY**
18 **RECOVER 50% OF THE PROPOSED CAPITAL SPENDING FOR MAOP**
19 **PIPELINE PREPLACEMENT PROJECTS?**

1 A. Yes. As discussed above and shown in the attachment to DR AG-CE-0357 (Exhibit AG-
2 5), the Company concluded that replacement of the pipeline segments is the only preferred
3 solution to reaffirm the MAOP and has rejected other options permitted under the PHMSA
4 rule. It is not clear how thorough the review process was to reach that conclusion. The
5 statements provided in the discovery response point to vague conclusions about
6 operational risk reduction and likelihood of success. The disallowance of 50% of the
7 project cost would give the Company the incentive to minimize capital expenditures if it
8 must absorb half the cost of the project. This extra incentive could spur the use of other
9 options and reduce overall capital expenditures.

10 **5. Material Condition Program – EIRP Capital Expenditures**

11 As shown on page 1 of Exhibit A-82 (KAP-4), the Company forecasted capital
12 expenditures for the Enhanced Infrastructure Replacement Program (EIRP) of \$195.6
13 million for 2024, \$207.3 million for the 10 months ending October 2025, and \$251.4
14 million for the 12 months ending October 2026. In comparison, the Company spent \$181.9
15 million in 2023. Company witness Kristine Pascarello discusses the EIRP beginning on
16 35 of her direct testimony.

17 **Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE EIRP.**

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

20 1. Replacement of all cast iron mains over the course of the 25-year program.

- 1 2. Replacement of all bare, oxyacetylene welded, threaded & coupled and
2 cathodically-unprotected steel mains over the course of the 25-year program.
- 3 3. Replacement of 100 miles of transmission gas mains located in high
4 consequence areas (HCA) over the 25-year program.
- 5 4. Replacement of approximately 70 miles of ERW piping located in gas storage
6 fields and install launcher/receivers, as necessary, to permit future inspection
7 by in-line inspection (ILI) technology.²⁹

8 According to the direct testimony of Steven Beachum in that rate case, the Company would
9 be able to achieve the 25-year replacement target with an annual capital spending level of
10 \$70 million. If that plan had been successful, full replacement of targeted mains would
11 have been achieved by the year 2036, or 11 years from now. However, the Company's
12 plan has not materialized at anything close to what was proposed in 2011.

13 At the beginning of the main replacement program, the Company had targeted replacement
14 of 2,869 miles of mains, which over the 25-year plan period would have resulted in an
15 annual replacement rate of 115 miles at an average annual capital spending level of \$70
16 million, or \$609,000 per mile. During the 13 years from 2012 to 2024, the Company
17 retired approximately 904 miles of the targeted old mains plus other at-risk mains for a
18 total of 1,131 miles of retired mains.³⁰ The Company replaced those mains by installing
19 1,100 miles of new mains at a cost of \$1.277 billion, or \$1,160,000 per mile.³¹ The
20 retirement rate per year on the old targeted mains has been 85 miles of main instead of the
21 planned 115 miles per year.

²⁹ MPSC Case No. U-16855, Steven Beachum direct testimony at page 33.

³⁰ Exhibit AG-7 includes DR AG-CE-0365 with Attachment.

³¹ Id. includes DR AG-CE-0386 with ATT_1 showing the miles installed. The \$1.277 billion cost is update from Case U-21490 of \$1.084 billion from 2012 through 2023 plus \$193 million spent in 2024.

1 What is most concerning is the fact that the Company had projected it would cost \$609,000
2 to replace a mile of main when it announced the program in 2011.³² Instead, the actual
3 average cost over the past 13 years has been \$1.2 million per mile, or nearly two times the
4 original estimate. Exhibit AG-7 includes the Company's response to discovery requests
5 AG-CE-0365, 0385, 0386 and 0390 with the information discussed above and additional
6 program details.

7 In addition to the base distribution system pipe replacement program, the Company also
8 includes in the EIRP the replacement of steel pipe for Transmission lines Operated by the
9 Distribution department. These are referenced or identified as TOD projects. During the
10 13 years from 2012 to 2024, the Company retired approximately 33.4 miles of TOD mains
11 and replaced them with 58.3 miles of new main.³³

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

15 A. Yes. After reviewing the list of EIRP projects with a cost of \$5 million or greater included
16 on page 3 of Exhibit A-82 (KAP-4), the Attorney General asked the Company to identify
17 the current phase of project development. In response, the Company identified projects
18 that were in different phases of development from Design Not Started to Design in

³² \$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.

³³ Exhibit AG-7 include DR AG-CE-0386 with ATT_1.

1 Progress, Design at 30%, Design at 90%, Design Completed, Released for Construction,
 2 and Under Construction.³⁴ Eighteen of the 30 projects listed in the \$5 million plus category
 3 have had no design started yet or the design is at 30% or less completed. The capital
 4 expenditures for the 18 projects total to \$166 million. A strong case can be made that these
 5 projects are still in the early phase of development and the capital expenditures should not
 6 be included in rate base in this rate case. Of the 18 projects, seven projects, all of which
 7 have been scheduled to be completed in 2026, have not yet had any design work started or
 8 only minimal design (less than 30%) completed for a portion of one project. These seven
 9 projects represent \$84,889,000 of capital expenditures for the projected test year. The
 10 projects are identified in the table below.

Line # Page 3 Exh. A-82	EIRP Project Description	Projected Test Year Capex
17	SAG4 - Ph 1,2,3	17,749
18	BCY2 - Ph 2	7,344
19	ALM2 - Ph 1,7,8	9,303
20	ALM5 - Ph 2 Line 1070g	4,713
23	ROK10 - Ph 1,2,3,4,5,6	15,423
24	ROK7 - Ph 4,5,6,7,8	23,625
25	KAL3 - Ph 8,9,10	6,732
	Total	\$ 84,889

11
 12 These projects are clearly in the initial phase of development with no design work started,
 13 or only a minimal amount in the case of one project, and a high degree of uncertainty about
 14 the cost and completion of the projects by the end of the projected test year. Therefore, I

³⁴ Exhibit AG-8 includes DR AG-CE-0430 with Attachment 1 and AG-CE-0802.

1 recommend that the \$84,889,000 of capital expenditures for this group of seven projects
2 be removed from this rate case. If the Company is able to complete these projects, it can
3 recover the related costs in the next rate case given the annual frequency of rate cases
4 filings.

5 **Q. DO YOU HAVE OTHER OBSERVATIONS AND RECOMMENDATIONS WITH**
6 **REGARD TO THE COMPANY'S FORECASTED EIRP CAPITAL**
7 **EXPENDITURES FOR THE PROJECTED TEST YEAR AND FUTURE YEARS?**

8 A. Yes. As stated earlier, the Company expects to reach a new peak level of capital spending
9 on the EIRP program in the projected test year at \$251.4 million. In contrast, the Company
10 spent \$181.9 million in 2023. The projected test year spending level is an increase of 38%
11 in less than 3 years. The Company is also not meeting its commitment to refrain spending.
12 In the settlement agreement for Case No. U-21490, the Company stated that it would keep
13 the EIRP spending level for the 12 months ending September 2025 at \$215.3 million.

14 As shown in Table 7 on page 49 of Ms. Pascarello's direct testimony, the Company now
15 forecasts that spending for 2025 will reach \$250 million or a prorated amount of \$237
16 million for the 12 months ending September 2025. This increasing spending trend for the
17 EIRP is not sustainable from a customer affordability viewpoint and must be reversed.
18 The Commission should set a firm spending budget for the EIRP to avoid the program's
19 current runaway cost.

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

7 Based on the actual spending of \$181.9 million in 2023 and adjusting that amount for
8 forecasted inflation of 3.2% in 2024, 2.4% in 2024, and 2.5% in 2026, I propose a spending
9 budget cap of \$197 million for the projected test year ending October 2026. That spending
10 level would be adjusted for the CPI rate of inflation in future years.

11 Although the lower spending level that I propose may reduce somewhat the number of
12 miles that the Company planned to retire and install in the projected test year and future
13 years, the completion of the program would not be affect significantly. In discovery, the
14 Attorney General asked the Company to provide the end year of the EIRP if the Company
15 pursued a pace of pipe replacement equivalent to the year 2023.

16 In response, the Company stated that under that assumption, the end date of the EIRP
17 program would be extended from the current expected date of 2035 to the year 2038. The
18 completion date would extend to 2040 if retirement of additional TOD steel pipe and
19 wrapped steel pipe is added to the EIRP.³⁵ This three-to-five-year extension of the

³⁵ Exhibit AG-9 includes DR AG-CE-0391 and 0781.

1 program seem reasonable if it helps moderate the rate of increase in spending to a level
2 equivalent to 2023 adjusted for inflation.

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

12 It should also be pointed out that through the risk-based approach to pipe replacement that
13 the Company has employed over the past 12 years, most of the high-risk mains and
14 services should already have been replaced. In fact, the Company admits that gas leak
15 data shows a downward trend. As expected, the Company stated in response to discovery
16 that as the pipe continues to age the number of gas leaks will increase.³⁶

17 However, this is a conclusion without any engineering analysis. The Company has not
18 provided any compelling evidence that a three-to-five-year extension of the program will
19 result in a material increase in gas leaks or larger infiltration of water in gas pipes above

³⁶ Exhibit AG-9 includes DR AG-CE-0389 and 0780.

1 recent historical levels. Also, there is no evidence that the planned increase in spending in
2 recent years and for the projected test year is tied to any increased safety risks. Therefore,
3 if the completion of the EIRP program is extended a few more years past the current 2035
4 date, it is a reasonable trade-off to balance against customer affordability from
5 uncontrolled capital spending on the program.

6 I recommend that the Commission approve the disallowance of \$84,889,000 from the
7 Company's forecasted capital expenditures of the projected test year and establish a
8 spending budget for the EIRP of \$197 million to be adjusted for the CPI rate of inflation
9 in future years.

10 **6. Material Condition Non-Modeled Program**

11 As shown on page 1 of Exhibit A-82 (KAP-4), the Company forecasted capital
12 expenditures for the Material Condition Non-Modeled Program of \$38.3 million for 2024,
13 \$36.4 million for the 10 months ending October 2025, and \$56.2 million for the 12 months
14 ending October 2026. In comparison the Company spent \$38.5 million in 2023.

15 Ms. Pascarello discusses this program beginning on page 50 of her direct testimony. In
16 contrast with the EIRP, which is a planned replacement of deteriorating pipelines and
17 services, the Material Condition Non-Modeled program addresses emergent needs for pipe
18 replacement and other work that arise during the course of the year. Beginning in 2024,
19 the Company expanded this capital program to undertake the replacement of wrought iron
20 mains, replacement of high-pressure mains at water crossings, leak mitigation activities,

1 and replacing obsolete meters. Of the \$17.7 million increase in spending in the projected
2 test year over 2023, \$5.0 million pertains to the replacement of wrought iron mains, \$5.0
3 million is for HP mains in water crossings, \$4.0 million for leak mitigation, and \$3.7
4 million to replace obsolete meters.³⁷

5 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY’S PROPOSED CAPITAL**
6 **SPENDING ON THE MATERIAL CONDITION NON-MODELED PROGRAM?**

7 A. There are several issues that arise after reviewing the Company’s proposed spending and
8 expansion of the program from the basic emergent problems that arise during the year that
9 need to be addressed.

10 Wrought Iron Mains - It seems that the Company has expanded the non-modeled program
11 to supplement the EIRP for work that should be done within that program. The
12 replacement of wrought iron mains is one such case. Wrought iron mains are similar to
13 cast iron mains that the Company has been replacing within the EIRP. Replacement of
14 those mains should be included in the EIRP and prioritized against other projects for risk
15 and replacement. Therefore, the forecasted capital expenditures of \$1.5 million for 2025
16 and \$5.0 million for 2026 should be removed from the non-modeled program.³⁸ The
17 amount to remove for the 10 months ending October 2025 is \$1,250,000 (\$1.5 million x
18 10/12) and the amount to remove for the projected test year is \$4,417,000.³⁹

³⁷ Kristine Pascarello’s direct testimony at page 51.

³⁸ Exhibit AG-10 includes DR AG-CE-0393, 0397, 0782, and 0785.

³⁹ \$5,000,000 x 10/12 + \$1,500,000 x 2/12 - \$4,417,000.

1 HP Water Crossing Mains - Regarding the HP main water crossing projects, in discovery
2 the Attorney General asked the Company to provide the phase of project development in
3 addition to other pertinent information. The information provided in response to the
4 request shows that eight projects are still in the scoping phase and 2 projects are beginning
5 to enter the design phase.⁴⁰ The total capital expenditures for the 10 projects are \$500,000
6 for the 10 months ending September 2025, and \$5.0 million for the projected test year.
7 These projects are still in the early stage of development and premature to be included in
8 rate base in this rate case. Therefore, I recommend that the \$500,000 and \$5.0 million be
9 removed from the Company's forecasted capital expenditures for the applicable forecasted
10 periods.

11 Risk Mitigation and Obsolete Meter Replacement – Ms. Pascarello's direct testimony is
12 devoid of any explanation or supporting evidence to justify either of these two spending
13 categories. The only mention for the two items is on page 51 of her testimony to identify
14 the amount of cost variance between the projected test year and the 2023 spending. As
15 shown in the table in DR AG-CE-0782 (Exhibit AG-10), capital spending for Risk
16 Mitigation begins in 2024 at \$2,971,000, followed by \$250,000 in 2025, and \$4,000,000
17 in 2026. There is no support for these capital expenditures. Therefore, I recommend that
18 the Commission remove the \$2,970,000 for 2024, \$208,000 for the 10 months ending

⁴⁰ Exhibit AG-10 includes DR AG-CE-0787.

1 October 2025 ($\$250,000 \times 10/12$), and $\$3,375,000$ for the 12 months ending October
2 2026.⁴¹

3 Similarly, for Obsolete Meter project, there is no testimony supporting the $\$3.7$ million in
4 forecasted capital spending in 2026. Therefore, I recommend that the Commission remove
5 $\$3,083,000$ for the 12 months ending October 2026 ($\$3,700,000 \times 10/12$).

6 Line 1010 MAOP Project – Beginning on page 55 of her direct testimony, Ms. Pascarello
7 discloses that the forecasted capital expenditures for Material Condition Non-Modeled
8 include the cost to replace Line 1010 in the amount of $\$10,300,000$ for 2024, $\$14,900,000$
9 for 2025, and $\$12,800,000$ for 2026. This line is a MAOP project similar to the other
10 projects discussed earlier in my testimony, which instead is being done under the Material
11 Condition Non-Modeled program. As stated in her testimony, the reason to replace this
12 line is the Company’s incomplete pressure test documentation and lack of other traceable,
13 verifiable, and complete records from the original installation of the pipeline. Although
14 this pipeline was purchased from another utility, the responsibility to maintain complete,
15 accurate and adequate records still falls on the Company and customers should not pay the
16 full cost to replace the pipeline due to those failures.

17 Therefore, I recommend that the Commission disallow 50% of the cost to replace this
18 pipeline. In response to discovery, the Company disclosed that it included capital
19 expenditures of $\$10,300,000$ in the 10 months ending October 2025 and $\$9,300,000$ in the

⁴¹ $\$4,000,000 \times 10/12 - \$250,000 \times 2/12 = \$3,375,000$.

1 projected test year.⁴² Based on those amounts and the 2024 amount previously identified
2 by the Company, I recommend that the Commission disallow \$5,150,000 for 2024,
3 \$5,150,000 for the 10 months ending October 2025 and \$4,650,000 for the projected test
4 year. These amounts represent 50% of the total capital expenditures identified by the
5 Company for the applicable periods.

6 **Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO**
7 **THE COMPANY’S FORECASTED CAPITAL EXPENDITURES FOR THE**
8 **MATERIAL CONDITION NON-MODELED PROGRAM?**

9 A. As discussed above, I recommend that the Commission remove \$8,121,000 for 2024,
10 \$7,108,000 for the 10 months ending October 2025, and \$20,525,000 for the projected test
11 year from the Company’s forecasted capital expenditures.

12 **7. Material Condition - Renewal Program**

13 As shown on page 1 of Exhibit A-82 (KAP-4), the Company forecasted capital
14 expenditures for the Material Condition – Renewal Program of \$31.9 million for 2024,
15 \$30.7 million for the 10 months ending October 2025, and \$33.2 million for the 12 months
16 ending October 2026. In comparison the Company spent \$31.8 million in 2023.

17 In my analysis I found the capital expenditures proposed by the Company for this program
18 to be reasonable. However, as described in pages 64 and 65 of Ms. Pascarello’s direct

⁴² Exhibit AG-10 includes DR AG-CE-0398.

1 testimony, the Company had anticipated that PHMSA would be issuing a new Leak
2 Detection and Repair (LDAR) rule in early 2025 that would potentially increase the
3 number of leak repairs that the Company would need to undertake. To address this
4 increase in workload, the Company forecasted \$1.5 million of additional capital
5 expenditures for the projected test year under the Renewals program.

6 In response to discovery, the Company stated that the new rule is currently on hold falling
7 under the Presidential Executive Order that placed all new regulations on hold pending
8 further review. As a result, it is unlikely that the new LDAR rule will be issued in the near
9 future and require the Company to undertake additional leak repair work in the projected
10 test year. Therefore, I recommend that the Commission remove the \$1.5 million from the
11 Company's forecasted capital expenditures for the projected test year.

12 **8. Vintage Services Replacement Program**

13 As shown on page 1 of Exhibit A-82 (KAP-4), the Company forecasted capital
14 expenditures for the Vintage Service Replacement Program of \$18.7 million for 2024,
15 \$25.9 million for the 10 months ending October 2025, and \$42.5 million for the 12 months
16 ending October 2026. In comparison the Company spent \$11.4 million in 2023.

17 Ms. Pascarello discusses this program beginning on page 66 of her direct testimony. This
18 program replaces deteriorating service lines outside of the EIRP. Beginning in 2022, the
19 Company began to align replacement of vintage services with the replacement of mains
20 under the EIRP to avoid duplicating work by replacing services before the associated

1 mains were replaced. From Table 9 on page 71 of Ms. Pascarello's testimony, it appears
2 that this effort resulted in fewer non-EIRP services replacements in 2022, 2023, and 2024.
3 Where in the three years prior to 2022, the Company replaced more than 5,000 service
4 under the VSR program annually, in 2022 the forecasted number declined to 2,176, and in
5 2023 it declined further to 1,228 services. In response to discovery, the Company reported
6 that the actual number of services replaced in 2024 was 2,564.⁴³

7 However, for 2025, the Company forecasted an increase of 64% to 4,194 services. For
8 2026, the forecasted the number of services to be replaced under the VSR program
9 increases further to 5,913 units for a cumulative increase of 131% from the number
10 completed in 2024. These forecasted quantities are excessive and go counter to the
11 declines observed in 2022 through 2024. From the discussion in Ms. Pascarello's
12 testimony, it is not clear why a resumption of a large replacement program is necessary
13 other than meeting an arbitrary program completion date. For example, the gas leak data
14 provided on page 67 of her testimony shows a slight uptick in the number of gas leaks in
15 2024 from 2023 but an overall declining trend for all types of gas services in the past three
16 to four years. The higher number of service replacements is not adequately supported and
17 should be scaled back.

18 While I would normally recommend the use of the average number of services replaced in
19 the most recent three-year 2022 through 2024, which would be 1,989 services, to facilitate
20 a more expeditious replacement of the remaining vintage services, I propose that the actual

⁴³ Exhibit AG-11 includes DR AG-CE-0793 with attachment.

1 number of services replaced in 2024 of 2,564 be used to forecast capital expenditures for
2 2025 and 2026. It is reasonable to conclude that the 2024 VSR program replacement rate
3 reflects the Company's most recent effort and commitment to the program. Based on the
4 unit costs for 2025 and 2026 shown in Table 9 on page 71 of Mr. Pascarello's direct
5 testimony, I arrived at forecasted capital expenditures of \$17,104,000 for 2025 and
6 \$14,254,000 for the 10 months ending October 2025 ($\$17,104,000 \times 10/12$). I calculated
7 capital expenditures of \$18,945,000 for 2026, and \$18,638,000 for the projected test
8 year.⁴⁴

9 Based on those calculations, I recommend that the Commission remove the excessive
10 capital expenditures of \$11,631,000 for the 10 months ending October 2025 and
11 \$23,875,000 for the 12 months ending October 2026.⁴⁵

12 **9. Compliance & Controls Projects**

13 On page 1 of Exhibit A-83 (KAP-5), the Company included forecasted capital
14 expenditures for Compliance and Controls Projects of \$4.9 million for 2024, \$447,000 for
15 the 10 months ending October 2025, and \$4.2 million for the 12 months ending October
16 2026. Included in these amounts are capital expenditures for the Advanced Methane
17 Detection (ADM) system and the Enterprise Corrective Action Plan, which I will discuss
18 below and propose certain adjustments.

⁴⁴ 2025: $2,564 \text{ units} \times \$6,671 = \$17,104,000 \times 10/12 = \$14,254,000$. For 2026: $2,564 \text{ units} \times \$7,389 =$
 $\$18,945,000 \times 10/12 + \$14,254,000 \times 2/12 = \$18,638,000$.

⁴⁵ $\$14,254,000 - \$25,885,000 = -\$11,631,000$ and $\$18,638,000 - \$42,513,000 = -\$23,875,000$.

1 As shown in Table 10 on page 73 of Ms. Pascarello’s direct testimony, the Company
2 forecasted capital expenditures for the ADM system of \$4,650,000 for 2024, \$265,000 for
3 2025, and \$3,181,000 for the projected test year. The Company began phase 1
4 implementation of the AMD system in 2021 and completed it in 2022 for a total capital
5 cost of \$7,035,000.⁴⁶ Based on information disclosed in the prior rate case No. U-21490,
6 Phase 2 of the project was to start in 2023. Based on the information provided in Table
7 10, it appears that Phase 2 was delayed to 2024.

8 On pages 73 through 80 of her direct testimony, Ms. Pascarello discusses the features of
9 the ADM system and the purported ability of the system to detect very small gas leaks that
10 current equipment supposedly cannot detect.

11 **Q. WHAT IS YOUR ASSESSMENT OF THE AMD PROJECT?**

12 A. At a cost of more nearly \$15 million, assuming no further costs past 2026, the AMD system
13 is a very costly project. Despite the Company’s claims and self-serving information
14 gathered from the marketing brochures from the vendor, there is insufficient evidence that
15 the new system will detect significant additional gas leaks of a threatening nature that are
16 currently missed by existing equipment. As I stated in my testimony in Case No. U-21490,
17 in response to discovery, the Company stated that it has not had problems identifying true
18 gradable gas leaks using its existing traditional leak detection tools. Asked to provide
19 quantifiable evidence of the value proposition of the new system, the Company provided

⁴⁶ U-21490 Exhibit AG-10 includes DR AG-CE-0373 ATT_1.

1 a general statement that the AMD increases public safety without providing any evidence
2 to support that statement and stating that value propositions have not been quantified.⁴⁷

3 Since Case No. U-21490, the Company performed a field test of the AMD equipment
4 during 2024 and reported that the AMD equipment found one gas leak for every 4.8 miles
5 surveyed, while the existing leak detection equipment found one gas leak for every 33.3
6 miles surveyed.⁴⁸ While the test would indicate that the new equipment would find more
7 gas leaks, it does not show that any of the additional found gas leaks are of great concern.
8 In discovery, the Attorney General asked the Company to provide the grade of the
9 additional gas leaks found by the ADM equipment. In response, the Company stated that
10 the test did not capture this important information.⁴⁹ The Company grades gas leaks by
11 level of severity. A Grade 1 leak is considered an immediate action leak and is escalated
12 for immediate remediation. A Grade 2 leak is scheduled for remediation within 6 months.
13 A Grade 3 leak is either remediated within 12 months or monitored annually to ensure the
14 leak has not increased in severity where it would pose a safety risk.⁵⁰ Most likely the ADM
15 equipment found more Grade 3 leaks, which are of very low priority that certainly do not
16 justifying nearly \$15 million in new equipment.

17 Furthermore, the ADM is not replacing existing leak detection equipment. According to
18 the Company, the ADM identifies only a general area where a gas leak may exist. The
19 Company than must use traditional gas leak detection equipment to pinpoint whether an

⁴⁷ Id. includes DR AG-CE-0370.

⁴⁸ Exhibit AG-12 includes DR AG-CE-0417

⁴⁹ Id. includes DR AG-CE-0794.

⁵⁰ Id. includes DR AG-CE-0471.

1 actual gas leak is occurring and from where it is occurring.⁵¹ Therefore, the ADM system
2 is at best of marginal benefit. There has been no evidence presented by the Company that
3 the existing leak detection is missing serious and dangerous gas leaks that is placing
4 customers and the public in danger or that large quantities of natural gas are escaping into
5 the atmosphere that pose a large financial loss or environmental hazard.

6 Although Ms. Pascarello references discussions with other utilities who have acquired the
7 system, when asked to describe what value these utilities have garnered from the new
8 system, her response was that the Company has not engaged in conversations with peer
9 utilities about AMD cost/benefits or value decisions.⁵² It is astonishing that the Company
10 would propose to invest nearly \$15 million in a new system without performing basic due
11 diligence to determine that the system actually provides incremental value.

12 In her testimony, Ms. Pascarello claims that the AMD will be required under the PHMSA
13 Advisory Bulletin. However, as discussed above, the proposed LDAR rule has been
14 placed on hold with no indication if and when it may be issued.⁵³

15 **Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

16 A. Given the high cost of the project, the lack of supporting evidence that a problem exists
17 that must be solved, and only marginal benefits, I recommend that the Commission reject
18 the Company's proposed capital expenditures for the AMD system of \$4,650,000 for 2024,

⁵¹ Id. includes DR AG-CE-041, 0418, and 0419.

⁵² U-21490 Exhibit AG-10 includes DR AG-CE-0371.

⁵³ Exhibit A-12 includes DR AG-CE-0405.

1 \$221,000 for the 10 months ending October 2025, and \$3,181,000 for the 12 months
2 ending October 2026.

3 **Q. PLEASE DISCUSS YOUR CONCERNS WITH THE PROPOSED SPENDING ON**
4 **THE ENTERPRISE CORRECTIVE ACTION PROGRAM.**

5 A. In Table 10 on page 73 of her direct testimony, Ms. Pascarello identified capital spending
6 for the Enterprise Corrective Action Program (ECAP) of \$49,000 in 2023, \$204,000 for
7 2024, \$200,000 for 2025 and \$33,000 for the projected test year. On pages 80 and 81 of
8 her testimony, Ms. Pascarello briefly discusses the program and the proposed capital
9 expenditures. From the testimony, it is not clear what the capital spending is for and what
10 benefits those expenditures and the program have achieved or will achieve. In discovery,
11 the Attorney General asked the Company to explain specifically what the capital spending
12 in each of the four phases of the ECAP implementation have accomplished or will
13 accomplish. The discovery request also asked the Company to identify what the systems
14 in Table 12 are used for, have accomplished or will accomplish.

15 In response to the first question, the Company mentions implementation of a corrective
16 and preventive action system to collect information, identify issues, and take timely action
17 to resolve and sustain resolutions in various departments of the Company. Other than
18 boilerplate statements, it is not clear what problems exist that the Company is trying to
19 resolve by implementing a new system to gather information it should already have. The
20 response to the second questions basically repeats the statements in the first answer with

1 more jargon and general concepts. No problems, likely solutions, or potential benefits
2 achieved or to be achieved were identified.⁵⁴

3 Given the unsupported capital spending in this area, I recommend that the Commission
4 remove all capital expenditures from 2023 through the projected test year. These amounts
5 include \$49,000 for 2023, \$204,000 for 2024, \$167,000 for the 10 months ending October
6 2025 (\$200,000 x 10/12), and \$33,000 for the projected test year.

7 **Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO**
8 **THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR**
9 **COMPLIANCE AND CONTROLS PROJECTS?**

10 A. As discussed above, I recommend that the Commission remove \$49,000 for 2023,
11 \$4,854,000 for 2024, \$488,000 for the 10 months ending October 2025, and \$3,214,000
12 for the projected test year from the Company's forecasted capital expenditures.

13 **10. Geospatial Inventory and Modelling Program**

14 On page 1 of Exhibit A-83 (KAP-5), the Company included forecasted capital
15 expenditures for the Geospatial Inventory & Modelling Program of \$5.8 million for 2024,
16 \$8.3 million for the 10 months ending October 2025, and \$7.5 million for the 12 months
17 ending October 2026. Included in these amounts are capital expenditures for the Utility
18 Network project, which I will discuss below and propose certain adjustments.

⁵⁴ Exhibit AG-13 includes DR AG-CE-0425.

1 As shown in Table 14 on page 85 of Ms. Pascarello’s direct testimony, the Company
2 forecasted capital expenditures for the Utility Network project of \$2,888,000 for 2024,
3 \$10,970,000 for 2025, and \$4,866,000 for the projected test year. In total, from 2024 to
4 2026, the Company forecasted capital spending of \$18.7 million for the project.
5 Additionally, from 2023 through 2026, the Company forecasted O&M expenses of \$3.1
6 million for a total project cost of \$21.8 million.

7 On pages 84 through 86 of her testimony, Ms. Pascarello describes the Utility Network as
8 a transformation of the Company’s current Geospatial Information Systems (GIS) into a
9 unified system and data model for gas transmission, distribution, and stations to support
10 engineering needs, operational processes, technologies and data. She states that managing
11 the current models is becoming a challenge and the existing software will not be supported
12 by the vendor starting in 2026 for some subsystems and later for other systems. She also
13 listed purported potential benefits or value that will be created by the new system, such
14 as mitigating risks, increase productivity, providing more asset visibility, and other
15 opaque features that seem to be sourced from a vendor marketing brochure.

16 **Q. WHAT IS YOUR ASSESSMENT OF THE GAS UTILITY NETWORK PROJECT**
17 **AND THE RELATED FORECASTED CAPITAL EXPENDITURES?**

18 A. In discovery, the Attorney General asked the Company to provide some additional
19 information on the project, including the current phase of the project, whether the detailed
20 requirements phase has been completed, what additional features and functionality the new
21 system provided that are not provided by the current system that are critically necessary,

1 and a copy of the cost/benefit analysis for the project that would provide economic support
2 to undertake the project.

3 In response, the Company stated that it has begun implementing some early aspects of the
4 system and is still defining many detailed system requirements with the start of the project
5 delayed somewhat. Several of the additional functionality supposedly provided by the
6 new system relate to quicker turnaround of information or visibility of data which point to
7 work efficiency. Other seem to relate to better management and improved processes which
8 can be achieve with any system either new or old. Most importantly, given the purported
9 increase work efficiencies, the Company did not prepare a cost/benefit analysis to identify
10 economic benefits from the new system.⁵⁵ Instead, the Company basis its decision to
11 undertake this costly project primarily on the obsolescence of and lack of vendor support
12 for the existing system in future years.

13 **Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE**
14 **COMPANY’S FORECASTED CAPITAL EXPENDITURES FOR THE UTILITY**
15 **NETWORK PROJECT?**

16 A. The marginal improvement in functionality and lack of a cost/benefit analysis do not
17 support undertaking the Utility Network project at a cost of approximately \$22 million,
18 including O&M expenses. Therefore, I recommend that the Commission remove
19 \$2,888,000 for 2024, \$10,255,000 for the 10 months ending October 2025, (\$12,306,368

⁵⁵ Exhibit AG-14 includes DR AG-CE-0427 with attachment.

1 x 10/12), and \$7,513,000 for the projected test year from the Company's forecasted capital
2 expenditures. Later in my testimony, I will address the disallowance of the O&M expense
3 portion of the project.

4 **B. Transmission Plant - Capital Expenditures**

5 In Exhibit A-12 (MPG-2), Schedule B-5.5, the Company shows forecasted capital
6 expenditures for Transmission Plant of \$313.8 million for 2024, \$176.8 million for the 10
7 months ending October 2025, and \$219.9 million for the 12 months ending October 2026.
8 In comparison, the Company spent \$350.6 million in 2023. The three programs within the
9 Transmission area are Asset Relocation, Regulatory Compliance, and
10 Capacity/Deliverability. In my testimony below, I propose adjustments to the capital
11 expenditures in several areas.

12 **1. Pipeline Integrity –TOD**

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

15 A. On page 1 of Exhibit A-60 (MPG-4), the Company shows forecasted capital expenditures
16 for Pipeline Integrity work for Transmission Operated by Distribution (TOD) of \$6.1
17 million for 2024, \$5.6 million for the 10 months ending October 2025, and \$10.0 million
18 for the projected test year. On page 22 of his direct testimony, Mr. Michael Griffin briefly
19 discusses the capital expenditures forecasted by the Company for the bridge periods and
20 the projected test year. He points to new requirements for Internal Corrosion Direct

1 Assessments (ICDA) beginning in 2023 and increased excavations as a result of the new
2 requirements. He also states that the installation of Ultrasonic Thickness (“UT”) sensors
3 during prior assessments will reduce the number of future excavations. Mr. Griffin
4 provided no other details about activities, and work volumes to support the forecasted
5 capital expenditures for TOD pipeline integrity work.

6 In discovery, the Attorney General asked the Company to provide additional details and
7 support for the level of work activity by year to justify the forecasted capital spending. In
8 response, the Company provide a table identifying six different components to the pipeline
9 integrity program with capital expenditures for 2023 through 2026 sourced from
10 workpapers. In a subsequent discovery response, the Company provided also the number
11 of High Consequence Area (HCA) miles to be assessed and other risk mitigation miles to
12 also to be assessed from 2021 through 2026.⁵⁶

13 This information shows that External Corrosion Direct Assessments (ECDA) and ICDA
14 costs for the forecasted periods are generally in line with historical expenditures.
15 However, the Company included a new category of costs, called Casings, beginning in
16 2024 with capital expenditures of \$178,000, which escalate to \$2.0 million annually in
17 2025 and 2026. Similarly, the Company included a new item, called Risk Mitigation in
18 2024 with actual capital expenditures of \$578,000, well below the \$1,665,000 forecasted
19 for the year. Capital expenditures for this item declines to \$661,000 in 2025 and then

⁵⁶ Exhibit AG-15 includes DR AG-CE-0316 Revised and 0748 with attachment.

1 jumps to \$4,866,000 in 2026. The large swings in spending in this area are perplexing for
2 a program that should consistently mitigate risk.

3 The discovery response states that casing assessments are done every seven years.
4 However, the Company forecasted capital expenditures have them repeating two years in
5 a row at the same amount of \$2.0 million. These amounts appear to be ballpark amounts
6 with no specific quantification of the forecasted cost. In response to additional discovery,
7 the Company stated that it has very limited experience with the cost of inspecting and
8 remediating casings. Furthermore, it disclosed that the casing projects are still in the
9 planning and scheduling phase, which is in the early phase of project development.⁵⁷ From
10 this information, I concluded that at least the 2026 projects are premature to include in rate
11 base in this rate case. Therefore, I recommend that only the 2025 amount be approved and
12 the 2026 forecasted cost be removed. This results in an adjustment of \$2.0 million for the
13 projected test year.

14 The risk mitigation work pertains to assessing and remediating non-HCA pipe. The
15 Company inspected and mitigated 18 miles in 2024 at a cost of \$578,000. For 2025, it has
16 forecasted to double the number of miles to 34 at a cost of \$661,000, which seems
17 reasonable. However, for 2026, the Company proposes to triple the number of miles to be
18 assessed and remediated to 105 from the number in 2025 at a cost of \$4,866,000. The
19 large increase in both the number of miles and cost is excessive and has not been supported
20 or justified. Furthermore, in response to discovery, the Company stated that the Risk

⁵⁷ Id. includes DR AG-CE-0329.

1 Mitigation work was still in the planning and scheduling phase, making the entire costs
2 uncertain and premature to include in rate base in this rate case.⁵⁸

3 Therefore, I propose that at most a doubling of the number of miles and cost of \$661,000
4 from 2025 to \$1,322,000 in 2026 is more appropriate and reasonable. This 2026 amount
5 is \$3,544,000 lower than the amount proposed by the Company. I recommend that the
6 Commission remove \$2,953,000 ($\$3,544,000 \times 10/12$) from the Company's forecasted
7 capital expenditures for the projected test year.

8 In summary, I recommend that the Commission reduce the Company's forecasted capital
9 expenditures for the projected test year for TOD Pipeline Integrity by \$4,953,000.

10 **2. Regulatory Compliance – Transmission MAOP Projects**

11 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED TRANSMISSION MAOP**
12 **PROJECTS AND RELATED CAPITAL EXPENDITURES.**

13 A. On page 1 of Exhibit A-60 (MPG-4), the Company shows forecasted capital expenditures
14 for MAOP Compliance for Transmission Pipelines of \$51,000 for 2024, \$2.4 million for
15 the 10 months ending October 2025, and \$3.0 million for the projected test year. In
16 workpaper WP-MPG-2, the Company lists the projects and related dollars that make up
17 the 2023 actual spending and the total forecasted capital expenditures for future periods.⁵⁹

⁵⁸ Id.

⁵⁹ Exhibit AG-16 includes WP-MPG-2.

1 Beginning on page 24 of his direct testimony, Mr. Griffin discusses the various activities
2 under the Regulatory Compliance Program, including the replacement of transmission
3 pipeline under MAOP projects. The issues here are the same as in the Distribution MAOP
4 projects. The Company lacks traceable, verifiable, and complete records to re-establish
5 the MAOP of the targeted pipelines and has decided to replace those pipelines or segments
6 of pipelines. As stated earlier in my testimony under the Distribution MAOP projects,
7 customers should not pay for the entire cost to replace the affected pipeline because of the
8 failure by the Company to have and maintain accurate and complete records on its
9 pipelines.

10 In response to discovery, the Company stated that Project GL-03042 in WP-MGP-2 is not
11 required at this time.⁶⁰ Therefore, the capital expenditures of \$1,692,000 for 2023 and
12 \$1,799,000 for 2024 can be removed from rate base in this rate case in their entirety. In
13 response to an additional discovery request, the Company confirmed that capital
14 expenditures of \$2,564,000 for the projected test year pertains to currently unknown
15 projects.⁶¹ This amount has been included as a placeholder and should be removed. As
16 stated earlier, the Commission has rejected the inclusion of placeholder amounts in rate
17 base.

18 Regarding the remaining projects listed in WP-MGP-2, the capital expenditures for those
19 projects total to \$4,419,000 for 2023, \$708,000 for 2024, \$2,409,000 for the 10 months

⁶⁰ Id. includes DR AG-CE-0750.

⁶¹ Id. includes DR AG-CE-0331.

1 ending October 2025, and \$452,000 for the projected test year. As discussed above, I
2 recommend that the Commission disallow recovery of 50% of the proposed capital
3 expenditures. Therefore, the Commission should remove capital expenditures of
4 \$2,210,000 for 2023, \$354,000 for 2024, \$1,205,000 for the 10 months ending October
5 2025, and \$226,000 for the projected test year.

6 In total, for the projects listed in WP-MPG-2, I recommend that the Commission remove
7 capital expenditures of ~~\$3,902,000~~\$2,212,000 for 2023, ~~\$2,153,000~~\$356,000 for 2024,
8 \$1,205,000 for 10 months ending October 2025, and \$2,790,000 for the projected test year.

9 **3. Asset Relocations**

10 On page 1 of Exhibit A-59 (MPG-3), the Company included forecasted capital
11 expenditures for Asset Relocation projects of \$17.4 million for 2024, \$19.1 million for the
12 10 months ending October 2025, and \$24.7 million for the projected test year. In
13 comparison, the Company spent \$6.2 million in 2023. In workpaper WP-MPG-1, the
14 Company provides the list of projects that comprise the total forecasted capital
15 expenditures.⁶²

16 In response to discovery, the Company reported that three of the listed projects in WP-
17 MPG-1 are still in the preliminary design phase. The projects are GL-00990 KZO 1200A
18 Wetland, GL-00991 KZO 1200A Townline Rd., and GL-02086 KZO 1200A Needham
19 Rd. The total capital expenditures for the three projects are \$129,000 for the 10 months

⁶² Exhibit AG-17 includes WP-MPG-1.

1 ending October 2025 and \$15,456,000 for the projected test year.⁶³ These projects are still
2 in the early stage of development with no design completed or significantly advanced. The
3 cost level and timing of the capital expenditures is still uncertain and premature to include
4 in rate base in this rate case.

5 Therefore, I recommend that the Commission remove \$129,000 for the 10 months ending
6 October 2025 and \$15,456,000 for the projected test year from the Company's forecasted
7 capital expenditures.

8 **4. Deliverability Field Measurement Projects**

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

12 A. On line 3 of page 1 of Exhibit A-61 (MPG-5), the Company included forecasted capital
13 expenditures for Field Measurement projects of \$6.8 million for 2024, \$10.3 million for
14 10 months ending October 2025, and \$19.9 million for the projected test year. In
15 comparison, the Company spent \$5.3 million in 2023. In workpaper WP-MPG-3, the
16 Company provided the list of projects that comprise the total capital expenditures.⁶⁴
17 Beginning on page 39 of his direct testimony, Mr. Griffin describes the program activities,
18 lists the major projects, and points to the Company's goals of improving gas measurement

⁶³ Id. includes DR AG-CE-0326.

⁶⁴ Exhibit AG-18 includes WP-MPG-3.

1 accuracy and reducing lost and unaccounted for (LAUF) gas in support of the capital
2 spending in this area.

3 In discovery, the Attorney General asked the Company to provide more pertinent
4 information on the larger projects, such as the current phase of project development, the
5 project cost/benefit analysis, what the capital dollars will be spent on, what the project
6 entails, and why it is necessary. In response, the Company reported that most projects are
7 in the early stage of design or design work has not yet started and will not start until later
8 in 2025 or 2026. The Company also reported that no cost/benefit analyses were prepared
9 for any of the projects. Other issues are discussed below for specific projects.⁶⁵

10 GM-01047 JXN-Lainsburg Inc. Meter Installation: Based on the information provided in
11 WP-MPG-3, this project entails the installation of a new meter at a total cost of \$4.4
12 million with capital expenditures of \$3,119,000 for the 10 months ending October 2025
13 and \$378,000 in the projected test year. The Company explains that the new meter is
14 needed to improve gas measurement accuracy. No specific problem has been identified
15 with the current meter and no specific benefits were identified other than vague statements
16 of improved metering accuracy for reducing LAUF gas. No cost/benefit analysis was
17 performed. Given the inadequate support provided for this project, I recommend that the
18 Commission remove the \$3,119,000 for the 10 months ending October 2025 and \$378,000
19 in the projected test year from the Company's forecasted capital expenditures.

⁶⁵ Id. includes DR AG-CE-0332 with ATT_1.

1 GM-01089 Williamston Transmission Meter Proving Station: This project requires the
2 construction of a new testing facility to prove and test transmission meters before
3 installation for compliance to API-1164. The total cost of this facility is at least \$9.4
4 million with \$226,000 included in forecasted capital expenditures for the 10 months
5 ending October 2025 and \$7,994,000 in the projected test year. The Company currently
6 uses a third-party testing facility. No cost/benefit analysis was performed by the Company
7 to justify this project and bring the work in-house. In an attempt to identify some cost
8 savings in Attachment 2 of DR AG-CE-0332 (Exhibit AG-18), the Company listed certain
9 items with related dollar amounts that it calls “1st Year Anticipated Capital Efficiencies.”
10 The first item is supposedly a cost savings of \$100,000 by building the facility with
11 Company resources. However, the Comparison here should be to the cost of third-party
12 services and not to building a facility with Company resources versus using contractor
13 resources. This would be a second step analysis after building a new facility is justified
14 versus continuing to use a third-party service provider. The second items for \$50,000 may
15 be a legitimate savings but there is no comparison to the current cost for the service
16 provided by the third-party versus the Company performing that function on its own. The
17 analysis is incomplete.

18 The third item for a purported savings of \$750,000 is difficult to understand even after
19 further explanation was requested in DR AG-CE-0758.⁶⁶ The Company wants to buy its
20 own tools and equipment to construct multiple gas analysis buildings. This appears to be

⁶⁶ Id. include DR AG-CE-0758.

1 an added cost not a savings versus using the third-party service. The fourth item could be
2 a cost savings but needs to be compared to the cost of building and operating the new
3 facility, which the Company has not done. In other words, the Company has not performed
4 a serious cost/benefit analysis to justify building and operating this new facility.
5 Therefore, I recommend that the Commission remove the \$226,000 included in forecasted
6 capital expenditures for the 10 months ending October 2025 and the \$7,994,000 in the
7 projected test year.

8 B-GM-00041 Rose Center Meter Replacement: This project entails another meter
9 replacement on the premise that the current meter has reached the end of its useful life.
10 The forecasted capital expenditures for this project are \$302,000 for the 10 months ending
11 October 2025 and \$818,000 for the projected test year. No specific problems were
12 identified with the current meter. No cost/benefit analysis was performed, and no other
13 benefits have been quantified for LAUF gas accuracy improvements, etc. No design work
14 has yet begun on this project with the expectation that design work would start sometime
15 in the second quarter of 2025. Aside for the project still being in the early stage of
16 development and all the related uncertainty with cost and timing of capital expenditures
17 that such an early-stage project entails, the project has not been adequately justified.
18 Therefore, I recommend that the Commission remove the forecasted capital expenditures
19 of \$302,000 for the 10 months ending October 2025 and \$818,000 for the projected test
20 year from this rate case.

1 The following six projects: B-GM-00042, B-GM-00043, and B-GM-00045 through B-
2 GM-00048 do not have any design work completed, and design work would not start until
3 late in the third quarter of 2025, near the end of 2025, or in 2026. Given the early stage of
4 development, it is premature to include the capital expenditures for these projects in rate
5 base in this rate case. The total capital expenditures forecasted by the Company for the
6 six projects are all in the projected test year for \$8,369,000. I recommend that the
7 Commission remove this amount from the forecasted capital expenditures in this rate case.

8 **Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR ADJUSTMENTS TO**
9 **THE COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR FIELD**
10 **MEASUREMENT PROJECTS?**

11 A. As discussed above, I recommend that the Commission remove \$3,647,000 for the 10
12 months ending October 2025, and \$17,559,000 for the projected test year from the
13 Company's forecasted capital expenditures.

14 **5. Deliverability Base Pipeline Program**

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

18 A. On line 4 of page 1 of Exhibit A-61 (MPG-5), the Company included forecasted capital
19 expenditures for the Deliverability Base Pipeline program of \$18.2 million for 2024, \$19.4
20 million for 10 months ending October 2025, and \$25.0 million for the projected test year.

1 In comparison, the Company spent \$18.8 million in 2023. In workpaper WP-MPG-4, the
2 Company provides the list of projects that comprise the total forecasted capital
3 expenditures.⁶⁷ In response to discovery, the Company provided additional details for
4 select larger projects, such as the current phase of development as of early April 2025.

5 Discovery response AG-CE-0333 shows that work on Project B-GL-00251 has been
6 cancelled. Based on WP-MPG-4, the forecasted capital expenditures for this project were
7 \$1,561,000 for the 10 months ending October 2025 and \$230,000 for the projected test
8 year. In the discovery response, the Company states the cancelled project was replaced by
9 another project.⁶⁸ However, insufficient information is available on the new project to
10 make a full assessment of the prudence of the forecasted cost to be incurred. Therefore, I
11 recommend that the capital expenditures forecasted for the cancelled project be removed
12 from this rate case.

13 The discovery response also identified 11 projects where no work has yet been done, and
14 no design work has been initiated or completed. The 11 projects are: B-GL-00259 through
15 B-GL-00267, B-GL-00280, and GL-03047.⁶⁹ Based on the information provided in WP-
16 MPG-4, the total capital expenditures for the 11 projects for the projected test year are
17 \$18,466,000. These projects are still in the early phase of development with no assured
18 timeline and thus premature to include in rate base in this rate case. Therefore, I

⁶⁷ Exhibit AG-19 includes WP-MPG-4.

⁶⁸ Id. includes DR AG-CE-0333.

⁶⁹ Id.

1 recommend that the Commission disallow \$18,466,000 of capital expenditures for the
2 projected test year.

3 In total for this program, I recommend that the Commission remove \$1,561,000 for the 10
4 months ending October 2025 and \$18,696,000 for the projected test year from the
5 Company's forecasted capital expenditures.

6 **6. T&S City Gate Projects**

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

10 A. On line 6 of page 1 of Exhibit A-61 (MPG-5), the Company included forecasted capital
11 expenditures for T&S City Gates of \$52.9 million for 2024, \$47.5 million for 10 months
12 ending October 2025, and \$59.0 million for the projected test year. In comparison, the
13 Company spent \$31.3 million in 2023. In workpaper WP-MPG-6, the Company provided
14 the list of projects that comprise the total capital expenditures.⁷⁰ In response to discovery,
15 the Company provided the cost of each project undertaken each year in 2022 through 2024
16 and the forecasted cost of projects planned for 2025 and 2026. The Company also
17 provided the phase of development of the planned projects as of early April 2025.⁷¹

⁷⁰ Exhibit AG-20 includes WP-MPG-6.

⁷¹ Id. includes DR AG-CE-0335 and 0753 with attachments.

1 Attachment 1 to discovery response AG-CE-0753 (Exhibit AG-20) shows the individual
2 projects and related cost by year. For the historical three years 2022-2024, I calculated an
3 average cost per project of \$6,093,000. Adjusted for inflation, the cost for 2025 is
4 \$6,239,000 and for 2026 is \$6,395,000. In comparison, for the 2025 projects, the Company
5 has forecasted a cost per project of \$7,404,000. This amount is nearly 19% over the
6 inflation adjusted cost for 2025. Similarly, the Company's 2026 forecasted cost per project
7 is \$7,757,000, or 21% above the inflation adjusted cost for the year. These large increases
8 in project costs are excessive and need to be moderated.

9 I will also point out that most of the 2025 and 2026 planned projects are still in the
10 engineering/design phase or in pre-engineering and design. Therefore, it is very likely that
11 the cost for these projects will change from the amounts proposed by the Company and
12 the timing of construction could slip into a future year.

13 To develop a reasonable forecast of capital expenditures for T&S Gate Stations, I have
14 applied the 2025 inflation adjusted cost of \$6,239,000 to the 7 projects planned by the
15 Company. The result is a capital expenditures amount of \$43,673,000 for 2025 or
16 \$36,394,000 for the 10 months ending October 2025 ($\$43,673,000 \times 10/12$). This amount
17 is ~~\$11,074,000~~\$4,196,000 lower than the ~~\$47,469,000~~\$40,590,000 forecasted by the
18 Company. For 2026, I multiplied the project cost of \$6,395,000 by the 7 projects planned
19 for the year to arrive at forecasted amount of \$44,765,000. The forecasted amount for the
20 projected test year is \$44,583,000. This amount is ~~\$14,408,000 lower~~\$3,607,000 higher
21 than the ~~\$58,991,000~~\$40,976,000 forecasted by the Company.

1 Therefore, I recommend that the Commission remove ~~\$11,074,000~~\$4,196,000 for the 10
2 months ending October 2025 and ~~\$14,408,000~~add \$3,607,000 for the projected test year
3 from the capital expenditures forecasted by the Company.

4 **7. Remote Control Valves (RCV)**

5 **Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU ARE PROPOSING TO THE**
6 **CAPITAL PROJECTS FOR RCV PROJECTS.**

7 A. On page 1, line 3, of Exhibit A-62 (MPG-6), the Company forecasted capital expenditures
8 for RCV projects of \$8.7 million for the 10 months ending October 2025, and \$18.1 million
9 for the 12 months ending October 2026. No capital expenditures were forecasted for 2024
10 in this subprogram. In comparison, the Company spent \$2.3 million in 2023. WP-MPG-
11 8 provides a list of projects with the related cost.⁷² In response to discovery, the Company
12 provided additional details, including the number of units installed in prior years and
13 planned for future years, as well as the current phase of development as of early April 2025
14 for projects in \$1 million or greater in size.

15 In the discovery response, the Company states that the 2025 planned projects were
16 currently in the design and procurement phase. However, the seven projects planned for
17 2026 of \$1 million or greater size are still in the planning and scoping phase.⁷³ These
18 projects are still in the early planning stage of development with no engineering/design yet
19 started or completed. It is premature to include the seven projects in rate base given that

⁷² Exhibit AG-21 includes WP-MPG-8

⁷³ Id. includes DR AG-CE-0336.

1 they are still being evaluated whether they should be pursued, and the forecasted costs are
 2 preliminary without any design work completed. Customers should not be charged for
 3 costs that may not occur during the projected periods. The following table shows the seven
 4 projects retrieved from WP-MGP-8.

Project ID	RCV Project Description	2026 Projection	12 Months Ending 10/30/2026 Projection
GL-02825	FDM-1200B Moscow VS Vlv 1252B Repl	\$ 1,084,230	\$ 1,073,387
GL-02943	FDM-2800 FDM,Milr,Hdsn,Sutn RCV Inst	3,252,688	3,220,161
GL-03049	SAG-250 MtPI to Zilwke RCV Inst	2,168,459	2,146,775
B-GL-00120	TEDI-Three Rivers Landfill	1,337,191	1,323,819
B-GL-00129	TEDI-North Bradley VS (Coleman-Beavert	2,840,682	2,812,275
B-GL-00140	TEDI-Blanchard Rd VS	1,951,613	1,932,097
B-GL-00214	Babcock VS	1,653,450	1,636,916
TOTAL EXPENDITURE		\$ 14,288,314	\$ 14,145,430

5

6 Therefore, I recommend that the Commission disallow \$14,145,000 for the projected test
 7 year from the Company’s forecasted capital expenditures.

8 **C. Gas Compression & Storage - Capital Expenditures**

9 On page 1 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company forecasted capital
 10 expenditures for Gas Compression and Storage projects of \$175.3 million for 2024, \$184.1
 11 million for the 10 months ending October 2025, and \$162.0 million for the 12 months
 12 ending October 2026. In comparison, the Company spent \$113.0 million in 2023.
 13 Included in these amounts are capital expenditures for projects where I will recommend
 14 certain adjustments as discussed in my testimony below.

1 **1. Lyon 29/34 (Northville Storage) Dehydration**

2 **Q. PLEASE DISCUSS THE NORTHVILLE STORAGE GAS DEHYDRATION**
3 **PROJECT.**

4 A. On line 10 of page 2 of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company shows the
5 forecasted capital expenditures for the Northville Storage Field at \$8.5 million for 2024,
6 \$25.4 million for the 10 months ending October 2025, and \$4.7 million for the 12 months
7 ending October 2026. Beginning on page 33 of his direct testimony, Mr. Timothy Joyce
8 discusses the Lyon 29/34 project which entails the construction of a dehydration system.
9 The Company seems concerned with the moisture content of the gas withdrawn from the
10 Northville gas storage field not meeting the 7bl. per Mcf required for delivery to
11 customers, as measure at the customer's meter. The Lyon 29/34 is a metering station
12 feeding gas to a transmission line and the Northville storage compressor station. To
13 resolve the occasional excessive moisture content of the gas stream, originating from the
14 Northville storage field during the gas withdrawal period, the Company wants to install a
15 gas purification/dehydration facility near the Northville compressor station.

16 Mr. Joyce does not identify the cost of this project in his testimony. In response to
17 discovery, the Company provided a schedule that shows the total cost from 2022 to the
18 end of 2026 at \$37.4 million.⁷⁴ ~~However, WP TJK-6 shows larger capital expenditures~~
19 ~~from 2024 to 2026, that when added to the amounts spent in 2022 and 2023 bring the total~~
20 ~~cost of the project to nearly \$41 million.~~ The Company spent \$1,149,000 in 2022,

⁷⁴ Exhibit AG-22 includes DR AG-CE-0506 with ATT_1.

1 \$1,191,000 in 2023, \$6,122,000 in 2024, and forecasted ~~\$8,453,000~~\$8,028,000 for 2024,
2 ~~\$25,351,000~~\$25,249,000 for the 10 months ending October 2025, and
3 ~~\$4,672,000~~\$3,649,000 for the projected test year.⁷⁵ These amounts totaling to
4 ~~\$40,816,000~~\$39,266,000 are included in this rate case.⁷⁶

5 In Attachment 2 to DR AG-GE-0506, the Company also mentions that it has filed an Act
6 9 application to build a pipeline to connect the dehydration facility to the transmission line.
7 There is no disclosure or discussion about this pipeline in Mr. Joyce's direct testimony. In
8 fact, for a ~~\$41~~\$37.4 million project there is inadequate testimony to support and justify the
9 project.⁷⁷

10 **Q. WHAT IS YOUR ASSESSMENT OF THE NORTHVILLE STORAGE GAS**
11 **DEHYDRATION PROJECT?**

12 A. The Company seems to have started work on certain portions of the project. However, the
13 cost of the project is significantly large at ~~\$41~~\$37.4 million and given the infrequent
14 occurrence of moisture issues with the gas stream from the Northville storage fields,
15 further work on the project should be avoided. In the last two rate cases, I filed testimony
16 proposing that the project should be analyzed further for a more cost-effective solution.
17 Due to the fact that the last two gas rate cases for the Company have been settled, the

⁷⁵ Exhibit A-22 DR AG-CE-0506 ATT_1 and WP-TJK-6 for Northville.

⁷⁶ The forecasted 2024 capital expenditures were included in the Company's filed rate instead of the actual 2024 capital expenditures.

⁷⁷ The \$37.4 million represents the project costs estimated by the Company through the end of 2026 with actual capital expenditures for 2024. The forecasted amount included in rate base by the Company through the 2026 projected test year is \$39,266,000 which includes forecasted capital expenditures for 2024.

1 Commission has not had an opportunity to rule on the reasonableness and prudence of this
2 project.

3 In response to discovery in the last two rate cases, the Company reported that it had
4 identified only a few incidents of excessive moisture in the gas stream between 2019 and
5 2021. In this rate case, the Attorney General asked the Company to update that
6 information. The updated information shows similar results with one well showing
7 unusual results due to a recent re-drilling of the well and injection of fluids in the well
8 during the re-drilling process.⁷⁸ No moisture readings have been taken since March 2021.
9 Beginning in 2021, the Company changed the utilization of the Northville storage fields
10 to be a peaking storage facility to be used only during days in the winter when customer
11 gas demand reaches near peak demand.⁷⁹ Therefore, like in 2021, in future years no gas
12 withdrawals from the fields may happen on a regular basis and may only occur on very
13 few select days. In fact, the Company withdrew gas from the field only once in 2021 in
14 March and perhaps once in 2022, and none in 2023 and 2024. It does not seem cost
15 effective to build a high-cost facility that will sit idle and not be utilized other than on rare
16 occasions.

17 Attachment 4 to DR AG-CE-0506 shows that the volume of gas withdrawn on those
18 unusual occasions in 2021 and 2022 represented less than 0.01% to 0.04% of the
19 Company's total system sendout on those days. These are infinitesimal percentage that

⁷⁸ Exhibit A-22 includes DR AG-CE-0506 ATT 3 and ATT 4, and DR AG-CE-0820.

⁷⁹ Case No. U-20541, Jonathon Guscinski direct confidential testimony at page 71.

1 should not pose a problem when the Company mixes the small amount of gas withdrawn
2 from the Northville field with the other gas supply flowing through the transmission lines
3 and ultimately delivered to customers. The end result is that natural gas delivered to
4 customers will be at moisture content well below the 7 lb. per Mcf standard measure at the
5 customer meter.

6 In discovery request AG-CE-0316 in Case No. U-21490 and again in this rate case, the
7 Attorney General asked the Company whether it had performed an analysis to see if gas
8 withdrawn occasionally from the Northville storage fields with higher moisture content
9 could be blended with drier gas from other sources as an effective solution to prevent a
10 moisture problem before delivering the gas to customers. In response, the Company stated
11 that it had not performed such an analysis because it does not recognize gas blending as a
12 competent means for ensuring gas quality.⁸⁰ Although such a position makes sense on a
13 wider scale, on the rare occasions of gas withdrawals from the Northville storage fields
14 and in limited volumes, it can be an effective strategy. DTE Gas utilizes gas blending
15 temporarily when it experiences failures with its gas dehydrating equipment at or near its
16 gas storage fields with no ill effect on customers' gas burning equipment.

17 The Company also raises concerns about pipe corrosion with moisture in the gas flow.
18 However, all gas has a certain amount of moisture and the small amount of gas with the
19 higher level of moisture of less than 15 lb. per Mcf withdrawn from the Northville field

⁸⁰ Exhibit AG-22 includes DR AG-0819.

1 instead of the typical 5 lb. or less per Mcf in the remaining gas flow from other sources
2 will not cause any measurable incremental corrosion in the Company's pipeline system.

3 **Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

4 A. The Lyon 29/34 Northville Gas Dehydration project is not a cost-effective solution for an
5 investment exceeding ~~\$41~~37.4 million on a project for a facility that would be rarely used.

6 Therefore, I recommend that the Commission remove the capital expenditure of
7 \$1,149,000 for 2022, \$1,191,000 for 2023, ~~\$8,453,000~~\$8,028,000 for 2024,
8 ~~\$25,351,000~~\$25,249,000 for the 10 months ending October 2025, and
9 ~~\$4,672,000~~\$3,649,000 for the projected test year from this rate case.

10 **2. Storage New Wells**

11 **Q. PLEASE IDENTIFY THE CAPITAL EXPENDITURES PROPOSED BY THE**
12 **COMPANY FOR DRILLING NEW STORAGE WELLS.**

13 A. On page 2, line 14, of Exhibit A-12 (TKJ-5), Schedule B-5.7, the Company forecasted
14 capital expenditures to drill new storage wells of \$17.2 million for 2024, \$28.0 million for
15 the 10 months ending October 2025, and \$32.3 million for the projected test year. In
16 comparison, the Company spent \$11.4 million in 2023. Mr. Joyce discusses the capital
17 expenditures for this program beginning on page 35 of his direct testimony.

18 In response to discovery, the Company provided an updated Table 7 from Mr. Joyce's
19 testimony with actual expenditures incurred for each well for the applicable year from

1 2019 to 2026.⁸¹ Regarding new wells, and excluding re-entry wells, the data shows that
2 the average cost to drill a new well in 2023 and 2024 on average was \$6,843,000. Adjusted
3 for inflation the cost for 2025 is \$7,007,000 and for 2026 is \$7,182,000.

4 For 2025, the Company plans to drill 4 new wells for a total amount of \$36,352,000 and
5 at an average cost per well of \$9,088,000. This cost is 30% higher than the 2025 average
6 cost per well of \$7,007,000 from 2024 adjusted for inflation. The Company's forecasted
7 cost per well is excessive and not justified. Using the inflation adjusted cost \$7,007,000
8 and applying it to the 4 planned wells, the total forecasted cost is \$28,028,000 for 2025
9 and \$23,357,000 for the 10 months ending October 2025. This amount is \$4,647,000 lower
10 than the \$28,004,000 forecasted by the Company.

11 For 2026, the Company plans to drill 4 new wells for a total amount of \$31,762,000 at
12 average cost per well of \$7,941,000. This cost is 11% higher than the 2024 average cost
13 per well adjusted for inflation of \$7,182,000. The Company's forecasted cost per well is
14 excessive and not justified. Using the inflation adjusted cost of \$7,182,000 and applying
15 it to the 4 planned wells, the total forecasted cost is \$28,728,000 for 2026. This amount is
16 \$3,034,000 lower than the Company's forecasted cost of \$31,762,000. The \$3,034,000
17 prorated for the 10 months in the projected test year plus two months from the 2025 lower
18 cost results in the projected test year adjustment of \$3,916,000.⁸²

⁸¹ Exhibit AG-23 includes DR AG-CE-0508.

⁸² 2025: $36,352,000 - \$28,028,000 = \$8,324,000 \times 2/12 = \$1,387,000 + 2026: \$3,034,000 \times 10/12 =$
\$3,916,000.

1 Therefore, I recommend that the Commission remove \$4,647,000 for the 10 months
2 ending October 2025 and \$3,916,000 for the projected test year from the Company’s
3 forecasted capital expenditures.

4 **3. Hessen Storage Pipeline**

5 **Q. PLEASE DISCUSS YOUR FINDINGS REGARDING THE HESSEN STORAGE**
6 **FIELD PIPELINE AND THE RELATED CAPITAL EXPENDITURES**
7 **PROPOSED BY THE COMPANY.**

8 A. In Table 8 on page 41 of his direct testimony, Mr. Joyce identified the Hessen field pipeline
9 as a project that requires Act 9 approval. The Company forecasted capital expenditures of
10 \$15,703,000 for 2025 with \$13,450,000 for the 10 months ending October 2025 and
11 \$2,003,000 for the projected test year.⁸³ In discovery, the Company disclosed that the Act
12 9 filing requesting Commission approval was filed on December 18, 2024.⁸⁴

13 The Company has not yet received approval to build this pipeline and related laterals.
14 Depending on when it receives approval, it is also uncertain when construction of the
15 pipeline and lateral will occur and what amount will be spent and when. Therefore, it is
16 premature to include the forecasted capital expenditures in rate base in this rate. I
17 recommend that the Commission remove the \$13,450,000 for the 10 months ending

⁸³ WP-TKJ-6.

⁸⁴ Exhibit AG-24 includes DR AG-CE-0509 with ATT_1.

1 September 2026 or later.⁸⁵ Clearly, these projects are not likely to be in significant
2 construction mode during 2026 or be completed by the end of projected test year ending
3 October 2026.

4 The thirteen projects have forecasted capital expenditures of \$786,000 for the 10 months
5 ending October 2025 and \$29,295,000 for the projected test year. Those projects have
6 been highlighted in a copy of WP-TKJ-5 provided by the Company and included in Exhibit
7 AG-25. Given the limited development of these projects and the uncertainty of the
8 forecasted costs, they are premature for inclusion in this rate case. Therefore, I recommend
9 that the Commission remove the \$786,000 for the 10 months ending October 2025 and
10 \$29,295,000 for the projected test year from the Company's forecasted capital
11 expenditures.

12 **5. Gas Compression & Storage – 2024 Capital Expenditures**

13 In discovery, the Attorney General asked the Company to provide the actual amount spent
14 on all Gas Compression and Storage capital programs during 2024. In response the
15 Company reported that it spent \$167,776,000 in 2024.⁸⁶ In Exhibit A-12 (TKJ-5),
16 Schedule B-5.7, page 1, the Company shows that it included \$175,339,000 of capital
17 expenditures for 2024 in this rate case. The difference is an underspent amount of
18 \$7,563,000. This amount should be removed from rate base in this rate case. The

⁸⁵ Exhibit AG-25 includes DR AG-CE-0827.

⁸⁶ Exhibit AG-26 includes DR AG-CE-0517.

1 Company did not incur this cost and it is not fair or reasonable for the Company to earn a
2 return and recover depreciation expense for costs in it did not incur.

3 Therefore, I recommend that the Commission remove the 2024 underspent amount of
4 \$7,563,000 from rate base in this rate case.

5 **D. Information Technology (IT) - Capital Expenditures**

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

11 **1. Gas Facilities Tracking and Traceability Project**

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

15 A. On page 76 of his direct testimony, Mr. Warriner discusses the Tracking and Traceability
16 system project with forecasted capital expenditures of \$5,295,411 and \$508,607 in O&M
17 development costs in the test year. However, a report provided by Company witness
18 Stacey Baker for ROM⁸⁷ adjusted IT capital expenditures shows that an additional
19 \$2,218,000 was included in the 10 months ending October 2025.⁸⁸ The project is intended

⁸⁷ ROM = Rough Order of Magnitude is an adjustment to compensate for forecasting errors in preliminary project cost estimates.

⁸⁸ Exhibit AG-27 includes DR AG-CE-0616 with ATT_1.

1 to develop a system to identify, track, and trace the Company’s gas facilities from pipes to
2 fittings and other components.

3 This project was also proposed in Case No. U-21490. In discovery in that case, the
4 Attorney General asked the Company to provide the project cost/benefit analysis and the
5 project development phases including the current phase of the project. In response, the
6 Company provided a copy of the project cost analysis showing that the estimated cost of
7 the project was in excess of \$15 million to be developed over the 2025 to 2027 timeframe.
8 No cost savings or financial benefits were identified for the project. The Company also
9 disclosed that the project last year was in the investment planning phase.⁸⁹

10 This rate case, the Company reported in response to discovery that the project is in the
11 Origination phase, which seems to be equivalent or close to the same stage of development
12 that it was in last year.⁹⁰ Page 138 of Exhibit A-21 (SHB-6) shows an update project cost
13 of \$17 million, including O&M development costs. No cost savings or financial benefits
14 have been identified in the financial analysis and the Benefit/Cost ratio is a negative 1.0,
15 meaning the project entails only costs and no financial benefits.

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

18 A. Aside from the fact the project is not economically justified, the project is in the early stage
19 of development being in the Origination phase. It appears that only high-level

⁸⁹ U-21490 Exhibit AG-31 includes DR AG-CE-0221 with related attachments.

⁹⁰ Exhibit AG-27 includes DR AG-CE-0370.

1 requirements have been identified and not much work has been done to assess and match
2 detailed system requirements to the prospective system to be acquired or developed. Given
3 the preliminary stage of development and the lack of an economic case for the project, I
4 recommend that the Commission remove the capital expenditures of \$2,218,000 for the 10
5 months ending October 2025 and \$5,295,000 from the projected test year, along with
6 \$509,000 from O&M expense.

7 **2. SAP-ERP Project (SAP S/4HANA)**

8 **Q. PLEASE BRIEFLY DISCUSS THE NEW SAP-ERP SYSTEM DEVELOPMENT**
9 **PROJECT PROPOSED BY THE COMPANY AND THE RELATED CAPITAL**
10 **EXPENDITURES.**

11 A. Beginning on page 104 of her direct testimony, Ms. Baker discusses the implementation
12 of a new Enterprise Resource Planning (ERP) system with SAP Software Company (SAP).
13 The Company also refers to this system as the SAP S4/HANA development project. The
14 Company identified the total cost of the project at [Begin Conf] [REDACTED]

15 [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED]
19 [REDACTED]
20 [REDACTED]

⁹¹ Exhibit AG-28 CONF includes DR AG-CE-0610 ATT_1 CONF.

1 [Redacted] [End
2 Conf].

3 In her direct testimony, Ms. Baker states that the current ERP system with SAP needs to
4 be modernized because it will reach the end of mainstream vendor maintenance on
5 December 31, 2027. Although the system would be modernized with a new software
6 system, it will basically replace the same functions of the current ERP system of billing,
7 materials purchasing, warehousing, finance, accounting, payroll, customer relationship
8 management, and other technical functions.⁹² In response to discovery, the Company
9 stated that the current SAP-ERP system functions well and it is being replaced because of
10 the end of system support by SAP.⁹³ This is clearly a case of forced obsolescence by the
11 vendor in order to sell new software, services, and technology.

12 On page 108 of her direct testimony, Ms. Baker states that the Company will extend the
13 current system support and maintenance service with SAP past the December 2027 date
14 and into 2028, noting that the extended support is only available until 2030. In discovery,
15 the Attorney General asked the Company whether it had asked SAP to extend the service
16 and support agreement through and potentially past 2030. In response, the Company stated
17 that it had not done so and pointed out that it would need to purchase extended support,⁹⁴
18 which in a subsequent discovery response the Company identified at [Begin Conf]
19 [Redacted] [End Conf].⁹⁵ This fee for system support is logical and is likely similar to

⁹² Id. includes DR AG-CE-0622 with ATT_1 CONF and AG-CE-0850 CONF.

⁹³ Exhibit AG-29 includes DR AG-CE-0624.

⁹⁴ Id.

⁹⁵ Exhibit AG-28 CONF includes DR AG-CE-0851.

1 what the Company currently pays for system support and software releases and upgrades.
2 Operating the current system past 2030 is a viable solution given that the system is still
3 functioning well and is meeting all the operating requirements of the Company.

4 Furthermore, the Company has not identified any cost savings or financial benefits for
5 implementation of a new ERP system. The project financial analysis on page 121 of
6 Exhibit A-21 Confidential show the project costs but no financial benefits and a negative
7 Cost/Benefit ratio of negative 1.0, meaning the project is not financially justified.

8 **Q. DID THE COMPANY IDENTIFY THE CURRENT STATUS AND PHASE OF**
9 **DEVELOPMENT OF THE NEW SAP-ERP PROJECT?**

10 A. Yes. In response to discovery, the Company stated that the project is currently in the
11 Investment Planning phase and it is currently preparing a Request for Proposal (RFP) to
12 be issued to different vendors in May 2025.⁹⁶ Although the Company seems to have a
13 high preference to stay with SAP to simplify the conversion to the new system, it is not
14 clear yet who the winning bidder will be and which system the Company will ultimately
15 select to implement and at what cost.

16 **Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION REGARDING THE**
17 **COMPANY PROPOSED IMPLEMENTATION OF A NEW ERP SYSTEM?**

18 A. From the discussion above, it is clear that the current ERP system still functions well and
19 meets the operating needs of the Company. The option also exists for the Company to

⁹⁶ DR AG-CE-0622d (Exhibit AG-28 CONF) and DR AG-CE-0625 in Exhibit AG-29.

1 continue to operate the system into 2030 and potentially past that date with system support
2 by SAP. The Company still has not selected a vendor for the new ERP system and will
3 likely undertake the evaluation of the optimal system to purchase in the second half of
4 2025. From various aspects, it is premature to include any capital expenditures in this rate
5 case and to defer large forecasted O&M costs in a regulatory asset without firm plans for
6 project execution.

7 Therefore, I recommend that the Commission remove the [Begin Conf] [REDACTED]
8 [REDACTED]
9 [REDACTED]
10 [REDACTED]
11 [REDACTED] [End Conf].

12 **3. ARP-OT Support Gas**

13 **Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE**
14 **COMPANY’S FORECASTED CAPITAL EXPENDITURES FOR THE**
15 **PURCHASE OF SERVERS AND RELATED EQUIPMENT UNDER THE ARP-OT**
16 **GAS SUPPORT PROGRAM.**

17 A. On pages 61 and 62 of her direct testimony, Ms. Baker discusses the purchase of computer
18 servers and related equipment on a five-year cycle, as this equipment ages and becomes
19 obsolete. On page 7 of Exhibit A-22, the Company shows the actual capital expenditures
20 of \$245,000 for 2023 and forecasted amounts of \$1,033,000 for 2024, \$979,000 for 2025,
21 \$816,000 for the 10 months ending October 2025, \$2,766,000 for 2026, and \$2,488,000
22 for the projected test year.

1 In response to discovery, the Company provided actual capital expenditures for 2022 and
2 2024.⁹⁷ The information provided by the Company both in its filed exhibit and in response
3 to discovery shows considerable variability in capital spending for a program that
4 functions on a routine five-year replacement cycle. Most concerning is the large increase
5 in capital expenditures in 2026 and the projected test year. The average capital spending
6 over the historical three years from 2022 to 2024 was \$496,000. For the 10 months ending
7 October 2025, the Company proposes to nearly double that amount to \$816,000 and for
8 the projected test year increase it five-fold to \$2,468,000.

9 Given the historical variability in spending on the program, I propose that the capital
10 expenditures for the forecasted periods be set at the three-year historical level plus an
11 adjustment for forecasted inflation. For 2025, the inflation adjusted amount is \$508,000
12 or \$423,000 for the 10 months ending October 2025. This amount is \$393,000 lower than
13 the \$816,000 forecasted by the Company.

14 For 2026, the inflation adjusted capital expenditures are \$521,000 with \$519,000
15 applicable to the projected test year.⁹⁸ The \$519,000 is \$1,949,000 lower than the
16 Company's forecast of \$2,468,000 for the projected test year.

17 To set the capital expenditures for this program at a reasonable level, I recommend that
18 the Commission approve the forecasted capital expenditures I calculated and remove the

⁹⁷ Exhibit AG-30 includes DR AG-CE-0638 with attachment.

⁹⁸ Two months from 2025 and 10 months from 2026.

1 excess amount of \$393,000 for the 10 months ending October 2025 and \$1,949,000 for the
2 projected test year from the Company's forecasted capital expenditures.

3 **4. ARP-Physical Security**

4 **Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE**
5 **COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE ARP-**
6 **PHYSICAL SECURITY PROJECT.**

7 A. On pages 62 and 63 of her direct testimony, Ms. Baker discusses upgrading the Company
8 physical security system by installing advanced door systems at its various buildings,
9 installing additional and upgraded security cameras, and various other equipment. The
10 proposed capital expenditures for the projected test year are \$747,000. Ms. Baker's
11 testimony does not identify significant problems with the current security equipment and
12 doors other than a desire to refresh the equipment.

13 In discovery the Attorney General asked the Company to identify major problems
14 experienced in the past three years and why advanced door systems were necessary. The
15 Company was also asked to confirm that it already has security cameras, gate and lock
16 systems, and other security equipment in place. In response to discovery, the Company
17 stated that some cameras are no longer working, they require cleaning and is experiencing
18 failures in some of the equipment. This information indicates routine problems that require
19 repair or replacement of certain items, as they fail, and not a wholesale investment in new
20 equipment and technology.⁹⁹

⁹⁹ Id. includes DR AG-0616 and 0849.

1 From the information gathered from the Company, my conclusion is that this is not a
2 priority project and should not be undertaken at this time given other more pressing
3 priorities for gas infrastructure upgrades. Therefore, I recommend that the Commission
4 remove the \$747,000 from the Company's forecast capital expenditures for the projected
5 test year.

6 **5. Forward Web Proxy Services**

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

10 A. On pages 115 and 116 of her direct testimony, Ms. Baker discusses undertaking this IT
11 system project to replace a system currently in place with a third-party vendor. The
12 Forward Web Proxy Services system works as a filtering process to direct customer
13 internet inquiry traffic to different subsystems in the Company's web server. According
14 to Ms. Baker's direct testimony the Company has experienced technical glitches with the
15 vendor service and now wishes to develop its own software at a cost of \$4.5 million with
16 \$1.2 million assigned to the gas business for the projected test year. The Company has
17 adjusted this amount down to \$939,000 after the ROM adjustment for inclusion in this rate
18 case.

19 In discovery, the Attorney General asked the Company to identify the total cost of the
20 project for both the gas and electric portions of the company, the frequency and number
21 of problems experienced, the cost/benefit analysis to justify undertaking the project, and

1 whether the Company has worked with the current service provider to resolve the technical
2 problems and improve the level of service provided. In response, the Company provided
3 the number of incidents and impact days on Company operations for the three years 2022-
4 2024. The information provided shows that the number of incidents declined significantly
5 in 2024 from prior years with few incidents and impacts on non-critical functions and no
6 incidents and impact on Company operations.¹⁰⁰

7 The Company also reported that it has been working with the vendor and acknowledged
8 service improvement overall in the past year with still some lingering issues. The
9 Company's financial analysis for the new proposed project shows a cost/benefit ratio of
10 negative 1.0, meaning that no financial benefits have been identified to undertake this
11 project.

12 My conclusion from the information provided by the Company is that the new software
13 development project is not necessary at this time and not a priority project that should be
14 undertaken for the projected test year. Therefore, I recommend that the Commission
15 remove the \$939,000 from the forecasted capital expenditures for the projected test year
16 along with the \$180,000 of O&M expense.

17 **6. OT Data Center Migration and Access Management Projects**

18 **Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE**
19 **COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE OT DATA**

¹⁰⁰ Exhibit AG-31 includes DR AG-CE-0630.

1 **CENTER MIGRATION AND PHYSICAL ACCESS MANAGEMENT AND**
2 **ALARM RESPONSE PROJECTS.**

3 A. On pages 100 and 101 of her direct testimony, Ms. Baker discusses the relocation of the
4 servers and systems, which monitor some of the Company’s electric and gas operations,
5 from the current location at the Parnel building to another location. Apparently, the
6 Company has experienced some problems with climate and water infiltration into the
7 building and feels that the situation is unreparable and untenable. The cost of the
8 relocation and associated equipment upgrades is \$11 million between capital expenditures
9 and O&M development costs, of which \$3.6 million would be assigned to the gas business.
10 The amount of capital expenditures included in this rate case is \$1,441,000 after the ROM
11 adjustment with \$716,000 of O&M development costs for the projected test year.

12 In response to discovery, the Company elaborated about the water infiltration risk and the
13 aging climate equipment. From the information provided, it is not clear why these
14 problems cannot be fixed at a lower cost than \$11 million and the current location made
15 safe and workable. In the discovery response, the Company also stated that the project is
16 currently in the investment planning phase, which indicates that it is in the early stage of
17 development.¹⁰¹

18 Regarding the Physical Access Management and Alarm Response project, Ms. Baker
19 discusses the replacement of the current physical access management system that manages
20 user identity, authentication, access to facilities, and reports on user activities. The

¹⁰¹ Id. includes DR AG-CE-0621.

1 Company finds the current system out of date, with inconsistent behavior, and some
2 glitches in its operation, which allegedly create work inefficiencies.

3 In discovery the Attorney General asked the Company to provide the total company cost
4 of the project, identify some of the major problems currently experienced, explain why the
5 problems with the current system cannot be fixed at a lower cost, and provide a copy of
6 the cost/benefit analysis showing that the cost savings from removing work inefficiencies
7 and other financial benefits justify undertaking the project.

8 In response to discovery, the Company reported that the total cost of the project, including
9 both capital expenditures and O&M development costs, would be approximately \$7.0
10 million of which \$2.2 million would be assigned to the gas business. For the projected test
11 year in this rate case, the Company has included \$678,000 of capital expenditures after the
12 ROM adjustment and \$102,000 of O&M expense.¹⁰²

13 The Company also identified a dozen or so technical glitches during 2024 which were
14 resolved in minutes or generally within 24 hours. The Company also reported that it has
15 worked with the vendor of the current system to resolve issues and made a system upgrade
16 in 2024. Regarding the new proposed system, the Company stated that it has not yet
17 chosen a specific vendor and will be conducting an RFP at some later date.¹⁰³ The
18 financial analysis prepared by the Company shows no cost savings or financial benefits

¹⁰² Id. includes DR AG-CE-0631 with ATT_1.

¹⁰³ Id. includes DR SA-CE-004.

1 from the implementation the new system despite claims of cost savings from reduced
2 equipment purchases and waste reductions.

3 **Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS FOR THE**
4 **TWO PROPOSED PROJECTS DISCUSSED ABOVE?**

5 A. The Company has not present sufficient information that it has performed a robust analysis
6 to continue to use the existing assets with appropriate changes and upgrades that will avoid
7 a combined \$18 million of capital expenditures and O&M development costs for the two
8 projects. Furthermore, the two projects are still in the initial phase of development with
9 no specific systems or vendors evaluated. The two projects are still premature and the
10 costs still preliminary and uncertain to include in rate base and O&M expense in this rate
11 case.

12 Therefore, I recommend that the Commission remove \$2,119,000 of capital expenditures
13 and \$818,000 of O&M expense for the two projects from this rate case.

14 **7. IT Projects – 2024 Capital Expenditures**

15 In discovery the Attorney General asked the Company to provide the actual amount spent
16 on all IT capital programs during 2024. In response the Company reported that it spent
17 \$26,378,000 in 2024.¹⁰⁴ In Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, the Company
18 shows that it included \$32,046,000 of capital expenditures for 2024 in this rate case. The
19 difference is an underspent amount of \$5,668,000. This amount should be removed from
20 rate base in this rate case. The Company did not incur this cost and it is not fair or

¹⁰⁴ Exhibit AG-32 includes DR AG-CE-0637 with attachment.

1 reasonable for the Company to earn a return and recover depreciation expense for costs in
2 it did not incur.

3 Therefore, I recommend that the Commission remove the 2024 underspent amount of
4 \$5,668,000 from rate base in this rate case.

5 **E. Transportation Fleet & Equipment Capex**

6 **Q. PLEASE DISCUSS WHAT ADJUSTMENTS YOU PROPOSE TO THE**
7 **COMPANY'S FORECASTED CAPITAL EXPENDITURES FOR THE**
8 **TRANSPORTATION FLEET AND EQUIPMENT.**

9 A. On page 1 of Exhibit A-12 (CEB-1) the Company shows forecasted capital expenditures
10 for Fleet Vehicle purchases, including electric vehicle purchases, of \$9.7 million for 2024,
11 \$6.8 million for the 10 months ending October 2025, and \$13.3 million for the projected
12 test year. On page 1 of Exhibit A-28 (CEB-3), the Company provided further details of
13 purchases by vehicle type with quantities and related dollars from 2023 to 2026 and the
14 projected test year.

15 In discovery, the Attorney General asked the Company to expand Exhibit A-28 to include
16 actual data for 2022 and 2024, explain the reasons for higher purchases of certain vehicle
17 types in 2026, and correct certain missing information. Based on the additional
18 information provided by the Company, I calculated an average purchased cost per vehicle
19 of \$76,892 based on the actual number of vehicles purchased in 2024. The average cost
20 per vehicle purchased in 2023 and 2022 was lower at \$66,406 and \$61,293, respectively.
21 In comparison, the Company's forecasted costs per vehicle for 2025 and the 2026

1 projected test year are \$118,128 and \$126,505, respectively. The forecasted increase over
2 the 2024 actual cost per vehicle is 54% for 2025 and 65% for 2026 purchases.¹⁰⁵

3 The forecasted cost increases are excessive and unsupported. To develop a reasonable
4 forecast for 2025 and 2026, I used the 2024 average cost per vehicle of \$76,892 and applied
5 the inflation factors of 2.4% and 2.5%. Based on these factors, I calculated an average
6 vehicle cost of \$78,737 for 2025, which multiplied by the 86 vehicles forecasted to be
7 purchased for the year results in forecasted capital expenditures of \$6,771,000 or
8 \$5,643,000 for the 10 months ending October 2025. This amount is \$1,202,000 lower than
9 the \$6,845,000 forecasted by the Company

10 For the projected test year, I calculated an inflation adjusted cost per vehicle of \$80,705,
11 which multiplied by the 105 vehicles planned to be purchased for the period results in
12 forecasted capital expenditures of \$8,474,000. This amount is \$4,809,000 lower than the
13 Company's forecasted amount of \$13,283,000.

14 To moderate the Company's excessive forecasted cost increases and capital expenditures,
15 I recommend that the Commission remove \$1,202,000 for the 10 months ending October
16 2025 and \$4,809,000 for the projected test year.

¹⁰⁵ Exhibit AG-33 includes DR AG—CE-0648 with attachment.

1 **F. Capital Expenditures - Summary**

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

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

7

Summary of AG Disallowed Capital Expenditures	
Revised	
	Amount (millions)
Distribution Plant	\$ 322.5
Transmission Plant	67.7
Gas Storage & Compression	100.9
Information Technology	35.8
Transportation Fleet	6.0
Total	\$ 533.0

8 Based on my analysis and the information presented in my testimony above, I recommend
9 that the Commission reduce the Company’s proposed capital expenditures by ~~\$563.0~~533.0
10 million and reduce average rate base by ~~\$535.1~~514.7 million, including an adjustment to
11 working capital of \$154 million, as shown in Exhibit AG-34. The resulting effect of the
12 lower rate base from the reduction in capital expenditures is a reduction in the revenue
13 deficiency of ~~\$42.7~~41.1 million.

1 **V. Depreciation Expense**

2 **Q. PLEASE DISCUSS THE DEPRECIATION EXPENSE ADJUSTMENT THAT**
3 **YOU PROPOSE.**

4 A. In Exhibit AG-34 CONF Revised, I identified the adjustments to be made to the
5 Company’s proposed capital expenditures. Those reductions lower the amount of
6 depreciation expense that the Company will incur during the projected test year. On the
7 same exhibit, I have calculated the reduction in depreciation expense of ~~\$13.7~~ \$13.3
8 million. I recommend that the Commission reduce the Company’s depreciation expense
9 by this amount for the projected test year.

10 **VI. Property Tax Expense**

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

13 A. In Exhibit AG-34 CONF Revised, I identified the adjustments to be made to the
14 Company’s proposed capital expenditures. Those reductions lower the amount of property
15 tax expense that the Company will incur during the projected test year. On the same
16 exhibit, I have calculated the reduction in property tax expense of ~~\$3.9~~ \$3.7 million. I
17 recommend that the Commission reduce the Company’s property tax expense by this
18 amount for the projected test year.

1 **VII. Working Capital**

2 **Q. THE COMPANY PROPOSED \$1.468 BILLION OF WORKING CAPITAL IN THIS**
3 **CASE.¹⁰⁶ DO YOU AGREE WITH THIS LEVEL OF WORKING CAPITAL?**

4 A. No. I recommend five changes in the working capital level, which total \$154.0 million.
5 These changes reduce the amount of Working Capital to \$1.314 Billion. The first change
6 reduces the Company's cash balance by \$16.1 million. The second change corrects an
7 error in deferred cloud computing costs for the SAP S/4 Hana project. The third item
8 pertains to a correction of other cloud computing deferred and amortized cost for the
9 projected test year. The adjustment to working capital for this item is approximately \$1.0
10 million. The fourth change removes \$7.4 million of deferred costs for the estimated loss
11 from the planned sale of the Riverside Storage field assets. The fifth change corrects an
12 error in the calculation of accrued taxes for a reduction in working capital of \$127.8
13 million. These changes are summarized on Exhibit AG-35.

14 **Q. PLEASE EXPLAIN YOUR PROPOSED INCREASE OF \$16.1 MILLION TO THE**
15 **COMPANY'S FORECASTED CASH BALANCE.**

16 A. As shown in Exhibit A-12 (HLR-34), Schedule B-4, the historical cash balance for 2023
17 was \$8.7 million. The average cash balance for the 13 months ended June 2024 decreased
18 to \$7.3 million, as shown in column (d) of the exhibit. The Company proposes to increase
19 this recent average cash balance by an additional \$21.1 million to arrive at the projected

¹⁰⁶ See Exhibit A-12 (HLR-34), Schedule B4

1 test year cash balance of \$28.4 million. According to page 39 of Mr. Bleckman's direct
2 testimony, the Company bases its adjustment and level of cash on hand on an assumed
3 ratio of 1% of cash on hand to revenues from an analysis it performed a few years ago for
4 a group of utilities. However, there are several problems with this approach.

5 First, the Company's current revenues are \$2.28 billion.¹⁰⁷ If we were to rely on the 1%
6 ratio, the forecasted case on hand should be \$22.8 million and not \$28.4 million. Even
7 using the Company's forecasted revenues of \$2.53 billion would yield a lower cash
8 balance. Of course, using the forecasted revenues would not be appropriate because the
9 Company is not likely to receive the entire additional revenue of \$248 million it seeks in
10 this rate case.

11 Second, cash on hand is not used to pay for revenues. It is used to pay operating expenses,
12 capital expenditures, and dividends to the parent company. Therefore, the ratio that the
13 Company has calculated to revenues has no logical connection to the need to keep cash on
14 hand. Third, utilities maintain different levels of cash on hand during different months of
15 the year depending on their seasonal needs for cash to pay for gas purchases, fund gas
16 inventories and pay for operating expenses and construction costs. The seasonality of cash
17 requirements is particularly pronounced for gas utilities given the large variability in
18 monthly gas sales, purchases and gas inventories.

¹⁰⁷ Exhibit A-16, Schedule F2, page 1.

1 Fourth, every utility has different short-term borrowing facilities and different practices as
2 to how they use or do not use them and may retain more or less cash on hand depending
3 on those circumstances. Therefore, using an average ratio of cash on hand to revenues at
4 a specific point in time does not take into consideration the unique aspect of a particular
5 utility. Fifth, the analysis that the Company performed to arrive at the 1% ratio was based
6 on cash reported by the other utilities in the financial statements. Those cash balances
7 include cash invested in short-term securities under generally accepted accounting
8 practices (GAAP). The Commission does not allow those short-term cash investments
9 with interest bearing securities in the calculation of cash on hand for inclusion in working
10 capital. Therefore, the 1% is likely inflated and inapplicable for ratemaking in a Michigan
11 rate case.

12 In his testimony in this rate case, Mr. Bleckman implies that in Case No. U-21389, the
13 Commission reconfirmed the use of the 1% ratio. However, a more thorough review of
14 the order shows that the Commission seemingly is not wedded to the Company's approach
15 by stating:

16 The Commission agrees that Consumers' 13-month average method is consistent with
17 past approvals of methods to determine cash balances and is reasonable given the
18 abnormal disruption in the company's typical cash balance. See, 4 Tr 627-628, 795-
19 800. However, the Commission notes that while it finds that the circumstances
20 described by Consumers in this case constitute an abnormal disruption, the
21 Commission will continue to evaluate the facts and circumstances of each rate case to
22 determine whether deviation from the historical period is appropriate.¹⁰⁸

¹⁰⁸ Case No. U-21389, MPSC order dated March 1, 2024.

1 In Case U-21585, I provided evidence that the Company has had a propensity in recent
2 rate cases to forecast cash balances that are well above the actual cash that the Company
3 ultimately keeps on hand, which inflates rate base and allows the Company to earn a return
4 on non-existing cash holdings. Although in that rate case, the Commission decided to
5 accept the Company's proposed cash balance, it made it clear that a different approach
6 may be in order in future rate case by stating:

7 Nevertheless, considering the company's actual cash balance amounts in recent years,
8 as illuminated by the Attorney General, and the Commission's evaluation of the facts
9 and circumstances surrounding this issue on a case-by-case basis, the Commission
10 finds it appropriate for Consumers to provide further and a more specific explanation
11 in its next electric rate case as to why the company's approach to determining its cash
12 balance remains appropriate and should continue to be approved.¹⁰⁹

13 In line with the Commission order, I propose in this rate case to use the average cash
14 balance that the Company actually held over the past three years based on the 13-month
15 average cash balances at the end of each year 2022, 2023, and 2024. This three-year
16 approach provides a normalized average of the cash needs of the Company over the most
17 recent three years and is specific to the Company and its needs for cash on hand. As shown
18 in Exhibit AG-35, the three-year average of cash on hand held by the Company was \$12.3
19 million, which is \$16.1 million lower than the amount forecasted by the Company. The
20 \$12.3 million is further supported by the Company's analysis provided in response to
21 discovery.¹¹⁰

¹⁰⁹ Case No. U-21585, MPSC order dated March 21, 2025 at page 213.

¹¹⁰ Exhibit AG-36 includes DR AG-CE-0498.

1 Therefore, I recommend that the Commission reject the Company's 1% ratio calculation
2 approach and instead adopt my proposed cash balance of \$12.3 million for the projected
3 test year and remove \$16.1 million from the Company's forecasted working capital and
4 rate base in this rate case.

5 **Q. PLEASE EXPLAIN THE REDUCTION OF \$1.7 MILLION TO DEFERRED**
6 **COSTS FOR THE IT SAP S/4 HANA CLOUD IMPLEMENTATION PROJECT.**

7 A. As discussed in the Capital Expenditures section of my testimony, the Company is
8 proposing to implement a new ERP system referenced as the SAP S/4 Hana system. As
9 part of the implementation, the Company proposed to run the system as a cloud computing
10 application. In this rate case, the Company forecasted that it would incur cloud computing
11 costs beginning in November 2025 through October 2026 accumulating to [Begin Conf]
12 [REDACTED] [End Conf] as of the end of October 2026, which it proposes to defer to a
13 regulatory asset account for later amortization to expense. In Exhibit A-26 (SHB-11)
14 Confidential, the Company shows a calculated 13-month average balance of [Begin Conf]
15 [REDACTED] [End Conf] in the deferred account for the projected test year. This amount is
16 also shown in column (n) of Exhibit A-12, Schedule B4

17 In response to discovery requesting the basis for the calculation of the deferred balance,
18 the Company reported that it had made an error in the calculation of the deferred balance
19 by including the total company costs instead of only the gas business portion.¹¹¹ With the

¹¹¹ Exhibit AG-37 CONF includes DR AG-CE-0628, part (b), and Attachment 1 Confidential.

1 discovery response, the Company provided a revised schedule showing a corrected
2 average deferred balance of [Begin Conf] ██████████ [End Conf] for the gas portion of its
3 business. Accordingly, the Commission should remove the excess amount of [Begin Conf]
4 ██████████ [End Conf] from the Company's proposed working capital balance.

5 **Q. PLEASE EXPLAIN THE OTHER ADJUSTMENT TO CLOUD COMPUTING**
6 **DEFERRED COSTS AND AMORTIZATION EXPENSE THAT YOU HAVE**
7 **IDENTIFIED.**

8 A. In column (g) of Exhibit A-12, Schedule B-4, the Company shows an increase of
9 \$2,724,000 in working capital for the projected test year pertaining to Prepaid Cloud
10 Computing. The Company's workpaper WP-HLR-25 calculated this amount.¹¹² In recent
11 years, the Company has moved more IT functions and processing to the "IT cloud" and
12 has accumulated pre-paid fees paid to the suppliers of cloud services. In discovery, the
13 Attorney General asked the Company to justify the increase in deferred costs and the
14 underlying balances and amortizations to expense.

15 In response, the Company stated that some errors were made in compiling the deferred
16 costs and the resulting amortization expense, which also affected the average deferred
17 balance for the projected test year. The revised information provided by the Company
18 shows that the average deferred balance for the projected test year declines by \$1,034,000

¹¹² Exhibit AG-38 includes WP-HLR-25.

1 from \$7,320,000 to \$6,286,000 after the correction. The amortization expense for the
2 projected test year declines by \$5,478,000 from \$17,352,000 to \$11,874,000.

3 Therefore, I recommend that the Commission reduce the projected working capital balance
4 by \$1,034,000 and remove \$5,478,000 from the Company's forecasted amortization
5 expense in this rate case.

6 **Q. PLEASE EXPLAIN WHY YOU ADVOCATE THE REMOVAL OF THE \$7.4**
7 **MILLION OF DEFERRED COSTS FOR THE RIVERSIDE STORAGE FIELD**
8 **ASSETS INCLUDED IN WORKING CAPITAL.**

9 A. In column (m) of Exhibit A-12, Schedule B4, the Company included \$7,398,000 pertaining
10 to the deferral and amortization of a loss from the expected sale of assets of the Riverside
11 storage field. In response to discovery, the Company disclosed that subsequent to the filing
12 of this rate case, the prospective buyer chose to terminate the preliminary agreement to
13 purchase the assets. Although the Company is in discussions with another prospective
14 buyer, the terms and timing of any potential agreement are currently unknown.¹¹³

15 Therefore, I recommend that the Commission remove the \$7,398,000 from the Company's
16 forecasted working capital for the projected test year.

17 **Q. PLEASE EXPLAIN YOUR CHANGE TO ACCRUED TAXES.**

¹¹³ Exhibit AG-39 includes DR AG-CE-500, 0817, and WP-HLR-34

1 A. In column (k) of Exhibit A-12 (HLR-34), Schedule B-4, the Company reduces Accrued
2 Taxes and increase working capital by \$138.9 million to arrive at a \$12.4 million balance
3 in the projected test year. Ms. Rayl, who sponsors this exhibit, provided no explanation
4 for this large change in her direct testimony.

5 In discovery, the Attorney General asked the Company to explain the large change in
6 Accrued Taxes and provide the supporting calculations. In response, the Company
7 reported that the calculation for Accrued Taxes in the project test year was incorrect and
8 should have been higher by \$127,805,000.¹¹⁴

9 Accordingly, I have adopted the Company's corrected balance of \$140,204,000, which
10 reduces working capital by \$127,805,000. I recommend that the Commission approve this
11 revision.

12 In summary, the changes discussed above result in a reduction of \$154 million to working
13 capital. I recommend that the Commission adopt this decrease in working capital for the
14 projected test year.

15 **VIII. Capital Structure and Cost of Capital**

16 **CAPITAL STRUCTURE**

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

¹¹⁴ Exhibit AG-40 includes DR AG-CE-499.

1 A. I recommend that the capital structure shown on page 1 of Exhibit AG-41 be used in this
2 case. The first three lines show the projected long-term debt, preferred equity and common
3 equity capital of the Company, which represents the permanent capital structure for the
4 test period ending October 2026. The capital balances in this exhibit reflect the amounts
5 shown in Company Exhibit A-14 (MRB-1), Schedule D1, with an adjustment to rebalance
6 the capital structure. The long-term debt component in Exhibit AG-41 has been increased
7 by ~~\$150~~\$194 million and the common equity component has been reduced by the same
8 amount. The result is a capital structure with 50% of common equity and 50% of debt and
9 preferred stock.

10 Q. **WHY DID YOU INCREASE LONG TERM DEBT BY ~~\$150~~\$194 MILLION AND**
11 **OFFSET THIS CHANGE WITH LOWER COMMON EQUITY OF ~~\$150~~\$194**
12 **MILLION?**

13 A. The Company has proposed a permanent capital structure with a common equity
14 component of 50.75%. This level of common equity exceeds the 50% equity ratio
15 approved by the Commission in the Company's last two fully contested rate cases, Case
16 Nos. U-21585 and U-21389.¹¹⁵ The capital structure in this rate case should similarly
17 mirror the common equity ratio last approved on March 21, 2025 of 50%. As discussed
18 in my testimony in Case No. U-21585, there are several factors that clearly support a 50%
19 common equity level.

¹¹⁵ Case No. U-21585 Commission order dated March 21, 2025 and Case No. U-21389 dated March 1, 2024. In Case No. U-23189, the Commission approved an equity ratio of 50.02%.

1 These factors include (1) the Commission’s consistent directive in the Company’s prior
2 electric and gas rate cases, which stated that a 50/50 capital structure is desirable and
3 appropriate to ensure reduced costs to customers and maintain the Company’s strong
4 financial position, unless the Company can demonstrate that a higher ratio is justified; (2)
5 The Company’s strong cash flow to debt coverage ratio and credit ratings; (3) the
6 Company’s common equity capital contributions by the parent company, albeit often
7 funded with long term debt issued at the parent company level; (4) the favorable regulatory
8 environment in Michigan supported by historical returns on common equity above
9 industry averages and in the top tier of the Company’s peer group; and (5) the fact that the
10 common equity ratio of the peer group, used to assess the cost of common equity in this
11 case, is approximately 47%.¹¹⁶

12 **Q. PLEASE EXPLAIN YOUR ASSESSMENT OF THE COMMISSION’S**
13 **DIRECTIVE TO THE COMPANY TO REBALANCE ITS CAPITAL**
14 **STRUCTURE TO EQUAL AMOUNTS OF DEBT AND EQUITY CAPITAL.**

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

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

¹¹⁶ Exhibit AG-46 shows that the equity ratio for each peer company and the peer group average ratio of 47.3%.

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

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

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

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

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

18 **Q. IN THE MOST RECENT MOODY'S CREDIT REPORT COVERING**
19 **CONSUMERS ENERGY, WHAT ARE THE REPORTED CASH FLOW TO DEBT**
20 **RATIO RESULTS?**

1 A The most recent Moody’s report of May 2024 shows the Company’s performance under
2 the CFO Pre-W/C to Debt ratio at 19.1% for 2023, 20.0% for 2022, 22.6% for 2021, and
3 21.5% for 2020, all of which are above the 18% downgrade threshold level.¹¹⁷

4 **Q. WHAT DID S&P STATE IN ITS MOST RECENT CREDIT REPORT ABOUT**
5 **CONSUMERS ENERGY’S CREDIT PROFILE?**

6 A. The S&P August 20, 2024 credit report on the Company states “Michigan’s regulatory
7 construct is above average compared to peers.” The report also points to the stream-lined
8 10-month rate case process, as well as the power supply and natural gas cost rider
9 adjustments, which help the Company to earn its authorized ROE. S&P also notes that the
10 Company’s senior secured debt is rated as “A” by S&P (the middle of the “A” category).¹¹⁸

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

13 We could lower our rating on CE if its stand-alone financial measures weaken such
14 that its FFO to debt weakens to consistently below 15% or we lower our rating on
15 parent, CMS Energy Corp.¹¹⁹

16 However, page 5 of the report shows that the coverage ratio was 17.6% for 2023. S&P
17 also estimated this ratio in the range of 18.3% for 2025 and 2026. These coverage ratios
18 are not indicative of any concerns about a possible debt rating downgrade and are well
19 above the 15% threshold set by S&P. On page 3 of the report, S&P states that the

¹¹⁷ Exhibit AG-51 includes DR AG-CE-0444 with the Moody’s credit report dated May 31, 2024 with ratio data shown.

¹¹⁸ Exhibit AG-51 includes DR AG-CE-0444 and the S&P report dated August 20, 2024

¹¹⁹ S&P’s FFO to debt ratio is similar to the Moody’s cash flow ratio “CFO Pre W/C referred to earlier.

1 Company's credit metrics were weak in 2023 largely due to weather-related issues which
2 they characterize as "mild sales and convective [higher] storm activities." S&P clearly
3 understood that the decline in the coverage ratio in 2023 was temporary and not reflective
4 of any long-term decline trends.

5 In 2023, the Company reported net income of \$865 million and a return on equity (ROE)
6 of 8.25% versus its authorized ROE of 9.90%. The lower net income and cash flow
7 temporarily reduced the coverage ratio. In 2024, the Company reported an increase of
8 16% in net income to over \$1.0 billion, or an increase of \$142 million over 2023. The
9 Company's earned ROE also increased to 9.1%.¹²⁰ As discussed in more detail below, the
10 increase in profitability nearer to the authorized ROE will boost the cash flow to debt
11 coverage ratio.

12 **Q. ON PAGE 15 OF HIS TESTIMONY, MR. BLECKMAN SATES THAT "THE**
13 **COMPANY'S FFO TO DEBT RATIO AS CALCULATED BY MOODY'S IS**
14 **TRENDING DOWN...WELL BELOW THE LOW END OF MOODY'S**
15 **EXPECTED RANGE..." DO YOU AGREE WITH THAT STATEMENT?**

16 A. No. Mr. Bleckman fails to explain the unusual and short-term issues faced by the Company
17 in 2022 and 2023, and mischaracterizes the situation in an attempt to mislead the
18 Commission. The cash flow to debt ratio declined somewhat in 2022 due to a temporary
19 increase in natural gas prices in 2022, which required the Company make larger short-term

¹²⁰ Based on total Consumers Energy reported net income of \$1.007 billion and average common equity of \$11,078.5 billion in the 2024 Form 10K.

1 borrowings. In 2022, this ratio was negatively impacted by higher gas rates which
2 increased the cost of gas purchases and gas inventories. This in turn caused the Company
3 to take on more debt which in turn reduced net income and increased the debt denominator
4 in the calculation of the coverage ratio.

5 Gas inventory levels increased from \$462 million in December 2021 to \$840 million in
6 December 2022. This increase of \$378 million in gas inventory required more temporary
7 debt financing for the year. The temporary increase in debt receded in 2023 and 2024.
8 Page 2 of Exhibit AG-49 shows that if we adjust for this temporary phenomenon the
9 Moody's FFO to Debt ratio would have been 20.9% instead of the actual result of 20%.

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

14 **Q. DID YOU CALCULATE THE IMPACT ON THE MOODY'S CASH FLOW TO**
15 **DEBT COVERAGE RATIO BASED ON A 50% EQUITY RATIO IN THE**
16 **COMPANY'S CAPITAL STRUCTURE AND AN AUTHORIZED ROE OF 9.75%**

17 A. Yes. On page 1 of Exhibit AG-49, I calculated the Company's key cash flow to debt ratio
18 for 2023 adjusted for the ROE and Common Equity ratio levels I advocate in this case. I
19 start with Moody's actual results for 2023 and adjust them to reflect a 9.75% ROE and a

1 50% common equity ratio. I chose 2023 because this is the most recent information
2 available from Moody's.

3 For my analysis of 2023 cash flow ratio results, I started with actual 2023 data on line 1 of
4 Exhibit AG-49. Next, on line 2, I adjust the capitalization to reflect a balanced capital
5 structure. This increases long-term debt and reduces common equity. On line 3, I adjusted
6 the cash flow upward to reflect a 9.75% ROE (versus the 8.25% ROE actually achieved in
7 2023). The result of these adjustments is shown on line 4 with a cash flow to debt ratio of
8 20.1%. This ratio is well above the 18% downgrade threshold noted by Moody's in its
9 most recent report.¹²¹ I have not presented any ratio results for S&P since the ratio
10 calculations are highly similar and the S&P downgrade threshold is lower at 15%.

11 I will point out that by starting with actual Moody's 2023 results, items such as leases and
12 short-term debt are already reflected in the cash flow and debt elements, which determine
13 the ratio. The Company often points to these as being "add-ons" which are not considered
14 in the permanent capital on a ratemaking basis. However, these are two separate
15 calculations for different purposes and should be confused with one another.

16 In summary, my analysis shows that the 9.75% ROE and 50% common equity ratio would
17 result in the Company's cash flow ratios being well above the long-term threshold levels
18 that would result in a credit downgrade.

¹²¹ Moody's indicates this to be "18% on a sustained basis".

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

3 A. No. S&P in its August 2024 report provides the following outlook for the Company:

4 The stable rating outlook on CE reflects our expectation that management will focus
5 on its core utility operations and reach constructive regulatory outcomes to avoid
6 increasing business risk. We expect CE will maintain stand-alone financial measures
7 consistent with the middle of the range for its financial risk profile category,
8 specifically FFO to debt of 17%-19%.¹²²

9 Similarly, in its May 31, 2024 report, Moody's provides the following rating outlook:

10 The stable outlook reflects our expectation that financial metrics will remain stable
11 and that Consumers Energy will continue to benefit from a consistent and generally
12 credit supportive regulatory environment. The stable outlook also incorporates our
13 view that Consumers Energy will maintain prudent financial policies while managing
14 through its robust investment cycle and that debt levels at the parent will not increase
15 materially.¹²³

16 Fitch Investor Service provided the following summary of the Company's credit profile in
17 its April 16, 2024 report:

18 Constructive Regulatory Environment: Fitch believes the regulatory environment in
19 Michigan under the Michigan Public Service Commission (MPSC) remains mostly
20 constructive from a credit perspective. The regulatory framework allows for full pass-
21 through of fuel costs and purchased power, forward-looking test years and a timely
22 10-month review period for general rate case resolution. Furthermore, Consumers
23 Energy's authorized ROE of 9.9% compares favorably with industry averages.
24 Increasing storm activity in Michigan and resultant power outages have attracted
25 regulatory focus on reliability. In March 2023, the MPSC tightened performance
26 standards for utilities by way of enhanced outage credits, and updated reliability
27 standards. An MPSC-led straw proposal for additional potential financial incentives
28 and disincentives has also been underway since August 2023. In Fitch's view, the risk
29 of performance-based penalties is manageable within Consumers Energy's current
30 credit profile. Fitch also does not expect a material negative outcome in the pending
31 audit ordered by MPSC in October 2022 to assess the compliance of Consumers

¹²² Exhibit AG-51 includes DR AG-CE-0444 with related attachment.

¹²³ Id.

1 Energy with storm outages and safety regulations during the 2021 storms in Michigan.
2 The final audit report is expected in summer 2024.¹²⁴

3 The credit reports provide a favorable outlook of the Company’s credit profile contrary to
4 Mr. Bleckman’s bleak predictions.

5 **Q. ON PAGE 21 OF HIS DIRECT TESTIMONY, MR. BLECKMAN REFERS TO**
6 **EXHIBIT A-107 (MRB-16), WHICH IS AN S&P REPORT NOTING NEGATIVE**
7 **CREDIT TRENDS IN THE UTILITY INDUSTRY. DO YOU BELIEVE THAT**
8 **THIS REPORT IS DIRECTLY APPLICABLE TO CONSUMERS ENERGY?**

9 A. No. The quoted information from the report noted on pages 21 and 22 of Mr. Bleckman’s
10 testimony is fairly generic. The key areas of concern on page 11 of the report, which Mr.
11 Bleckman omitted, are higher interest rates, changes to inflation, delays of offshore wind
12 projects, and rising taxes. On pages 7 and 8, the S&P report also points to concerns with
13 wildfire risks for utility companies west of the Mississippi River.

14 Most of these risks do not apply to the Company. First, CMS Energy and Consumers have
15 no off-shore wind projects. Second, the projected test year ratemaking construct used in
16 Michigan permits utility companies to recover projected costs and CPI inflationary
17 increases for O&M expenses and capital expenditures in setting new rates. Third,
18 regarding “higher interest rate risk”, most of the Company’s debt is long-term fixed-rate
19 debt with only seasonal short-term debt which are forecasted for the projected test year
20 and included in rates. In contrast, other utilities may use significant short-term debt and

¹²⁴ Id.

1 do not have a projected test year cost recovery mechanism. As such, the Company is in a
2 superior position on this issue relative to other utilities.

3 Fourth, S&P's concerns with the potential higher tax rates at this time appears to be a
4 minor risk. No federal legislation is currently being considered that would increase the
5 corporate income tax rate. Interestingly, on page 16 and 17 of his direct testimony, Mr.
6 Bleckman seems concerned that the corporate tax rate may decline from 21% to 15% and
7 have a negative effect on the cash flow to debt coverage ratio.

8 In summary, the Commission should dismiss the generic utility industry concerns raised
9 by Mr. Bleckman pertaining to the S&P report, as inapplicable to the Company's
10 regulatory and financial position.

11 **Q. ON PAGE 16 OF HIS TESTIMONY, MR. BLECKMAN DISCUSSES THE**
12 **POTENTIAL FOR NEW TAX LEGISLATION THAT COULD AFFECT THE**
13 **COMPANY'S CASH FLOW AND HE SUGGESTS THAT THIS ISSUE BE**
14 **CONSIDERED AS A FACTOR IN DETERMINING THE COMPANY'S ROE**
15 **RATE AND EQUITY RATIO IN THIS RATE CASE. DO YOU AGREE?**

16 A. No. Any discussion of reductions in the federal corporate income tax rate is pure
17 speculation. No such tax reduction proposal has been taken up by the U.S. Congress at
18 this time. Until such a time that tax legislation is passed and evaluated within a rate case,
19 the Commission should disregard the speculative proposition advanced by Mr. Bleckman.

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

4 A. There are several issues in the financial transactions between Consumers Energy and its
5 parent company, CMS Energy (“CMS”), which cannot be ignored when analyzing the
6 Company’s proposed capital structure. First, CMS can make the Company’s common
7 equity ratio whatever it wants. The same executive management that runs CMS Energy
8 also operates the Company. Management can direct at any time how much in capital it
9 wants to inject into the Company from the parent company and call it equity capital. In
10 fact, it has done just that over the years. In response to a discovery request, the Company
11 has stated that the injection of common equity from CMS Energy is at the discretion of
12 management with no approval from the Board of Directors.¹²⁵ Such freedom to call for
13 equity capital would not exist if Consumers Energy itself was a publicly traded company.

14 Over the five years 2020 to 2024, Consumers Energy’s Common Equity has increased
15 from \$7.7 billion at year end 2019 to \$11.4 billion in 2024, which is an increase of \$3.7
16 billion. An analysis of the Company’s financial statements filed with the Securities and
17 Exchange Commission shows that the \$3.7 billion increase is due to the following factors:

¹²⁵ CECO response to discovery request U-18322-AG-CE-439.

Table 1		
Consumers Energy		
Common Equity Change for Five Years (Dec. 2020 - 2024)		
		<u>\$ Billions</u>
1	Net Income of Consumers Energy	\$ 4.5
2	Dividends Paid to CMS	(3.6)
3	Return of Capital	(0.3)
4	New CMS Investment in Consumers Energy	3.1
5	Total Change in Common Equity	\$ 3.7

1

Table 2		
CMS Energy		
CMS Funds Available to Invest in Consumers Energy (Dec. 2020 - 2024)		
		<u>\$ Billions</u>
a.	Dividends From Consumers Energy	\$ 3.6
b.	Less: Dividends to CMS Shareholders	(2.7)
c.	CMS Net Equity Issued	0.8
d.	Increase in CMS Equity Capital	1.7
e.	Increase in Parent Company Debt	1.7
f.	Other CMS Changes	(0.3)
g.	Funds From CMS Invested in Consumers Energy	\$ 3.1

2

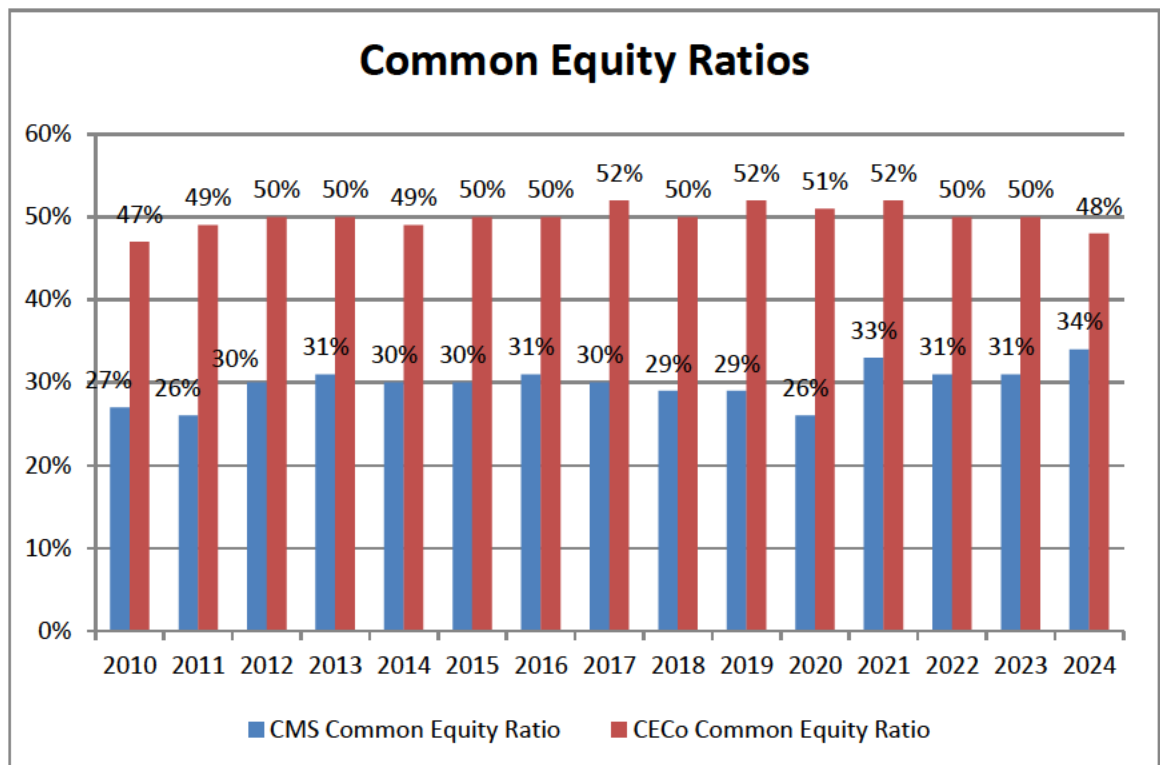
3 Clearly, as shown in table 2 above, of the \$3.1 billion of new equity invested by CMS into
 4 Consumers, \$1.7 billion (or 55%) is from new CMS debt (line e versus line g).

5 Second, to further support my point, CMS Energy is a frequent issuer of long-term debt in
 6 the capital markets. Over the last five years, CMS parent-only debt increased \$1.7 billion

1 from \$3.3 billion at year end 2019 to \$5.0 billion at year end 2024.¹²⁶ Yet the only
2 substantive business CMS Energy owns is Consumers Energy.

3 The following chart displays the gap in equity capital between Consumers Energy and
4 CMS over the years 2010 to 2024. While cash raised from the issuance of long-term debt
5 at CMS is not immediately injected into Consumers Energy, it is nonetheless being utilized
6 in part to fund CMS's so-called equity infusions into CECO.

7



8

¹²⁶ From SEC filings on Form 10-K for the years ended 2020 (p. 124) and 2024 (p. 123).

1 It is important to remember that nearly 95% of CMS' assets and revenue come from
2 Consumers Energy.¹²⁷ Therefore, from a practical operating standpoint, CMS and
3 Consumers Energy are one and the same.

4 My analysis clearly shows that CMS is using a form of double leverage by using debt
5 capital to make its equity infusions into Consumers Energy. Although a strong argument
6 could be made that the common equity capital of the Company should be less than 50%
7 given the evidence I have presented, the Commission certainly should not permit a capital
8 structure with common equity capital above 50%.

9 From the statements in Moody's credit reports and similar concerns expressed by other
10 rating agencies, it appears that the debt-laden capital structure of CMS has contributed to
11 a lower debt rating than the Company could have achieved if CMS was capitalized with
12 more equity capital. For example, on page 1 of the May 31, 2023 credit report, Moody's
13 states:

14 Consumers Energy's stand-alone financial performance has historically been affected
15 by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2
16 stable). However, CMS has made notable progress in reducing the percentage of
17 parent debt in its capital structure over the last 2-3 years. We now estimate that the
18 percentage of parent debt will remain around mid-20% of total consolidated debt.

19 Similarly, on page 2 of the February 13, 2023 credit report, Fitch Investor Service states:

20 There is parent-subsidary rating linkage between CMS Energy and Consumers
21 Energy. Fitch determines CMS Energy's standalone credit profile (SCP) based upon
22 consolidated metrics. Fitch considers Consumers Energy's SCP to be stronger than
23 CMS Energy's. Emphasis is placed on Consumers Energy's status as a regulated
24 entity. Legal ring-fencing is considered porous given the general protections afforded
25 by economic regulation. Access and control are also evaluated as porous. CMS Energy

¹²⁷ CMS Energy 2024 Form 10K at page 171.

1 centrally manages the treasury function for all of its entities. However, both the parent
2 and Consumers Energy issue their own long-term debt. Due to the aforementioned
3 linkage considerations, Fitch will limit the difference between the Long-Term Issuer
4 Default Ratings (IDRs) of CMS Energy and Consumers Energy to two notches.

5 The result has been higher interest costs for customers. Partially to compensate for this
6 significant leverage at CMS, the Company now wants a higher equity ratio in the capital
7 structure that will further increase costs to customers.

8 **Q. YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP**
9 **USED TO ASSESS THE COST OF COMMON EQUITY IS APPROXIMATELY**
10 **47%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE**
11 **COMMON EQUITY RATIO FOR THE COMPANY.**

12 A. As shown in Exhibit AG-44, the average common equity ratio of the peer company group
13 for 2024 was 47.3%. The cost of equity for those companies in the peer group is highly
14 dependent on the financial risk reflected in their capital structure. Thus, it is critical to
15 synchronize the capital structure of the Company to the peer group average as closely as
16 possible, in order to have consistency with the cost of equity capital derived from those
17 peer group companies. The Company's proposed common equity capital ratio of 50.75%
18 creates a disconnect that is not acceptable and is also more costly to customers.

19 **Q. WITNESS BLECKMAN SPONSORS EXHIBIT A-32 (MRB-10) SHOWING THE**
20 **COMMON EQUITY RATIOS FOR VARIOUS GAS AND ELECTRIC UTILITY**
21 **COMPANIES SUPPOSEDLY DECIDED IN RATE CASES DURING 2020 TO**

1 **2024. THE EXHIBIT SHOWS AN AVERAGE COMMON EQUITY RATIO OF**
2 **54.05%. DO YOU FIND THIS EXHIBIT WORTHY OF CONSIDERATION?**

3 A. No. It appears that Mr. Bleckman’s purpose in presenting this exhibit showing an average
4 common equity ratio of 54.05% is an attempt to support his recommended 50.75% equity
5 ratio and to suggest that his rate is conservative and very reasonable compared to the equity
6 ratios approved for other utility companies. The caption in column (c) of this exhibit is
7 “Proxy Group Company”. Yet, units of Black Hills, WEC Energy and CenterPoint Energy
8 are not in the Company’s peer group. As such, 16 of the 30 companies shown in this
9 exhibit, or approximately one-half of the listed utilities are not in the Company’s peer
10 group in this rate case.

11 The Commission should not rely on the information provided by Mr. Bleckman in Exhibit
12 A-32 because it is neither accurate nor comprehensive to provide a proper context to
13 establish an appropriate common equity ratio for the Company. He presents only selective
14 information. The major flaws are discussed below.

15 First, several of the companies in the exhibit reflect equity ratios calculated based on only
16 long-term debt and common equity when the commissions in those jurisdictions also
17 included a permanent layer of short-term debt as part of the permanent capital structure.
18 The reality of the situation is that short-term debt is employed as a permanent financing
19 tool, which results in a lower equity ratio if taken into account. Spire Missouri is one such
20 company. A review of Mr. Bleckman’s workpapers show the capital structure from the
21 rate case as being 49.66% common equity, 41.83% long-term debt and 8.51% short-term

1 debt. For purposes of Exhibit A-32 (MRB-10), Mr. Bleckman recomputes a 54.28% equity
2 ratio by looking only to common equity and long-term debt. Other companies have short-
3 term debt factored into the rate-making capital structure as permanent financing, which
4 lowers the equity ratios presented by Mr. Bleckman. The Commission should recognize
5 that while CECO uses short-term debt strictly as a seasonal financing tool, many other
6 companies use it both to meet short-term and long-term needs.

7 Second, several of the companies in Exhibit A-31 are relatively smaller utilities in
8 comparison to Consumers Energy. Smaller utilities tend to have higher equity ratios to
9 sustain them during potential volatility in their business, which larger utilities can better
10 manage. For example, line 10 of this exhibit shows Cheyenne Light Fuel and Power with
11 a 52% equity ratio. This small utility sells gas and electricity to approximately 80,000
12 customers in Wyoming. Another small utility on line 11 of the exhibit is CenterPoint's
13 Arkansas operation with a capital base of only \$658 million according to Mr. Bleckman's
14 workpapers.

15 Mr. Bleckman also included North Shore Gas with 55.58% equity ratio when this
16 company's rate base is approximately \$450 million in 2024.¹²⁸ In contrast, Consumers
17 Energy's electric rate base was \$13.8 billion in 2023, and when including the gas business,
18 the total company rate base is in excess of \$22 billion with revenues of \$7.2 billion for
19 2023, serving 3.7 million electric and gas customers.¹²⁹ Also, the Atmos subsidiaries in

¹²⁸ Page 19 of the WEC Energy Group 2023 Form 10-K.

¹²⁹ Consumers Energy Exhibit A-1, Schedule A-1, in Case No. U-21490 and U-21585

1 all states, except for Texas, reflect smaller units with rate base of \$600 million or less
2 suggesting a “small company size” factor could be behind the higher equity ratios.

3 In summary, Mr. Bleckman has constructed a selective group of utilities in Exhibit A-32
4 that are not representative of the gas utility industry or the Company’s peer group with the
5 simple objective to create an inflated average equity ratio. For example, utilities on the
6 east coast of the United States were not represented in Mr. Bleckman’s exhibit, where
7 equity ratios and ROEs tend to be lower and more conservative. The Commission should
8 disregard the Company’s attempt in Exhibit A-32 to present a misleading industry average
9 equity ratio that is disconnected from the calculations of the cost of equity capital of the
10 companies in the peer group.

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

14 A. The difference is approximately \$8.0 million annually. This reflects (a) the difference
15 between the pre-tax cost of common equity of approximately 14.1% versus the cost of
16 long-term debt of 4.3%; (b) the Company’s proposed rate base of approximately \$11.8
17 billion; and (c) the percentage of total capital being shifted from common equity to long
18 term debt.

19 **Q. DID YOU MAKE ANY OTHER ADJUSTMENTS TO OTHER ITEMS INCLUDED**
20 **IN THE COMPANY’S PROPOSED CAPITAL STRUCTURE?**

1 A. No. Except for the common equity and long-term debt balances which I have changed (as
2 explained earlier in my testimony), I have utilized the capital balances sponsored by
3 witness Bleckman in Exhibit A-14 (MRB-1), Schedule D1, page 1.

4 **COST OF CAPITAL**

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

7 A. I am recommending an overall return on capital of 5.97%, which includes a return on
8 common equity of 9.75%, as shown in Exhibit AG-41. Even though the average ROE
9 calculated under the three methods discussed below is slightly less than 9.75%, I have used
10 a 9.75% ROE rate to calculate the overall cost of capital for reasons I will explain later in
11 my testimony.

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

13 A. For the long-term debt cost rate, I used a rate of 4.35% based upon Mr. Bleckman's
14 recommendation.

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

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

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

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

4 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF**
5 **CAPITAL IN EXHIBIT AG-41.**

6 A. To develop the overall cost of capital on line 12, column (f), I have first developed the
7 percentage weighting of each capital component in column (d) by dividing the individual
8 capital balances in column (b) by the total of all capital components in that column. Next,
9 I have multiplied the weightings in column (d) by the cost rates in column (e) to arrive at
10 the values in column (f). The total of the individual values in column (f) is the total cost
11 of capital of 5.97%.

12 Regarding the pretax weighted cost of capital on line 12, column (h), I have multiplied
13 each cost component in column (f) by the conversion factors in column (g). These
14 conversion factors are included to reflect the impact of income and other taxes paid by
15 CECo for calculation of the pretax weighted cost of 7.36% in column (h).

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

18 A. A utility company is entitled to a fair return that will allow it to attract capital and be
19 sufficient to assure investors of its financial soundness. In its opinion in Bluefield Water

1 Works and Improvement Company v Public Service Commission of West Virginia (the
2 “Bluefield Case”) 262 U.S. 679 (1923), the United States Supreme Court indicated that:

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

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

14 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON**
15 **EQUITY IN EXHIBIT AG-42.**

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

22 While Exhibit AG-42 shows an average ROE of 9.52% from the three methodologies, I
23 recommend an allowed rate of return on equity of 9.75% for the reasons explained later in
24 this section of my testimony. In connection with these methods for determining the cost

1 of common equity, I have considered the cost of common equity for a proxy group of peer
2 companies.

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

5 A. To develop an appropriate peer group, I started with the 9 utility companies followed by
6 the Value Line Investment Survey in its “Natural Gas Utility Industry” section. I
7 eliminated two of these companies from consideration which are (a) New Jersey Resources
8 because it earns less than 50% of its income from the utility business; and (b) UGI
9 Corporation due to its foreign investments and heavy reliance on propane sales.

10 Additionally, I have added one other company to my peer group which Value Line
11 classifies as an electric utility. The additional company is Black Hills. This company
12 earns approximately 50% of its income from natural gas distribution and as such is suitable
13 to be included in CECO’s natural gas distribution peer group.

14 The result is the group of eight companies shown in Exhibit AG-43, all of which have
15 growing earnings and dividends.

16 **Q. HOW DOES YOUR PEER GROUP COMPARE TO THE COMPANY’S PEER**
17 **GROUP?**

18 A. The Company’s peer group contains six of the companies in my peer group. Potential peer
19 companies excluded by the Company’s witness were Chesapeake Utilities and Black Hills.

1 Chesapeake was excluded because it did not have a bond rating in 2024, which it now has
2 with a rating of “A-” by Fitch. Black Hills presumably was excluded because Value Line
3 classifies it as an electric utility even though its sales to gas customers represented 54% of
4 total Operating Income in 2024.

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

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

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

12
$$R = D/P + g$$

13 *where “R” = the Required Equity Return*

14 *“D/P” = the Dividend Yield on the Security*

15 *and “g” = the expected growth rate in dividends*

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

17 A. The results of my DCF analysis are summarized in Exhibit AG-43. The stock price
18 information in column (c) of this exhibit reflects the average of the high and low prices for
19 each of these equity securities on each of the 30 trading days from February 3 to March
20 17, 2025. The annual dividend in column (d) is the forecasted average dividend level for
21 2025 and 2026 as projected by the Value Line Investment Survey. Column (h) shows the

1 average long-term earnings growth rate based on (1) the estimate of earnings growth
2 through 2029 per Value Line; and (2) the earnings growth estimates per Zacks as included
3 in the Company's DCF analysis.

4 The resulting calculation of the DCF Method is an average return on common equity for
5 the proxy group of 9.11%.

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

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

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

14 A. The results of my DCF analysis and those of witness Bulkley are dependent in large part
15 upon the overall dividend yield in each case as well as the average growth rate of each
16 peer sample. Company witness Bulkley's DCF result of 9.87% is 76 basis points higher
17 than the 9.11% DCF result I calculated.¹³⁰

¹³⁰ This Company's 9.87% DCF ROE rate is shown on page 1 of Exhibit A-14 (AEB-1).

1 The dividend yield in my analysis is 3.5% but the Company’s is higher at 3.71%. This
2 accounts for approximately 30% of the 76-basis point difference. Also, the projected
3 growth rate is higher in the Company’s case at 6.05% vs. 5.57% in my analysis.¹³¹ I will
4 point out that the data on the dividend yield and the earnings growth rates used by the
5 Company were compiled sometime in the fourth quarter of 2024 and are now stale. The
6 stock prices of the utilities in the peer group are now higher, thereby justifying a lower
7 dividend yield compared to the Company’s filed case. Also, the growth rates that I used
8 include results for Black Hills and Chesapeake Utilities which are slightly lower than the
9 six companies in the Company’s peer group, resulting in a lower average earnings growth
10 rate for the peer group. Therefore, the more recent information I included in my peer group
11 analysis provides an updated and reasonable DCF result of 9.11%.

12 **Capital Asset Pricing Model**

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

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

18
$$k_e = R_f + (B \times R_p)$$

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

20 R_f = the “risk free” rate of return

¹³¹ The 3.71% dividend yield and 6.05% growth rate of the Company’s peer group analysis is from page 3 of n Exhibit A-14 (AEB-1)

1 $R_p =$ the overall return of the market less the risk-free rate (over several years)

2 $B =$ the systematic risk of a particular common equity security vs. the market

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

4 A. This measure of risk reflects the extent to which the price of a particular security varies in
5 relationship to the movement of the overall market. Securities that vary over time more
6 than the overall market will have a Beta that is greater than 1.00. Some securities vary
7 less in price over time than the overall market. In these cases, the Beta will be less than
8 1.00. Utility stocks tend to move less than the overall market. Reflective of this outcome,
9 the average Beta of my Peer Group is 0.91.

10 **Q. PLEASE EXPLAIN EXHIBIT AG-44 SHOWING THE RESULTS OF THE CAPM**
11 **APPROACH.**

12 A. Exhibit AG-44 shows the results of the CAPM method based upon (1) a 4.0% risk-free
13 rate; (2) the Betas of the companies in the Peer Group taken from Value Line; and (3) the
14 7.30% historical Market Risk Premium (R_p) return from the years 1926 to 2023.¹³²

15 Regarding the use of a risk-free rate for CAPM purposes, I used a 4.0% rate which is the
16 30-year U.S. Treasury Bond for the second quarter of 2026 sourced from economic
17 projections provided by the Company.¹³³

¹³² WP-AG-44.

¹³³ Discovery response AG-CE-440 showing a 4.0% 30-Year U.S. Treasury rate.

1 The result of my CAPM approach using the 6.66% adjusted risk premium (7.30% Risk
2 Premium x 0.91 Beta) plus the 4.0% risk-free rate is a cost of equity capital of 10.66% for
3 the proxy group average.

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

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

12 **Utility Risk Premium Approach**

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

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

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

1 A. Exhibit AG-45 shows the components required to derive a cost of common equity capital
2 for the peer companies on lines 3 and 4. The 5.40% on line 3 is the projected average rate
3 for utility bonds rated “A” and “BBB”. This rate is determined in footnote 2 of the exhibit
4 from average spreads of 30-year utility bonds in 2024 compared to 30-year U.S. Treasury
5 bonds. The spread rate of 3.80% on line 4 of the exhibit is the historical rate of gas utility
6 returns versus “A” rated debt yields from 1952 to the present. The total of the two rates
7 equals the Risk Premium return rate of 9.20% on line 5 of the exhibit.

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

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

12 **Q. PLEASE SUMMARIZE WITNESS BULKLEY’S TESTIMONY ON PAGES 30**
13 **THROUGH 33 STARTING UNDER THE HEADING “BYRP ANALYSIS” ON**
14 **PAGE 30.**

15 A. Witness Bulkley states in her testimony that she compared authorized ROEs from gas
16 utility rate case decisions from 1980 to 2024 and compared the authorized ROEs to 30-
17 year U.S. bond yields. She ran a regression model with this data and claims to have found
18 a strong relationship between these bond yields and authorized ROEs. Based on the results
19 of the three cases prepared using this approach, she concludes that the average risk
20 premium over the 1980-2024 period is 6.12%. To this 6.12% developed risk premium,

1 she adds an estimated rate of 4.13% for the 30-year U.S. bond yield for the projected test
2 year to arrive at a 10.25% ROE rate for the projected test year under this unorthodox
3 approach. The calculation is shown on page 22 of Exhibit A-14.

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

6 A. There are three major flaws with Ms. Bulkley's Bond Plus Risk Premium methodology.
7 First, it lacks any comparison of actual utility returns achieved from price appreciation and
8 dividends to bond yields. It is the actual return on utility common equities that is the key
9 and necessary measurement in any risk premium analysis. Using authorized ROEs as a
10 substitute ignores investors' return expectations. Second, the analysis is biased because it
11 covers a period when interest rates were declining from 12.1% in late 1980 to 4.2% in
12 2024¹³⁴.

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

¹³⁴ Exhibit A-14 (AEB-1) pages 23 and 25

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

3 A. Ms. Bulkley presents the results of her projected CAPM, Projected ECAPM, and Projected
4 Risk Premium methods in Exhibit A-14, page 1. In the table below, I show the
5 development of Ms. Bulkley's CAPM ROE results compared to mine.

Comparison of CAPM Estimates of AG and Company High Case		
<u>Line</u>	<u>AG Case*</u>	<u>Company High Case**</u>
1 Market Risk Premium (MRP)***	7.30%	7.74%
2 Beta (based on proxy group companies)	<u>0.91</u>	<u>0.875</u>
3 MRP x Beta	6.66%	6.77%
4 Risk Free Rate	<u>4.00%</u>	<u>4.30%</u>
5 CAPM Result (L3 + L4)	<u>10.66%</u>	<u>11.07%</u>

* Exh. AG-44.
** Exh. A-14, p. 8 of 29.
*** Company MRP = 12.04% less T bond Rate.

6

7 Key differences noted above are a higher Market Risk Premium and a higher Risk-Free
8 Rate, both of which are discussed below. The Company's ECAPM results are all slightly
9 higher than the CAPM results in the table above due to the different approach used. This
10 is discussed below in my testimony.

11 **Q. PLEASE EXPLAIN THE COMPANY'S DECISION TO USE A 4.30% RATE FOR**
12 **THE 30-YEAR U.S. TREASURY RATE AS THE RISK-FREE RATE AND YOUR**

1 **ASSESSMENT REGARDING THE USE OF THIS RATE TO DEVELOP THE**
2 **ROE ESTIMATES FOR THE PROJECTED TEST YEAR.**

3 A. The Company developed multiple CAPM ROE estimates using 4%, 4.07%, and 4.30%
4 Risk-Free rates. The Company’s use of multiple rates seems to be a hunt for an approach
5 that will result in a higher ROE rate. The use of the higher 4.30% 30-year forecasted U.S.
6 Treasury bond rate is particularly flawed because it reflects U.S. Treasury rates forecasts
7 for 2026 to 2030, which in large part includes periods beyond the test year ending October
8 2026. Instead, I used the single rate of 4.00% for the 30-year U.S. Treasury bond rate
9 forecasted for the first quarter of 2026, which is about the mid-point of the projected test
10 year.¹³⁵

11 **Q. PLEASE PROVIDE YOUR ASSESSMENT OF THE COMPANY’S**
12 **CALCULATED MARKET RISK PREMIUM OF 7.74%.**

13 A. Instead of using a proven historical market risk premium (MRP), the Company developed
14 its MRP based largely on future expected stock price growth rates and dividends for a
15 select group of companies from the S&P 500 stock index over the next three to five years.
16 Based on her sample of companies, Ms. Bulkley calculates a forecasted stock market return
17 of 12.04%. From this percentage, she deducts the forecasted 30-year U.S. Treasury risk-
18 free rate of 4.30% to arrive at a forecasted of 7.74%.

¹³⁵ Discovery Response AG-CE-0440

1 There are a number of problems with this approach to developing an MRP. First, short-
2 term fluctuations in expectations and projections of stock market returns for the sample
3 companies can cause the forecasted MRP rates to vary significantly. Second, as can be
4 seen from an examination of pages 16 to 21 of Exhibit A-14, many of the companies with
5 dividend yields and long-term growth estimates are omitted. Approximately 125
6 companies or 25% of the named companies in the S&P 500 are not represented in the
7 calculation of the 12.04% stock market return. In contrast, many large technology
8 companies with high growth prospects have a larger than normal weighting in the
9 calculation of the 12.04% return due to their relatively large market capitalization.

10 **Q. PLEASE EXPLAIN FURTHER THE SHORTCOMINGS WITH THE MARKET**
11 **RISK PREMIUM DEVELOPED BY WITNESS BULKLEY?**

12 A. Witness Bulkley is using an extremely short period of 3 to 5 years to measure stock market
13 returns in determining the MRP. The projected MRP does not include a complete cycle
14 of economic expansion and contraction, which is what occurs over the long-term. To adopt
15 the Company's approach would be akin to only selecting the positive return years over the
16 98-year historical period of stock market returns I used and not the losses in the downturn
17 years. Expectedly and incorrectly, we would derive a far higher overall return for the
18 market and far higher market risk premium, which is the flawed result achieved by witness
19 Bulkley in the 12.04% market return and forecasted MRP.

20 These concerns are also echoed by Dr. Roger Morin, a recognized expert on regulatory
21 finance matters, who strongly supports the use of the longest possible period for

1 calculating a market risk premium. On page 114 of his book “New Regulatory Finance”
2 Dr. Morin states the following:

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

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

12 For the above reasons, witness Bulkley’s development of the forecasted MRP used by the
13 Company in the CAPM and ECAPM cost of equity calculations is seriously flawed and
14 should be rejected.

15 **Q PLEASE COMMENT ON MS. BULKLEY’S USE OF THE ECAPM METHOD.**

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

19 Notwithstanding Ms. Bulkley’s arguments, there is academic disagreement with the
20 validity of the original studies that led to the use of ECAPM. First, the original study used
21 raw betas and not the adjusted Value Line betas, which I use, and other cost of capital
22 experts normally rely upon. Second, the original studies relied upon short-term risk-free

1 rates. Instead, cost of capital witnesses, including myself, who have been involved in the
2 Company's rate cases use long-term risk-free rates in the CAPM model.

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

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

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

12 A. No. In response to a discovery request in Case No. U-18424, the Company stated that
13 ECAPM "... is supported by orders from regulatory bodies in Maryland, Mississippi and
14 Alberta..." As a result of this claim, the Company was asked to provide the specific rate
15 orders from these regulatory commissions.¹³⁶ The information provided in response to this
16 discovery request was less than convincing.

¹³⁶ CECo responses to U-18424 AG-CE-206 and AG-CE-386.

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

4 Regarding the Maryland commission, Company witness Maddipati pointed out on page
5 58 of his direct testimony in Case No. U-18424 that the Maryland Commission stated that
6 they found the DCF and ECAPM “helpful” in Case 9326. However, in a more recent case
7 involving PEPCO (case 9418) with an order issued on November 15, 2016, the result is
8 different. As shown in the summary positions articulated in the order in this case, no party
9 involved in the proceedings, other than the company, put forth an ECAPM ROE estimate.
10 In this case, the Maryland commission basically adopted the Staff’s position with no
11 ECAPM estimate and rounded down the Staff’s recommended ROE of 9.57% to 9.55%.

12 In this regard, the Maryland Commission stated on page 100 of the order the following.
13 *“Our Decision today most closely aligns with Staff’s recommendation of 9.57% although*
14 *we do not expressly reach the same conclusion as Staff. We find that a slightly lower ROE*
15 *of 9.55% is both adequate and appropriate for Pepco...”* Furthermore, in its decision in
16 this case, the Maryland commission expressed no position on ECAPM. I am not aware of
17 any more recent cases that show a change in the commission’s view of the ECAPM
18 methodology.

19 **Q. ON EXHIBIT AG-46, YOU PROVIDE INFORMATION REGARDING THE MIX**
20 **OF UTILITY AND NON-UTILITY BUSINESSES OF THE PEER GROUP YOU**

1 **USE. WHAT DOES THIS ANALYSIS REVEAL ABOUT THE RISKS OF THE**
2 **PEER GROUP RELATIVE TO THE COMPANY’S GAS BUSINESS?**

3 A. In general, the peer group has a higher degree of risk compared to the gas business of
4 Consumers Energy. Some companies in the peer group are involved in energy ventures,
5 energy services, and gas marketing. The non-utility, and often non-regulated, businesses
6 place the peer group at greater risk. Also, the peer group companies are more financially
7 leveraged with higher debt as a percentage of total capital, which makes them riskier.

8 **Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER**
9 **REGULATORY COMMISSIONS HAVE GRANTED IN 2023 AND 2024.**

10 A. Exhibit AG-48 shows the ROEs granted by state regulatory commissions for U.S. gas
11 utilities in 2023 and 2024. The majority of the 36 ROE decisions in 2023 and 41 decisions
12 in 2024 are at rates well below 9.9%, which is CECo’s current authorized ROE.¹³⁷ As
13 noted on page three of the exhibit, only three decisions in 2023 and nine decisions in 2024
14 are at rates of 9.9% or greater. These higher rates, which are summarized on page 3 of
15 Exhibit AG-48, are primarily from regulatory commissions in California, Florida, and
16 Michigan or pertain to small companies. ROEs in California have been at or above 10%
17 reflecting the unique challenges for utilities in that state with wildfires and earthquakes.
18 ROEs in Florida reflect damage to utility property and financial losses from hurricanes,
19 which is an on-going challenge for the utilities in the state. High ROEs in other

¹³⁷ The 2023 and 2024 decisions exclude Limited Issue Rider cases.

1 jurisdictions tend to reflect smaller utilities or unique geographical challenges, such as in
2 Alaska, as shown on page 3 of Exhibit AG-48.

3 For most of the other gas utilities that have business and financial risks comparable to
4 Consumers Energy's operations, the ROE rates have averaged around 9.5% in the past two
5 years. This evidence supports my calculations of an overall cost of equity of 9.52% and
6 suggests that the Company's current ROE rate of 9.90% is excessive and "out of line" with
7 comparable gas utilities and the true cost of equity capital. The Company's proposed ROE
8 rate of 10.25% is even further removed from reality and clearly unsupportable. My
9 recommended ROE rate of 9.75% in this rate case provides a bridge to ultimately reach
10 the true cost of capital for the Company and is quite reasonable.

11 I will also point out that the most current average ROE rate for the peer group of utility
12 companies is 9.61%. Exhibit AG-50 shows that information. This is another benchmark
13 that shows the 9.75% ROE rate I have proposed is reasonable, if not generous for the
14 Company.

15 **Q. IN THIS RATE CASE, MR. BLECKMAN SPONSORS EXHIBIT A-33 (MRB-11)**
16 **SHOWING THE ROE RATES AND COMMON EQUITY RATIOS OF SELECT**
17 **UTILITY COMPANIES. WHAT IS YOUR ASSESSMENT?**

18 A. Much of the information in Exhibit A-33 is incorrect, misleading, and does not provide a
19 proper context for the metrics noted in the exhibit. Below, I discuss the key problems with
20 the information presented by Mr. Bleckman.

1 First, with regard to Florida Power & Light, the 10.60% ROE was established by the
2 Florida Commission in 2021 as part of a multi-year agreement covering the years 2022 to
3 2025. Under this agreement rate increases are capped, and any other relief would be
4 dependent upon extraordinary circumstances.¹³⁸ In addition, this Company's service
5 territory is buffeted by hurricanes each year which can disrupt electric service for
6 prolonged periods and potentially reduce revenues and profits. The ROE rate granted to
7 Florida electric utilities is not applicable to Consumers Energy's gas business.

8 Second, Alabama Power information, a Southern Company subsidiary, shows a 55%
9 Common Equity ratio and a 10.9% ROE. The utility may potentially increase its rates each
10 year but on a rolling two-year basis. However, the increases are limited to no more than
11 8% in a two-year period or 4% on average annually. The increases are authorized under
12 the company's Rate RSE (established before 2016) which is determined by considering
13 the level of earned returns on equity and the percentage of equity in the capital structure
14 based on the company's Weighted Equity Cost Rate (WECR).¹³⁹

15 In 2018, the Alabama Commission and the company agreed to a higher common equity
16 ratio of 55% by 2025 from 47% in December 2018. The change to Rate RSE for Alabama
17 Power was approved in May 2018 with no compensating rate increases and the company
18 at that time consented to a nominal reduction in the WECR with no annual Rate RSE
19 increases in 2019, 2020 and 2022. Rates were increased by 4.09% in 2021, but the

¹³⁸ NextEra 2022 Form 10-K, page 9.

¹³⁹ Southern Company Form 2022 10-K starting at Page II-139 under "Rate RSE".

1 Company also made refunds to customer via bill credits in the amount of \$50 million for
2 2020, \$181 million for 2021, and \$62 million for 2022.¹⁴⁰ What is happening in this
3 situation is that the Company is increasing the common equity ratio gradually with no
4 compensating increases in the WECR. The practical effect of these rate actions is to
5 reflect recognition of a lower cost of common equity. This special rate and capital
6 structure arrangement is not applicable to Consumers Energy for purposes of establishing
7 an appropriate ROE rate in this rate case.

8 Third, the exhibit shows Georgia Power, another Southern Company subsidiary, with a
9 56% common equity ratio and an 10.50% authorized ROE. Georgia Power has been in a
10 special situation involving significant expenditures for two nuclear power plants where (1)
11 the original contractor declared bankruptcy; and (2) the Company has been forced to write-
12 off approximately \$2.0 billion of cost overruns in 2021 and 2022; and (3) the Company
13 has only recently completed one of the new nuclear units and may face uncertainty
14 regarding the future recoverability of costs related to the new nuclear generating units.¹⁴¹
15 The Georgia Commission has been very supportive of the company through this troubled
16 time. The ROE and capital structure for Georgia Power are not applicable to Consumers
17 Energy's gas business given the unusual circumstances.

18 Fourth, with regard to WEC, which owns gas and electric utilities in Wisconsin and other
19 jurisdictions, the 10.16% ROE shown in the exhibit is unsupported and faulty. Recent

¹⁴⁰ Id.

¹⁴¹ Id. page II-147.

1 decisions from the Wisconsin Commission in general rate cases have granted ROEs of
2 9.8%.¹⁴² It appears that Mr. Bleckman may have increased the ROE rate in his chart by
3 including Limited Issue Riders. These riders are not applicable to a general rate case and
4 not applicable to Consumers Energy in this proceeding.

5 Fifth, for UGI, all of this utility's recent general rate cases in 2020 through 2024 have been
6 settled without published rate metrics. So, the information shown in this exhibit is stale or
7 inapplicable.

8 In summary, Mr. Bleckman's attempt to inflate his ROE recommendation by pointing to
9 select and inapplicable ROE rates granted to other utilities fails to provide convincing
10 evidence and should be rejected by the Commission.

11 **Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN**
12 **AUTHORIZED ROE BELOW 9.90% IN THIS CASE WILL LEAD TO**
13 **IMPAIRMENT OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL**
14 **MARKETS?**

15 A. No. From time to time in general rate case proceedings, certain rate case applicants,
16 including the Company, have raised arguments that they should receive higher ROEs to
17 ensure the financial soundness of the business and to maintain its strong ability to attract
18 capital in addition to being compensated for risk. However, those concerns are not
19 supported by the evidence. Exhibit AG-48 shows several gas utilities that have accessed

¹⁴² Regulatory Research Associates 2024 Report.

1 the capital markets at competitive interest rates since receiving a ROE near or below the
2 average rate of 9.50%.

3 Similarly, there is no evidence equity investors have abandoned utilities that have been
4 granted ROEs near or below the industry average. On the contrary, stock investors
5 continue to migrate to utility stocks, recognizing that authorized ROEs are still above the
6 true cost of equity. Exhibit AG-47 shows the market to book ratios for each of the peer
7 group companies, and many of these companies have received rate orders during the past
8 few years reflecting ROEs as low as 9.37%. Yet this group of companies has an average
9 Market to Book common equity value ratio of approximately 1.5 times.

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

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

17 The fact that the Company needs to raise capital because of a large capital investment
18 program to upgrade its infrastructure and for other purposes is not unique to Consumers
19 Energy. Most gas utilities face the same issues and are able to raise capital with ROEs at
20 or near the 9.5% average rate. Therefore, this issue is another “red herring”.

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

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

12 As a supporting point, in Exhibit AG-52, I have included a Value Line Funds article written
13 by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility is not
14 risk. He also points out that volatility in 2017 was low by historical standards and it was
15 near normal levels in 2018. Mr. Appel goes on to say later in this article that “...volatility
16 is only risk if you act during down times, that is, only if you sell a stock.” This principle
17 still applies to events today.

18 Additionally, I will submit that those who invest money in equity portfolios over longer
19 periods of time and particularly in utility stocks have an aversion to market volatility and
20 the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty
21 and volatility because they are not as susceptible to volatility as the general stock market.

1 This is reflected in the average Beta value of 0.91 of the utility peer group used in the
2 CAPM discussed earlier, in contrast with the general stock market value of 1. The recent
3 stock market volatility in April 2025 due to the imposition of trade tariffs is an example
4 where utility stocks have outperformed the general stock market as a safer heaven for
5 investment.¹⁴³ Therefore, the Commission should not give any weight to arguments that
6 the Company's ROE should reflect investors' concerns with stock market volatility.

7 **Q. HAS THE MARKET FOR NEW LONG-TERM DEBT BEEN RECEPTIVE TO**
8 **NEW UTILITY DEBT ISSUES IN 2023 AND 2024?**

9 A. Yes. As shown on Exhibit A-31(MRB-9), the market for new utility debt issues has been
10 very robust with over 350 new issues completed in 2023 and the first nine months of 2024.
11 Also, as can be seen from Exhibit AG-48, a large number of utility companies issued new
12 debt shortly after receiving a rate order with ROEs below 9.50%.

13 Consumers Energy issued \$700 million of long-term debt in July 2024 at an interest rate
14 of 4.7% and a 5-year term. Also, in January of 2024, Consumers Energy issued \$600
15 million of new 10-year debt at an interest rate of 4.6%. CMS Energy has also come to
16 market and issued \$1.0 billion of new 30-year debt at a rate of 6.5%. On my Exhibit AG-
17 48, I show several utility companies who came to market not long after a rate case decision
18 and issued significant quantities of new long-term debt.

¹⁴³ From the end of 2024 and through April 15, 2024, CMS Energy Stock is up 9.1% while the S&P 500 Index is down 8.2%.

1 Accordingly, the debt markets are receptive to utility companies' capital raising activities.

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

5 A. In Exhibit AG-42, I summarized the cost of equity rates from the three methods I discussed
6 above. The range of returns for the industry peer group is from 9.11% at the low end,
7 using the DCF approach and 10.66% at the high end using the CAPM approach.

8 As explained earlier in my testimony, I give 50% weight to the DCF method as a more
9 reliable approach to estimating the cost of equity for a utility, which from my analysis is a
10 rate of 9.11%. In this regard, on line 4 of Exhibit AG-42, I have calculated a weighted
11 return on equity from the three methodologies using a 50% weight for DCF and 25% for
12 each of the other two methods. The result is a weighted average cost of common equity of
13 9.52%. To this base cost of equity capital, I have added an additional premium adjustment
14 of 23 basis points to arrive at a recommended ROE rate of 9.75% for Consumers Energy's
15 gas business. I have added this additional ROE cushion to the calculated cost of capital
16 due to the uncertainty of the timing in the decline in interest rates in the coming year. The
17 23-basis points cushion compensates for a potential increase in the 4.0% risk-free rate I
18 used in the calculation of the cost of equity. Therefore, there is no need to further increase
19 the ROE rate above the 9.75% for further interest rate risk and I urge the Commission to
20 adopt this proposed rate.

1 **Q. IF THE COMMISSION APPROVES A 9.90% COST OF COMMON EQUITY IN**
2 **THIS CASE, AS IT DID IN CASE NO. U-21585, WHAT IS THE ADDITIONAL**
3 **COST TO CUSTOMERS COMPARED TO AN ROE OF 9.75%.**

4 A. If the Commission were to grant a 9.90% ROE in this case versus a 9.75% ROE, the
5 additional cost to customers is approximately \$10 million annually. There is absolutely
6 no need to burden customers with this additional cost, when historically the Company has
7 been earning well above its true cost of common equity.

8 I recommend that the Commission take note of the evidence and arguments I have
9 presented in my testimony and grant the Company a ROE rate of no more than 9.75%.

10

IX. Revenue

11

Gas Sales and Transportation Revenue

12 **Q. WHAT ARE YOUR FINDINGS FROM ANALYZING THE COMPANY'S**
13 **PROJECTED LEVEL OF GAS SALES AND TRANSPORTATION VOLUMES?**

14 A. In Exhibit A-15 (MA-6), Schedules E-2, Company witness Mustafa Ahmed presents the
15 Company's forecast of gas sales and transportation deliveries for the projected test year
16 ending October 2026. The Company forecasted total gas sales of 223.8 billion cubic feet
17 (Bcf) and end-user transportation deliveries of approximately 84.0 Bcf for total gas
18 deliveries of 307.7 Bcf for the projected test year. The projected sales represent an increase
19 of approximately 4.0 Bcf from the most recently available actual weather-normalized sales

1 in 2024, while the projected transportation gas volumes represent a decrease of 0.5 Bcf
2 from weather-normalized 2024 volumes.¹⁴⁴

3 According to Mr. Ahmed's direct testimony and responses to discovery, the Company
4 calculated the forecasted sales and transportation volumes based on various regression
5 projection models applied to customers' historical gas consumption during the January
6 2013 to March 2024 timeframe.¹⁴⁵ The models also develop or make use of other historical
7 and projected data, including number of customers, weather degree days, population
8 changes, manufacturing activity, and other econometric data.

9 After reviewing the Company's sales and transportation forecast by customer class against
10 the historical weather-normalized gas deliveries, I determined that the Company has
11 captured the recent historical trend in gas sales and transportation deliveries to most
12 customer classes relatively well, and I do not dispute those forecasts. However, I believe
13 that the Company has underestimated commercial transportation volumes and the related
14 revenues for the projected test year by a significant amount.

15 **Q. WHAT IS THE BASIS FOR YOUR CONCLUSION THAT COMMERCIAL GAS**
16 **TRANSPORTATION DELIVERIES ARE UNDERSTATED?**

17 A. In response to discovery, the Company provided actual weather-normalized gas sales and
18 transportation deliveries along with the related number of customers by customer class for

¹⁴⁴ Exhibit AG-53, column (k) plus Inter-Departmental sales of 114 MMcf and transportation volumes of 45 MMcf from DR AG-C-0310 Attachment 1 and Part III Information Schedule 15.

¹⁴⁵ DR AG-CE-0306.

1 each year from 2019 to 2024 and for the forecasted years 2025, 2026, and the projected
2 test year. From the data provided by the Company, in Exhibit AG-53, I calculated the
3 average weather-normalized annual gas usage per customer for each of the customer
4 classes. The analysis on lines 11 and 12 of Exhibit AG-53 shows that from 2019 to 2024,
5 the average annual gas usage per commercial transportation customer declined from
6 9,695.18 Mcf to 9,593.75 Mcf, or an average of 0.2% annually over the five-year period.

7 For the more recent three years, from the end of 2021 to the end of 2024, the annual rate
8 of decline was 0.5%. In contrast, the Company projected a decline in gas usage of 5.5%
9 in 2025 from actual weather-normalized gas deliveries in 2024 with an additional decline
10 of 0.6% in 2026 for a cumulative decline of 5.9% between 2024 and the end of the
11 projected test year. This large rate of decline over less than a two-year period is excessive
12 and unsupported. Mr. Ahmed's direct testimony is devoid of any explanations as to the
13 reasons for such a decline when other customer classes, including transportation gas
14 deliveries, have considerably lower rates of decline over the 2024 to 2026 period or have
15 increases in sales and transportation deliveries.

16 Exhibit A-15 (MA-4), Schedule E-10, shows a similar decline in overall transportation gas
17 deliveries between the 2023 historical test year and the projected test year. The decline in
18 transportation deliveries of 1,764 MMcf on line 13, column (e), is primarily attributable to
19 the decline in commercial transportation volumes discussed above. In discovery, the
20 Attorney General asked the Company to explain this unusual decline in forecasted
21 volumes. In response, the Company had no specific or pertinent answer other than to state

1 that it was mathematical calculation driven by economic indicators and usage patterns in
2 recent history.¹⁴⁶

3 However, that explanation does not fit the evidence shown in Exhibit AG-53. The recent
4 usage pattern in the most recent three years shows a decline of only 0.5% for the
5 commercial transport class and an annual increase of 2.6% for the industrial transportation
6 class, which has even larger delivery volumes than the commercial class. Therefore,
7 overall transportation volumes should be increasing and not decreasing. Similarly, the
8 economic indicators apply to both commercial and industrial customers, which also
9 invalidates that explanation.

10 The logical conclusion that can be drawn from this analysis is that the Company's
11 forecasting model provided a forecast for commercial transportation deliveries that is
12 inaccurate.

13 **Q. DID YOU CALCULATE REVISED COMMERCIAL TRANSPORTATION**
14 **VOLUMES AND THE RELATED REVENUE ADJUSTMENT BASED ON YOUR**
15 **ANALYSIS?**

16 A. Yes. Exhibit AG-54 show the calculations of the incremental volumes and revenue for the
17 forecasted test year for the commercial transportation customer class. To arrive at the
18 revised volumes, I started with the actual weather-normalized sales per customer for 2024
19 from Exhibit AG-53 and adjusted those volumes down based on the underlying average

¹⁴⁶ Exhibit AG-55 includes DR AG-CE-0313 and 0746.

1 annual rate of decline in volume from the three-year period 2021 to 2024. The calculation
2 includes those adjustments for the 10 months ending October 2025 and for the 12 months
3 ending October 2026. The adjusted gas usage per customer for the projected test year was
4 then multiplied by the number of customers forecasted by the Company for the projected
5 test year.

6 Based on those calculations, I forecasted commercial transportation volumes of 26,373
7 MMcf for the projected test year, which is an increase of 1,325 MMcf over the Company's
8 forecast. I then allocated the incremental volumes by rate schedule based on the allocation
9 methodology provided by the Company and applied the respective current distribution
10 rates to calculate the incremental revenue.

11 In total, the incremental forecasted revenue for the projected test year is \$1,822,000.

12 **Q. WHY DID YOU USE THE 2024 AVERAGE USAGE PER CUSTOMER AND THE**
13 **HISTORICAL THREE-YEAR RATE OF DECLINE IN COMMERCIAL**
14 **VOLUMES TO FORECAST THE PROJECT TEST YEAR VOLUMES?**

15 A. The weather-normalized usage per customer for the year 2024 represents the most recent
16 gas usage profile. The three-year rate of volume decline represents a realistic trendline
17 over the most recent three years and normalizes any temporary annual variances in usage
18 volumes. In that regard, it provides a more current and accurate forecast than the
19 Company's forecasting model, which uses stale customer usage data from 11 years ago,

1 starting in 2013, and which has been tainted by unusual events, such as the Covid
2 pandemic.

3 **Q. ON PAGE 8 OF HIS DIRECT TESTIMONY, MR. AHMED IMPLIES THAT HIS**
4 **FORECASTING MODEL IS HIGHLY ACCURATE. HOW DO YOU RESPOND?**

5 A. In his testimony, Mr. Ahmed states that the mean absolute percentage error (MAPE), also
6 known as the mean absolute percentage deviation, of his forecasting model is 0.6%. While
7 that percentage may seem low, it means that on average the sales forecasted by the model
8 are 2.6 Bcf lower or higher than the actual results. Those 0.6% and 2.6 Bcf deviations
9 were calculated on average over a 7-year period. In the prior rate case No. U-21490, the
10 Company calculated the deviation over a 10-year period with an average percentage of
11 1.0% and 4 Bcf, which is even a larger volume deviation in the forecasting model. In
12 response to discovery in that case, the Company provided the standard deviation by year
13 and the volume variance. That information shows that in any year the standard deviations
14 can range from nearly zero to 3.5% and the volume variance can range from near zero to
15 10 Bcf.¹⁴⁷

16 As shown in Exhibit AG-54, the transportation volume adjustment I proposed of 1.3 Bcf
17 results in a revenue adjustment of nearly \$1.8 million. Therefore, the 2.6 Bcf or 4.0 Bcf
18 standard deviation volume variance that Mr. Ahmed considers highly accurate can still
19 result in millions of dollars of lower or higher forecasted revenue.

¹⁴⁷ U-21490 DR AG-CE-0336.

1 **Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

2 A. The commercial transportation volumes and the related revenue forecasted by the
3 Company are understated and need to be adjusted. I recommend that the Commission
4 adopt my volume adjustment and increase the revenue forecasted by the Company for the
5 projected test year by \$1,822,000.

6 **X. Operations and Maintenance Expenses**

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

9 A. Exhibit A-13 (HLR-41), Schedule C-5, shows the Company forecasted total O&M
10 expenses of \$297.9 million for the projected test year.¹⁴⁸ While this expense level is \$23.0
11 million lower than the historical test year, the 2023 historical expense includes \$52.9
12 million of expenses for the Appliance Service Plan, which the Company has sold. This
13 expense has been excluded from the project test year. The decline in expense also reflects
14 the increase in negative expense for Pension and Other Post Employment Benefits (OPEB)
15 of \$15.3 million primarily due to increased stock market returns. After adjusting for these
16 expense items, the decrease in expense for the projected test year is actually an increase of
17 \$45.1 million.

¹⁴⁸ See line 34 of Exhibit A-13 (HLR-41), Schedule C-5, excluding LAUF and Company Use Gas.

1 In my testimony below, I recommend that the Company's forecasted O&M expense should
2 be reduced by ~~\$73.3~~\$56.4 million. Exhibit AG-56 CONF revised shows a summary of my
3 proposed O&M expense adjustments.

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

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

8 **A. Inflationary Adjustments to O&M Expenses**

9 **Q. HAVE YOU MADE ANY ADJUSTMENTS TO THE INFLATION AND MERIT**
10 **INCREASE ADJUSTMENTS TO O&M EXPENSES PROPOSED BY THE**
11 **COMPANY IN THIS RATE CASE?**

12 A. In Exhibit A-13, Schedule B-5.1, the Company shows inflation and merit adjustments
13 totaling to \$3.7 million from 2024 to the end of the projected test year. The calculation of
14 these inflationary adjustments was based on forecasted CPI rates of 3.2% for 2024, 2.4%
15 for 2025, and 2.5% for 2026. However, these adjustments apply to only a portion of the
16 Company's historical O&M expenses. For other O&M expenses, the Company used
17 inflationary increase and wage increase of 3.5% or higher. The Company's reasoning is
18 that these other costs are increasing at rates higher than the CPI forecasted inflation factors

1 and should be accorded higher cost increases for 2024 through the end of the projected test
2 year.

3 Although the assumed rates of increase are not often clearly disclosed and are excessive,
4 in my analysis of the forecasted expenses within certain operating units and cost functions,
5 I proposed specific adjustments to expenses where I found those cost increases excessive
6 and unsupported. However, I recommend that the Commission direct the Company to
7 clearly disclose by operating unit and cost function the forecasted inflationary cost
8 increases it has included in the bridge period and the projected test year for specific
9 expense items if those increases are different than the CPI forecasted inflation rates
10 reported separately.

11 **B. Gas Engineering and Gas Supply**

12 **1. System Integrity Expense**

13 **Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE**
14 **FORECASTED O&M EXPENSE FOR SYSTEM INTEGRITY FOR THE**
15 **PROJECTED TEST YEAR.**

16 A. On line 5 of page 5 of Exhibit A-81 (KAP-2), the Company shows an increase in O&M
17 expense of \$1,513,000 under Other Adjustments. On page 19 of her direct testimony, Ms.
18 Pascarello attributes this and other expenses to the departmental reassessment of work
19 activities with no further details. In discovery, the Attorney General asked the Company
20 to specifically explain the increase of \$1.5 million. In response, the Company stated that
21 the \$1.5 million does not represent an increase in workload, but instead a reclassification

1 of existing salaries and expenses. No additional information was provided from where
2 those costs were reclassified, and no showing was made that a comparable decrease in
3 expense was included in the function where those costs previously resided.¹⁴⁹

4 In a related discovery request, the Attorney General asked the Company to provide a pro-
5 forma comparison of the 2023 expense to the forecasted expenses for the subsequent years
6 for the departments that were involved in the departmental reorganization to better assess
7 how costs changed or did not change over the three-year period 2023-2026. In response,
8 the Company refused to provide the request information, claiming that it had not prepared
9 such information, and it would be difficult and burdensome to prepare it.¹⁵⁰

10 In prior rate cases, the Commission ruled that the Company has the responsibility to
11 provide sufficient and comparable historical information to explain and shows cost
12 changes resulting from departmental reorganizations. In this case, the Company failed to
13 do so. Without comparable and sufficient historical information clearly disclosed, it is not
14 possible to trace and validate the historical costs and ensure they were removed and offset
15 the increase in the new function or area where they now reside for the projected test year.
16 Therefore, lacking this information, I recommend that the Commission remove the
17 \$1,513,000 expense from the Company's forecasted O&M expense for the projected test
18 year.

¹⁴⁹ Exhibit AG-57 includes DR AG-CE-0381.

¹⁵⁰ Id. includes DR AG-CE-0374.

1 **2. Quality Lean Office Expense**

2 **Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE**
3 **FORECASTED O&M EXPENSE FOR THE QUALITY LEAN OFFICE EXPENSE**
4 **FOR THE PROJECTED TEST YEAR.**

5 A. On line 1 of page 5 of Exhibit A-81 (KAP-2), the Company shows forecasted O&M
6 expenses of \$3,152,000 for Gas Project Management and Quality Lean Office with an
7 increase in expense of \$1,843,000 from the 2023 historical level shown under Other
8 Adjustments. On page 12 of her direct testimony, Ms. Pascarello discusses the functions
9 within this department. With regard to the Quality Lean Office, she states that the key
10 responsibilities for this function are to develop and implement policies, process, and
11 procedures, among other tasks, to improve business efficiencies, reduce waste and errors,
12 enhance customer satisfaction and create company-wide value streams. Ms. Pascarello
13 also stated that in August 2024 the Company integrated the Enterprise Corrective Action
14 Program with the Quality Lean office.

15 In discovery, the Attorney General asked the Company to provide the number of
16 employees working in the Quality Lean Office, the O&M expense incurred by the
17 department, and the list of major accomplishments achieved during the 2021-2024 period
18 and the cost savings or financial benefits realized. In response, the Company identified 24
19 employees assigned to the gas side of the business within the total Quality Lean Office and
20 an additional 32 employees assigned to the electric side of the company. The Company

1 also reported that the forecasted O&M expense for the gas portion of the department for
2 the projected test year is \$1,259,000.¹⁵¹

3 However, in response to the request for accomplishments and cost savings or financial
4 benefits, the Company could not provide any pertinent information. Instead, it provided a
5 general statement that the Quality Lean Office itself does not achieve improvements but
6 provides support to other Company personnel.¹⁵² That response does not provide any
7 evidence that the cost paid by customers for this function is having a significant beneficial
8 impact, reducing costs or achieving other financial benefits. Without that information, it
9 is not possible to assess the value created by the Quality Lean Office.

10 Therefore, the forecasted expense is not justified and should be disallowed. I recommend
11 that the Commission remove the \$1,259,000 of O&M expense from this rate case.

12 **3. Advanced Methane Detection Expense**

13 **Q. PLEASE DISCUSS THE ADJUSTMENT THAT YOU PROPOSE TO THE**
14 **FORECASTED O&M EXPENSE FOR THE ADVANCED METHANE**
15 **DETECTION EXPENSE FOR THE PROJECTED TEST YEAR.**

16 A. In the Capital Expenditures section of my testimony, I proposed the removal of capital
17 expenditures for the AMD program. Related to the capital expenditures, the Company
18 forecasted \$1,969,000 of O&M expense to implement the AMD program.¹⁵³ Consistent

¹⁵¹ Id. includes DR AG-CE-0373 and 0378.

¹⁵² Id.

¹⁵³ Id. includes DR AG-CE-0422 with attachments.

1 with my recommendation in the Capital Expenditures section, I recommend that the
2 Commission also remove the O&M expense of \$1,969,000 from this rate case.

3 **C. Operations, Maintenance & Metering**

4 **1. Leak Repair & Survey Expense**

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

8 A. On line 7 of page 1 of Exhibit A-87 (JPP-2), the Company shows forecasted O&M
9 expenses of \$17,680,000 for Leak Repair & Survey, which is an increase in expense of
10 \$2,814,000 from the 2023 historical level. On pages 34-40, Company witness James
11 Pnacek discusses the major components of the increase in expense. Although some of the
12 increase in the forecasted expense is meant to address a plan to reduce the backlog in
13 outstanding gas leaks, the Company also included \$1,300,000 of expense pertaining to the
14 anticipated implementation of the new LDAR rule proposed by PHMSA. As discussed
15 earlier under the Capital Expenditures section of my testimony, the proposed rule has been
16 placed on hold, and it is not known at this time if and when it may be issued.

17 Therefore, the forecasted expense should not be incurred in the projected test year. I
18 recommend that the Commission remove the \$1,300,000 for the Company's forecasted
19 O&M expense.

1 **2. Gas Line Staking & Locating Expense**

2 **Q. PLEASE BRIEFLY DESCRIBE THE COMPANY’S PROPOSED CHANGES TO**
3 **THE GAS LINE STAKING AND LOCATING PROGRAM AND THE IMPACT**
4 **ON FORECASTED O&M EXPENSE FOR THE PROJECTED TEST YEAR.**

5 A. On line 9 of page 1 of Exhibit A-87 (JPP-2), the Company shows Staking expense
6 increasing from \$12.4 million in 2023 to \$24.4 million for the projected test year for an
7 increase of \$12.0 million or 97%. Beginning on page 43 of his direct testimony, Mr.
8 Pnacek discusses the Staking and Locating program and on page 44 identifies the major
9 drivers for the increase in expense. The largest increase at \$15.1 million pertains to the
10 expansion of the Gas Only locating program to other areas of the Company service area
11 outside of the Oakland and Kent counties. Costs are also increasing in Oakland and Kent
12 counties by \$4.0 million and in other areas of the program by \$1.0 million. This increases
13 are partially reduced by terminating the shared staking and locating contracts.

14 Where typically gas, electric, water, and cable companies share the cost of locating
15 underground facilities when Miss Dig is requested to locate underground facilities by
16 customers, contractors, and other parties, in 2023, the Company began a program of
17 staking only its own gas and electric facilities in Oakland and Kent counties and now wants
18 to expand the program to the rest of the state.

19 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY’S PROPOSED CHANGES**
20 **TO THE GAS LINE STAKING AND LOCATING PROGRAM?**

1 A. The change to a dedicated model emanated from internal and external problems that the
2 Company had in managing its staking and locating program in recent years primarily in
3 Oakland and Kent counties. The Company-only dedicated staking and locating program
4 started in Oakland County and was an experimental program to establish whether the
5 incremental benefits justified the incremental cost of a dedicated program. That evaluation
6 was never thoroughly presented in prior rate cases or this rate case.

7 On page 51 of his direct testimony, Mr. Pnacek tries to justify the expansion of the
8 dedicated Company-only program by pointing to less than two years of data from Oakland
9 and Kent counties. Throwing more resources at the problem at twice to three times the
10 previous costs may show better statistics but does not mean it is the optimal approach to
11 take. There has been no evidence presented in this rate case or previous rate cases that the
12 Company attempted to work with the shared model staking and locating contractors to
13 resolve whatever problems with performance existed and in turn minimize the cost of
14 staking and location.

15 In this rate case, the Company proposes to expand the dedicated Company-only model to
16 other counties in Michigan at an additional cost of \$12 million without providing any
17 evidence that a serious problem with staking and locating exists in those counties that
18 cannot be resolved in other ways. This is not a prudent way to spend money that the
19 Company seeks to recover from customers.

20 On page 52 of his testimony, Mr. Pnacek states that based on recent bids received from
21 contractors the cost per unit is lower for the dedicated model than the shared model. This

1 is counter to the historical evidence presented by the Company. As shown in Table 29 on
2 page 44 of Mr. Pnacek’s direct testimony, the Company forecasted that the cost to expand
3 the dedicated model to areas outside of Oakland and Kent will be \$15.1 million while
4 eliminating only \$7.9 million in costs from the shared model. The bidding process that
5 the Company went through in 2024 cannot be relied on. The Company has made it clear
6 publicly in testimony in at least the last two rate cases that it prefers to move to a dedicated
7 model and contractors have understood that preference. Contractors also prefer a
8 dedicated model because it increases their revenue by expanding their services. Their bids
9 likely reflect that common desire to move to a dedicated model and should not be relied
10 on by the Commission in reaching a decision in this matter.

11 **Q. WHAT IS YOUR CONCLUSION AND RECOMMENDATION?**

12 A. The Company did not provide any compelling and convincing evidence that a problem
13 exists in other counties outside of Michigan that cannot be resolved within the shared
14 staking and locating model. The shift to the Company-only dedicated model is
15 unsupported and very expensive. The bidding process showing of a lower cost for the
16 dedicated model against the shared model is counter to recent historical evidence and
17 cannot be relied on.

1 Therefore, I recommend that the Commission remove the incremental O&M expense of
2 \$11,184,000 included by the Company in the projected test year.¹⁵⁴

3 **3. EIRP Training Expense**

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

7 A. On line 9 of page 1 of Exhibit A-88 (JPP-3), the Company shows forecasted O&M
8 expenses of \$5,048,000 for the EIRP, which is an increase in expense of \$1,700,000 from
9 the 2023 historical level. On pages 85-88 of his direct testimony, Company witness James
10 Pnacek discusses the major components of the increase in expense. Table 62 shows that
11 \$1,656,000 of the increase pertains to EIRP Labor OM&C Training. Mr. Pnacek's direct
12 testimony does not explain this increase in expense.

13 In discovery, the Attorney General asked the Company to expand the table on page 86 of
14 Mr. Pnacek's testimony and provide the historical expenses for 2022-2024. The Company
15 was also asked to explain the reasons for the increase of approximately \$1.6 million. In
16 response, the Company stated that the EIRP workforce continues to grow requiring
17 additional training expense from 2023 to the projected test year.¹⁵⁵

¹⁵⁴ James Pnacek direct testimony, Table 29: 2023: Shared Services of \$7,865,196 + Dedicated Oakland & Kent \$2,766,691 – PTY: Dedicated Services Oakland & Kent of \$6,703,509 – Dedicated Other Areas of \$15,112,608 = \$11,184,000 rounded.

¹⁵⁵ Exhibit AG-58 includes DR AG-CE-561 Revised with attachment.

1 A. On page 29 of his direct testimony, Mr. Griffin discusses the O&M expense that the
2 Company plans to incur to identify deficiencies with traceable, verifiable, and complete
3 records to reestablish the MAOP for transmission, storage, and distribution pipelines.
4 Page 16 of Ms. Pascarello's also briefly discusses this matter. In response to discovery,
5 the Company confirmed that for the projected test year, it forecasted \$1,122,000 to perform
6 the MAOP records review.¹⁵⁷

7 As discussed, in the Capital Expenditures section of my testimony regarding MAOP
8 projects, the Commission ruled in a previous rate case that recovery of only 50% of this
9 expense should be allowed and the remaining 50% should be disallowed. Therefore, I
10 recommend that \$561,000 of expense be removed from the Company's forecasted O&M
11 expense.

12 2. Corrosion Control Expense

13 **Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO**
14 **FORECASTED TRANSMISSION O&M EXPENSE FOR THE PROJECTED**
15 **TEST YEAR FOR CORROSION CONTROL.**

16 A. On line 2 of page 2 of Exhibit A-58 (MPG-1), the Company shows an increase of
17 \$1,263,000 in Corrosion Control under Other Adjustments from the 2023 historical
18 expense to the projected test year. In discovery, the Attorney General asked the Company
19 to explain this increase in expense and provide pertinent support for it. In response, the

¹⁵⁷ Exhibit AG-59 includes DR AG-CE-0380 and 0778.

1 Company stated that the increase pertained to changes in the PHMSA regulations to
2 prevent atmospheric corrosion and recoat pipelines and related facilities. The discovery
3 response also provided a table showing historical and forecasted component expenses from
4 2023 to the projected test year. No work units or quantity of activities were provided to
5 support the annual expenses.¹⁵⁸

6 In a subsequent discovery response, the Company elaborated that the atmospheric
7 corrosion work being done is basically repainting sections of pipelines and related facilities
8 both above ground and below ground. Painting of pipelines and facilities is not a new
9 requirement and any expansion of requirements under PHMSA regulations also existed in
10 2023 and 2024 when costs were less than half the amount forecasted for the projected test
11 year.

12 The increase in expense for the projected test year is not supported by any increased work
13 units or work activities and the PHMSA reference by itself does not justify the increase in
14 expense. To arrive at a reasonable expense forecast, I applied the forecasted CPI inflation
15 factors to the 2023 actual expense and calculated a forecasted expense of \$1,024,000. This
16 amount is \$1,186,000 lower than the Company's forecasted expense of \$2,210,000.
17 Therefore, I recommend that the Commission remove \$1,186,000 in expense from the
18 Company's forecasted O&M expense for the projected test year.

¹⁵⁸ Id. includes DR AG-CE-0338.

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3. Riverside Storage Field Expense

Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO THE COMPANY’S FORECASTED AMORTIZATION EXPENSE FOR THE RIVERSIDE STORAGE FIELD LOSS.

A. As discussed in the Working Capital section of my testimony, the Company had recorded a loss to a deferred regulatory asset account on the expectation that it would sell the field to a prospective buyer. The Company amortized and recorded one-third of the loss to expense in this rate case. With the sale no longer proceeding, the amortization expense of \$2,959,000 should be removed from the expense. I recommend that the Commission remove this amount from the Company’s forecasted expense from the projected test year.

E. Customer Service Expense

1. Analytics & Outreach Expense

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

A. On line 1 of page 3 of Exhibit A-37 (URB-2), the Company shows \$2,325,000 of O&M expense for the Analytics and Outreach function. Witness Jessica Byrom’s direct testimony is devoid of any testimony addressing this expense function. In discovery, the Attorney General asked the Company to provide the historical and forecasted number of employees and contractors, the number of work units or work activities, and the tasks and

1 outcomes accomplished in the past two years and planned for 2025 and 2026 in this
2 department or function.

3 In response, the Company identified 58 employees and 14 contractors working in this area
4 for total of 72 people in 2024, and that number increases to 74 for the projected test year.
5 For work units, the Company identified 17 customer interactions in 2022, and that number
6 fell to 7 interactions in 2024 and stays at 7 for the projected test year. From the response,
7 it is not clear what customer interactions entail, why there are so few, and why they decline
8 from 2022 and stay the same between 2024 and the projected test year when the number
9 of employees and contractors in this function increases.¹⁵⁹

10 Regarding tasks performed and accomplishments achieved, the information provided is
11 very general about improving the customer experience, whatever that means, and does not
12 make a compelling case that significant value is being generated for the \$2.3 million
13 expense.¹⁶⁰ The evidence is inadequate, and the expense remains unsupported. Therefore,
14 I recommend that the Commission disallow recovery of the \$2,325,000 from the
15 Company's forecasted O&M expense for the projected test year.

¹⁵⁹ Exhibit AG-60 includes DR AG-CE-0659 with attachments.

¹⁶⁰ Id.

1 **2. Digital Customer Operations Expense**

2 **Q. PLEASE DISCUSS THE ADJUSTMENTS THAT YOU PROPOSE TO**
3 **FORECASTED CUSTOMER SERVICE O&M EXPENSE FOR THE PROJECTED**
4 **TEST YEAR FOR DIGITAL CUSTOMER OPERATIONS.**

5 A. On line 5 of page 3 of Exhibit A-37 (URB-2), the Company shows \$1,072,000 of O&M
6 expense for the Digital Customer Operations. Witness Jessica Byrom’s direct testimony
7 is devoid of any testimony addressing this expense item. In discovery, the Attorney
8 General asked the Company to provide the historical and forecasted number of employees
9 and contractors, the number of work units or work activities, and the tasks and outcomes
10 accomplished in the past two years and planned for 2025 and 2026 in this department or
11 function.

12 In response, the Company identified 23 employees and 5 contractors working in this area
13 for total of 28 people in 2024, and that number increases to 29 for the projected test year.
14 For work units, the Company identified 4 customer interactions in 2022, and that number
15 fell to 3 in 2024 and stays at 3 for the projected test year. From the response, it is again
16 not clear what customer interactions entail, why there are so few, and why they decline
17 from 2022 to the projected test year.¹⁶¹

18 Regarding the task performed and accomplishments achieved, the information identified
19 the major tasks performed. However, it is not clear why most of the system functions

¹⁶¹ Exhibit AG-60 includes DR AG-CE-0659 with attachments.

1 already developed would require repeat work using the same number of employees and
2 contractors every year. The general description of accomplishments does not make a
3 compelling case that significant value is being generated. There is insufficient support to
4 justify the number of resources assigned to this function. The evidence is inadequate, and
5 the expense level remains unsupported. Therefore, I recommend that the Commission
6 disallow recovery of at least 50% of the \$1,072,000 or \$536,000 from the Company's
7 forecasted O&M expense for the projected test year.

8 **F. Company Use & LAUF Gas Expense**

9 **~~Q. PLEASE DISCUSS THE ADJUSTMENTS YOU PROPOSE TO COMPANY USE~~**
10 **~~GAS AND LAUF GAS FOR THE PROJECTED TEST YEAR.~~**

11 ~~A. Regarding Company Use Gas expense, in Exhibit A 75 (TKJ 4) the Company calculated~~
12 ~~the projected test year expense of \$5,502,000 based on volumes determined in WP TKJ~~
13 ~~15. In response to discovery, the Company reported that the volumes flowing from WP~~
14 ~~TKJ 14 into WP TKJ 15 were incorrect as filed. The Company provided revised credit~~
15 ~~volumes received from Act 9 transportation customers for the historical 5 year period,~~
16 ~~which average to 2,089 MMcf.¹⁶² The forecasted volumes for the projected test year are~~
17 ~~set based on the historical 5 year average. Using the revised volumes in the Excel financial~~
18 ~~model for Exhibit A 75, I recalculated the forecasted expense for Company Use Gas at~~

¹⁶² ~~Exhibit AG 61 includes DR AG CE 0516 and Attachment 1 and 2.~~

1 ~~\$3,702,000.⁺⁶³ This amount is \$1,800,000 lower than the amount calculated by the~~
2 ~~Company.~~

3 ~~The revised transportation volumes also affected the calculation of the LAUF Gas expense~~
4 ~~due to the partial transportation offset included in the calculation of this expense. The~~
5 ~~result is a revised expense for LAUF Gas of \$8,551,000.⁺⁶⁴ This amount is \$4,158,000~~
6 ~~lower than the \$12,709,000 calculated by the Company.~~

7 ~~Therefore, I recommend that the Commission remove the \$1,800,000 and \$4,158,000 from~~
8 ~~the Company filed O&M expense for Company Use and LAUF Gas, respectively, for the~~
9 ~~projected test year.~~

10 **Q. DO YOU PROPOSE ANY ~~OTHER~~ ADJUSTMENTS TO LAUF GAS EXPENSE?**

11 A. Yes. On pages 24 and 25, Mr. Joyce discusses several initiatives undertaken by the
12 Company to reduce LAUF Gas, including the replacement of leaky pipes and its Net Zero
13 Methane Emission goal. Beginning on page 77 of the most recent Natural Gas Delivery
14 Plan, filed in this rate case as Exhibit A-42 (NPD-1), the Company outlined its Gas System
15 Decarbonization plan and states that by 2030 it will reduce methane emissions by 80%
16 from the 2023 level of 13,811 metric tons.

⁺⁶³ ~~Exhibit AG-62.~~

⁺⁶⁴ ~~Id.~~

1 The 80% reduction translates into 11,049 fewer metric tons of methane emissions, which
2 is equivalent to 545,379 Mcf less natural gas in LAUF gas.¹⁶⁵ For the seven-year period
3 from 2023 to 2030, the reduction is 77,911 Mcf per year. Over the 34 months from January
4 2024 to October 2026, the cumulative reduction is 220,748 Mcf.¹⁶⁶ This volume
5 multiplied by the average cost of gas rate of \$3.296 shown in Exhibit A-75 results in a
6 LAUF Gas expense reduction of \$728,000.

7 The Company appears committed to achieving the 80% target reduction and is planning
8 to spend large sums in capital investments and O&M expense to achieve it. Within the
9 context of a projected test year rate case, it is reasonable to expect that the Company will
10 achieve its overall goal between 2023 and the projected test. Hence, the Company should
11 be held accountable for the planned result. Therefore, I recommend that the Commission
12 remove \$728,000 of LAUF Gas expense from the Company's projected O&M expense.

13 **G. Information Technology Expense**

14 **1. IT Investment Expense**

15 **Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO IT INVESTMENT**
16 **O&M EXPENSE.**

17 **A.** On line 3 of page 1 of Exhibit A-19 (SHB-3), the Company forecasted IT Investment O&M
18 expense of \$16,814,000 for the projected test year. This level of expense is an increase of

¹⁶⁵ One Metric Ton = 49.36 Mcf.

¹⁶⁶ 77,911 Mcf ÷ 12 x 34 months.

1 \$12,938,000 over the 2023 historical expense of \$3,876,000. [Begin Conf] [REDACTED]
2 [End Conf] of the increase pertains to the proposed SAP S/4 HANA ERP project.¹⁶⁷

3 As I stated in the Capital Expenditures section of my testimony, the proposed ERP project
4 is still premature and inadequately justified to include in rate base and all related capital
5 expenditures should be removed from this rate case. Similarly, the Commission should
6 remove the [Begin Conf] [REDACTED] [End Conf] in O&M expense from this rate case.

7 In a similar vein, the recommendation by Company witness Heidi Myers on page 15 of
8 her testimony to establish deferred regulatory asset accounts to record the IT Investment
9 O&M costs and the cloud implementation costs for development of the SAP/ERP projects
10 should be denied at this time as premature and unnecessary.

11 **2. Cloud Computing Expense**

12 **Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO IT INVESTMENT**
13 **O&M EXPENSE.**

14 **A.** As discussed in the Working Capital section of my testimony, the Company made an error
15 in calculating the amortization expense for cloud computing fees and costs that have been
16 deferred. The Company rate case filing included \$17,351,545 of expense. The correct
17 amortization expense should be \$11,874,017.¹⁶⁸ Therefore, the difference of \$5,478,000

¹⁶⁷ Stacy Baker confidential direct testimony at page 104.

¹⁶⁸ Exhibit AG-38.

1 should be removed from the expense forecasted by the Company for the projected test
2 year. I recommend that the Commission remove this amount.

3 **3. IT Projects Disallowed - Expense**

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

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

- 10 1. The Utility Network: \$517,000
- 11 2. Data Center Migration: \$716,000
- 12 3. Gas Tracking and Traceability: \$509,000

13 The total expense for the three projects is \$1,742,000. I recommend that the Commission
14 remove this amount from the Company's forecasted OM expense.

15 **H. Voluntary Separation Program Expense Savings**

16 **Q. PLEASE DISCUSS YOUR PROPOSED O&M EXPENSE ADJUSTMENTS FOR**
17 **THE VOLUNTARY SEPARATION PROGRAM.**

18 A. In 2023, the Company began a Voluntary Separation Program (VSP) to downsize its
19 workforce. The downsizing program continued into 2024 and accumulated significant
20 cost savings. In discovery, the Attorney General asked the Company to provide the

1 amount of cost savings since the beginning of the program and through the projected test
2 year. The Company was also asked to provide the underlying calculations of the costs
3 savings and a reference in which exhibit and line number the cost savings were reflected
4 with supporting evidence through workpapers and other schedule that would show the cost
5 savings were included in the forecasted expense of each department or area for the
6 projected test year.

7 In response, the Company identified \$7,989,000 of cost savings for the projected test
8 year.¹⁶⁹ However, the Company did not provide the underlying calculations showing how
9 the cost savings were calculated. No labor hours, labor rates, other cost savings, and
10 reductions in employee benefits were disclosed. The Company also did not provide any
11 workpapers or supporting schedules that would show the cost savings were actually
12 included in the forecasted periods and the projected test year in each exhibit for each of
13 the affected departments. The result is that the cost savings cannot be traced back to the
14 various departments and the referenced exhibit lines and validated. Therefore, there is no
15 certainty that the cost savings were incorporated in the projected test year forecasted O&M
16 expense of each of the affected departments.

17 I recommend that the Commission remove the entire \$7,989,000 of VSP cost savings from
18 the Company's forecasted O&M expense for the projected test year to ensure that the cost
19 savings are appropriately reflected in rates in this rate case

¹⁶⁹ Exhibit AG-63 includes DR AG-CE-0372 with ATT_1.

1 **I. Corporate O&M Expense**

2 ~~Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENT TO CORPORATE O&M~~
3 ~~EXPENSE.~~

4 ~~A. On line 6 of Exhibit A-44 (MJF-2), the Company shows Corporate General Activities~~
5 ~~cost and credits from 2023 through the projected test year. The amount under the Labor~~
6 ~~column for 2023 of \$7,428,000 is unusual and excessive. In discovery, the Attorney~~
7 ~~General asked the Company to expand Exhibit A-44 and provide similar information for~~
8 ~~actual years 2021, 2022, and 2024. The additional historical information shows that the~~
9 ~~Labor amount for General Activities in 2021 was a negative amount of \$12.2 million.~~
10 ~~The 2022 amount was also negative at \$1.6 million, and 2024 has a negative amount of~~
11 ~~\$2,770,000.¹⁷⁰~~

12 ~~— In discovery, the Attorney General asked the Company to provide the components of the~~
13 ~~\$7,428,000 expense and a thorough explanation of the unusual positive amount in 2023~~
14 ~~when the other years show negative amounts for Labor in this General Activities~~
15 ~~category. However, the requested cost components were not provided, and the~~
16 ~~explanations were not directly pertinent to the amount requested to be explained, and~~
17 ~~were inadequate.¹⁷¹ The \$7,428,000 labor amount from 2023 remains unexplained and~~
18 ~~unsupported by the Company~~

¹⁷⁰ ~~Exhibit AG-64 includes DR-AG-CE-0297 with Attachment.~~

¹⁷¹ ~~Id. includes DR-AG-CE-0741.~~

~~To develop a reasonable forecast for General Activities, I used the negative amount of \$2,770,000 from 2024, as the most recent basis to calculate the forecasted amount for the projected test year. After adjusting that amount for inflation, I arrived at the projected test year negative amount of \$2,896,000.¹⁷² After including the inflation adjustments calculated by the Company from 2023 to the projected test year, the \$7,428,000 increased to \$8,014,000 at the end of the projected test year.¹⁷³ The difference between the negative \$2,896,000 and the \$8,014,000 is \$10,910,000 (\$2,896,000 — 8,014,000).~~

~~I recommend that the Commission remove the \$10,910,000 from the Company's projected test year O&M expense for the Corporate General Activities.~~

J. Active Health Care Expenses

Q. PLEASE DISCUSS THE COMPANY'S PROJECTED EXPENSE FOR ACTIVE HEALTH CARE, LIFE INSURANCE AND LONG-TERM DISABILITY.

A. Line 4 of Exhibit A-64 (KKG-1) shows actual health care, life insurance and long-term disability (Health Care & Other) expense of \$19,765,000 for the projected test year, which is an increase of approximately \$1.4 million or 10.6% over the 2023 historical expense. To arrive at the projected test year expense, the Company applied the forecasted CPI inflation rates of 3.2%, 2.4% and 2.5% from 2024 through the 10 months of 2026.

¹⁷² ~~\$2,770,000 x 1.024 x 1.021 = \$2,896,000.~~

¹⁷³ ~~\$7,428,000 + \$238,000 for 2024 + \$184,000 for 2025 — \$164,000 for the 10 months in 2026 = \$8,014,000.~~

1 In discovery, the Attorney General asked the Company to identify the cost savings of
2 various initiatives taken in recent years and anticipated to be taken in 2025 and 2026 to
3 reduce health care costs. In response, the Company identified cumulative cost savings by
4 year from 2023 to 2026. For 2023, the Company realized \$3,763,000 in cost savings. By
5 2025 and 2026, the Company expects to achieve cost savings of between \$6,378,000 and
6 \$7,211,000.¹⁷⁴ The prorated amount for the projected test year based on those amounts is
7 \$6,517,000. This amount is \$2,754,000 above the \$3,763,000 realized in 2023.

8 **Q. WHAT IS YOUR PROPOSED ADJUSTMENT TO HEALTH CARE EXPENSE**
9 **FOR THE PROJECTED TEST YEAR?**

10 A. I recommend that the Commission reduce the Company's Active Health Care expense for
11 the projected test year by the estimated cost savings of \$2,754,000.

12 **K. Incentive Compensation Expense**

13 Through the testimony of witnesses Amy Conrad and Ashley Meschke, the Company
14 proposes to recover in rates \$1,546,000 of short-term incentive compensation.¹⁷⁵

15 In the following pages of my testimony, I will analyze the Company proposal to include
16 in rates the cost of incentive compensation and the alleged benefits to customers provided
17 in the testimony of Ms. Meschke. Over the past few years, the Company has made several
18 changes to the incentive plan that have made it easier for the Company to payout incentive

¹⁷⁴ Exhibit AG-65 includes DR AG-CE-0686.

¹⁷⁵ Exhibit A-41 (AMC-3).

1 compensation. For example, the operating performance measures that drive the short-term
2 incentive payouts under the plan were revamped in recent years. Beginning in 2022, the
3 ability to trigger a payout has been modified to make it much easier for employees to
4 receive incentive compensation payments. I will discuss these changes in more detail later
5 in my testimony.

6 **Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY’S SHORT-TERM**
7 **INCENTIVE COMPENSATION PLAN.**

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

11 The major components of the EICP for non-officer employees are shown in Exhibit A-39
12 (AMC-1). Fifty percent (50%) of the target award in 2023 was based on achieving 6
13 performance measures related to employee safety, employee satisfaction surveys,
14 customer experience surveys, electric reliability, waste elimination and methane emission
15 reduction.

16 This 50/50 combination of operating and financial measures started in 2012. In 2010 and
17 2011, the calculation of the non-officer EICP was based solely on achieving operating
18 performance measures. The requirement to achieve 100% payout of target was also stricter
19 with accomplishment of 9 measures out of 11 needed. The Company then adjusted this
20 percentage based on the percent payout of the officers’ EICP. Over the last seven years,

1 non-officer employees have received incentive payouts as a percentage of target of 123%
2 in 2018, 111% in 2019, 139% in 2020, 77% in 2021, 160% in 2022, 140% in 2023, and
3 136% in 2024.¹⁷⁶ The only year in the past fourteen years where a bonus payout was not
4 made to non-officer employees was in 2011 when only 6 of the 11 operating measures
5 were achieved. These consistent payouts indicate that incentive compensation is not at-
6 risk compensation based on achieving superior performance, but it simply supplements
7 base pay.

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

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

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

16 For the 2023 plan cycle, half of the non-officer employee EICP payouts and 70% of the
17 Officer EICP payouts were dependent upon the financial metrics. As such, the officer
18 group that sets the direction of the Company is still far too focused on financial results.
19 Customers do not directly benefit from shareholders achieving a higher return on their

¹⁷⁶ DR AG-CE-00672 with attachments and U-21490 DR AG-CE-165 with attachment.

1 investment. Although the Company has argued in the past that happy investors will be
2 more attracted to the Company debt and common stock issues and therefore provide a
3 lower cost of capital, it has not offered direct proof to support this argument. The argument
4 is particularly hollow since the Company has not issued any significant common stock in
5 more than five years. Later in my testimony, I will discuss in more detail the customer
6 benefits put forth by Ms. Meschke.

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

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

16 Additionally, the fact that the performance measures use CMS Energy financial
17 information and comingle electric and gas business measures is a concern. Although the
18 Company is a combined gas and electric utility and makes up 95% of CMS Energy,
19 appropriate cost segregation is required to avoid having gas customers subsidize other
20 businesses, particularly non-utility operations.

1 Lastly, the Company has stated that it continues to pay salary increases each year of
2 approximately 3.5%.

3 **Q. PLEASE BRIEFLY SUMMARIZE AND PROVIDE YOUR ASSESSMENT OF THE**
4 **CUSTOMER BENEFITS PRESENTED BY THE COMPANY TO JUSTIFY**
5 **RECOVERY OF INCENTIVE COMPENSATION COSTS.**

6 A. In her testimony, Ms. Meschke attempts to quantify certain benefits related to the
7 operating performance measures that are part of the EICP. In Exhibit A-96 (AEM-2), Ms.
8 Meschke shows the number of Safety Incidents, which were 102 in 2020 and 125 in 2023.
9 The actual trend of safety incidents has been upwards. To calculate cost savings, the
10 Company assumed it would be able to reduce the number of incidents to 81 in 2024 and
11 based the calculation on that lower number. However, this is wishful thinking and not
12 actual cost savings achieved. With higher safety incidents in 2023 than in 2020, costs have
13 increased and not decreased. The exhibit also shows that the Company's Workers
14 Compensation and other related costs have been erratic from 2020 to 2023 with no
15 consistent downward trends to create cost savings. Clearly, these results do not show
16 superior performance or an improving trend.

17 In Exhibit A-97 (RMS-3), Ms. Meschke shows the Company's SAIDI Index results as a
18 measure of Electric Reliability. Instead of using actual SAIDI results for the past year to
19 show a trend, she uses a four-year average from 2020 to 2023 and compares that average
20 to a 2024 goal to calculated potential savings instead of actual savings. This approach of

1 estimating potential cost savings instead of realized actual savings is an attempt to show
2 cost savings where none have existed.

3 Ms. Meschke also calculates certain savings related to the Company's Culture Index based
4 on purported cost savings from lower employee turnover. However, Exhibit A-98 shows
5 that employee turnover was 2.7% in 2023 compared to 1.1% in 2020. Clearly, this is not
6 an improving trend. To try and show some costs savings, the Company makes a
7 comparison to other utilities. However, there is a clear mismatch between the employee
8 satisfaction measures which are solely based on internal company surveys and cost savings
9 calculated based on peer company turnover rates.

10 In summary, the cost savings calculated by Ms. Meschke are inconsistent with recent
11 trends in performance, aspirational, and not based on actual achievements. They do not
12 justify the \$1.5 million of incentive compensation that the Company seeks to recover in
13 this rate case.

14 **Q. BASED ON YOUR REVIEW OF RESULTS DURING THE PAST FIVE YEARS,**
15 **HAS THE COMPANY ACHIEVED THE TARGET LEVEL OF PERFORMANCE**
16 **FOR THE OPERATING MEASURES DURING THOSE YEARS?**

17 A. No. In discovery, the Attorney General asked the Company to provide the target operating
18 measures, and the actual performance achieved for each year from 2020 to 2024. The
19 information provided by the Company shows that in 2020 the Company only met 7 of the
20 9 operating performance measures at 100% of target or higher for an average achievement

1 rate 78% of target. In 2021, only 6 of 9 were met at least at 100% for a 67% achievement
2 rate. In 2022, 4 of the 6 operating measures were achieved at least at 100% of target for a
3 67% achievement rate. In 2023, only 3 of the 6 operating measures were met at least at
4 100% for a 50% achievement rate and in 2024 only 4 of the 6 measures were met at 100%
5 of target for a 67% achievement rate. The average achievement rate for the past five years
6 was 66%.¹⁷⁷

7 In forecasting the amount of EICP expense of \$1,546,000 included in the forecasted test
8 year, the Company assumed that all operating measures would be achieved at least at 100%
9 of target for both the officer and non-officer EICP. The results of the last five years do not
10 support this expected performance level. Customers should not pay for expected
11 performance that does not materialize. Therefore, recovery of incentive compensation at
12 less than 100% of target is warranted. Using the 66% average performance achievement
13 rate, the most that the Company should be allowed to recover in this rate case is \$1,020,000
14 (\$1,546,000 x 66%). The remaining amount of \$526,000 should be disallowed.

15 **Q. WHAT CONCLUSIONS AND RECOMMENDATIONS HAVE YOU REACHED**
16 **WITH REGARD TO RECOVERY OF INCENTIVE COMPENSATION COSTS IN**
17 **RATES?**

18 A. As discussed above, the focus of the short-term incentive compensation plans is
19 overwhelmingly directed at creating shareholder value, not customer benefits, and the

¹⁷⁷ Exhibit AG-66 includes DR AG-CE-0672 with attachments and Part III Item 86 Information.

1 officer group that directs the day-to-day operations is only minimally incentivized to meet
2 operational goals. Certain design flaws with the EICP tend to reward mediocre
3 performance and diminish any real customer benefits. Incentive compensation should be
4 paid for exceptional performance, at least to pass the test of cost recovery in rates.
5 Performance that is ordinary and achieves basic goals and efficient operations is paid for
6 in base salaries.

7 Both management and other employees have received large annual merit salary increases
8 since at least 2009. The Company argues that it must pay a competitive compensation
9 package to retain talented management and employees. Although that may be the case, it
10 does not mean that customers should pay for all or most of that expense. Shareholders
11 also significantly benefit from talented management, perhaps even more so than
12 customers. Customers are paying for higher base pay each year. Shareholders can share
13 the burden by paying for the incentive compensation that disproportionately favors their
14 interests.

15 The Company's proposed incentive compensation expense of \$1,546,000 for the projected
16 test year assumes that the Company will achieve target performance for all its goals. There
17 is no track record that supports that conclusion. It is probable that the Company may fall
18 short of achieving 100% of the performance measures in the projected test year. Although
19 I do not believe the Company has made a compelling case to justify recovery of any
20 amount of incentive compensation and therefore no incentive compensation should be
21 included in rates.

1 In recent rate cases the Commission has approved a portion of incentive compensation
2 pertaining to operating measures and if it decides to do so in this case, I recommend that
3 the Commission approve at most recovery of the \$1,020,000 incentive compensation
4 amount I calculated above based on the Company achieving just 66% of the operating
5 performance measures. Therefore, the Commission should disallow at least the remaining
6 amount of \$526,000 if not the entire amount of \$1,546,000 from the Company's forecasted
7 O&M expense for the projected test year.

8 **L. O&M Adjustments - Summary**

9 **Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO O&M**
10 **EXPENSE.**

11 A. Operations and maintenance expenses represent a large part of the Company's cost
12 structure. My analysis of the expense level proposed by the Company has shown that in
13 the following areas these expenses are excessive or not needed and should be removed.

Summary of O&M Expense Reductions Revised	Amount (\$ Millions)
Gas Engineering	\$ 4.7
Gas Distribution Operations	14.1
Gas Transmission & Storage	4.7
Customer Service	2.9
Company Use and Lost Gas	0.7
Information Technology	17.0
Corporate Programs	8.0
Health Care Costs	2.8
Incentive Compensation	1.5
Total	\$ 56.4

1

2

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I recommend that the Commission reduce the amount of total O&M costs proposed by the Company by ~~\$73.3~~\$56.4 million and reduce the revenue deficiency accordingly. Exhibit AG-56 CONF Revised provides further details.

5

XI. Adjustments To Revenue Deficiency

6

7

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

8

9

10

A. Revised Exhibit AG-67 summarizes the adjustments to rate base and operating income. The net result is a revised revenue deficiency of ~~\$76.5~~\$95.6 million, which is a reduction of ~~\$171.5~~\$152.4 million from the Company's requested level of \$248 million.

11

12

I recommend the Commission adopt these adjustments and issue an order granting rate relief to the Company in an amount not exceeding ~~\$76.5~~\$95.6 million.

1 **XII. Deferred Accounting Requests**

2 **Q. PLEASE PROVIDE YOUR RECOMMENDATIONS REGARDING THE**
3 **DEFERRED ACCOUNTING REQUESTS MADE BY THE COMPANY.**

4 A. In their direct testimony both witnesses Heidy Myers and James Pnacek request that the
5 Commission approve deferred accounting treatment of staking and locating expense
6 because increasing staking volumes and external factors contribute to volatile expense.
7 The Commission should reject this proposal. No compelling evidence has been presented
8 that staking and locating requests have been highly volatile to cause significant expense
9 variations from year to year. The only large variation in expense in this area has been the
10 Company’s pursuit to change from a shared contractor model to a Company-only
11 dedicated model, as discussed in more detail in the O&M Expense section of my
12 testimony.

13 Company witnesses Myers and Pnacek are also requesting that the Commission approve
14 deferred accounting treatment for O&M expenses pertaining to the previously proposed
15 LDAR rule by PHMSA. That rule is currently on hold₂ and it is not known if and when it
16 will be issued. Approval of deferred accounting at this time is premature and the
17 Commission should deny it.

18 Witnesses Griffin and Rayl request that the Company receive approval to capitalize MAOP
19 retesting projects. In response to discovery, the Company stated that it does not currently

1 have any such expenses to capitalize.¹⁷⁸ This request is also premature and there is no
2 need for the Commission to grant approval at this time. More information needs to be
3 gathered from the Company once tangible examples of expenses arise to make a
4 determination whether those expenses truly qualify for capitalization.

5 Ms. Myers has requested that O&M development costs for the new ERP project be
6 deferred for later amortization and has requested deferred accounting treatment. As
7 discussed earlier in my testimony under the Capital Expenditures section, this project has
8 not been adequately justified, and the Company has not yet completed the vendor bidding
9 process for it to be considered ripe for start of project execution. Until there is a real
10 project ready for execution which has been adequately justified, the Commission should
11 deny the request for deferral of O&M expenses.

12 **XIII. Rate Design**

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

15 A. In his direct testimony, Company witness Austin Smith proposes to increase the monthly
16 service charge for residential customers from \$15.00 to \$20.00 per month. According to
17 his testimony, the proposed monthly service charge reflects a rate of increase considerably

¹⁷⁸ DR AG-CE-0693.

1 less than the actual customer-related fixed costs calculated in the Company's cost of
2 service study.

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

4 A. No. The proposed change from \$15.00 to \$20.00 per month represents an increase of 33%.
5 Such a large increase could cause financial hardship to customers in smaller households
6 who use less gas than the average customer. They would see their monthly gas bill increase
7 without using any more gas. Fixed monthly charges also discourage energy conservation.
8 It is best to increase the volumetric rate paid by customers because the higher cost
9 encourages conservation. The customer can take steps to reduce usage and thus lower the
10 gas bill. The customer cannot reduce fixed monthly charges.

11 **Q. WHAT DO YOU RECOMMEND?**

12 A. The Company received a 10% increase in the monthly service charge in the last rate case
13 about one year ago from \$13.60 to \$15.00. I recommend that the Commission reject the
14 proposed increase and keep the residential customer monthly charge at \$15.00.

15 **Q. WHAT INCREASE IN THE MONTHLY SERVICE CHARGE FOR GENERAL
16 SERVICE GS-1 CUSTOMERS HAS THE COMPANY PROPOSED?**

17 A. In his direct testimony, Mr. Smith proposes to increase the monthly service charge for
18 customers on Rate GS-1 from \$18.00 to \$24.00 per month. Although not stated directly

1 in his testimony, it appears that the proposed monthly service charge for this rate schedule
2 also reflects the actual fixed costs calculated in the Company's cost of service study.

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

4 A. No. The proposed change from \$18.00 to \$24.00 per month represents an increase of 33%.
5 Such a large increase could cause some hardship to customers with smaller businesses who
6 use less gas than the average commercial customer. They would see their monthly gas bill
7 increase without using any more gas. As stated above, fixed monthly charges also
8 discourage energy conservation. It is best to increase the volumetric rate paid by customers
9 because the higher cost encourages conservation. The customer can take steps to reduce
10 usage and thus lower the gas bill. The customer cannot reduce fixed monthly charges.

11 **Q. WHAT DO YOU RECOMMEND?**

12 A. In the last rate case, the Company received approval to increase the GS-1 monthly
13 customer charge by nearly 13% from \$16.00 to \$18.00. At this time, I recommend that
14 the Commission should reject the Company's request and keep the month charge at \$18.00.

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

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

Computation of Revenue Deficiency for Projected Test Year Ending October 2026

(\$000)

Line	Description (a)	Company Filed Amount (b)	AG Recommended Adjustments (c)	Revised Amount (d)
1	Rate Base ⁽¹⁾	\$ 11,750,740	\$ (514,702)	\$ 11,236,038
2	Rate of Return	6.22%	-0.25%	5.97%
3	Income Required	\$ 730,838	\$ (60,047)	\$ 670,791
4	Adjusted Net Operating Income ⁽²⁾	545,492	53,854	599,346
5	Income Deficiency (Sufficiency)	\$ 185,346	\$ (113,901)	\$ 71,445
6	Revenue Multiplier	1.3381	1.3381	1.3381
7	Revenue Deficiency (Sufficiency)	\$ 248,008	\$ (152,408)	\$ 95,600

⁽¹⁾ Rate Base Adjustments Revised Exhibit AG-34.

			Source
⁽²⁾	AG adjustments to Operating Income		
	Revenue	\$ 1,822	Exhibit AG-54
	Lower Forecast of O&M Expenses	56,422	Revised Exhibit AG-56
	Property Taxes	3,731	Revised Exhibit AG-34
	Depreciation Expense	13,250	Revised Exhibit AG-34
	Total	\$ 75,225	
	Effective Tax Rate (1-1/1.3381)	25.27%	
	Taxes	19,006	
	Interest Synchronization for cap. Ex. adjustments	(2,364)	AG-67 WP1
	Adjusted Net Operating Income	\$ 53,854	

PROOF OF SERVICE - U-21806

The undersigned certifies that a copy of the *Attorney General's PUBLIC REVISED 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 23rd day of May 2025.

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