

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

MPSC Case No. U-21585

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

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of
Attorney General Dana Nessel

September 27, 2024

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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 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 setting and other regulatory proceedings.

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

1 A. I have performed rate case analyses and filed testimony in several electric general rate
2 cases addressing issues on revenue requirement, sales level determination, operation and
3 maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of
4 service and rate design, and various cost tracking mechanisms. In addition, I have
5 performed analysis of power costs and filed testimony in power supply cost recovery cases,
6 including reconciliation of annual power supply costs.

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

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

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

- 17 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
18 Company (DTEE) 2024 gas rate case U-21534 on several issues, including
19 operation and maintenance expenses, capital expenditures, cost of capital, and
20 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.

- 1 ○ Filed testimony on behalf of the Michigan Attorney General in the Michigan
2 Gas Utilities Corporation (MGUC) 2024 gas rate case U-21540 on several
3 issues, including operation and maintenance expenses, capital expenditures, cost
4 of capital, and other items.
- 5 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy
6 Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- 7 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas
8 Company (DTE Gas) 2024 gas rate case U-21291 on several issues, including
9 sales, operation and maintenance expenses, capital expenditures, cost of capital,
10 and other items.
- 11 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-
12 2023 GCR reconciliation in case No. U-21065.
- 13 ○ Filed testimony on behalf of the Michigan Attorney General in Consumers
14 Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales,
15 operation and maintenance expenses, capital expenditures, cost of capital, and
16 other items.
- 17 ○ Filed testimony on behalf of the Michigan Attorney General in DTM Michigan
18 Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in
19 case No. U-21525.
- 20 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2022
21 PSCR reconciliation in case No. U-21051.
- 22 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2022-
23 2023 GCR reconciliation case No. U-21067.
- 24 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2022
25 PSCR reconciliation in case No. U-21049.
- 26 ○ Filed testimony on behalf of the Michigan Attorney General in the Indian
27 Michigan Power Company's 2023 electric rate case U-21461 on several issues,
28 including sales, operation and maintenance expenses, capital expenditures, cost
29 of capital, and other items.
- 30 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-
31 2024 GCR plan in case No. U-21271.
- 32 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2023-
33 2024 GCR plan in case No. U-21269.
- 34 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2023
35 electric rate case U-21389 on several issues, including operation and
36 maintenance expenses, capital expenditures, cost of capital, and other items.

- 1 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-
2 2024 GCR plan in case No. U-21277.
- 3 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 rate
4 case U-21297 on several issues, including operation and maintenance expenses,
5 capital expenditures, cost of capital, and other items.
- 6 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-
7 2024 GCR plan in case No. U-21273.
- 8 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2022 gas
9 rate case U-21308 on several issues, including sales revenues, operation and
10 maintenance expenses, capital expenditures, cost of capital, and other items.
- 11 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-
12 2022 GCR plan reconciliation case No. U-20817.
- 13 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2021
14 PSCR plan reconciliation case No. U-20827.
- 15 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-
16 2022 GCR plan reconciliation case No. U-20819.
- 17 ○ Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula
18 Power Company 2022 general rate case No. U-21286.
- 19 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-
20 2022 GCR plan reconciliation case No. U-20823.
- 21 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2022-
22 2023 GCR plan case No. U-21062.
- 23 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-
24 2023 GCR plan case No. U-21070.
- 25 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2022
26 electric rate case U-21224 on several issues, including operation and maintenance
27 expenses, capital expenditures, cost of capital, and other items.
- 28 ○ Filed testimony on behalf of the Public Counsel Division of Washington Attorney
29 General in the Avista 2022 electric and gas rate cases on several issues, including
30 operation and maintenance expenses, capital expenditures, and other items.

31 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")
4 Electric Rate Case filing in Case No. U-21585. This testimony presents a report of that
5 analysis with 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 for electric distribution
9 facilities
- 10 2. Adjustments to depreciation expense
- 11 3. The Company's cost of capital
- 12 4. The Company's working capital
- 13 5. The level of operations and maintenance expenses
- 14 6. The Company's proposed modifications to the Investment Recovery Mechanism
15 (IRM)
- 16 7. The Company's proposed Service Restoration Cost Sharing Mechanism

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 specific issues within the available
20 resources.

21 Michael Deupree has also filed testimony on behalf of the Attorney General in this rate
22 case. His proposed capital expenditures disallowances and related items have been

1 included in the total rate base adjustments and revenue deficiency amounts presented in
2 my direct testimony.

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

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

- 6 1. Exhibit AG-1.1 DR Response – Capex U-21389 Path vs. Reliability Roadmap
- 7 2. Exhibit AG-1.2 DR Response – Reliability Goal Achievement Timeframe
- 8 3. Exhibit AG-1.3 DR Response – Inflation factors
- 9 4. Exhibit AG-1.4 DR Response – Contractor Service Installation vs. Employees
- 10 5. Exhibit AG-1.5 DR Response – LVD Lines Demand Failures
- 11 6. Exhibit AG-1.6 DR Response – LVD Lines Reliability
- 12 7. Exhibit AG-1.7 DR Response – LVD Substation Reliability
- 13 8. Exhibit AG-1.8 DR Response – Fractionalization
- 14 9. Exhibit AG-1.9 DR Response – Undergrounding
- 15 10. Exhibit AG-1.10 DR Response –LVD Projects over \$1 million
- 16 11. Exhibit AG-1.11 DR Response – Wildfire Program
- 17 12. Exhibit AG-1.12 DR Response – HVD Lines and Substation Rehab
- 18 13. Exhibit AG-1.13 DR Response – HVD Large Transformer Pre-Purchase
- 19 14. Exhibit AG-1.14 DR Response – Grif Modernization Programs
- 20 15. Exhibit AG-1.15 Summary Cap Ex, Rate Base, Depreciation & Tax Expense
- 21 16. Exhibit AG-1.16 Overall Cost of Capital
- 22 17. Exhibit AG-1.17 Cost of Common Equity
- 23 18. Exhibit AG-1.18 Cost of Common Equity-DCF
- 24 19. Exhibit AG-1.19 Cost of Common Equity-CAPM
- 25 20. Exhibit AG-1.20 Cost of Common Equity-Risk Premium
- 26 21. Exhibit AG-1.21 ROE Decisions by Regulatory Commissions
- 27 22. Exhibit AG-1.22 Peer Group Selection Screening

- 1 23. Exhibit AG-1.23 Pro-Forma Cash Flow Coverage Ratios
- 2 24. Exhibit AG-1.24 Market to Book Ratios
- 3 25. Exhibit AG-1.25 DR Response – Moody’s Rating Report May 31, 2024
- 4 26. Exhibit AG-1.26 DR Response – S&P Rating Report August 17, 2023
- 5 27. Exhibit AG-1.27 DR Response – August 2024 10-Year U.S. Treasury Rates
- 6 28. Exhibit AG-1.28 Values Line Report on Market Volatility vs. Risk
- 7 29. Exhibit AG-1.29 Working Capital Interest Accrual
- 8 30. Exhibit AG-1.30 DR Response – Ludington/Toshiba Deferral
- 9 31. Exhibit AG-1.31 O&M Adjustments Summary
- 10 32. Exhibit AG-1.32 O&M Adjustments - Distribution Operations
- 11 33. Exhibit AG-1.33 Service Restoration Cost Adjustment
- 12 34. Exhibit AG-1.34 Staking & Locating O&M Adjustments
- 13 35. Exhibit AG-1.35 Forestry Cost Savings for Service Restoration
- 14 36. Exhibit AG-1.36 DR Response – CECo Calculation of Forestry Savings
- 15 37. Exhibit AG-1.37 DR Response – Distribution LVD O&M expense increases
- 16 38. Exhibit AG-1.38 DR Response – Distribution HVD O&M Expense increases
- 17 39. Exhibit AG-1.39 DR Response – Underground Workforce
- 18 40. Exhibit AG-1.40 DR Response – Generation Base O&M Expense Analysis
- 19 41. Exhibit AG-1.41 DR Response – Customer Interactions Cost Trends
- 20 42. Exhibit AG-1.42 DR Response – Insurance Forecast
- 21 43. Exhibit AG-1.43 AF Recalculation of Insurance Expense
- 22 44. Exhibit AG-1.44 DR Response – Incentive Compensation at Threshold
- 23 45. Exhibit AG-1.45 AG Revenue Deficiency Calculation

24 **II. SUMMARY CONCLUSIONS & RECOMMENDATIONS**

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

1 A. The Company filed for a rate increase of \$302.6 million. The rate increase represents an
2 overall increase in rates of 6.5% and an increase of 8.2% to residential rates.

3 Based on my analysis, I have identified several cost disallowances to the Company's
4 proposed cost levels and capital projects, which I recommend that the Commission adopt.

5 As a result of these adjustments, I have determined that the Company has a revenue
6 deficiency of \$82.9 million at most, which represents an overall increase in rates of 1.8%.

7 My conclusions and related adjustments are summarized below:

- 8 1. On behalf of the Attorney General, Mr. Michael Deupree and I recommend
9 a reduction in capital expenditures of \$1.350 billion and a reduction of \$950.2
10 million to rate base for the test year, including a \$44.3 million reduction to
11 working capital. This reduces the Company's revenue deficiency by \$75.5
12 million.
- 13 2. I recommend that the Commission adopt a lower cost of capital rate of 5.94%,
14 a capital structure with 50% equity capital and a return on common equity of
15 9.80%. These recommendations reduce the Company's revenue deficiency
16 by \$55.3 million.
- 17 3. I recommend a lower level of Operations and Maintenance expenses for the
18 test year. This reduces the Company's revenue deficiency by \$48 million.
- 19 4. I recommend a lower amount of depreciation expense of \$43.1 million
20 pertaining to the lower capital expenditures and additions to plant discussed
21 above. This adjustment reduces revenue deficiency by the same amount.

1 5. I recommend a lower amount of property tax expense of \$3.4 million
2 pertaining to the lower capital additions to plant discussed above. This
3 adjustment reduces revenue deficiency by the same amount.

4 6. I recommend that the Commission reject the Company's proposed increase
5 to capital expenditures for the second year of the IRM.

6 7. I recommend that the Commission reject the Company's proposed Service
7 Restoration Cost Sharing Mechanism.

8 **Q. DO YOU HAVE ANY GENERAL OBSERVATIONS ABOUT THE COMPANY'S**
9 **RATE CASE FILING?**

10 A. Yes. I have four general observations. First, the Company filed this rate case with a
11 projected test year ending February 28, 2026, and a bridge period of 14 months
12 incorporating the year 2024 and two months of 2025. This short two-month extension of
13 the bridge period into 2025 and the test year into 2026 unnecessarily complicates the
14 analysis, comparison, and calculation of capital expenditures, and operation and
15 maintenance (O&M) expenses against historical periods. With the odd bridge and
16 projected test year, forecasted amounts and proposed disallowances require proration
17 between several periods increasing the analytical and calculation burden and also the
18 potential for calculation errors. Inflation adjustments also must be segmented into three
19 separate periods for 2024, 2025, two months in 2025, and two months for 2026.

20 This is the second consecutive rate case where the Company has used this odd projected
21 test year and bridge period. Given the tight time constraints to review rate cases and the

1 increasing number of issues presented, the Company should avoid projected test years and
2 bridge periods that do not end in a calendar year or at least at the end of a calendar quarter
3 in future rate cases. For example, in Case No. U-21224, filed one month earlier on April
4 28, 2022, the Company had a bridge period for the calendar year 2022 and a projected test
5 year for the calendar year 2023, which simplified the analysis and testimony.

6 Second, the Company stated in response to discovery that monthly financial forecasts for
7 capital expenditures for distribution facilities for 2025 and 2026 were not developed by
8 the Company in this rate case.¹ The lack of monthly data further complicates the proration
9 of capital expenditures between annual periods, the forecasted bridge, and the projected
10 test year. It is also perplexing how the Company can forecast capital expenditures for a
11 14-month bridge period ending February 2025 and a projected test year ending February
12 2026 without knowing what the monthly amounts are for each year.

13 Third, in this rate case as in other recent rate cases, there has been an increase in the number
14 of Company witnesses that cover common topics. This causes considerable duplication
15 and often repetitive testimony. For example, in this rate case, the Company had 6
16 witnesses (Pamela Bolden, Michael Kelly, Donald Lynd, Keith Kurdziel, Scott McPhail,
17 and Daniel Schmoekel) who provided testimony on various sections of the electric
18 distribution system and related technology. Some of the testimony repeats the same basic
19 topics and is unnecessarily verbose.

¹ U-21585 DR AG-CE-0443.

1 This segmentation in testimony and exhibits complicates the analysis of capital
2 expenditures and often creates uncertainty as to which witness is sponsoring specific
3 capital expenditures and where in the testimony the explanations are located. Given the
4 tight time constraints to review rate cases, the Company should refrain from having
5 multiple witnesses covering common areas and duplicating testimony.

6 Fourth, the quantity of testimony has also increased exponentially in recent rate cases, but
7 the quality of the information has not increased commensurately. The testimony often
8 makes general statements and fails to provide relevant information to support its proposal
9 and some of the exhibits have become lengthier with unnecessary minutia or general
10 descriptions and repetitive statements.

11 I recommend that the Commission direct the Company to avoid projected test years and
12 bridge periods that do not end in a calendar year or at least the end of a calendar quarter.

13 I also recommend that the Commission direct the Company to minimize duplicative
14 testimony, be more concise and direct in presenting pertinent evidence to support its
15 forecasted costs.

16 **III. CAPITAL EXPENDITURES AND RATE BASE**

17 **Q. WHAT ARE YOUR FINDINGS IN ANALYZING THE COMPANY'S PROPOSED**
18 **LEVEL OF CAPITAL EXPENDITURES ADDED TO RATE BASE?**

19 A. The Company is continuing the major ramp up of capital expenditures in a variety of areas.
20 In this rate case, CECo proposes capital expenditures of \$1.7 billion for 2023, \$1.6 billion

1 for the 14 months ending February 2025, and an additional \$2.1 billion for the 12 months
2 ending February 2026.² These amounts totaling to \$5.4 billion are in addition to capital
3 expenditures of \$4.0 billion made during the prior four years from 2019 to 2022.³

4 In the Electric Distribution area in this rate case filing, the Company is requesting approval
5 for \$2.3 billion in capital expenditures for the 26 months from January 2024 to February
6 2026.⁴ In comparison, in the last electric rate case (Case No. U-21389), the Company
7 requested approval of \$1.6 billion in the Electric Distribution for the 26 months ending
8 February 2025.⁵ The requested capital spending in this rate case represents a 44% increase
9 over that case. The Company attempts to justify the increased spending by pointing to the
10 implementation of the Reliability Roadmap investment plan it filed in September 2023 and
11 included in this rate case as Exhibit A-111 (MPK-19).

12 Cost increases related to capital spending from return on investment, depreciation expense,
13 property taxes, and O&M expenses make up \$280 million, or 86%, of the requested rate
14 increase of \$325 million in this rate case.⁶ The compounding effect of large additions to
15 rate base will continue to increase customer rates to a level that is unaffordable for many
16 customers, particularly lower income customers. This trend is not sustainable for
17 customers.

² Exhibit A-12, Schedule B5.

³ Exhibit A-12, Schedule B-5 in MPSC Case Nos. U-20963, U-20697, U-21224, U-21389.

⁴ Exhibit A-12, Schedule B5.

⁵ Case No. U-21389, Exhibit A-12, Schedule B5.

⁶ Heidi Myers direct testimony at page 5.

1 **Q. ARE THE FORECASTED IMPROVEMENTS IN SERVICE RELIABILITY**
2 **COMMENSURATE WITH INCREASED CAPITAL SPENDING?**

3 A. No. In Figure 6 on page 23 of his direct testimony, Mr. Michael Kelly replicates a chart
4 from the Reliability Roadmap investment plan about the projected improvement in the
5 System Average Interruption Duration Index (SAIDI), excluding Main Event Days
6 (MEDs), from 2023 to 2032. The chart displays the potential results based on two
7 scenarios. The first scenario is to continue the capital spending on Distribution facilities
8 at the level proposed by the Company in Case No. U-21389. Under this scenario, SAIDI
9 ex-MEDs could improve from 178.2 minutes in 2023 to 139.9 minutes in 2032. This
10 would represent a 21% improvement over a 9-year period. To accomplish this, the
11 Company would spend a cumulative amount of \$6.9 billion from 2024 to 2032 on
12 replacing and upgrading distribution facilities.⁷

13 The second scenario embedded in the Reliability Roadman investment plan filed in
14 September 2023 would double the spending to \$14 billion over the 9-years from 2024 to
15 2032.⁸ According to Figure 6, the SAIDI ex-MEDs could potentially decline to 116
16 minutes in 2032. The improvement in SAIDI over the first scenario is 17%. In other
17 words, for a relatively small improvement in SAIDI, customers would need to pay twice

⁷ Exhibit AG-1.1 includes DR AG-CE-0405 (Revised) with ATT 2 (Rate Case).

⁸ Id. (EDIIP).

1 the cost, or an incremental \$7 billion, over the 9-year period. The incremental costs and
2 benefits are not commensurate and are not a good deal for customers.

3 **Q. ON PAGE 24 OF HIS DIRECT TESTIMONY, MR. KELLY PRESENTS THREE**
4 **GOALS THAT WOULD SUPPOSEDLY SET THE COMPANY ON A PATH OF**
5 **SIGNIFICANTLY IMPROVED RELIABILITY. WHAT IS YOUR ASSESSMENT?**

6 A. In his testimony, Mr. Kelly states that the Reliability Roadmap will set the Company on a
7 path to deliver on three reliability goals: (1) deliver reliability in the second quartile of
8 nationwide utilities, (2) deliver a grid where no single outage event affects more than
9 100,000 customers, and (3) deliver a grid where no customer is without power for more
10 than 24 hours following an outage event. These are laudable goals. However, when asked
11 in discovery to state a timeframe when the Company plans to achieve the three goals, the
12 response pointed to the SAIDI goal ex-MEDS and could not provide a timeframe for
13 achieving the other goals or a level of confidence that those goals would be achieved.⁹
14 Clearly, the Company's spending levels come without an adequate assurance that
15 improvements will be achieved in the near term.

16 **Q. BASED ON THE HISTORICAL CAPITAL SPENDING TO DATE, IS THERE ANY**
17 **EVIDENCE THAT THE PROPOSED CAPITAL SPENDING LEVEL**

⁹ Exhibit AG-1.2 includes DR AG-CE-0406 and DR MNSC-CE-0301.

1 **INCORPORATED IN SCENARIO ONE FROM CASE U-21389 WOULD ACHIEVE**
2 **THE PROJECTED RELIABILITY IMPROVEMENTS?**

3 A. No. From 2015 to 2022, the Company spent \$4.5 billion in capital replacements, upgrades,
4 additions, and other improvements to the distribution grid with no significant improvement
5 in the reliability indices. Figure 31 on page 86 of Mr. Kelly’s direct testimony shows the
6 actual SAIDI numbers excluding MEDs from 2014 to 2023. The SAIDI minutes were at
7 168 in 2014 and have been above that number each year since that time except for 2017
8 when they temporarily dropped to 161 minutes. The 176 minutes in 2023 are at the same
9 level that they were in 2014 and 2015 with 168 to 177 minutes, respectively. Furthermore,
10 SAIDI minutes ex-MEDs reached peak levels of 233 in 2019 and 228 minutes in 2021.
11 There is no trend of steady improvements in SAIDI performance from the Company capital
12 spending in the past 8 years.

13 The SAIDI numbers with Major Event Days show an even worse result with SAIDI
14 minutes climbing from below 441 minutes in the 2014 to 2016 periods to over 900 minutes
15 in 2021 and 2023.¹⁰ In other words, the \$4.5 billion spent on Electric distribution grid in
16 the past 8 years does not give much confidence that even spending Scenario One at \$6.9
17 billion will reach the forecasted 139.9 SAIDI minutes excluding MEDs by 2032.

18 To put the SAIDI data in more relatable terms, in discovery the Attorney General asked
19 the Company to provide the actual number of power outages experienced by customers

¹⁰ Michael Kelly direct testimony at page 87, Figure 32.

1 during All-Weather Events and for Events excluding MEDs from 2016 to 2023.
2 Additionally, the Attorney General asked the Company to provide the forecasted number
3 of power outages based on both spending Scenario One (Case No. U-21389) and spending
4 Scenario Two (EDIIP or Reliability Roadmap).

5 For All-Weather conditions, customers experienced between 2,079,621 and 2,973,272
6 power outages annually during the eight-year period from 2016 to 2023 with 2,565,577
7 outages experienced in 2023. Under capital spending Scenario One, the Company
8 forecasts that by 2032 the number of power outages could be reduced to 2,183,195 for a
9 cumulative improvement of 15% over the 9-year period. This is an average annual
10 improvement of 1.67% with cumulative capital expenditures of \$6.9 billion over the 9-
11 year period. Under spending Scenario Two, the Company forecasts that the number of
12 power outages would decline to 1,931,351 by 2032 for a cumulative reduction of 25%, or
13 a 2.78% average annual improvement, with cumulative spending of \$14 billion over the
14 9-year period.¹¹

15 For Events excluding MEDS, the reduction in power outages is even less with 10% for
16 Scenario One and 20% for Scenario Two over the 9-year period.¹²

¹¹ Exhibit AG-1.1 includes DR AG-CE-405 (Revised) ATT 1 with calculations performed by Mr. Coppola as highlighted.

¹² Id.

1 This additional information confirms my analysis above that the Company's Reliability
2 Roadmap does not provide sufficient benefits to customers to justify the higher spending
3 levels proposed in this rate case and likely in future rate cases.

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

6 A. Yes. I have analyzed the Company's forecasted capital expenditures by specific program,
7 projects, or capital spending category, and I have identified more reasonable and prudent
8 expenditure levels that the Commission should consider. In my analysis, I will often use
9 recent historical actual costs and unit costs, where applicable, to determine the
10 reasonableness of the Company's forecasted costs. This approach normalizes various
11 costs from year to year and reflects the most recent costs experienced by the Company.

12 To provide some allowance for future increases in costs, I have applied an inflation
13 escalator of 4.1% for 2023, 2.4% for 2024, and 2.2% for 2025 and 2022 in forecasting
14 future capital expenditures where applicable. These inflation rates represent the average
15 inflation rates forecasted for those years as of October 2023 by S&P Global and provided
16 by the Company in WP-JCA-51.¹³ For years 2024, 2025 and 2026, the Company used
17 the same inflation rates when forecasting O&M costs in its rate case filing.

¹³ Exhibit AG-1.3 includes WP-JCA-53.

1

A. Electric Distribution Capital Expenditures

2

As shown in Exhibit A-12 (MPK-1), Schedule B-5.6, the Company incurred capital expenditures of \$770.1 million for Electric Distribution plant in 2023. It forecasted \$1,017 million for the 14 months bridge period ending February 2025 and \$1,307 million for the projected test year ending February 2026. Included in these total amounts are capital expenditures for New Business, Reliability programs, Capacity expansions, Demand Failures upgrades, Asset Relocation projects, and Other Electric Operations. In my testimony below, I will evaluate and propose adjustments to several of these programs, subprograms, and component projects.

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In their testimony and accompanying exhibits, Company witnesses Keith Kurdziel and Donald Lynd present forecasted capital expenditures in two major categories in line with the design of its distribution system, consisting of High Voltage Distribution (HVD) and Low Voltage Distribution (LVD) facilities. Witnesses Michael Kelly and Scott McPhail also provided testimony on certain topics to which I will respond or will recommend cost disallowances.

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Q. DO YOU HAVE ANY OBSERVATIONS ABOUT THE CAPITAL EXPENDITURES INFORMATION PRESENTED BY MR. KURDZIEL AND MR. LYND IN THEIR TESTIMONY, EXHIBITS, AND RESPONSES TO DISCOVERY?

17

18

19

A. Yes. In total, Mr. Kurdziel and Mr. Lynd filed 302 pages of testimony describing individual capital programs within the Electric Distribution area. In Exhibit A-95 (MPK-

20

1 3), Mr. Kelly sponsored the combined HVD and LVD capital expenditures for the
2 historical five years 2019-2023 and the projected periods with a variance column at the
3 capital program and sub-program level. In Exhibit A-112 (MPK-20), Mr. Kelly provided
4 the capital expenditures for the five historical years 2019-2023 at the sub-program level
5 with the related number of units and unit costs. In their testimony, Mr. Kurdziel and Mr.
6 Lynd provide forecasted capital expenditures at both the program and subprogram levels
7 with the number of units and some unit costs for the bridge period and projected test year.
8 Additionally, those witnesses sponsored Exhibits A-125 (KMK-3), A-126 (KMK-4), A-
9 127 (DAL-1) and A-118 (DAL-2) showing individual projects and related expenditures
10 within capital programs.

11 Although Mr. Kurdziel and Mr. Lynd dismiss the applicability of unit costs to assess the
12 reasonableness of historical and forecasted capital expenditures for most programs, I find
13 this information useful. The alternative would be to review the individual project cost
14 workup and engineering cost estimates prepared by the Company for thousands of
15 projects. Such an approach would require unlimited resources, would be prohibitively
16 expensive and impossible to achieve within the 10-month timeframe of a rate case.

17 In my analysis below, I will rely heavily on the information presented in the exhibits
18 identified above along with information provided in the testimony of Mr. Kurdziel and Mr.
19 Lynd, and responses to discovery requests.

1 **1. LVD Lines New Business**

2 On line 1 of Exhibit A-95 (MPK-3), the Company shows actual capital expenditures of
3 \$136,886,000 for the year 2023 to build new LVD lines for residential and small
4 commercial customers. It also forecasted expenditures of \$142,153,000 for the 14-month
5 bridge period ending February 2025, and \$128,160,000 for the projected test year ending
6 February 2026. Beginning on page 9 of his direct testimony Mr. Lynd discusses this
7 program and presents the number of new service lines, unit costs, and capital expenditures
8 for the historical years, the bridge period and the projected test year.

9 After evaluating the historical number of new service lines recently installed and recent
10 economic trends, I find the Company's forecasted units of 10,183 and 8,974 for the bridge
11 period and projected test year to be reasonable. However, I find the unit cost forecasted
12 for the bridge period and the projected test year to be excessive relative the average cost
13 during the most recent historical years. The cost per unit in 2021 was \$10,507 and
14 increased by 27% in 2022 to \$13,340. Although in 2023, the cost per unit increased
15 slightly to \$13,646, this new level should not be considered a permanent increase that
16 would carry into the bridge period and the projected test year.

17 On page 14 of his direct testimony, Mr. Lynd attributes the increase in the unit cost to
18 inflation and the increase in the average length of new service lines. However, Figure 6
19 on page 15 of his testimony shows that the average length of a new service line declined
20 in 2023 from 2022 and although inflation may have had a temporary impact on costs, the

1 Company needs to find ways to manage and offset those cost increases with operating
2 efficiencies. Continued escalation in costs should not be accepted as a given. The
3 Company's forecast of unit costs of \$13,960 for the bridge period and \$14,281 for the
4 projected test year need to be moderated.

5 In his direct testimony on this same program in Case No. U-21389, Mr. Lynd stated that
6 the Company was able to mitigate some of the contractor cost increases by having fewer
7 service line installations performed by contractors and instead having Company crews
8 those installations at a lower cost.

9 In response to discovery, the Company elaborated further on the reasons for the cost
10 increases but could not provide a comparison of the cost of installation of service lines by
11 contractors versus Company crews. In 2019, the Company paid direct costs of \$15.4
12 million to contractors. In contrast, in 2022 the Company paid direct costs of \$32.8 million
13 for fewer units installed. Furthermore, in 2020, the Company installed 55% of the total
14 number of new service lines. The percentage was similar in 2021 at 54%, but in 2022 the
15 percentage increased to 68% based on the response to DR U-21389 AG-CE-0441d.¹⁴
16 Therefore, in 2022 the Company paid contractors more money for fewer units installed.
17 The experience in 2022 also shows that the Company has the capacity to handle more
18 installations with Company crews and thus avoid or reduce higher contractor costs.

¹⁴ Exhibit AG-1.4 includes U-21389 DR AG-CE-0441.

1 The Company needs to reverse the trend of higher service line installation costs by either
2 negotiating lower unit costs with new contractors, shift more work to Company crews, or
3 find other ways to reduce costs.

4 To provide the Company with the needed incentive to reduce costs, I propose that the unit
5 cost for the bridge period and the projected test year be set at the average cost during the
6 most recent three years from 2021 to 2023 and adjusted by the general inflation rates
7 discussed above. For the three-year historical period, the average unit cost was \$12,498.
8 After applying the inflation rate, the unit cost for the bridge period is \$12,845 and \$13,127
9 for the projected test year.¹⁵

10 For the 14 months bridge period, the Company forecasted 10,183 units, which when
11 multiplied by the unit cost of \$12,845 results in forecasted capital expenditures of
12 \$130,801,000. This amount is \$11,352,000 lower than the \$142,153,000 forecasted by the
13 Company. Similarly, for the projected test year, the Company forecasted 8,974 units.
14 After multiplying those units by the unit cost of \$13,127, the result is forecasted capital
15 expenditures of \$117,802,000. This amount is \$10,358,000 lower than the Company's
16 forecast of \$128,160,000.

17 I recommend that the Commission reduce the Company's forecasted capital expenditures
18 by \$11,352,000 for the bridge period and \$10,358,000 for the projected test year.

¹⁵ $\$12,498 \times 1.024 \times 1.00367 = \$12,845 \times 1.022 = \$13,127.$

1 **2. LVD Lines Demand Failures**

2 On line 34 of Exhibit A-95 (MPK-3), the Company shows forecasted expenditures for
3 LVD Lines Demand Failures of \$153,646,000 for the 14-month bridge period ending
4 February 2025 and \$147,408,000 for the projected test year ending February 2026. Mr.
5 Lynd discusses this subprogram beginning on page 21 of his direct testimony.

6 Although the number of work units planned for the bridge period and projected test year
7 are in line with historical levels, the Company used a forecasted unit cost of \$5,300 to
8 forecast capital expenditures for this subprogram. In discovery, the Attorney General
9 asked the Company to provide the basis and show how it determined the \$5,300 average
10 unit cost. In response, the Company provided vague statements about analyzing historical
11 data, considering variations in unit cost, and projecting future expenditures based on
12 anticipated needs. It also made vague reference to increased cost of material and increased
13 amounts of materials.¹⁶ Page 30 of Mr. Lynd’s testimony also lacks specifics on cost
14 drivers. None of this information is helpful in establishing how the \$5,300 was determined
15 and whether it is appropriate.

16 From reviewing Figure 13 on page 30 of Mr. Lynd’s testimony, it is apparent that the unit
17 cost demand failures took a big jump in 2021 and continued to escalate in 2022 and 2023.
18 From 2020 to 2023, the unit cost increased from \$3,381 to \$5,058 for a cumulative increase
19 of 38% in 3 years. Continued large escalation in unit costs are not sustainable. The

¹⁶ Exhibit AG-1.5 includes DR AG-CE-0469.

1 Company needs to find work efficiencies and other means to reverse the current trend of
2 cost increases in this subprogram. Due to the Company's inability to justify the \$5,300
3 unit cost for the forecasted periods and to provide an added incentive to reduce costs, I
4 propose that the unit cost for the bridge period and the projected test year should be set at
5 the average historical period from 2021 to 2023 and adjusted for general inflation. The
6 average unit cost for the three-year period was \$4,557. Adjusted for inflation, the average
7 unit cost for the bridge period is \$4,683, and for the projected test year is \$4,786.¹⁷

8 For the bridge period, the Company forecasted 29,000 units, which when multiplied by the
9 unit cost of \$4,683 results in forecasted capital expenditures of \$135,807,000. This amount
10 is \$17,839,000 lower than the Company's forecast of \$153,646,000. For the projected test
11 year, the Company forecasted 27,800 units, which when multiplied by the unit cost of
12 \$4,786 results in forecasted capital of \$133,051,000. This amount is \$14,357,000 lower
13 than the Company's forecast of \$147,408,000.

14 Therefore, I recommend that the Commission remove \$17,839,000 and \$14,357,000 from
15 the Company's forecasted capital expenditures for the bridge period and the projected test
16 year. respectively.

¹⁷ $\$4,557 \times 1.024 \times 1.00367 = \$4,683 \times 1.022 = \$4,786.$

1 **3. LVD Substations Demand Failures**

2 Line 36 of Exhibit A-95 (MPK-3) shows forecasted capital expenditures for LVD
3 Substations Demand Failures of \$8,720,000 for the 14-month bridge period ending
4 February 2025 and \$9,000,000 for the projected test year ending February 2026. Figure
5 15 on page 34 of Mr. Lynd’s direct testimony shows that this subprogram consists of four
6 capital categories. In Figure 15, the Company also shows the forecasted capital spending
7 and related units from which I calculated the respective unit costs for each category.

8 Although I find the unit cost reasonable for three of the four categories when comparing it
9 to the historical level, the unit cost for Regulators is excessive. For the 50 Regulators
10 forecasted for the bridge period, the unit cost is \$66,000 and for the 58 units in the
11 projected test year, the unit cost is \$65,862. In contrast, for the three years 2021 to 2023,
12 the average unit cost was \$41,756 with a significant jump to \$58,837 in 2023.¹⁸ The
13 \$66,000 forecasted unit cost represents a 41% increase over the recent average historical
14 unit cost. Mr. Lynd’s direct testimony is devoid of any detailed explanation for this large
15 cost increase beginning in 2023 and continuing into the bridge period.

16 Given the lack of justification for the forecasted unit rate, I propose that the forecasted
17 capital expenditures for this component of LVD Substations Demand Failures be
18 determined based on the three average unit cost adjusted for future inflation. For the bridge

¹⁸ Exhibit A-112, line 145.

1 period the forecasted unit cost is \$42,915 and for the projected test is \$43,859.¹⁹ Based on
2 the Company's forecast of 50 Regulators for the bridge period, the forecasted capital
3 expenditures are \$2,146,000. This amount is \$1,154,000 lower than the \$3,300,000
4 forecasted by the Company.

5 For the projected test year, the Company forecasted 58 units, which when multiplied by
6 the unit cost of \$43,859 results in capital expenditures of \$2,544,000. This amount is
7 \$1,276,000 below the Company's forecast of \$3,820,000.

8 I recommend that the Commission remove \$1,154,000 of capital expenditures from the
9 Company's forecasted capital expenditures for the 14-month bridge period and \$1,276,000
10 from the projected test year.

11 **4. LVD Lines Reliability**

12 On line 7 of Exhibit A-95 (MPK-3), the Company shows forecasted capital expenditures
13 for LVD Lines Reliability of \$103,005,000 for the 14-month bridge period ending
14 February 2025 and \$298,720,000 for the projected test year ending February 2026. In
15 comparison, the Company spent \$38.8 million on average annually in this subprogram.
16 Figure 39 on page 82 of Mr. Lynd's direct testimony shows seven capital expenditure
17 categories and the related number of units for the bridge period and projected test year.

¹⁹ $\$41,756 \times 1.024 \times 1.00367 = \$42,915 \times 1.022 = \$43,859.$

1 Although some of the capital categories have been used in prior years, the Zonal Health
2 Improvements, Secondary, and Right-of-Way categories are new for the bridge period and
3 for the projected test year. These three categories make up more than half of the forecasted
4 capital expenditures for the LVD lines Reliability subprogram for the bridge period and
5 nearly 90% of the projected test year capital expenditures of \$298.7 million.

6 **Q. WHAT IS YOUR ASSESSMENT OF THE FORECASTED CAPITAL**
7 **EXPENDITURES FOR THE ZONAL HEALTH IMPROVEMENT PROGRAM?**

8 A. Beginning on page 65 of his direct testimony, Mr. Lynd discusses the Company’s new
9 approach of targeting specific zones within a circuit that cause the highest number of
10 power outages by replacing fuses, conductor lines, switches, reclosers and other
11 equipment. The Company aggregates these improvements under the category of Zonal
12 Health Improvements. It is not clear from Mr. Lynd’s testimony why this focus on the
13 most troublesome areas or zones of the Company’s electrical circuits is something the
14 Company has now decided to focus on. It seems reasonable that the Company would have
15 focused on the worst parts of the circuits all along, as part of sound operating management
16 and service reliability.

17 It is perplexing why beginning with the bridge period in this rate case the Company now
18 proposes to spend \$45 million on Zonal Health Improvements and dramatically ramp up
19 the spending to \$224.2 million in the projected test year. Figure 39 shows that for the
20 bridge period the Company would complete 7,337 units at an average unit cost of \$6,138

1 and for the projected test year would complete 6,372 units at a unit cost of \$35,183. The
2 unit cost is dramatically different between the bridge period and the projected test year
3 likely reflecting different types of installations.

4 In reviewing the list of items that comprise Zonal Health Improvements for the bridge
5 period in Exhibit A-126 and for the test year in Exhibit A-127, it is apparent that the
6 projects entail replacing fuses, miles of conductor wire, and completion of other projects
7 of an undefined nature. Mr. Lynd made no effort in his testimony to show how the capital
8 spending in Zonal Health Improvements breaks down between fuse replacements, wire or
9 line replacements, and projects, and to explain why \$45 million and \$224.2 million in
10 capital spending in the bridge period and the projected test year is justified.

11 My review of Exhibits A-127 and A-128 shows that the Company forecasted installation
12 of 7,193 fuses during the bridge period at a cost of \$20.8 million and installation of 5,211
13 fuses in the projected test period at a cost of \$10.4 million. The Company also plans to
14 install 56 miles of conductor wire at \$22.5 million in the bridge period and significantly
15 increase the number of installations to 472 miles in the projected test year at a cost of
16 \$194.3 million. For other projects, the Company forecasted 10 projects for the bridge
17 period at a cost of \$1.8 million with a significant ramp up to 156 projects in the projected
18 test year at a cost of \$19.5 million.

19 For a program that is a new approach to purportedly improve the health of sections of the
20 electrical circuits, the significant ramp up from the bridge period to the projected test year

1 is risky and not adequately justified. We first need to see whether this new approach is an
2 improvement or a failure and what actual results and benefits it is producing. It is also not
3 clear what other programs are being affected or will be reduced for similar work that the
4 Company was previously performing under a different approach or spending categories.

5 Therefore, I recommend that for the projected test year and at least the subsequent year,
6 the Company maintain the level of spending and activity at the \$45 million level proposed
7 in the bridge period. Once sufficient results and benefits are evident, the program can be
8 adjusted to an appropriate level in future years. I will point out that the \$45 million
9 spending level in the bridge period is a significant level of spending for a program with no
10 track record.

11 By setting the capital spending for the Zonal Health Improvements program for the
12 projected test year at \$45 million plus inflation, or \$46 million, I recommend that the
13 Commission remove \$178,189,000 from the Company's forecasted capital expenditures
14 for the projected test year.

15 **Q. WHAT IS YOUR ASSESSMENT OF THE FORECASTED CAPITAL**
16 **EXPENDITURES FOR THE SECONDARY WIRE PROGRAM?**

17 A. Beginning on page 70 of his direct testimony, Mr. Lynd discusses the Company's plans to
18 convert secondary wire installations to a multiplex system over a 10-year period. Mr.
19 Lynd admits that secondary wires do not affect a large number of customers and may affect
20 certain communities more than others. He also states that power outages for secondary

1 wires have a longer duration. No specific evidence was presented to support these claims
2 other than a map of Michigan with large, highlighted areas.

3 For the bridge period, the Company forecasted replacement of four miles of secondary
4 wire at a cost of approximately \$1.0 million. However, for the projected test year, the
5 Company significantly ramps up the program to 94 miles at a cost of \$28,180,000. This
6 is another new program with no historical track record, at least in the current configuration.
7 It is possible that some similar work was done with secondary wires under other wire
8 replacement programs. At this point, the program does seem to be a high priority given
9 its limited impact to few customers. The program should be scaled back and completed
10 over a 20-year period instead of 10 years. Therefore, I recommend that for the projected
11 test year, the Commission remove half of the forecasted capital expenditures or
12 \$14,090,000.

13 **Q. WHAT IS YOUR ASSESSMENT OF THE FORECASTED CAPITAL**
14 **EXPENDITURES FOR THE RIGHT-OF-WAY PROGRAM?**

15 A. In Figure 39 on page 82 of his direct testimony, Mr. Lynd show capital expenditures of
16 \$7.5 million for the bridge period and \$12.0 million for the projected test year. On page
17 80 of his testimony, Mr. Lynd briefly discusses the purchase of right-of-way (ROW)
18 easements for new, relocated, and rebuilt lines, but does not associate the forecasted costs
19 to any specific lines or miles of lines. In discovery, the Attorney General asked the

1 Company to identify the projects that require ROW easements, the number of miles, and
2 related costs.

3 In the response, the Company did not provide the requested information and instead
4 discussed the accounting of costs, stating that the requested information was not
5 available.²⁰ If this basic information is not available, it is difficult to understand how the
6 Company was able to forecast the \$7.5 million and \$12.0 million ROW purchases. Line
7 19 of Exhibit A-112 shows that on average during the most recent historical three years,
8 the Company incurred \$4,641,000 in costs to purchase ROW easements. Given the lack
9 of any specific information about the costs included in future periods, this is the best basis
10 to forecast costs for ROW easements for the bridge and test year period. Since ROW
11 easements are the result of negotiations with landowners, inflation adjustments are not
12 applicable.

13 Therefore, I recommend that the Commission remove the difference in capital
14 expenditures between the historical amount of \$4,641,000 and the \$7,500,000 forecasted
15 by the Company. The difference for the bridge period is \$2,859,000. Similarly, I
16 recommend that the Commission remove \$7,359,000 for the projected test year,
17 representing the difference between \$4,641,000 and the Company's forecasted \$12.0
18 million.

²⁰ Exhibit AG-1.6 includes DR AG-CE-0477.

1 **5. LVD Substation Reliability**

2 On line 9 of Exhibit A-95 (MPK-3), the Company shows forecasted capital expenditures
3 for LVD Substation Reliability of \$19,156,000 for the 14-month bridge period ending
4 February 2025 and \$43,725,000 for the projected test year ending February 2026. Figure
5 45 on page 94 of Mr. Lynd’s direct testimony shows the capital expenditures and the
6 related number of units for the six spending categories within this sub-program. I will
7 address the spending level for the New or Rebuilt Substations and the DSCADA Projects.

8 **Q. WHAT IS YOUR ASSESSMENT OF THE FORECASTED CAPITAL**
9 **EXPENDITURES FOR THE NEW OR REBUILT SUBSTATIONS?**

10 A. Line 28 of Exhibit A-112 shows that in past five years the Company has built or rebuilt
11 between 2 to 6 substations annually at a unit cost ranging from \$562,330 to \$2,022,614
12 and averaging to \$1,313,000 in the most recent three years. For the bridge period, the
13 Company plans to build or rebuild 8 substations at an average units cost of \$1,123,125.
14 Although the Company is ramping up the number of substations from 4 to 8, the unit cost
15 is in line with the most recent three years, and I find the forecasted capital expenditures
16 reasonable for the bridge period.

17 For the projected test year, the Company proposes to further increase the number of units
18 to 12 and is forecasting to spend \$25,442,000 at a unit cost of \$2,036,833. On page 90 of
19 his direct testimony, Mr. Lynd states that certain HVD line work associated with new and
20 existing LVD substation projects was being moved from other subprograms to the LVD

1 Substation Reliability sub-program. However, in response to discovery, the Company
2 could not identify the amount of costs that were being moved over.²¹

3 There are two problems with this spending category. First, the tripling in the number of
4 stations that the Company plans to address from 4 on average in the past five years to 12
5 in the projected test year is excessive. With the bridge period already doubling the number
6 to 8, it seems prudent to maintain that pace also for the projected test year to lessen the
7 burden on customers from larger cost recoveries. Second, the average cost per substation
8 in the projected test year is forecasted to increase 55% from the most recent three-year
9 historical average of \$1,313,000 to \$2,036,833 in the projected test year. The unit cost
10 should be adjusted to the level of the historical average plus an inflation adjustment.

11 To address both problems, I propose that the cost per substation be set at \$1,379,000 for
12 the projected test year and be applied to 8 substations.²² The result is forecasted capital
13 expenditures of \$11,032,000 for the projected test year. This amount is \$14,410,000 lower
14 than the \$25,442,000 forecasted by the Company.

15 I recommend that the Commission remove the \$14,410,000 from the Company's projected
16 capital expenditures for the projected test year.

²¹ Exhibit AG-1.7 includes DR AG-CE-0480.

²² $\$1,313,000 \times 1.024 \times 1.022 \times 1.00367 = \$1,379,000$.

1 **Q. WHAT IS YOUR ASSESSMENT OF THE FORECASTED CAPITAL**
2 **EXPENDITURES FOR THE DSCADA PROJECTS?**

3 A. In Figure 45 on page 94 of his direct testimony, Mr. Lynd shows capital expenditures of
4 \$2,847,000 for 5 DSCADA projects for the bridge period and \$8,002,000 for 24 projects
5 in the projected test year. The average cost per project is \$569,400 for the bridge period
6 and \$333,417 for the projected test year. According to page 90 of Mr. Lynd's testimony,
7 this item also was moved from other subprograms to this subprogram.

8 In response to discovery, the Company provided historical spending amounts and the
9 number of units from 2019 to 2023 for DSCADA projects.²³ Based on the information
10 provided in discovery, I calculated an average unit cost per project of \$242,859 for the
11 most recent three historical years 2021-2023. This actual cost per project is significantly
12 lower than the \$569,400 for the bridge period and the \$333,417 for the test year included
13 in the Company forecasted spending. A reasonable approach to forecast capital spending
14 for the two future periods is to use the most recent three-year average, which normalizes
15 any year-to-year variances, and to apply an inflation rate. Based on this methodology, I
16 determined a project unit cost of \$249,600 for the bridge period and \$255,091 for the
17 projected test year.

18 For the bridge period, the \$249,600 multiplied by 5 projects results in forecasted capital
19 expenditures of \$1,248,000, or \$1,599,000 lower than the Company's forecast. For the

²³ Exhibit AG-1.7 includes DR ST-CE-0006 with Attachment 1.

1 projected test year, the \$255,091 multiplied by 24 projects results in forecasted capital
2 expenditures of \$6,122,000, or \$1,880,000 lower than the Company's forecast.

3 Therefore, I recommend that the Commission remove the \$1,599,000 and \$1,880,000 from
4 the Company forecasted capital expenditures for the bridge period and the projected test
5 year, respectively.

6 **6. LVD Repetitive Outages**

7 On line 12 of Exhibit A-95, the Company shows forecasted capital expenditures for LVD
8 Repetitive Outages of \$11,538,000 for the bridge period and \$10,141,000 for the projected
9 test year. Figure 48 on page 101 of Mr. Lynd's direct testimony shows that capital
10 spending on this subprogram has been erratic from year to year ranging from \$4.1 million
11 in 2023 to \$10.7 million in 2021. This spending pattern is confusing given that repetitive
12 outages have been an area of concern for the Commission and other parties participating
13 in prior proceedings, including the Attorney General.

14 In discovery, the Attorney General asked the Company to explain why the capital spending
15 on this subprogram varied significantly from year to year. In response, the Company
16 pointed back to pages 102 and 103 of Mr. Lynd's direct testimony for the explanation.²⁴
17 The referenced testimony beginning on line 18 of page 102 and carrying into the next page
18 seems to indicate that additional work was done to add fusing to certain circuits in 2023.

²⁴ DR AG-CE-0484.

1 However, despite this work, spending was at the lowest level in 2023 than in any of the
2 previous four years. The testimony also seems to indicate that work and spending was
3 shifted to LVD Lines Reliability. If it is true that work accomplishes the same outcome,
4 it is not clear why forecasted capital expenditures for the bridge period and the projected
5 test year need to increase over the 2023 spending level.

6 On page 101 of his direct testimony, Mr. Lynd states that the Company plans to complete
7 197 projects for the bridge period and 116 projects for the projected test year. On line 45
8 of Exhibit A-112, the Company shows the average cost per project for the five historical
9 years. Using the most recent three years 2021 to 2023, I calculated an average project cost
10 of \$30,272.

11 To establish a reasonable forecast for the future periods, I applied the general inflation
12 rates to this amount to calculate an average project cost of \$31,112 for the bridge period
13 and \$31,796 for the projected test year. By multiplying those unit project costs by the
14 number units of 197 and 116, I calculated capital expenditures for the bridge period of
15 \$6,129,000 and \$3,688,000 for the projected test year. These amounts are \$5,409,000 and
16 \$6,453,000 lower than the Company's forecast for each respective period.

17 Therefore, I recommend that the Commission remove \$5,409,000 and \$6,453,000 from
18 the Company's forecasted capital expenditures for the bridge period and projected test
19 year, respectively.

1 **7. LVD Lines Rehabilitation**

2 On line 19 of Exhibit A-95 (MPK-3), the Company shows forecasted capital expenditures
3 for LVD Lines Rehabilitation of \$14,488,000 for the 14-month bridge period ending
4 February 2025 and \$15,000,000 for the projected test year ending February 2026. Figure
5 62 on page 128 of Mr. Lynd’s direct testimony shows the capital expenditures and the
6 related number of units for the three capital spending categories within this sub-program.
7 In my testimony below, I will address the Imminent Rehabilitation capital spending
8 category.

9 For the bridge period, the Company forecasted capital expenditures of \$14,404,000 to
10 complete 461 projects at an average unit cost of \$24,738. For the projected test year, the
11 Company forecasted \$11,492,000 in capital spending to complete 374 units at an average
12 unit cost of \$30,727. The historical data on line 93 of Exhibit A-112 show that the average
13 unit cost during the past five years ranged from \$9,527 in 2020 to a high of \$18,198 in
14 2021. For the most recent three years, the average unit cost was \$15,496. The Forecasted
15 unit cost for the bridge period and projected test year at \$24,738 and 30,727 are 60% and
16 98% over the three-year historical average. These increases are excessive and
17 unsupported.

18 On page 130 of his direct testimony, Mr. Lynd states that in 2021 and 2022 the scope of
19 work for imminent rehabilitation was more extensive than in other years and points to
20 more underground work with no specifics. If true, then the 2021-2023 average unit cost I

1 calculated should reflect this increased scope of work. Mr. Lynd also points to the usual
2 claim that there is a wide variation in the cost of specific projects within this work category.
3 However, with 374 projects in the projected test year and 461 projects in the bridge period,
4 plus using a three-year average to calculate an historical baseline, any variations from
5 project to projects are smoothed out.

6 To establish a reasonable unit cost forecast, I propose using the three-year historical unit
7 cost of \$15,496 adjusted for inflation. This results in a forecasted unit cost of \$15,926 for
8 the bridge period. By multiplying this unit cost by the 461 forecasted units, I calculated
9 forecasted capital expenditures of \$7,342,000. In comparison, the Company forecasted
10 \$11,404,000 for the bridge period. The difference is \$4,062,000.

11 For the projected test year, the forecasted unit cost is \$16,276, which when multiplied by
12 the 374 forecasted unit, results in forecasted capital expenditures of \$6,087,000. This
13 amount is \$5,405,000 lower than the Company's forecast of \$11,492,000.

14 Therefore, I recommend that the Commission remove \$4,062,000 and \$5,405,000 from
15 the Company's forecasted capital expenditures for the bridge period and the projected test
16 year, respectively.

17 **8. Resiliency**

18 On line 22 of Exhibit A-95 (MPK-3), the Company shows forecasted capital expenditures
19 for Resiliency of \$13,768,000 for the 14-month bridge period ending February 2025 and

1 \$22,623,000 for the projected test year ending February 2026. The Company only spent
2 \$1.4 million in 2023 on this subprogram and no amounts in prior years. This is a new
3 subprogram created by the Company, however similar costs were incurred in prior years,
4 according the information provided by the Company in its exhibits.

5 Figure 71 on page 144 of Mr. Lynd’s direct testimony shows the capital expenditures and
6 the related number of units for each of the two components of this sub-program. The two
7 components are Fractionalization and Undergrounding Overhead Lines. For
8 Fractionalization, the Company forecasted \$8,189,000 to complete 2 projects in the bridge
9 period and \$12,623,000 for 4 projects in the projected test year. For the Overhead to
10 Underground initiative, the Company forecasted \$5,579,000 to complete 14 miles in the
11 bridge period and \$10.0 million to complete 25 miles in the projected test year. I will
12 address each of the two spending programs.

13 **Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES**
14 **FORECASTED BY THE COMPANY FOR THE FRACTIONALIZATION?**

15 A. Mr. Lynd discusses the fractionalization initiative beginning on page 138 of his direct
16 testimony. Fractionalization is the process of segmenting LVD circuits into smaller
17 sections with fewer customers to reduce the number of customers impacted by a single
18 event. According to Mr. Lynd, the Company has prioritized circuits that would most
19 benefit from fractionalization into top tiers. In Figure 72, the Company presents the 6
20 proposed fractionalization projects to be addressed in the bridge period and the projected

1 test year, showing each project, the targeted circuits, the number of customers currently
2 on the circuit, the miles of lines on the circuit, the post-implementation configuration with
3 the number of customers moved to segments of the circuit and mile of line on each sub-
4 circuit.

5 From reviewing the information presented in Figure 72, it is readily apparent that some of
6 the circuits listed in the table are not being fractionalized given that the same number of
7 customers are retained on the lines after fractionalization as they were pre-
8 fractionalization. Examples include Backus Substation-Maple Valley with 1,001
9 customers pre and post; Bennington Substation-Manitou 759 customers; pre and post
10 Eagle Substation-Chicago 1,892 customers pre and post, Pioneer 1,171 customers pre and
11 post, and Cottonwood 2,083 customers pre and post. Other circuits show only minimal
12 fractionalization of customers to different circuits or lines. In discovery, the Attorney
13 General asked the Company to explain what the purpose and benefit fractionalization
14 serves if no changes or no significant are made to those circuits.

15 In response, the Company stated that it has not yet defined a definitive fractionalizing end-
16 state and is only performing select changes with certain circuits and sub-circuits. In
17 response to another discovery request, the Company stated that fractionalization is a
18 relatively new concept at the Company and a final goal has not been established. In
19 discovery, the Attorney General also asked the Company to provide the number of outages
20 that occurred on the targeted fractionalization circuits during each year from 2019 to 2023
21 and the outages expected after fractionalization. In the response, the Company shows that

1 most of the circuits had from zero to 2 outages over the past five years with less than a
2 handful with 3 or more outages. In the response, the Company also stated that an overall
3 reduction in outage incidents is not anticipated for fractionalizing projects.²⁵ This
4 information does not show a compelling case to target the listed circuits for
5 fractionalization.

6 On page 145 of his testimony, Mr. Lynd states that the fractionalization of the circuits in
7 Figure 72 may benefit about 28,000 customers. Figure 74 on page 148 of his testimony
8 shows that fractionalization of the circuits for the 6 projects could save 655,000 outage
9 minutes. Dividing the saved minutes by the number of customers shows that the benefit
10 would be about 23 minutes of potentially avoided outage time per customer. This also is
11 not compelling justification when other customers are without power for a full day or
12 longer.

13 The justification to undertake a combined \$20.8 million in capital spending between the
14 bridge period and the projected test year on a program that has not yet been fully defined
15 with marginal benefits is inadequate. The Company needs to better define and justify why
16 this program is significantly beneficial to customers to spend tens of millions of dollars on
17 it.

²⁵ Exhibit AG-1.8 includes DR AG-CE-0490, 0495, and 0496 with attachment.

1 Therefore, I recommend that the Commission disallow the \$8,189,000 and \$12,623,000 in
2 capital expenditures for the bridge period and projected test year for the fractionalization
3 initiative.

4 **Q. PLEASE SUMMARIZE THE COMPANY’S PROPOSAL TO ACCELERATE**
5 **CONVERSION OF OVERHEAD LINES TO UNDERGROUND AND THE**
6 **RELATED CAPITAL EXPENDITURES.**

7 A. Mr. Lynd provides a discussion of Overhead to Underground Conversions beginning on
8 page 141 of his direct testimony. On page 142, Mr. Lynd identifies 9 criteria for selecting
9 overhead lines for undergrounding. These criteria span from selecting single-phase LVD
10 lines, number of power outages, customers affected, duration of outages, dense tree cover,
11 and end of circuit lines only. In Figure 71 on page 144 of Mr. Lynd’s testimony, the
12 Company shows forecasted capital expenditures of \$5,579,000 to convert 14 miles during
13 the bridge period and \$10.0 million to convert 25 miles for the projected test year.

14 Mr. Kelly also provides a discussion of undergrounding overhead lines on pages 42 and
15 43 of his direct testimony. He states that in the Company’s last rate case (Case No. U-
16 21389), the Commission approved a pilot program for undergrounding overhead lines. In
17 Figure 10 on page 43 of his testimony, Mr. Kelly also provides comparative net present
18 value costs of undergrounding overhead lines versus other options and posits that
19 undergrounding is a lower cost option versus Aerial Spacer Cable and Tree Wire
20 reinforcement of overhead lines.

1 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY’S PROPOSAL TO**
2 **UNDERTAKE AN EXPANDED CONVERSION OF OVERHEAD LINES TO**
3 **UNDERGROUND?**

4 A. There are several problems with the Company’s proposal. First, the criteria outlined on
5 page 142 of Mr. Lynd’s direct testimony are relatively low thresholds that could result in
6 hundreds if not thousands of overhead lines that could qualify for conversion to
7 underground. For example, low thresholds such as only one outage in the last 24 months,
8 10 to 100 customers affected, and lines located in an area of dense trees would likely apply
9 widely. It is not clear how these thresholds were determined and why they are relevant.
10 In discovery, the Attorney General asked the Company to provide the number of projects
11 and miles of overhead lines that would meet the 9-point criteria and the related cost to
12 achieve the undergrounding of those lines in future years. In response, the Company stated
13 that it had not determined the number of projects and the miles of overhead lines that would
14 meet all nine criteria.²⁶ It is hard to understand how the Company can develop relevant
15 criteria without knowing what the outcome would be.

16 Second, the criteria do not include a cost/benefit analysis (CBA) to determine whether the
17 conversion is economic versus other options for each project. This is a major shortcoming,
18 and the Commission should not approve any underground program that lacks such a key

²⁶ Exhibit AG-1.9 includes DR AG-CE-0492.

1 criterion. In response to discovery, the Company had no relevant answer why a CBA was
2 not incorporated in the selection criteria.²⁷

3 Third, in the Reliability Roadmap (Exhibit A-111), the Company forecasted that
4 approximately 3,200 miles could be candidates for conversion from overhead lines to
5 undergrounding. If we can believe the Company's estimated conversion cost of \$400,000
6 per mile, the total cost for converting the 3,200 miles would be a staggering \$1.3 billion
7 and probably grow from there.

8 Third, in response to discovery, the Company reported that the \$400,000 conversion cost
9 per mile was informed by an earlier study and included in a report filed with the
10 Commission on October 1, 2021 in Case No. U-21122. That report shows that the average
11 cost per mile to convert overhead lines to underground in rural areas was \$626,000 per
12 mile and in urban areas \$1,342,000 per mile with an upper range of \$1,926,000.²⁸ It is
13 difficult to understand how the Company now can forecast a lower cost of \$400,000 per
14 mile when inflationary cost increases for material and labor would have further increased
15 the 2021 forecasted costs. Compared to the costs included in the report, the \$400,000 cost
16 per mile does not seem realistic.

17 Fourth, in Figure 10 on page 43 of his direct testimony, Mr. Kelly shows that the present
18 value of the cost of undergrounding 10 miles of overhead lines is \$6.6 million over the

²⁷ Id.

²⁸ Id. includes DR AG-CE-0208.

1 approximately 60 years life of the line and this cost is lower than the other alternative,
2 except vegetation management. However, the Excel model where the Company calculated
3 the present values has formula errors that increased the return-on-investment cost for the
4 Aerial Spacer Cable and Tree Wire alternative. After correcting those errors, the Present
5 Value of the Revenue Requirement (PVRR) are \$5.7 million for Undergrounding, \$5.1
6 million for Ariel Space Cable, \$5.0 million for Tree Wire, and \$3.3 million for Vegetation
7 Management. The corrected values show that Undergrounding is the most expensive
8 option. It is noteworthy to disclose also that the PVRR for Undergrounding still assume a
9 cost per mile of \$400,000. If this amount is significantly understated, the PVRR cost will
10 increase significantly.

11 Fifth, in Case No. U-21389, in March 2024, the Commission approved a pilot program for
12 undergrounding that limited the Company to converting 10.3 miles of overhead lines at a
13 cost of \$3.7 million for the projected test year ending February 2025. The Company's
14 forecasted capital expenditures in the current case exceed that approved amount.

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

16 A. The Company's proposal to undertake an expanded conversion of overhead lines to
17 underground has not been well defined, it lacks important criteria to ensure that sound
18 economic decisions are made, it is based on incorrect financial analysis, and is premature.
19 The purpose of doing a pilot is to determine the major issues faced with undergrounding
20 overhead lines in both rural and urban areas and determine what the actual cost of

1 conversion, maintenance and repairs will be over time. The results from the findings of
2 the pilot are not yet available. Therefore, it is premature on undertake an expansion of
3 undergrounding past the current pilot phase.

4 I recommend that the Commission remove the incremental capital spending of \$1,879,000
5 proposed by the Company for the bridge period over the \$3.7 million approved in Case
6 No. U-21389. I also recommend that the Commission remove the \$10.0 million of capital
7 expenditures for undergrounding forecast for the projected test year.

8 **Q. WHAT IS THE TOTAL CAPITAL EXPENDITURES DISALLOWANCE THAT**
9 **YOU PROPOSE FOR THE RESILIENCY SUBPROGRAM?**

10 A. For the total Resiliency subprogram, I recommend that the Commission remove
11 \$10,068,000 for the bridge period and \$22,623,000 for the projected test year.

12 **9. LVD Line Capacity**

13 On line 24 of Exhibit A-95 (MPK-3), the Company shows forecasted capital expenditures
14 for LVD Line Capacity of \$19,082,000 for the 14-month bridge period ending February
15 2025 and \$56,723,000 for the projected test year ending February 2026. Figure 77 on page
16 158 of Mr. Lynd's direct testimony shows the capital expenditures and the related number
17 of units for the two component categories in this sub-program: the Overload Equipment
18 Upgrades and the Lines Capacity Projects for Substation Work.

1 **Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES**
2 **FORECASTED BY THE COMPANY FOR THE OVERLOADED EQUIPMENT**
3 **UPGRADES?**

4 A. According to line 111 of Exhibit A-112, during the past five years from 2019 to 2023, the
5 Company completed from 29 to 59 overload upgrade projects annually with the highest
6 number in 2022 and the lowest in 2023. The average number of upgrades completed in
7 the most recent three years 2020-2022, excluding the low year of 2023, was 44 at an
8 average unit cost of \$136,429.

9 In this rate, the Company forecasted capital expenditures of \$6,437,000 for the bridge
10 period to complete 18 projects at an average unit cost of \$357,611. For the projected test
11 year, the Company forecasted to complete 327 projects at a cost of \$45,662,000 at an
12 average unit cost of \$139,609. There are two issues that need to be addresses with the
13 Company's forecast.

14 First, the unit cost of \$357,611 in the bridge period is unprecedented in the past five years.
15 The highest unit cost was \$153,776 in 2021. The unit cost is excessive and unjustified.
16 Using the three-year average unit cost of \$136,429 adjusted for inflation to \$140,216
17 provides a more reasonable benchmark. By multiplying the \$140,216 by the 18 units
18 forecasted by the Company the forecasted capital expenditures for the projected test year
19 are \$2,524,000. This amount is \$3,913,000 lower than the amount forecasted by the
20 Company.

1 Second, the 357 projects forecasted for the projected test year is also unprecedented. As
2 stated above, the highest number of projects completed in the past five years was 59 in
3 2022. In his direct testimony beginning on page 150, Mr. Lynd discusses the need to
4 complete more upgrades for overloaded equipment and points to the Reliability Roadmap
5 in Exhibit A-111 for the accelerate plan. However, other than classifying overloaded
6 equipment in certain categories and showing forecasted capital expenditures for five years,
7 there is no plan outlined of how many projects for what equipment at which locations are
8 to be addressed each year and over what timeframe.

9 Mr. Lynd's direct testimony does not address any of this information either. It is
10 perplexing why the Company would have the lowest number of projects for the past five
11 years at 29 in 2023, reduce that number further in 2024 to 18 for the bridge period, and
12 then increase the number dramatically to 327 projects in the projected test year. If these
13 projects are critical to address overloaded equipment that is near to failure, one would
14 expect a higher and more consistent number of projects in recent years.

15 The ramp-up to 327 units in a single year is excessive and unsupported. The Company
16 has not made a compelling case that such a large increase in a single year is necessary. I
17 propose a more gradual escalation by doubling the current three historical number of
18 projects from 44 to 90 for the projected test year with further increments in future years,
19 as necessary. Based on the 90 projects and the unit cost of \$140,216 from the bridge year
20 adjusted for inflation to 143,301, I forecast capital expenditures of \$12,897,000 for the

1 projected test year. This amount is \$32,755,000 lower than the \$45,652,000 forecasted by
2 the Company.

3 Therefore. I recommend that the Commission remove \$3,913,000 for the bridge period
4 and \$32,755,000 for the projected test year from the capital expenditures forecasted by the
5 Company.

6 **Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES**
7 **FORECASTED BY THE COMPANY FOR THE LINES CAPACITY PROJECTS**
8 **FROM SUBSTATION WORK?**

9 A. According to line 112 of Exhibit A-112, during the past five years from 2019 to 2023, the
10 Company completed from 4 to 16 lines-capacity projects annually with the highest number
11 in 2023 and the lowest in 2022. The average number of upgrades completed in the most
12 recent three years 2020-2023, excluding the 2022 low year, was 11 at an average unit cost
13 of \$373,747.

14 In this rate, the Company forecasted capital expenditures of \$12,645,000 for the bridge
15 period to complete 8 projects at an average unit cost of \$1,580,625. For the projected test
16 year, the Company forecasted to complete 16 projects at a cost of \$11,071,000 at an
17 average unit cost of \$691,938. Although the number of projects to be completed in the
18 bridge period and projected test year is reasonable relative to historical levels the average
19 unit cost is not. The \$1,580,625 unit cost for the bridge period and \$691,938 for the
20 projected test year are unprecedented compared to the past five years. The highest average

1 unit cost for this work was \$581,976 in 2020. It is not clear why projects for the bridge
2 period and projected test year are now nearly twice more expensive as they were in 2020
3 or during the most recent three years 2020, 2021, and 2023.

4 To adjust the forecasted capital expenditures to reasonable levels, I used the three-year
5 historical average unit cost of \$373,747 adjusted for inflation to \$384,121 for the bridge
6 period. This unit cost multiplied by the 8 units forecasted by the Company results in capital
7 expenditures of \$3,073,000. This amount is \$9,572,000 lower than the \$12,645,000
8 forecasted by the Company.

9 For the projected test year, I used the bridge period average unit cost and adjusted it for
10 inflation to \$381,969. This unit cost multiplied by the 16 units forecasted for the projected
11 test year results in forecasted capital expenditures of \$6,112,000. This amount is
12 \$4,959,000 lower than the Company's forecast.

13 Therefore, I recommend that the Commission remove \$9,572,000 for the bridge period
14 and \$4,959,000 for the projected test year from the Company's forecasted capital
15 expenditures.

16 **Q. WHAT IS THE TOTAL CAPITAL EXPENDITURES DISALLOWANCE THAT**
17 **YOU PROPOSE FOR THE LVD LINES CAPACITY SUBPROGRAM?**

18 A. For the total LVD Lines Capacity subprogram, I recommend that the Commission remove
19 \$10,068,000 for the bridge period and \$22,623,000 for the projected test year.

1 **10. LVD Premature Projects**

2 In discovery, the Attorney General asked the Company to provide a list of LVD projects
3 of \$1.0 million or greater included in the bridge period and the projected test year,
4 specifying the current phase of development of the project. The request also asked the
5 Company to identify the next phase of project development with start and completion dates
6 along with the cost of the project and other pertinent information.

7 The information provided by the Company shows that 8 projects in the bridge period are
8 currently in the planning phase or have been deferred and no design work has been
9 completed. The projects have been highlighted and identified in Exhibit AG-1.10.

10 These projects are still in the early phase of development, and it is uncertain if and when
11 they will be completed and at what specific cost. Therefore, it is premature to include the
12 capital expenditures for these projects in rate base. Customers should not pay in rates for
13 the return on investment, depreciation expense, and other costs related to projects that may
14 not go into service and be used and useful before the end of the projected test year. If the
15 Company completes the projects, the costs related to those projects can be recovered in a
16 subsequent rate case.

17 The capital expenditures for the 8 projects in the bridge period total to \$14,428,000. I
18 recommend that the Commission remove this amount from the Company's forecasted
19 capital expenditures.

1 Similarly, for the projected test year, there are 26 projects that are currently in the planning
2 phase or have been deferred and no design or engineering work has yet been completed.
3 Those projects have been highlighted and identified on pages 2 and 3 of Exhibit AG-1.10.
4 For the same reasons discussed above for the bridge period, the capital expenditures related
5 to these projects should not be included in rate base. The total capital expenditures for the
6 26 projects are \$45,483,000.

7 However, 12 of the projects identified as premature pertain to subprograms or components
8 of subprograms where in my testimony above I recommended a reduction in the number
9 of projects to be approved for the projected test year. To avoid any duplication in cost
10 disallowance, I propose not including those 12 projects and the related \$31,339,000 in
11 capital expenditures in my proposed disallowance. Those projects have been separately
12 identified in Exhibit AG-1.10.

13 Therefore, I recommend that the Commission remove the net amount of \$14,144,000 from
14 the Company's forecasted capital expenditures for the projected test year.

15 **11. Wildfire Mitigation Program**

16 On line 52 of Exhibit A-95 (MPK-3), the Company shows forecasted capital expenditures
17 of \$12,000,000 for the Wildfire Risk Mitigation program for the projected test year ending
18 February 2026. This is a new program beginning with the projected test year. Mr. Kelly
19 discusses this program beginning on page 35 of his direct testimony and supplements his
20 testimony with Exhibit A-114 (MPK-22). On page 38, he defines the Company's strategy

1 to reduce the risk of wildfires by performing risk assessments, weather monitoring,
2 increasing line inspections, changing field operating procedures during period of elevated
3 risk, improving emergency response, undergrounding overhead lines, installing covered
4 conductor wires, installing sectionalizing devices, and reducing the tree and line clearing
5 cycle in wildfire risk areas from 7 to 5 years.

6 The Company plans to spend the \$12 million of capital expenditures equally in three areas:
7 \$4 million for undergrounding overhead lines, \$4 million to install covered conductor wire,
8 and \$4 million for installing protective line devices. In addition, the Company proposes
9 to spend and recover \$652,000 in O&M expense for the projected test year to increase line
10 clearing and reduce the clearing cycle (\$321,000), buy or lease a LiDAR software system
11 to monitor vegetation growth and density (\$319,000), and purchase wildfire-specific
12 weather forecasting data (\$12,000).

13 **Q. WHAT IS YOUR ASSESSMENT OF THE PROPOSED WILDFIRE RISK**
14 **MITIGATION PROGRAM?**

15 A. The risk of electric lines wildfires in the Company's service territory is minimal and the
16 proposed program would add unnecessary costs to an already large capital spending
17 program in other areas of the Company. In his testimony and in the report in Exhibit A-
18 114, Mr. Kelly inflates the risk of wildfires in Michigan by referencing wildfires that have
19 occurred in California, Hawaii, and Texas. Michigan's climate is not the same as the

1 climate in those states. Although wildfires do occur in Michigan due to many reasons,
2 they are usually easily contained and do not pose a large risk to the state's population.

3 In response to discovery, the Company provided data gathered by the Michigan
4 Department of Natural Resources (DNR) that shows powerlines may have caused only
5 9.5% of total fires started in the Michigan Lower Peninsula during the 10 years from 2012
6 to 2023 and accounted for only 2.5% of the acres of land burned.²⁹ Each fire started by a
7 power line burned 2.8 acres of land.³⁰ This is relatively small and containable. By far,
8 most wildfires and acres burned are caused by miscellaneous and unknown reasons, debris
9 burning, campfires, lighting, arson, and other ignition sources.

10 In discovery, the Attorney General asked the Company to provide the list of wildfires
11 started by the Company's electric lines or equipment in the past 20 years and the details
12 of each incident, such as location, date, what Company equipment started the fire and how,
13 acres burned, damage sustained, repairs made, and liability costs assessed to the Company.
14 In response, the company stated that it did not have this information and had not performed
15 any such analysis and pointed to the DNR information provided in response to DR AG-
16 CE-0417 (Exhibit AG-1.11).³¹ From the response, it is evident that the Company is
17 proposing a solution without first analyzing and understanding the problem.

²⁹ Exhibit AG-1.11 includes DR AG-CE-0417 with attachments.

³⁰ Id. Figure 5: 671 acres divided by 242 fires.

³¹ Id. includes DR AG-CE-0409.

1 The proposed \$12 million in capital expenditures proposed for the wildfire program for
2 the projected test year is only the beginning salvo. In response to discovery, the Company
3 confirmed that the capital spending on this program would grow to \$73 million by the end
4 of 2028. O&M expenses would also grow from \$652,000 to \$4 million by 2028.³² Given
5 the Company's spending trends, those levels of spending will most likely increase past
6 2028.

7 Although increased situational analysis, changes in operational procedures, increased
8 inspections, and more frequent line clearing from tree and brush should be undertaken,
9 capital expenditures for undergrounding, covered conductors and sectionalizing devices as
10 a special program are premature until the Company better defines the extent of the problem
11 and the causes of wildfires started by power lines.

12 Therefore, I recommend that the Commission disallow the \$12 million in capital
13 expenditures proposed by the Company for the projected test year.

14 The Company should also work more closely with the DNR and other agencies to ensure
15 that active forest management is on-going, including clearing dying or dead trees, clearing
16 brush, and building fire breaks and corridors to minimize the spread of wildfires.

³² Id. includes DR AG-CE-0410.

1 **12. HVD Lines Reliability**

2 On line 8 of Exhibit A-95 (MPK-3), the Company shows forecasted capital expenditures
3 for HVD Lines Reliability of \$51,162,000 for the 14-month bridge period ending February
4 2025 and \$90,995,000 for the projected test year ending February 2026. Figure 11 on page
5 26 of Mr. Kurdziel’s direct testimony shows the capital expenditures and the related
6 number of units for the six capital spending components within this sub-program. In my
7 analysis below, I will focus on the Pole Replacements and ROW components.

8 **Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES**
9 **FORECASTED BY THE COMPANY FOR THE HVD POLE REPLACEMENTS?**

10 A. On line 24 of Exhibit A-112, the Company shows that during the five years from 2019 to
11 2023, capital spending on pole replacements ranged from approximately \$6.0 million in
12 2023 to \$15.2 million in 2022 with the number of poles replaced ranging from 234 to 545.
13 During the most recent three years, the average annual spending in this area was
14 \$10,301,330 to replace 394 on average each year.

15 In Figure 11, the Company shows forecasted capital expenditures of \$20,208,000 in the
16 bridge period to replace 847 poles and \$21,593,000 for the projected test year to replace
17 905 poles. From this information, it is evident that the Company is proposing a major
18 130% increase in pole replacements and related capital spending for the bridge period and
19 projected test year. On page 24 of his direct Testimony, Mr. Kurdziel states that the
20 Company’s inspection and replacement criteria presented in Exhibit A-123 (KMK-1) in

1 this rate case are the same as in the two prior rate cases. Therefore, it is perplexing why a
2 doubling of pole replacement activity is now necessary. No evidence has been presented
3 that there has been a spike in failing poles since the last two rate cases to justify the increase
4 in pole replacements and capital spending in this rate case.

5 To give the Company the benefit of the doubt that some increased pole failures may occur
6 during the bridge and projected test year period, I propose that the increase in pole
7 replacements forecasted by the Company over the recent three-year historical average be
8 spread over a three-year period. For the bridge period, the Company forecasted 847 pole
9 replacements. This is an incremental 453 pole replacements over the historical three-year
10 average of 394.

11 Spreading the 453 incremental pole replacements over three years, results in an additional
12 151 pole replacements in the bridge period over the historical average, or 545 pole
13 replacements. Multiplied by the average unit cost of \$23,858 reflected in the Company's
14 forecast,³³ the result is a reasonable capital expenditure forecast for pole replacements for
15 the bridge period of \$13,003,000.³⁴ This amount is \$7,205,000 lower than the Company's
16 forecast of \$20,205,000.

17 Similarly, for the projected test year, I propose an additional 151 poles to the 545 pole
18 replacements forecasted for the bridge period to bring the total to 696 pole replacements.

³³ $\$20,208,000 \div 847 = \$23,858$.

³⁴ $545 \times \$23,858 = \$13,003,000$.

1 This number multiplied by the average unit cost of \$23,860 reflected in the Company's
2 forecast³⁵ results in a reasonable forecast of \$16,607,000 in capital expenditures for the
3 projected test year. This amount is \$4,986,000 lower than the \$21,593,000 forecasted by
4 the Company.

5 I recommend that the Commission remove \$7,205,000 and \$4,986,000 from the
6 Company's forecasted capital expenditures for the bridge period and the projected test
7 year, respectively.

8 **Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES**
9 **FORECASTED BY THE COMPANY FOR THE HVD LINES RELIABILITY**
10 **ROW?**

11 A. In Figure 11 on page 26 of Mr. Kurdziel's direct testimony, the Company shows ROW
12 acquisition costs increasing from \$6,333,000 in the bridge period to \$11.0 million in the
13 projected test year. In discovery, the Attorney General asked the Company to identify the
14 projects that require new easements, renewals, or expansion of the easement. In its
15 response, the Company describes in general terms when ROW easements are required and
16 provides a list of names of locations with no pertinent information, such the miles of ROW
17 and related costs for each project or location.³⁶ ROW easements are primarily associated

³⁵ \$21591,000 ÷ 905 = \$23,860.

³⁶ DR AG-CE-0528.

1 with line rebuilds. The Company forecasted 45 miles of line rebuilds in Figure 11, which
2 is an increase of 43% over the 31.5 miles forecasted for the bridge period.

3 By applying the 43% rate of increase for the forecasted line rebuilds to the bridge period
4 ROW costs of \$6,333,000, I determined a reasonable forecast for the projected test year of
5 \$9,056,000. This amount is \$1,944,000 lower than the Company's forecast of \$11.0
6 million. I recommend that the Commission remove the \$1,944,000 from the Company's
7 forecasted capital expenditures for the projected test year.

8 **Q. WHAT IS THE TOTAL CAPITAL EXPENDITURES DISALLOWANCE THAT**
9 **YOU PROPOSE FOR THE HVD LINES RELIABILITY SUBPROGRAM?**

10 A. For the total HVD Lines Reliability subprogram, I recommend that the Commission
11 remove \$7,205,000 for the bridge period and \$6,930,000 for the projected test year.

12 **13. HVD Lines and Substations Rehabilitation**

13 On line 17 of Exhibit A-95 (MPK-3), the Company shows forecasted capital expenditures
14 for HVD Lines and Substation Rehabilitation of \$39,881,000 for the 14-month bridge
15 period ending February 2022 and \$70,900,000 for the projected test year ending February
16 2026. In Figure 26 on page 53 of Mr. Kurdziel's testimony, the Company shows 5
17 component spending categories. I will focus my discussion below on the Pole Top
18 Assembly Replacements and the HVD Substation Replacement Projects.

1 **Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES**
2 **FORECASTED BY THE COMPANY FOR THE HVD POLE TOP ASSEMBLY**
3 **REPLACEMENTS?**

4 A. On line 24 of Exhibit A-112, the Company shows that during the five years from 2019 to
5 2023, capital spending on pole top assembly replacements ranged from approximately \$3.0
6 million in 2020 to \$5.6 million in 2021 with the number of replacements ranging from 373
7 to 563. During the most recent three years, the average annual spending in this area was
8 \$ 5,079,250 to replace 529 pole top assemblies on average each year.

9 In Figure 26, the Company shows forecasted capital expenditures of \$2,144,000 in the
10 bridge period to replace 233 pole top assemblies and \$10,399,000 for the projected test
11 year to replace 1,130 pole top assemblies. From this information, it is evident that, while
12 reducing the number of work units in the bridge period, the Company is proposing to
13 increase pole top assembly replacements by over 100% in the projected test year compared
14 to recent historical levels and doubling related capital spending.

15 In response to discovery requesting a justification for the significant escalation in spending
16 between the bridge period and the projected test year, the Company points to Priority 3
17 anomalies shown in Figure 23 and two photos of pole top assemblies on pages 43 and 46
18 of Mr. Kurdziel direct testimony.³⁷ This information does not show any large changes in
19 recent years to justify a 100% increase in pole top assembly replacements with

³⁷ Exhibit AG-1.12 includes DR AG-CE-0533c.

1 commensurate increase in capital spending. No evidence has been presented that there has
2 been a spike in failing pole top assemblies in recent years to justify the 100% increase in
3 replacements for the projected test year. In addition, it is not clear why the Company
4 would cut in half the number of replacements in the bridge period from historical levels if
5 this is a critical area for improvement.

6 While a 100% increase has not been justified by the Company, I propose that the increase
7 in pole top assembly replacements forecasted by the Company for the projected test year
8 over the recent three-year historical average be spread over a three-year period in the event
9 that some increased pole top assembly failures occur during the projected test year. The
10 difference between the 1,130 units forecasted by the Company and the 529 average units
11 in the three-year historical period is 601 units.

12 Spreading the 601 incremental pole top assembly replacements over three years, results in
13 an additional 200 units over the historical average, or 729 for the projected test year.
14 Multiplied by the average unit cost of \$9,203 reflected in the Company's forecast,³⁸ the
15 result is a reasonable capital expenditure forecast of \$6,709,000.³⁹ This amount is
16 \$3,690,000 lower than the Company's forecast of \$10,399,000.

17 I recommend that the Commission remove \$3,690,000 from the Company's forecasted
18 capital expenditures for the projected test year.

³⁸ $10,399,000 \div 1,130 = \$9,203$.

³⁹ $729 * \$9,203 = \$6,709,000$.

1 **Q. WHAT IS YOUR ASSESSMENT OF THE CAPITAL EXPENDITURES**
2 **FORECASTED BY THE COMPANY FOR THE HVD SUBSTATION**
3 **REPLACEMENT PROJECTS?**

4 A. On line 84 of Exhibit A-112, the Company shows that during the five years from 2019 to
5 2023, capital spending on HVD substation replacement projects ranged from
6 approximately \$6.8 million in 2020 to \$25.4 million in 2022. No project numbers were
7 provided by the Company in this exhibit. During the most recent three years, the average
8 annual spending in this area was \$21,551,810.

9 In Figure 26, the Company shows forecasted capital expenditures of \$31,543,000 in the
10 bridge period and \$50,136,000 for the projected test year for these projects. The forecasted
11 amounts represent an increase of 46% in the bridge period and 133% for the projected test
12 year over recent annual spending levels. In response to discovery, the Company provided
13 some additional information on the number of stations rehabilitated in prior years and
14 planned for the bridge and test year periods. The numbers do not track with the historical
15 and forecasted capital spending with number of station projects ranging from zero to four.
16 There is no clear indication of why replacing two substations in the bridge period would
17 cost \$31.5 million and the same number of projects would cost \$50.1 million in the
18 projected test year. The list of projects in Exhibits A-125 and A-126 does not help in
19 explaining this divergence. Worse yet, four substations rehabilitated in 2023 only cost
20 \$19.6 million. The disparity is significant, and the discovery response does not provide
21 any more clarity and simply repeats the general conditions of the fleet of HVD substations

1 with no specific information that justifies the 46% to 133% increase in spending on two
2 projects each year.⁴⁰

3 The best information available is the average spending level over the past three years of
4 \$21,551,810. Adjusting this amount for inflation results in bridge period capital
5 expenditures of \$22,150,000.⁴¹ This amount is \$9,393,000 lower than the Company's
6 forecasted amount of \$31,543,000. For the projected test year, adjusting the \$22,150,000
7 for inflation results in forecasted capital expenditures of \$22,637,000.⁴² This amount is
8 \$27,499,000 lower than the Company's forecast of \$50,136,000.

9 I recommend that the Commission remove \$9,393,000 and \$27,499,000 from the
10 Company's forecasted capital expenditures for the bridge period and the projected test
11 year, respectively.

12 **Q. WHAT IS THE TOTAL CAPITAL EXPENDITURES DISALLOWANCE THAT**
13 **YOU PROPOSE FOR THE HVD LINES AND SUBSTATIONS REHABILITATION**
14 **SUBPROGRAM?**

15 A. For the total HVD Lines and Substations Rehabilitation subprogram, I recommend that the
16 Commission remove \$9,303,000 for the bridge period and \$31,189,000 for the projected
17 test year.

⁴⁰ Id. includes DR AG-CE-0533b and c.

⁴¹ $\$21,551,810 \times 1.024 \times 1.00367 = 22,150,000$.

⁴² $\$11,150,000 \times 1.022 = \$ 22,637,000$.

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14. Large Transformer Pre-Purchases

Beginning on page 93 of his direct testimony, Mr. Kurdziel discusses the advance purchase of large transformers based on the probability that the Company may land new large customers in the future and would need those transformers to expedite initiation of electrical service. In Exhibits A-125 and A-126, the Company included \$10,200,000 in both the bridge period and projected test year to make those purchases.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY’S PROPOSAL TO PRE-PURCHASE LARGE TRANSFORMERS BEFORE HAVING A CUSTOMER REQUEST AND COMMITMENT TO TAKE SERVICE?

A. The purchase of transformers and other equipment to provide service to unknown customers is risky and burdens customers with costs that are not readily covered by new revenues. In discovery, the Attorney General asked the Company to provide the probability percentage that new projects will come to pass. In its response, the Company did not directly answer the request and instead provided a vague answer about tracking several large high-probability projects.⁴³ Although the Company may be in discussion with prospective customers, often those customers are in discussions with other utilities in other states and can easily lose interest.

⁴³ Exhibit AG-1.13 includes DR AG-CE-0536.

1 In his testimony, Mr. Kurdziel states that the large transformer have a long lead time and
2 the untimely availability of transformers could put the Company at a disadvantage.
3 However, in response to discovery, he admitted that the same problem with long lead times
4 would affect other utilities with which the Company would compete.⁴⁴

5 The key problem with the Company's proposal is that the entire risk of pre-purchasing
6 large transformers rests entirely on customers because the Company wants to earn a return
7 on the purchase costs by including them in rate base. In effect, the Company earns a return
8 on assets that may not be in use while the customer pays the cost. This is not a fair and
9 reasonable outcome.

10 If the Company was truly interested in facilitating the construction of new facilities to
11 expedite the new customer service date, it should be willing to bear the cost of holding on
12 to unproductive assets until they are place in service and then earn a quicker return on the
13 assets than would otherwise occur. In this regard, the Company was asked in discovery
14 whether it was willing to forfeit earning a return on the transformer costs until they were
15 placed in service and were used and useful. In response, the Company stated that it was
16 not willing to do so.⁴⁵

⁴⁴ Id.

⁴⁵ Id.

1 I recommend that the Commission reject the Company’s proposal to pre-purchase large
2 transformers and remove the capital expenditures of \$10,200,000 included in the bridge
3 period and the projected test year.

4 **15. Grid Modernization**

5 On line14 of Exhibit A-95 (MPK-3), the Company shows forecasted capital expenditures
6 for Grid Modernization of \$24,258,000 for the bridge period and \$37,689,000 for the
7 projected test year. This subprogram consists of various spending categories, as detailed
8 in Figure 1 on page 11 of Mr. Scott McPhail’s direct testimony. I will focus on the Line
9 Sensors, Distribution Asset Management, Planning System Modernization, and
10 Operational Systems Modernization categories in my testimony below.

11 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY’S PROPOSED CAPITAL**
12 **SPENDING FOR LINE SENSORS?**

13 A. In figure 1, Mr. McPhail shows forecasted capital spending for Line Sensors of
14 \$10,714,000 for the bridge period and \$6,808,000 for the projected test year. Based on
15 information provided on page 19, line 6, of Mr. McPhail’s testimony, I calculated that the
16 Company plans to deploy 3,027 Line Sensors in the bridge period and 833 in projected test
17 year.⁴⁶ The unit cost for each period is \$3,539 and \$8,173, respectively. In contrast, during
18 the most recent historical three years, the Company experienced actual average annual unit

⁴⁶ $2,800 \text{ in } 2024 + 1,000 \times 2/12 = 3,027$ for bridge period. For projected test year being last year: $1,000 \times 10/12 = 833$.

1 costs of \$2,905. On page 21 of his testimony, Mr. McPhail first dismisses the use of unit
2 costs to assess the reasonableness of future spending for Line Sensor but admits that unit
3 costs were calculated based on historical data and that over multiple years the costs level
4 off. However, it remains unexplained why unit costs rise so dramatically in the bridge
5 period and projected test year, particularly when 2025 is the last year for the program.

6 To calculate a reasonable forecast of capital expenditures for the future periods, I used the
7 three-year historical average unit cost of \$2,905 and adjusted it for future inflation. For
8 the bridge period, the forecasted unit cost is \$2,986.⁴⁷ This rate multiplied by the 3,027
9 units forecasted for the bridge period results in forecasted capital expenditures of
10 \$9,039,000. This amount is \$1,675,000 lower than the \$10,714,000 forecasted by the
11 Company.

12 For the projected test year, I further adjusted the \$2,986 for inflation to \$3,052. This rate
13 multiplied by 833 units results in forecasted capital expenditures of \$2,542,000. This
14 amount is \$4,266,000 lower than the Company's forecast of \$6,808,000.

15 Therefore, I recommend that the Commission remove \$1,675,000 and \$4,266,000 from
16 the Company's forecasted capital expenditures for the bridge period and the projected test
17 year, respectively.

⁴⁷ $\$2,905 \times 1.024 \times 1.00367 = \$2,986$.

1 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY’S PROPOSED CAPITAL**
2 **SPENDING ON THE DISTRIBUTION ASSET MANAGEMENT, PLANNING**
3 **SYSTEMS MODERNIZATION, AND THE OPERATIONAL SYSTEMS**
4 **MODERNIZATION?**

5 A. Mr. McPhail discusses the Distribution Asset Management, Planning Systems
6 Modernization, and the Operational Systems Modernization beginning on page 60 of his
7 testimony. In Figure 11, he shows capital expenditures for the projects that total to
8 \$7,285,000 for the bridge period and \$20,912,000 for the projected test year.

9 In discovery, the Attorney General asked the Company to explain why these new systems
10 are needed at this time when the focus should be on reducing power outages by replacing
11 failing infrastructure and why current systems could not still be used. The Attorney
12 General also asked that the Company provide the total cost of each project from inception
13 to completion, the current phase of the project and next phase with timelines, and a copy
14 of the cost benefit analysis (CBA) that economically justifies undertaking these projects.

15 The response shows that the total amount of capital and O&M spending to get the projects
16 completed would be in excess of \$66 million. This is a staggering amount that could be
17 redirected to more immediate needs. The response also does not make a compelling case
18 that the new systems are necessary at this time and current systems can no longer be used.

19 In the response, the Company also stated that either a CBA had not been done or provided
20 only scant information on potential cost savings and not a full economic justification to

1 undertake the projects. Furthermore, the discovery response show that most segments of
2 the projects are in the initial scoping and conceptual phase or early development of system
3 requirements.⁴⁸ It is both premature and unwise to include the proposed capital
4 expenditures in rate base in this rate case.

5 Therefore, I recommend that the Commission remove \$7,285,000 for the bridge period
6 and \$20,912,000 for the projected test year from the Company's forecasted capital
7 expenditures.

8 **Q. WHAT IS THE TOTAL CAPITAL EXPENDITURES DISALLOWANCE THAT**
9 **YOU PROPOSE FOR THE GRID MODERNIZATION SUBPROGRAM?**

10 A. For the total Grid Modernization subprogram, I recommend that the Commission remove
11 \$8,960,000 for the bridge period and \$25,178,000 for the projected test year.

12 **16. Distribution Capital Expenditures Adjustments - Summary**

13 **Q. WHAT IS THE TOTAL AMOUNT OF THE CAPITAL EXPENDITURE**
14 **ADJUSTMENTS FOR THE ELECTRIC DISTRIBUTION PROGRAMS THAT**
15 **YOU RECOMMEND?**

⁴⁸ Exhibit AG-1.14 included DR AG-CE-0543 and 0544.

1 A. For the Distribution programs discussed above, I recommend a total disallowance of
2 forecasted capital expenditures of \$116,769,000 for the 14-month bridge period and
3 \$412,479,000 for the projected test year.

4 **B. Capital Expenditures - Summary**

5 **Q. WHAT IS THE ATTORNEY GENERAL OVERALL RECOMMENDATION**
6 **REGARDING THE LEVEL OF CAPITAL EXPENDITURES?**

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

Summary of AG Disallowed Capital Expenditures	
	Amount (millions)
Distribution Plant	\$ 529.2
Power Generation	778.8
Operations Support	42.2
Total	\$ 1,350.2

10

11 Therefore, the Commission should reduce the Company's proposed capital expenditures
12 by \$1,350 million and reduce average rate base by \$950.2 million, including working
13 capital adjustments, as shown in Exhibit AG-1.15. The resulting effect of the lower rate
14 base from the reduction in capital expenditures is a reduction in the revenue deficiency of
15 \$75.5 million.

1 **C. Investment Recovery Mechanism**

2 **Q. PLEASE SUMMARIZE THE COMPANY’S PROPOSAL TO INCREASE THE**
3 **CAPITAL EXPENDITURE LEVELS IN THE SECOND YEAR OF THE**
4 **INVESTMENT RECOVERY MECHANISM (“IRM”).**

5 A. Beginning on page 25 of her direct testimony, Company witness Heidi Myers proposes
6 that the Commission increase the capital spending levels in Year 2 of the IRM for each of
7 the three components to coincide with the capital spending proposed in the Company’s
8 Reliability Roadmap. Table 3 on page 28 of her testimony shows the specific amounts for
9 Lines Reliability-LVD, Resiliency, and System Protection. The total amount requested is
10 for Year 2 is \$278.6 million. In contrast, the previous amount included in Year 2 was
11 \$49.3 million. The new proposal would increase the capital spending amount by more
12 than five-fold.

13 **Q. WHAT IS YOUR ASSESSMENT OF THE PROPOSED INCREASE?**

14 A. The Company’s proposal shows the dramatic increase in capital spending that the
15 Company has included in the Reliability Roadmap and reflected in this rate case. As I
16 discussed above in the Capital Expenditures section of my testimony, I disagree with the
17 large and unprecedented increase in capital spending in many of the areas proposed by the
18 Company, including Lines Reliability-LVD and Resiliency. Many of the new
19 subprograms proposed by the Company are not adequately justified, are controversial, and

1 will need to be litigated in this case. It would not be wise or reasonable to approve
2 uncontrolled spending on many of the subprograms included in these two areas before the
3 subprograms have been fully vetted in a rate case and have progressed past the initial year
4 of implementation to ensure the pace of capital spending is reasonable.

5 Therefore, I recommend that the Commission retain the spending level for Year 2 of the
6 IRM at the previously approved amount of \$49.3 million.

7 **IV. Depreciation Expense**

8 **Q. PLEASE DISCUSS THE DEPRECIATION EXPENSE ADJUSTMENT THAT**
9 **YOU PROPOSE.**

10 A. In Exhibit AG-1.15, I identified the adjustments to be made to the Company's proposed
11 capital expenditures. Those reductions lower the amount of depreciation expense that the
12 Company will incur during the projected test year. On the same exhibit, I calculated the
13 reduction in depreciation expense of \$43.1 million. I recommend that the Commission
14 reduce the Company's depreciation expense by this amount for the projected test year.

15 **V. Property Tax Expense**

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

18 A. As discussed above, I identified the adjustments to be made to the Company's proposed
19 capital expenditures in Exhibit AG-1.15. Those reductions lower the amount of property

1 tax expense that the Company will incur during the projected test year. On the same
2 exhibit, I have calculated the reduction in property tax expense of \$3.4 million. I
3 recommend that the Commission reduce the Company's property tax expense by this
4 amount for the projected test year.

5 **VI. Cost of Capital**

6 **A. Capital Structure**

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

9 A. I recommend that the capital structure shown on page 1 of Exhibit AG-1.16 be used in this
10 case. The first three lines show the projected long-term debt, preferred equity and common
11 equity capital of the Company, which represents the permanent capital structure for the
12 projected test year ending February 2026. The capital balances in this exhibit reflect the
13 amounts shown in Company Exhibit A-14 (MRB-1), Schedule D1, with an adjustment to
14 rebalance the capital structure. I increased the long-term debt component in Exhibit AG-
15 1.16 by \$183 million and reduced the common equity component by the same amount.
16 The result is a capital structure with 50% of common equity and 50% of debt and preferred
17 stock.

18 **Q. WHY DID YOU INCREASE LONG TERM DEBT BY \$183 MILLION AND**
19 **OFFSET THIS CHANGE WITH LOWER COMMON EQUITY BY THE SAME**
20 **AMOUNT?**

1 A. The Company proposed a permanent capital structure with a common equity component
2 of 50.75%. This level of common equity exceeds the 50.02% level granted in the
3 Company's last fully contested rate case, Case No. U-21389 on March 1, 2024. The capital
4 structure in this rate case should similarly mirror the common equity ratio approved on
5 March 1, 2024, which I have rounded down to 50%. As discussed in Case No. U-21389,
6 there are several factors that clearly support a 50% common equity level.

7 These factors include (1) the Commission's consistent directive in the Company's prior
8 electric and gas rate cases, which stated that a 50/50 capital structure is desirable and
9 appropriate to ensure reduced costs to customers and maintain the Company's strong
10 financial position, unless the Company can demonstrate that a higher ratio is justified; (2)
11 The Company's strong cash flow to debt coverage ratio and credit ratings; (3) the
12 Company's common equity capital contributions by the parent company, albeit often
13 funded with long term debt issued at the parent company level; (4) the favorable regulatory
14 environment in Michigan supported by historical returns on common equity above
15 industry averages and in the top tier of the Company's peer group; and (5) the fact that the
16 common equity ratio of the peer group, used to assess the cost of common equity in this
17 case, is approximately 44%.⁴⁹

⁴⁹ Exhibit AG-1.19 shows that the equity ratio for each peer company and the peer group average ratio of 43.7%.

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

3 A. In the recent March 1, 2024 order in Case No. U-21389, the Commission decided to set
4 the common equity ratio at 50.02%, as recommended by the MPSC Staff and supported
5 by the Attorney General and by ABATE who recommended a 50% common equity ratio
6 be adopted. On page 129 of the order, the Commission stated the following:

7 The Commission finds that the record supports the adoption of a balanced capital
8 structure. The Commission is unpersuaded by the company's arguments that the
9 adoption of a balanced capital structure will degrade Consumers' credit metrics. The
10 adoption of a balanced capital structure results in a modest reduction in the
11 authorized equity layer, given Consumers' agreement to a 50.75% equity layer in
12 case U-21224. *See*, January 19 order, Exhibit A, p. 4. The Commission also finds
13 that the ALJ did not ignore or improperly reject the company's evidence as claimed
14 by Consumers in exceptions. *See*, PFD, pp. 217-261.

15 Notwithstanding the above, the Commission finds that the most reasonable and
16 prudent approach to achieving this goal was set forth by the Staff. Therefore, the
17 Commission finds that a common equity layer on \$10.880 billion should be adopted,
18 which equates to a 50.02% equity ratio in the permanent capital structure. *See*, 5 TR
19 3623, Exhibit S-4, Schedule D-1, line 3. This equity balance is a slight reduction to
20 the 50.75% equity layer agreed to by the parties in Case U-21224, which is consistent
21 with prior Commission directives to gradually achieve a balanced capital structure.

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

25 **Q. IN THE MOST RECENT MOODY'S CREDIT REPORT COVERING**
26 **CONSUMERS ENERGY, WHAT ARE THE REPORTED CASH FLOW TO DEBT**
27 **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% threshold level.⁵⁰

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

6 A. According to S&P’s August 17, 2023 report the Company’s senior secured debt is rated as
7 “A” by S&P (the middle of the “A” category).⁵¹ Furthermore, on page 2 of this report on
8 Consumers Energy, S&P made the following statement in the section “Downside
9 Scenario”.

10 We could lower our rating on Consumers Energy if its stand-alone financial measures
11 weaken such that its FFO to debt weakens to consistently below 15%. We could also
12 lower our rating on Consumers Energy if we lower our rating on its parent, CMS
13 Energy.⁵²

14 Page 3 of this S&P report shows this key ratio at 18.7% for 2022. S&P also estimated this
15 ratio in the range of 18% to 20% for 2023 and 2024. These coverage ratios are not
16 indicative of any concerns about a possible debt rating downgrade and are well above the
17 15% threshold set by S&P.

18 **Q. DID THE COMPANY PROVIDE ANY EXHIBITS SHOWING THE**
19 **CALCULATION OF THE MOODY’S OR S&P CASH FLOW RATIOS?**

⁵⁰ Exhibit AG-1.25 includes DR AG-CE-273 with the Moody’s credit report dated May 31, 2024.

⁵¹ Exhibit AG-1.26 includes DR AG-CE-273 with the S&P report dated August 17, 2023.

⁵² S&P’s FFO to debt ratio is similar to the Moody’s cash flow ratio “CFO Pre W/C.”

1 A. Partially. Witness Wehner on pages 8 and 9 of his testimony includes a formulistic
2 equation to compute the Cash Flow to Debt ratio. The result of this equation shows a
3 17.5% result based on a 50% equity ratio and a 9.9% ROE. This equation is severely
4 flawed and misleading. The major problems with this equation are that it ignores cash
5 flow from deferred income taxes and understates the benefit of the depreciation
6 component.

7 **Q. PLEASE ELABORATE ON THE SPECIFICS OF WHY MR. WEHNER'S**
8 **EQUATION TO CALCULATE FFO TO DEBT RATIOS IS FLAWED.**

9 A. First, as stated above, the equation does not take into account Deferred Taxes. Accelerated
10 depreciation allowed under tax law benefits the Company from a cash flow perspective
11 and the benefits are reflected in Deferred Taxes, which is a source of capital at no cost to
12 the Company. Between 2021 and 2023 years, Deferred Taxes on the Company's balance
13 sheet increased from \$3.8 billion to \$4.0 billion.⁵³ This is an average increase of
14 approximately \$100 million per year. The ratio of this amount to the Company's total debt
15 of \$11.6 billion shown in the most recent Moody's report is 0.86%. Therefore, if this
16 additional cash flow is added to Mr. Wehner formula result of 17.5% it increases the FFO
17 to Debt coverage ratio to approximately 18.4%, which a substantial change.

18 Second, Mr. Wehner's equation contains a 3.8% depreciation component. Footnote 3 on
19 page 9 of his direct testimony shows that he obtained this depreciation rate from the

⁵³ Exhibit A-14 (MRB-2) Schedule D-1a page 1 in each Case Nos. U-21224 and 21585.

1 Company's 2023 MPSC report. The problem here is that the 3.8% rate is being applied to
2 gross plant to calculate depreciation. However, it is the Company's net plant (not its gross
3 plant) that is being financed. Therefore, the rate that should be used in formula should be
4 derived from the average of depreciation expense to rate base. These rates are 5.7% and
5 3.8% for the Company's electric and gas businesses. Using a simple average of these two
6 rates produces an average of 4.75%. The differential between this rate and the Company's
7 3.8% rate results in approximately a 200 basis points increase in the FFO to Debt rate.⁵⁴

8 The addition of 86 basis points for Deferred Taxes and 200 basis points related to
9 depreciation and amortization brings Mr. Wehner's equation outcome of 17.5% to 20.4%.

10 While these changes make the equation results more realistic, I will point out that the most
11 accurate approach to establishing the impact of changes in the capital structure and the
12 equity return is to start with the rating agencies' cash flow to debt coverage calculations
13 and update them for proposed changes. This is the approach I have taken, as discussed in
14 more detail below.

15 **Q. DID YOU CALCULATE THE IMPACT ON THE MOODY'S CASH FLOW TO**
16 **DEBT COVERAGE RATIO BASED ON A 50% EQUITY RATIO IN THE**
17 **COMPANY'S CAPITAL STRUCTURE AND AN AUTHORIZED ROE OF 9.80%**

⁵⁴ Depreciation and amortization on Exhibit A-3, Schedule C1 from this case and Case No. U-21490 is \$787M and \$331M for the Company's electric and gas businesses respectively. Dividing these amounts by rate base on Exhibit A-2, Schedule B1 in each case (\$13.9B electric and \$8.7B gas) results in a ratio of depreciation and amortization to rate base of 5.7% and 3.8% with a simple average being 4.75%.

1 A. Yes. In Exhibit AG-1.23, I calculated the Company's key cash flow to debt ratio for 2023
2 adjusted for the ROE and Common Equity ratio levels I advocate in this case. Starting
3 with Moody's actual results for 2023, I adjust these results to reflect a 9.80% ROE and a
4 50% common equity ratio.

5 For my analysis of the 2023 cash flow ratio results, I started with actual 2023 data on line
6 1 of Exhibit AG-1.23. Next, on line 2, I added additional long-term debt to reflect the
7 lower common equity ratio and adjusted the cash flow downward to reflect lower earnings.
8 On line 3, I adjusted the cash flow upward to reflect a 9.80% ROE versus the 8.26% ROE
9 actually earned in 2023. The result of these adjustments is shown on line 4 with a cash
10 flow to debt ratio of 20.2%. This ratio is well above the 18% downgrade threshold noted
11 by Moody's in this report. I have not presented any ratio results for S&P since the ratio
12 calculations are highly similar, and the S&P downgrade threshold is lower at 15%.

13 I will point out that by starting with actual Moody's 2023 results, items such as leases and
14 short-term debt are already reflected in the cash flow and debt elements it uses to determine
15 the ratio. The Company often points to these as being "add-ons" which are not considered
16 in looking at the permanent capital of CECo on a ratemaking basis. This analysis shows
17 that the 9.80% ROE and 50% common equity ratio leaves the Company's ratios above the
18 ratio levels where it could face a downgrade of its debt, even considering the Company's
19 preferred add-ons.

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.⁵⁵ 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 from December 2018 to 2023, Consumers Energy's Common Equity
15 has increased by \$1.8 billion. An analysis of the Company's financial statements filed
16 with the Securities and Exchange Commission shows that the \$3.9 billion increase in
17 Consumers Energy common equity is due to the following factors:

⁵⁵ U-21389 Exhibit AG-1.28 which included CECO response to discovery request AG-CE-0295.

1

Table 1		
Consumers Energy		
Common Equity Change for Five Years (Dec. 2018 - 2023)		
		<u>\$ Billions</u>
1	Net Income of Consumers Energy	\$ 4.2
2	Dividends Paid to CMS	(3.4)
3	New CMS Investment in Consumers Energy	3.1
4	Total Change in Common Equity	\$ 3.9

2

Table 2		
CMS Energy		
CMS Funds Available to Invest in Consumers Energy (Dec. 2018 - 2023)		
		<u>\$ Billions</u>
a.	Dividends From Consumers Energy	\$ 3.4
b.	Less: Dividends to CMS Shareholders	(2.5)
c.	Plus: Other CMS Activity	(0.2)
d.	Sub Total	0.7
e.	Increase in Parent Company Debt	1.8
f.	CMS Net Equity Issued	0.6
g.	Funds For New CMS Investment in Consumers Energy	\$ 3.1

3

Clearly, of the \$3.1 billion of new equity invested by CMS, \$1.8 billion (or 58%) is from new CMS debt.

4

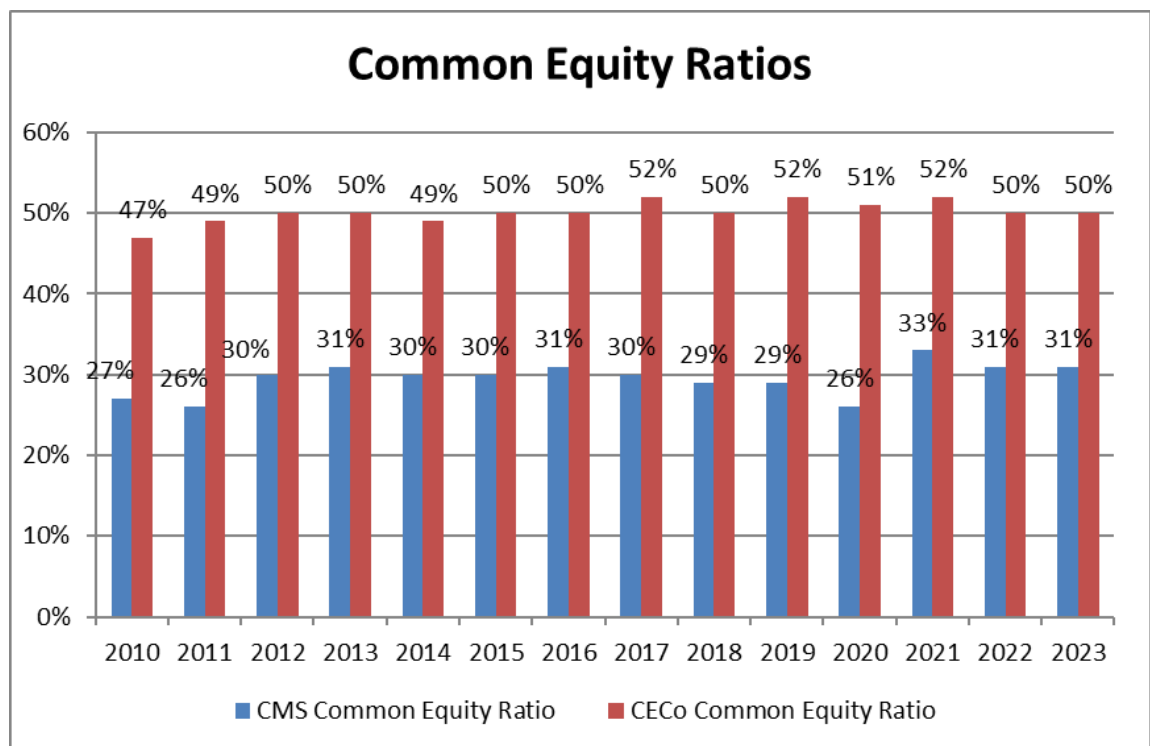
5

Second, to further support my point, CMS Energy is a frequent issuer of long-term debt in the capital markets. Over the last five years, CMS parent-only debt has increased from

6

1 \$3.0 billion at year end 2018 to \$4.8 billion at year end 2023.⁵⁶ Yet the only substantive
2 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 2023. 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

⁵⁶ From SEC filings on Form 10-K for the years ended 2018 and 2023.

1 It is important to remember that nearly 100% of CMS’ assets and earnings come from
2 Consumers Energy. 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 The excessive debt and low common equity ratio at CMS (31% at year-end 2023) have
10 been a concern for the rating agencies when assessing the debt rating of Consumers
11 Energy. In its May 31, 2024 report, Moody’s stated that their current stable outlook
12 incorporates their view that “debt levels at the parent will not increase materially.”⁵⁷ Also,
13 in its May 24, 2022 credit update report on the Company, Moody’s noted under “Credit
14 challenges” that the higher leverage at the parent company was a concern”.⁵⁸ Similarly,
15 page 2 of the Moody’s report issued a year earlier on May 10, 2021 contains a substantially
16 similar comment. Yet, CMS continues to have a high debt level of 69% and only a 31%
17 equity ratio in its balance sheet at the parent company while funding equity contributions
18 into Consumers Energy with debt.

⁵⁷ Exhibit AG-1.25 includes DR AG-CE-273 with the Moody’s credit report dated May 31, 2024.

⁵⁸ Exhibit AG-1.26 includes the May 24, 2022 Moody’s Report (see page 2) provided in DR AG-CE-279.

1 From the statements in Moody’s credit reports and similar concerns expressed by other
2 rating agencies, it appears that the debt-laden capital structure of CMS has contributed to
3 a lower debt rating than the Company could have achieved if CMS was capitalized with
4 more equity capital. The result has been higher interest costs for customers. Partially to
5 compensate for this significant leverage at CMS, the Company seeks a higher equity ratio
6 in the capital structure that will further increase costs to customers.

7 **Q. YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP**
8 **USED TO ASSESS THE COST OF COMMON EQUITY APPROXIMATES 44%.**
9 **PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE**
10 **COMMON EQUITY RATIO FOR THE COMPANY.**

11 A. As shown in Exhibit AG-1.19, the average common equity ratio of the peer company group
12 for 2023 was 43.7%. The cost of equity for those companies in the peer group is highly
13 dependent on the financial risk reflected in their capital structure. Thus, it is critical to
14 synchronize the capital structure of the Company to the peer group average as closely as
15 possible, to have consistency with the cost of equity capital derived from those peer group
16 companies. The Company’s proposed common equity capital ratio of 50.75% creates a
17 disconnect that is not acceptable and is also more costly to customers.

18 **Q. WITNESS BLECKMAN SPONSORS EXHIBIT A-36 (MRB-10) SHOWING THE**
19 **COMMON EQUITY RATIOS FOR VARIOUS GAS AND ELECTRIC UTILITY**
20 **COMPANIES SUPPOSEDLY DECIDED IN RATE CASES DURING 2020 TO**

1 **2023. THE EXHIBIT SHOWS AN AVERAGE COMMON EQUITY RATIO OF**
2 **53.32% FOR THE LISTED COMPANIES. WHAT IS YOUR ASSESSMENT OF**
3 **THE INFORMATION PROVIDED IN THIS EXHIBIT?**

4 A. It appears that Mr. Bleckman’s intent in presenting the average common equity ratio of
5 53.32% is to influence the Commission’s views on the Company’s equity ratio and to
6 suggest that his proposed 50.75% ratio is reasonable compared to other utility companies.
7 In this exhibit, he presents selective information related to some of the operating units of
8 Alliant Energy, Ameren, Entergy, Portland General Electric, WEC Energy Group, and
9 Xcel Energy, representing only six of the twelve peer companies included in Mr. Wehner’s
10 peer group used in his analysis to determine the cost of equity capital.

11 The Commission should not rely on the information provided by Mr. Bleckman in Exhibit
12 A-36 because it is neither accurate nor comprehensive to provide a proper context to
13 establish an appropriate common equity ratio for the Company. The major flaws are
14 discussed below.

15 First, of the eighteen operating companies in Exhibit A-36, five, or 28%, are Wisconsin
16 regulated entities. In general, the Wisconsin commission appears to be targeting a 53%
17 common equity ratio for the companies it regulates, which may be due to circumstances
18 specific to the utilities based in Wisconsin. This high concentration on Wisconsin utilities
19 is not representative of most peer companies. Furthermore, the 59.01% equity ratio for
20 Wisconsin Electric Power shown in Exhibit A-36 is inaccurate. Mr. Bleckman’s

1 workpaper “WP-MRB-25” shows a page from this company’s 2022 rate order. The rate
2 order established the equity component in the capital structure at a “...test-year authorized
3 level of 53.00%”. WEC Energy Group discloses in its financial statements and investor
4 presentations that Wisconsin Electric Power’s authorized equity ratio is 53% and that its
5 revenues are subject to refund requirements if its earned ROE exceeds 9.95%.⁵⁹
6 Unfortunately, Mr. Bleckman did not disclose or consider these factors in his exhibit in
7 his attempt to justify a higher equity ratio.

8 Second, Mr. Bleckman inappropriately includes small utilities in Exhibit A-36 to bolster
9 the average equity ratio. Smaller utilities tend to have higher equity ratios to sustain them
10 during potential volatility in their business, which larger utilities can better manage. For
11 example, Mr. Bleckman included North Shore Gas with 55.56% equity ratio when this
12 company’s rate base is approximately \$450 million in 2024.⁶⁰ In contrast, Consumers
13 Energy’s electric rate base was \$13.8 billion in 2023, and when including the gas business,
14 the total company rate base is in excess of \$22 billion.⁶¹ Similarly, Mr. Bleckman included
15 Minnesota Energy Resources in Exhibit A-36 with a 55.4% equity ratio when this
16 company has a customer base of 251,000 and annual revenues of approximately \$350
17 million.⁶² In comparison, Consumers Energy reported revenues of \$7.2 billion for 2023,
18 serving 3.7 million electric and gas customers.

⁵⁹ See page 19 of the WEC Energy Group 2023 Form 10-K and see the WEC investor presentation filed with Form 8-K dated February 24, 2023.

⁶⁰ Page 19 of the WEC Energy Group 2023 Form 10-K.

⁶¹ Consumers Energy Exhibit A-1, Schedule A-1, in Case No. U-21490 and U-21585

⁶² Minnesota Energy website under the section “About Us”.

1 Third, Mr. Bleckman excluded DTE Energy with a common equity ratio of 50% from
2 Exhibit A-36 but included that company in the peer group when calculating the cost of
3 equity or ROE rate. Additionally, Mr. Bleckman excluded the operating units of
4 FirstEnergy from Exhibit A-36 while including this company in the cost of equity peer
5 group. If Mr. Bleckman had included the subsidiaries of FirstEnergy in Exhibit A-36,
6 there would have been an additional eleven operating companies on the list with common
7 equity ratios ranging from 46% to 53% and averaging 50%.⁶³

8 In summary, Mr. Bleckman has constructed a selective group of utilities in Exhibit A-36
9 that are not representative of the electric utility industry or the Company's peer group with
10 the simple objective to create an inflated average equity ratio. The Commission should
11 disregard the Company's attempt in Exhibit A-36 to present a misleading industry average
12 equity ratio.

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

16 A. The difference is approximately \$9.1 million annually. This reflects (a) the difference
17 between the pre-tax cost of common equity of approximately 14% versus the cost of long-

⁶³ FirstEnergy 2023 Form 10-K, page 60. These operating companies are Cleveland Electric Illuminating, Metropolitan Edison, Monongahela Power, Jersey Central Power & Light, Ohio Edison, Pennsylvania Electric, Pennsylvania Power, Toledo Edison, West Penn Power and the operations of Potomac Edison in two states.

1 term debt of 4.3%; (b) the Company's proposed rate base of approximately \$15.6 billion;
2 and (c) the percentage of total capital being shifted from common equity to long term debt.

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

5 A. No. Except for the common equity and long-term debt changes discussed above, I have
6 utilized the capital balances sponsored by witness Bleckman on his Exhibit A-14 (MRB-
7 1), Schedule D1, page 1.

8 **B. Overall Rate of Return**

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

11 A. I am recommending an overall return on capital of 5.94%, which includes a return on
12 common equity of 9.80%, as shown in Exhibit AG-1.16, page 1. Even though the average
13 ROE rate calculated under the three methods discussed below is 9.71%, I rounded this
14 result up to 9.80% in calculating the overall cost of capital for reasons I will explain later
15 in my testimony.

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

17 A. For the long-term debt cost rate, I used a rate of 4.26%. This rate is 9 basis points lower
18 than the rate proposed by the Company and the calculation of the 4.26% rate is shown on

1 page 2 of Exhibit AG-1.16. The lower average rate for long-term debt reflects (a) the
2 Company's actual issuance of new long-term debt in August 2024 at 4.90% versus the
3 5.90% interest rate assumed by the Company and (b) the issuance of new long-term debt
4 in 2025 at 5.37% versus the 5.89% rate assumed by the Company. The lower interest rate
5 for the debt issued in 2025 reflects a 3.95% 30-year U.S. Treasury rate, whereas the
6 Company assumed a 4.42% U.S. Treasury rate to develop its overall interest rate for new
7 debt to be issued in 2025.⁶⁴ Corporate bond issues are typically priced off a base U.S.
8 Treasury rate plus a spread rate reflective of the issuing company's credit rating.

9 The interest cost savings from the lower coupon rates I calculated above are approximately
10 \$5.8 million annually for the Company's electric customers.⁶⁵

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

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

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

16 A. For Short Term Debt, forecasted interest rates for the projected test year have fallen since
17 the Company filed its case and I have adjusted the cost rate from 4.97% to 4.28% (a 69-

⁶⁴ Exhibit A-14 (MRB-4), line 77.

⁶⁵ Reflects a 9 basis points reduction in debt cost or $0.0009 \times 41\% \text{ long term debt ratio} \times \$15.57 \text{ billion of rate base}$ which equals to \$5.746 million per year.

1 basis point reduction) based on information received from the Company.⁶⁶ For Deferred
2 Taxes, I used the zero-cost rate recommended by witness Bleckman. Cost rates for JDITC
3 reflect those rates I used for the permanent capital sources.

4 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF**
5 **CAPITAL IN EXHIBIT AG-1.16.**

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 5.94%.

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 7.33% in column (h).

16 **C. Return on Equity**

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

⁶⁶ Exhibit AG-1.16, page 3.

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

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

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

16 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON**
17 **EQUITY IN EXHIBIT AG-1.17.**

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

1 While Exhibit AG-1.17 shows an average ROE of 9.71% from the three methodologies, I
2 recommend an allowed rate of return on equity of 9.80% for the reasons explained later in
3 this section of my testimony. In connection with these methods for determining the cost
4 of common equity, I have considered the cost of common equity for a proxy group of peer
5 companies. As discussed in more detail below, the cost of equity of a proper peer group
6 of other utilities provides the best guide to establishing an appropriate ROE rate for the
7 Company.

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

10 As reflected on Exhibit AG-1.22, to develop my peer group, I started with the 38 electric
11 utility companies followed by the Value Line Investment Survey. From this group of
12 companies, I removed seven companies due to size considerations, which include Duke
13 Energy, Exelon, Nextera, Southern Company, and Pacific Gas & Electric. These are
14 extremely large companies with revenues that are three times more on average compared
15 to the Company's revenue of \$7.5 billion. At the other extreme, I excluded MGE and
16 Until with annual revenues of less than \$700 million due to their small size. Next, I
17 excluded several other companies with non-growing dividends, foreign operations,
18 wildfire and off-shore wind construction risks, as well as companies with large non-utility
19 investments, merger and acquisition activity or corporate reorganizations, and companies
20 facing earnings growth challenges.

1 Exhibit AG-1.22, page 1 shows the starting group of 38 electric utilities I initially
2 considered with the analysis and reasons to arrive at the proposed peer group of companies.
3 The result is the group of ten companies shown in Exhibits AG-1.18 and AG-1.19, all of
4 which have growing earnings and dividends, and are comparable to the Company.

5 **Q. HOW DOES YOUR PEER GROUP OF TEN COMPANIES COMPARE TO THE**
6 **COMPANY'S ELECTRIC PEER GROUP?**

7 A. The Company's electric peer group is presented by witness Todd Wehner on page 1 of
8 Exhibit A-14 (TAW-1) and consists of a group of twelve companies. This group includes
9 only three of the companies in my peer group. The other nine companies in the CEC
10 peer group are discussed below.

11 Three of the companies in the Company's peer group are PPL, WEC Energy Group, and
12 FirstEnergy. These companies have been or are currently involved in buying out-of-state
13 solar assets, such as WEC Energy, or corporate restructuring. PPL has been involved in a
14 significant restructuring of its business in recent years having sold foreign assets and
15 purchased some domestic utility companies. As a result, it will take time to assess the
16 normalized earnings power and long-term growth rate of this company and therefore it is
17 inappropriate for inclusion in the peer group for this case.

1 According to Value Line, FirstEnergy is restructuring its business and has recently sold
2 \$3.5 billion of transmission assets.⁶⁷ As a result, the stock price, dividend yield and
3 earnings growth for this Company have been impacted by the restructuring and not
4 representative of normal operations, making it a poor fit for the Company's peer group.

5 Also, Value Line reports that Xcel Energy (another CECo peer group company) is
6 involved in significant wildfire litigation in Texas and Colorado. Value Line notes that
7 the stock price of this Company has fallen 14% during the first six months of 2024
8 compared to a 2% decline in the Value Line Utility Index over the same time frame.⁶⁸ The
9 impact of the litigation risk on the stock price, dividend yield and earnings growth rate
10 makes this company also a poor fit for the Company's peer group.

11 Regarding the other companies in the CECo peer group (Eversource, Entergy, OGE Energy,
12 Pinnacle West, and Portland General Electric), these companies have declining earnings
13 per share trends, as shown in Exhibit AG-1.22, page 2. Therefore, these companies also
14 are inappropriate for inclusion in the Company peer group.

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

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

17 A. The DCF approach is based on the proposition that the price of any security reflects the
18 present value of all future cash flows (dividend flows) from the security discounted at a

⁶⁷ Page 139 of the Value Line Investment Survey dated August 9, 2024

⁶⁸ Page 212 of the Value Line Investment Survey dated July 12, 2024

1 single discount rate which, in the case of common stocks, is the required return on equity.
2 Expressed mathematically, the resulting equation can be reconfigured to solve for the
3 required rate of return and this equation is:

$$4 \quad R = D/P + g$$

5 where "R" = the Required Equity Return

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

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

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

9 A. The results of my DCF analysis are summarized in Exhibit AG-1.18. The stock price
10 information in column (c) of this exhibit reflects the average of the high and low prices for
11 each of the equity securities for each of the 30 trading days from July 5, 2024 to August
12 15, 2024. The annual dividend in column (d) is the forecasted average dividend level for
13 2024 and 2025 as projected by the Value Line Investment Survey. Column (h) shows the
14 average long-term earnings growth rate based on (1) the estimate of earnings growth for
15 the five years from 2023 to 2028 per Value Line; and (2) the earnings growth estimates by
16 stock analysts over the next five years which is available from Yahoo.com.

17 The resulting calculation of the DCF Method is an average return on common equity for
18 the proxy group of 9.27%.

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

1 A. The DCF analysis relies upon financial market information for the dividend yield portion
2 of the equation. However, it also relies upon judgments of dividend and earnings growth
3 prospects of security analysts which may or may not be consistent with the beliefs of
4 investors. I place a fairly high degree of reliability in the DCF results when considered in
5 conjunction with the results of other methods in determining the cost of common equity.
6 The DCF model fits best in evaluating the cost of capital of utilities because of their
7 relatively steady earnings growth and dividends paid to investors.

8 **Q. HOW DOES YOUR DCF COST OF CAPITAL ESTIMATE COMPARE TO THE**
9 **COMPANY’S DCF ESTIMATE?**

10 A. The 9.27% rate I calculated is lower than the Company’s “analyst-based dividend growth”
11 DCF calculation of 9.85%. This estimate is shown on page 5 of Exhibit A-14 (TAW-1).
12 The 58-basis points difference is largely due to the dividend growth rates used by the
13 Company in the DCF formula. I and most cost of capital practitioners utilize earnings
14 growth in lieu of dividend growth since it is earnings growth that makes higher dividends
15 possible. Mr. Wehner has utilized a higher dividend growth of 5.7%, whereas I used an
16 earnings growth factor of 5.18% as shown on exhibit AG-1.18.⁶⁹ The temporary higher
17 dividend growth rates used by Mr. Wehner may not be sustainable in the long-term, if they
18 are not reflective of long-term earnings growth.

⁶⁹ The Company’s 5.7% estimate reflects its peer group excluding OGE Energy, Pinnacle West and Portland General Electric which witness Wehner deemed as “not meaningful”.

1 Mr. Wehner’s unconventional approach in this area results in a higher ROE rate which the
2 Commission should reject.

3 **Capital Asset Pricing Model**

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

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

9
$$k_e = R_f + (B \times R_p)$$

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

11 R_f = the “risk free” rate of return

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

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

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

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

1 1.00. Utility stocks tend to move less than the overall market. Reflective of this outcome,
2 the average Beta of my Peer Group is 0.93.

3 **Q. PLEASE EXPLAIN EXHIBIT AG-1.19 SHOWING THE RESULTS OF THE**
4 **CAPM APPROACH.**

5 A. Exhibit AG-1.19 shows the results of the CAPM method based upon (1) a 3.95% risk-free
6 rate; (2) the Betas of the companies in the Peer Group taken from Value Line; and (3) the
7 7.17% historical Market Risk Premium (R_p) return from the years 1926 to 2022 developed
8 by Company witness Wehner in Exhibit A-14 (TAW-1), Schedule D-5, page 7, line 51.

9 Regarding the use of the 3.95% risk free rate, this is based on the S&P Global economic
10 projection provided by the Company through discovery, showing projected 10-year U.S.
11 Treasury rates in the fourth quarters of 2024 at 3.99%, 2025 at 3.45% and 2026 at 3.24%.⁷⁰

12 Based on these forecasted 10-year U.S. Treasury rates at different points in time at the
13 beginning and through the projected test year, I calculated a forecasted average rate of
14 3.66% for the projected test year. I also determined that the average spread differential
15 between the 10-year and 30-year U.S. Treasury bonds as of August 2024 was 29 basis
16 points.⁷¹ Adding this 29-basis point differential to the 3.66% projected 10-year U.S.
17 Treasury rate results in a 3.95% projected 30-year U.S. Treasury bond.⁷² This is the risk-

⁷⁰ Exhibit AG-1.27 includes discovery response AG-CE-403 showing these rates.

⁷¹ Per U.S. Treasury Department web site.

⁷² The determination of the 3.95% rate is shown in the footnotes to Exhibit AG-1.19.

1 free rate I used in my analysis for the calculation of the cost of equity capital under the
2 CAPM and Utility Risk Premium methodologies.

3 The result of my CAPM approach using the 6.63% adjusted risk premium (7.17% Risk
4 Premium x 0.93 Beta) plus the 3.95% risk-free rate equals a cost of equity capital of
5 10.58% for the proxy group average.

6 **Q. IS THE S&P GLOBAL PROJECTION OF FALLING INTEREST RATES**
7 **REFLECTED IN THE AUGUST 2024 REPORT CONSISTENT WITH MARKET**
8 **EXPECTATIONS AND THE PROJECTIONS BY ECONOMISTS?**

9 A. Yes. After maintaining a policy of higher interest rates during 2023 and most of 2024,
10 Federal Reserve Bank Chairman Jerome Powell indicated a shift in policy in his speech
11 on August 23, 2024. In that speech, he noted that his confidence has grown that inflation
12 is on a sustainable path back to 2 percent. He also made the following statement about the
13 direction of interest rates.

14 The time has come for policy to adjust. The direction of travel is clear, and the
15 timing and the pace of rate cuts will depend on incoming data, the evolving
16 outlook and the balance of risks. We will do everything we can to support a
17 strong labor market as we make further progress toward price stability.

18 Additionally, Morningstar, an investment research and analysis service firm, recently
19 published an article noting that their "...long-run expectation for the 10-year Treasury
20 yield is 2.75%, significantly below the current yield of 4.20% as of July 2024."⁷³

⁷³ Morningstar article "When Will the Fed Start Cutting Interest Rates" of July 17, 2024.

1 Furthermore, the 30-year U.S. Treasury rate declined from 4.50% in July 2024 to
2 approximately 4.06% in the first four days of September. This early September average
3 rate is only 11 basis points over the 3.95% rate I use in my analysis and the Federal Reserve
4 Bank has not even begun to cut interest rates.

5 In contrast, Mr. Wehner used a 4.53% 30-year U.S. Treasury for his risk-free rate. In
6 discovery, the Attorney General asked the Company to provide the basis for this rate. In
7 response, the Company could not provide clear explanation or a reference to an
8 independent source or basis for that rate.⁷⁴ The only hint about the 4.53% rate is on page
9 22 of Mr. Wehner’s direct testimony where he states that “...market expectations are for
10 interest rates to be higher for longer...” This expectation of “higher for longer” is no
11 longer valid given Federal Reserve Chairman Powell’s comments and financial market
12 projections for declining interest rates starting later in 2024 and into 2025.

13 Therefore, the 3.95% 30-year U.S. Treasury rate I have derived from S&P Global
14 forecasted U.S. Treasury interest rates is far more reasonable to use as the risk-free rate
15 for the projected test year ending February 2026.

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

17 A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios
18 of stocks. As such, it can be useful. However, the key issue with CAPM is that it assumes

⁷⁴ Exhibit AG-COC1 includes DR AG-CE-0283.

1 that the entire risk of a stock can be measured by the “Beta” component. As such, the only
2 risk to the investor is from fluctuations in the overall market. In actuality, investors take
3 into consideration company-specific factors in assessing the risk of each particular
4 security. Therefore, I give the CAPM approach less weight than the DCF approach in
5 determining the cost of common equity.

6 **Utility Risk Premium Approach**

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

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

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

13 A. Exhibit AG-1.20 shows the components required to derive a cost of common equity capital
14 for the peer companies on lines 3 and 4. The 5.65% on line 3 is the projected average rate
15 for utility bonds rated in the “A” and “BBB” categories and consists of (a) the 3.95% U.S.
16 Treasury rate discussed in my CAPM analysis above; and (b) the 1.70% average spread of
17 30-year utility bonds compared to 30-year U.S. Treasury rates. Both the 1.70% average
18 spread and the 5.65% rates are determined in footnote 2 of Exhibit AG-1.20.

1 To the 5.65% rate I added the average spread of 4.07% between the 30-year utility bonds
2 to 30-year U.S. Treasury bonds. This average spread rate was determined based on a
3 4.37% rate calculated by the Company in Exhibit A-35 (MRB-9), page 9, with two
4 adjustments I made to correct for data inconsistencies, as shown in the footnote in Exhibit
5 AG-1.20

6 The sum of the 4.07% rate and the bond rate of 5.71% results in the Risk Premium return
7 rate of 9.78% as shown in Exhibit AG-1.20.

8 **Q. HOW DO YOUR CAPM AND UTILITY RISK PREMIUM ROE RESULTS**
9 **COMPARE TO THE RESULTS PRESENTED BY COMPANY WITNESS**
10 **WEHNER?**

11 A. The results are shown in the table below.

	<u>CAPM</u>	<u>ECAPM</u>	<u>Utility Risk Prem.</u>
Attorney General ROE	10.58%	N/A	9.72%
12 Company ROE	12.51%	12.60%	10.62%

13 The large difference between my CAPM estimate and that of the Company is primarily
14 due to the Company's use of a forecasted risk premium based on flawed premises. The
15 ECAPM ROE rate proposed by Mr. Wehner is also flawed and inappropriate. I will
16 discuss these issues in more detail below.

1 The 90-basis points difference between the Company's Utility Risk Premium estimate and
2 my estimate is due to (a) the lower 58 basis points lower risk-free interest rate of 3.95% I
3 developed versus the inflated 4.53% rate used by the Company and (b) the 30-basis points
4 difference in the bond risk premium discussed above.

5 **Q. WHAT IS MR. WEHNER'S RATIONALE FOR THE USE OF A PROJECTED**
6 **RISK PREMIUM FOR DEVELOPMENT OF HIS CAPM AND ECAPM ROE**
7 **ESTIMATES?**

8 Mr. Wehner presents his CAPM estimate on Exhibit A-14 (TAW-1), page 2, which shows
9 a 12.51% ROE result using an 8.48% risk premium. This risk premium is approximately
10 131 basis points above the historical 1926 to 2022 long-term average of 7.17%. His
11 ECAPM estimate also utilizes the same 8.48% risk premium. Mr. Wehner discusses his
12 rationale for the use of his risk premium approach beginning on page 37 of his direct
13 testimony. On Exhibit A-14 (TAW-1), page 10, he shows the development of his
14 estimated Market Risk Premium (MRP) of 8.48% based on an expected market ROE of
15 13.01% less his assumed risk-free rate of 4.53%. I will point out that this risk premium
16 developed from Bloomberg earnings growth rates is based on estimates of growth over a
17 three-to-five-year period which is extremely short when compared to the 1926-2022
18 historical performance of the stock market.

1 **Q. WHY IS THE USE OF A SHORT PERIOD INAPPROPRIATE IN**
2 **CALCULATING THE RISK PREMIUM FACTOR?**

3 A. The use of a short time period to calculate the market risk premium does not take into
4 consideration the stock market returns and utility bond yields during both expansion and
5 contractions in the economy. To determine an appropriate expected market return and risk
6 premium, multiple economic cycles over a long timeframe must be considered. Otherwise,
7 the calculations of market risk premiums result in very high ROEs during periods of
8 economic expansion, as Mr. Wehner has done under his unconventional approach, and
9 much lower premiums during periods of economic declines.

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

13 Dr. Morin states the following:

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

21 Clearly, Mr. Wehner’s approach to calculating a projected MRP is not academically or
22 practically sound. As such, I view this alternative MRP development as unreliable and
23 merely an attempt to produce a result that is more favorable to the Company. The

1 Commission should give no weight to the Company’s CAPM and ECAPM ROE
2 calculation methods.

3 **Q PLEASE COMMENT ON MR. WEHNER’S USE OF THE ECAPM METHOD.**

4 The basic premise for the use of the ECAPM method is that the Beta factors published by
5 Value Line when used in CAPM analysis do not accurately predict stock performance.
6 However, this argument is flawed. Notwithstanding Mr. Wehner’s arguments, there is
7 academic disagreement with the validity of the original studies that led to the use of
8 ECAPM. First, the original study used raw betas and not the adjusted Value Line betas,
9 which I use, and other cost of capital experts normally rely upon. Second, the original
10 studies relied upon short-term risk-free rates. Instead, cost of capital witnesses, including
11 myself, who have been involved in the Company’s rate cases use long-term risk-free rates
12 in the CAPM model.

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

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

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

3 A. No. In response to a discovery request in Case No. U-18424, the Company stated that
4 ECAPM "... is supported by orders from regulatory bodies in Maryland, Mississippi and
5 Alberta..." As a result of this claim, the Company was asked to provide the specific rate
6 orders from these regulatory commissions.⁷⁵ The information provided in response to this
7 discovery request was less than convincing.

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

11 Regarding the Maryland commission, Company witness Maddipati pointed out on page
12 58 of his direct testimony in Case No. U-18424 that the Maryland Commission stated that
13 they found the DCF and ECAPM "helpful" in Case 9326. However, in a subsequent case
14 involving PEPCO (case 9418) with an order issued on November 15, 2016, the result is
15 different.

16 As shown in the summary positions articulated in the order in this case, no party involved
17 in the proceedings, other than the company, put forth an ECAPM ROE estimate. In this
18 case, the Maryland commission basically adopted the Staff's position with no ECAPM

⁷⁵ CECOs responses to U-18424 AG-CE-206 and AG-CE-386.

1 estimate and rounded down the Staff’s recommended ROE of 9.57% to 9.55%. In this
2 regard, the Commission stated on page 100 of the order the following. “*Our Decision*
3 *today most closely aligns with Staff’s recommendation of 9.57% although we do not*
4 *expressly reach the same conclusion as Staff. We find that a slightly lower ROE of 9.55%*
5 *is both adequate and appropriate for Pepco...*”

6 Furthermore, in its decision in case 9418, the Maryland commission expressed no position
7 on ECAPM. I am not aware of any more recent cases that show a change in the Maryland
8 commission’s view of the ECAPM methodology. Mr. Wehner’s testimony related to
9 Maryland PSC Staff reliance on ECAPM in an even earlier case (Case 9299 from 2012) is
10 irrelevant given the Maryland PSC decision in Case 9418.

11 Mr. Wehner also pointed to the Alberta Utilities Commission decision (Decision 20622-
12 D01-2016).⁷⁶ This decision dated October 7, 2016 results from a generic proceeding
13 regarding cost of capital for a number of utilities. The Alberta commission noted on page
14 45, paragraph 199 that the ECAPM “...*appears to be a model that could contribute to the*
15 *Commission’s determination of a fair allowed ROE...*” However, later in the same
16 paragraph, the commission noted the high degree of judgment required by the ECAPM
17 methodology and stated: “*Consequently, the Commission will not rely heavily on the*
18 *ECAPM results in this proceeding...*”

⁷⁶ Todd Wehner’s direct testimony at page 40.

1 On page 40 of his testimony in this rate case, Mr. Wehner also points to a case in Alaska
2 decided in 2002 where the Alaska Commission gave formal recognition to an adjustment
3 for ECAPM, but he presents no more recent information on the Alaska Commission's
4 views on this methodology. Also, he claims that the New York State Public Service
5 Commission uses a so-called "zero beta" CAPM model that supposedly is similar to the
6 ECAPM. While in a previous case he did provide a copy of a 2017 rate order noting the
7 use of zero beta CAPM, the continued use of this method is unsubstantiated, and the
8 method approved by the New York Commission is unknown.

9 The fact that other cost of capital practitioners representing utility companies have used
10 the ECAPM model in other cases to boost the proposed ROE rate does not mean that the
11 methodology has been endorsed by the regulatory commissions adjudicating those rate
12 cases.

13 In summary, the use of ECAPM is controversial and not widely accepted by state
14 regulatory commissions regulating gas and electric utilities. The Commission should
15 disregard the Company's ECAPM cost of equity estimate.

16 **Q. PLEASE COMMENT ON MR. WEHNER'S COMPARABLE EARNINGS**
17 **ANALYSIS.**

18 A. As shown on page 6 of Exhibit A-14 (TAW-1), Schedule D-5, Mr. Wehner derives a
19 11.22% projected average ROE rate based on the forecasted earnings divided by the book
20 value of common equity for his peer group.

1 Unfortunately, this is not an academically sound approach to determine the cost of
2 common equity for any company. What Mr. Wehner is doing is simply dividing (1) the
3 projected earnings per share (“EPS”) approximately three years from now for each peer
4 group company (as estimated by Value Line) by (2) the projected Book Value for each
5 such peer group company. This exercise perhaps has some use in evaluating how well
6 each peer group company employs capital over longer periods of time but is useless as a
7 tool to set the authorized ROE of a utility company. This method does not take into
8 account investors’ expectations or stock market parameters.

9 In summary, this approach appears to be another attempt to find a cost of capital
10 calculation method to fit a desired level of return on equity. My recommendation is that
11 the Commission should disregard this alternative method.

12 **Q. PLEASE DISCUSS THE RETURN ON EQUITY RATES OTHER REGULATORY**
13 **COMMISSIONS HAVE GRANTED IN 2022, 2023, AND MORE RECENTLY**
14 **DURING THE FIRST SIX MONTH OF 2024.**

15 A. Exhibit AG-1.21 shows the ROE rates granted by state regulatory commissions for U.S.
16 electric utilities in the twelve-month periods ending June 2023 and June 2024. The ROE
17 rates approved by regulatory commissions in electric cases has been on a steady decline
18 from over 12.70% in 1990 to approximately 9.60% during the 24 months ended June 2024.
19 The majority of the 44 ROE decisions in the twelve-month period ending in June 2023 and
20 50 decisions in the comparable 2024 period are at rates well below 9.9%, which is CEC’s

1 current authorized ROE rate. Pages 1 and 2 of the exhibit show the ROEs below 9.9%
2 and page 3 shows the ROEs at or above 9.9% which I mentioned above.

3 ROEs in California have been at or above 10% reflecting the unique challenges for utilities
4 in that state with wildfires and earthquakes. Other special situations with ROE rates above
5 10% include an isolated utility in Alaska with 17,000 customers and Georgia Power with
6 troubled nuclear power plant construction at the time of the decision. Dayton Power &
7 Light was granted a 10% ROE in 2023. However, 100% of this company's customers
8 may opt to select an alternative energy provider.⁷⁷ Two other cases involve Duke Energy
9 and its utilities in North Carolina and South Carolina with ROEs of 10.10% and 9.94%,
10 respectively. Both of these decisions involve multi-year rate agreements. However, the
11 North Carolina decision has been appealed by the North Carolina Attorney General and
12 other parties.⁷⁸ The South Carolina decision reflects a settlement agreement where the
13 company agreed to flow back to customers all unprotected deferred income taxes over two
14 years.⁷⁹

15 For most of the other electric utilities that have business and financial risks comparable to
16 Consumers Energy's operations, the ROE rates have averaged between 9.37% and 9.50%
17 in the past two years ending June 2024. Furthermore, it is noteworthy that the most recent
18 ROEs granted to peer group utilities averages to 9.50%. This evidence supports my

⁷⁷ AES 2023 Form 10-K, pages 25 and 26

⁷⁸ Duke Energy 2023 Form 10-K page 143

⁷⁹ Duke Energy Form 10-Q for the June 2024 period page 50.

1 proposed ROE rate of 9.80% as quite reasonable, if not favorable to the Company, and
2 suggests the Company's current ROE rate of 9.90% is excessive and "out of line" with
3 comparable electric utilities. The Company's proposed ROE rate of 10.25% is even further
4 removed from reality and clearly unsupportable.

5 **Q. IN THIS RATE CASE, MR. BLECKMAN SPONSORS EXHIBIT A-37 (MRB-11)**
6 **SHOWING THE ROE RATES AND COMMON EQUITY RATIOS OF SELECT**
7 **UTILITY COMPANIES. WHAT IS YOUR ASSESSMENT?**

8 A. Much of the information in Exhibit A-37 is incorrect, misleading, and does not provide a
9 proper context for the metrics noted in the exhibit. I will discuss the key problems with
10 the information presented by Mr. Bleckman.

11 First, with regard to Florida Power & Light, the 10.80% ROE was established by the
12 Florida Commission in 2021 as part of a multi-year agreement covering the years 2022 to
13 2025. Under this agreement, rate increases are capped, and any other relief would be
14 dependent upon extraordinary circumstances which would likely result in regulatory lag.
15 In addition, this Company's service territory is buffeted by hurricanes each year which can
16 disrupt electric service for prolonged periods and potentially reduce revenues and profits.
17 The ROE rates granted to Florida utilities is not applicable to Consumers Energy's electric
18 business.

19 Second, Alabama Power, a Southern Company subsidiary, is shown to have a 55%
20 Common Equity ratio and a 10.9% ROE. Actual common equity of this company at year

1 end 2023 was 52.4%. The utility may potentially increase its rates each year, but on a
2 rolling two-year basis, the increases are limited to no more than 8% (or 4% on average
3 annually). The increases are authorized under the company's Rate RSE (established before
4 2016) which is determined by considering the level of earned returns on equity and the
5 percentage of equity in the capital structure based on the company's Weighted Equity Cost
6 Rate (WECR).

7 In 2018, the Alabama Commission and the company agreed to a higher common equity
8 ratio of 55% by 2025 from 47% in December 2018. The change to Rate RSE for Alabama
9 Power was approved in May 2018 with no compensating rate increases and the company
10 at that time consented to a nominal reduction in the WECR with no annual Rate RSE
11 increases in 2019 and 2020. The last rate increase granted to the Company under Rate RSE
12 was implemented in 2021 and was \$228 million.⁸⁰ More recently, Alabama Power has
13 exceeded its 6.15% WECR threshold triggering refunds/book liabilities of \$181 million,
14 \$62 million, and \$15 million for the years 2021 to 2023. Similar to 2022 and 2023, the
15 Company indicates it will not receive an increase under Rate RSE in 2024.⁸¹ As such,
16 what is happening in this situation is that the Company is increasing the common equity
17 ratio gradually with no compensating increases in the WECR and limited rate relief. The
18 practical effect of these rate actions is to reflect recognition of a lower cost of common

⁸⁰ 2020 Southern Company Form 10-K, page II-152.

⁸¹ 2023 Southern Company Form 10-K, pages II-138 and II-139.

1 equity. This special rate and capital structure arrangement is not applicable to Consumers
2 Energy for purposes of establishing an appropriate ROE rate in this rate case.

3 Third, Exhibit A-37 includes Georgia Power, another Southern Company subsidiary, with
4 a 56% common equity ratio and an 10.50% authorized ROE. Georgia Power is a special
5 situation, involving significant expenditures for two nuclear power plants where (1) the
6 original contractor declared bankruptcy; and (2) the Company has been forced to write-off
7 approximately \$2.0 billion of cost overruns in 2021 and 2022; and (3) the Company has
8 only recently completed the two new nuclear units.⁸² The Georgia Commission has been
9 very supportive of this company through this troubled time in its history. The ROE and
10 capital structure for Georgia Power are not applicable to Consumers Energy given the
11 unusual circumstances.

12 Fourth, regarding WEC Energy, which owns gas and electric utilities in Wisconsin and
13 other jurisdictions, the 10.16% ROE shown in the exhibit is unsupported and faulty.
14 Recent decisions from the Wisconsin Commission in general rate cases have granted ROEs
15 of 9.80%. It appears that Mr. Bleckman may have boosted the ROE rate in his chart by
16 including Limited Issue Riders. These riders are not applicable to a general rate case and
17 not applicable to Consumers Energy in this proceeding.

18 Fifth, the information regarding IPL is inaccurate and misleading. Some of the electric
19 assets of IPL have 10% or higher ROEs, but these pertain to certain electric generating and

⁸² 2022 Southern Company Form 10-K, page II-147.

1 transmission assets. The authorized ROE and equity ratio for IPL's electric distribution
2 business are 9.5% and 51%, respectively.⁸³

3 Sixth, for UGI, all of this utility's recent general rate cases in 2020 through 2023 have
4 been settled without published rate metrics. So, the information shown in this exhibit is
5 stale or inapplicable.

6 In summary, Mr. Bleckman's attempt to support Mr. Wehner's inflated ROE
7 recommendation by pointing to select and inapplicable ROE rates granted to other utilities
8 fails to provide convincing evidence and should be rejected by the Commission.

9 **Q. ON PAGE 29, MR. WEHNER COVERS THE SUBJECT OF THE COMPANY**
10 **HAVING UNDER-EARNED ITS AUTHORIZED ROE IN THE YEARS 2019 TO**
11 **2022. WHAT IS YOUR VIEW ON THIS MATTER.**

12 A. The inability of the Company to earn its authorized ROE in past years due to abnormal
13 weather, adverse service restoration costs, or other factors is not a reason to approve a
14 higher ROE in this rate case. The Company is not guaranteed a return. It must earn it. If
15 the Company believes it is experiencing events that are impacting its earnings, then it needs
16 to address these issues in another part of this case or in separate proceedings.

17 In Exhibit A-172, Mr. Wehner relies upon an exhibit filed by Staff to try and make his
18 point. However, while the Staff exhibit shows the actual ROE rate earned in the electric

⁸³ Alliant Energy's 2023 Form 10-K, page 36.

1 business at 9.03% in 2021 and 8.90% in 2022, the Company actually earned an ROE of
2 9.75% in each of those years for the combined electric and gas businesses.⁸⁴ This total
3 return was near the authorized ROE rate in both businesses and shows that the Company
4 was able to offset the performance deficiency in the electric business with better earnings
5 in the gas business.

6 The Commission should not be swayed to authorize a higher ROE due to the Company's
7 inability to earn the authorized ROE rate in certain years.

8 **Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN**
9 **AUTHORIZED ROE OF 9.80% IN THIS CASE WILL LEAD TO IMPAIRMENT**
10 **OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?**

11 A. No. In recent general rate case proceedings, certain rate case applicants have raised
12 arguments that they should receive higher ROEs to ensure the financial soundness of the
13 business and to maintain its strong ability to attract capital in addition to being
14 compensated for risk.⁸⁵ Exhibit AG-1.21 shows several electric utilities that have
15 accessed the capital markets at competitive interest rates since receiving a ROE near or
16 below the average rate of 9.60%.

⁸⁴ Based upon Consumers Energy Form 10-K financial statements for 2022 and 2021. Net Income for Consumers Energy was \$943 million and \$866 million in the two respective years. Average common equity for the two years was \$9.7 billion and \$8.9 billion. Therefore, the Company's ROE results were approximately 9.75% in each year.

⁸⁵ For example, see page 5 of Mr. Wehner's direct testimony in this rate case.

1 Similarly, there is no evidence equity investors have abandoned utilities that have been
2 granted ROEs near or below the industry average. On the contrary, stock investors
3 continue to migrate to utility stocks, recognizing that authorized ROEs are still above the
4 true cost of equity. Exhibit AG-1.24 shows the market to book ratios for each of the peer
5 group companies, and many of these companies have received rate orders during the past
6 few years reflecting ROEs as low as 8.72%. Yet this group of companies has an average
7 Market to Book common equity value ratio of approximately 1.55 times, indicating that
8 investors' expectations of returns from utility stock investments are below the ROE book
9 return rate.

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

12 The fact that the Company needs to raise capital because of a large capital investment
13 program to upgrade its infrastructure and for other purposes is not unique to Consumers
14 Energy. Most electric utilities face the same issues and are able to raise capital with ROEs
15 at or near the 9.6% average rate. Therefore, this issue is another "red herring".

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

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

8 As a supporting point, in Exhibit AG-1.28, I have included a Value Line Funds article
9 written by Mitchell Appel, President of Value Line Funds. Mr. Appel states that volatility
10 is not risk. He also points out that volatility in 2017 was low by historical standards and
11 it was near normal levels in 2018. Mr. Appel goes on to say later in this article that
12 "...volatility is only risk if you act during down times, that is, only if you sell a stock."
13 This principle still applies to events in 2023 and 2024.

14 Additionally, I will submit that those who invest money in equity portfolios over longer
15 periods of time and particularly in utility stocks have an aversion to market volatility and
16 the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty
17 and volatility because they are not as susceptible to volatility as the general stock market.
18 This is reflected in the average Beta value of 0.93 of the utility peer group used in the
19 CAPM discussed earlier, in contrast with the general stock market value of 1. Therefore,
20 the Commission should not give any weight to arguments that the Company's ROE should
21 reflect investors' concerns with stock market volatility.

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

3 A. Yes. As shown on Exhibit A-35 (MRB-9) the market for new utility debt issues has been
4 very robust with over 200 new issues completed in 2023 and 80 new issues completed in
5 the first three months of 2024. Also, as can be seen from Exhibit AG-1.21, a large number
6 of utility companies issued new debt shortly after receiving a rate order with ROEs below
7 9.60%.

8 Consumers Energy issued \$600 million of long-term debt in January 2024 at an interest
9 rate of 4.60% and a 5-year term. Also, in August 2024, Consumers Energy issued \$700
10 million of debt at an interest rate of 4.7% debt with a maturity of approximately 5.5 years.⁸⁶
11 Accordingly, the debt markets are receptive to utility companies' capital raising activities.

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

15 A. In Exhibit AG-1.17, I have summarized the cost of equity rates from the three methods I
16 discussed above. The range of returns for the industry peer group is from 9.27% at the
17 low end, using the DCF approach and 10.58% at the high end using the CAPM approach.

⁸⁶ The January 2024 issuance is included on Exhibit A-14 (MRB-4), Schedule D2 and the August 2024 issuance was disclosed in DR AG-CE-272.

1 As explained earlier in my testimony, I give 50% weight to the DCF method as a more
2 reliable approach to estimating the cost of equity and 25% weight in each case to the
3 CAPM and Utility Risk Premium approach. In this regard, on line 4 of Exhibit AG-1.17,
4 I have calculated a weighted return on equity from the three methodologies of 9.71%,
5 which I have rounded up to a recommended ROE rate of 9.80%.

6 **Q. IS 9.80% A REASONABLE ROE RATE FOR THE PROJECTED TEST YEAR**
7 **FOR THE COMPANY’S ELECTRIC BUSINESS?**

8 A. Yes. As discussed above, the general expectation by economists and from the Federal
9 Reserve Bank is that interest rates will decline as early as the fourth quarter of 2024 and
10 through the Company’s project test year. This a material change in circumstances that the
11 Commission should take into account in lowering the Company’s current authorized ROE
12 rate from 9.90% to 9.80%.

13 In calculating the 9.80%, I used forecasted U.S. Treasury rates beginning in the fourth
14 quarter of 2024, which are likely overstated and not fully reflective of the actual interest
15 rates that may occur during the March 2025 to February 2026. As such, the proposed
16 9.80% ROE rate is very conservative, and the cost of equity capital could decline further
17 with lower interest rates during the projected test year. Therefore, I recommend that the
18 Commission set an authorized ROE rate in this rate case that is no higher than 9.80%

1 **Q. IF THE COMMISSION WERE TO APPROVE A 9.90% COST OF COMMON**
2 **EQUITY IN THIS CASE, AS IT DID IN CASE NO. U-21389, WHAT IS THE**
3 **ADDITIONAL COST TO CUSTOMERS COMPARED TO AN ROE OF 9.80%.**

4 A. If the Commission were to grant a 9.90% ROE in this case versus a 9.80% ROE, the
5 additional cost to customers is approximately \$8.9 million annually. There is absolutely
6 no need to burden customers with this additional cost.

7 I recommend that the Commission take note of the evidence and arguments I have
8 presented in my testimony and grant the Company a ROE of no more than 9.80%.

9 **VII. Working Capital**

10 **Q. THE COMPANY HAS PROPOSED \$3.187 BILLION OF WORKING CAPITAL IN**
11 **THIS CASE.⁸⁷ DO YOU AGREE WITH THIS LEVEL OF WORKING CAPITAL?**

12 A. No. I recommend four adjustments to the Working Capital for the projected test, which
13 total to \$44.3 million and reduce the forecasted amount to \$3.144 Billion. The first
14 adjustment reduces the Company's forecasted test-year cash level by \$27.0 million to
15 reflect a more representative average cash balance for the projected test year. The second
16 adjustment is an increase of \$7.7 million to the Company's Accrued Interest amount,
17 which decreases Working Capital. The third adjustment involves a \$6.2 million correction
18 decreasing the Company's Working Capital level related to the Pension/OPEB Volatility

⁸⁷ See Exhibit A-12 (JCA-34), Schedule B4

1 Mechanism. The fourth change is the exclusion of \$3.4 million of Deferred Regulatory
2 Asset related to the Company’s ownership of the Ludington Pumped Storage facility.

3 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY’S PROJECTED CASH**
4 **LEVEL INCLUDED IN WORKING CAPITAL?**

5 A. The requested \$45.6 million in average Cash balances to be included in Working Capital
6 is excessive and should be denied. This is the second consecutive rate case where the
7 Company has advocated for an increase in the average Cash balance to be included the
8 projected test year Working Capital amount.

9 In Case No. U-21224, the Company requested, and the Commission approved, a Cash
10 Balance for the 2023 projected test year of \$43.8 million. However, the actual result for
11 2023 shows that the Company’s actual average cash balance was \$18.6 million. In
12 discovery, the Attorney General asked the Company to explain why its Cash balance was
13 \$25.2 million less than the proposed amount. The Company responded that several factors
14 contributed to the lower Cash balance which included “...unfavorable weather in 2023, as
15 well as storm restoration activity well beyond the 5-year historic average...”⁸⁸

16 The reasons provided by the Company are not convincing. Unfavorable weather would
17 reduce accounts receivable, but the Company would still need to have the same cash on
18 hand to meet payment obligations. Similarly, higher storm restoration costs would

⁸⁸ Exhibit AG-1.29 includes DR AG-CE-0385.

1 increase the need for cash to pay higher expenses. As a result of the \$25.2 million lower
2 cash balance, the Company earned an excess return of \$1.8 million during 2023 on the
3 \$25.2 million of Cash it did not use and continued to earn an excess return in future months
4 until rates were reset in Case No. U-21389.

5 In Case No. U-21389 with a projected test year ending February 28, 2025, the Company
6 proposed an average Cash balance of \$53.7 million claiming that the historical 2022
7 average cash balance of \$20.2 million was too low.⁸⁹ The Commission approved the \$53.7
8 million despite the Attorney General’s recommendation that the Commission should have
9 approved at most \$30.4 million. Yet, we now discover that in the subsequent year of 2023,
10 the Company only needed \$18.6 million of Cash on hand. Similarly, in Case No. U-20963,
11 the Company proposed a Cash Balance of \$47.9 million for the 2022 projected test year
12 while the actual average Cash balance for that year turned out to be only \$20.2 million.

13 In approving the \$53.7 million in Cash balances in Working Capital in Case No. U-21389,
14 the Commission stated:

15 However, the Commission notes that while it finds that the circumstances described
16 by Consumers in this case constitute an abnormal disruption, the Commission will
17 continue to evaluate the facts and circumstances of each rate case to determine
18 whether deviation from the historical period is appropriate.⁹⁰

19 The Commission was prescient in this conclusion in its order in Case No. U-21389 and
20 will have an opportunity in this rate case to set a proper Cash balance. In the current rate

⁸⁹ Case No. U-21389, Mark Bleckman direct testimony at 47 and 48.

⁹⁰ Case No. U-21389, March 1, 2024 order at page 120.

1 case, the Company proposes that the average Cash balance of \$18.6 million in 2023
2 historical test year should be increased by \$27 million to \$45.6 million for the projected
3 test year ending February 28, 2026. The Company again relies on its “rule of thumb” that
4 the average Cash balance for the projected test year should be set at 1.0% of revenues. As
5 we have seen from Case Nos. U-21224 and U-20963, this theoretical balance of 1% of
6 revenues does not reflect the Company’s actual cash needs.

7 The Company’s request for a high cash balance in Case Nos. U-20963, U-21224, U-21389,
8 and again in this rate case simply increases working capital to earn a higher return on an
9 inflated rate base level. The Company has ample access to cash to meet its payment
10 obligations by using its short-term borrowing facilities. As shown on page 2 of Exhibit A-
11 14 (MRB-5), Schedule D-3, the Company has \$1.7 billion in short-term borrowing
12 facilities in place for which customers are paying \$10.7 million in annual fees. It is
13 unnecessary and exceedingly costly for the Company to have those borrowing facilities in
14 place and at the same time request to include higher cash balances in Working Capital for
15 the projected test year.

16 I will also point out that the Company invested excess cash in short-term investment
17 securities during 2023 earning an additional return over the excess return on higher rate
18 base discussed above. In response to discovery, the Company disclosed that it had in
19 excess of \$155 million of short-term cash investments during February to June 2023 on

1 which it earned \$4.0 million in interest income that it fully retained for the benefit of its
2 pre-tax bottom line.⁹¹

3 **Q. WHAT IS THE AVERAGE CASH BALANCE THAT YOU PROPOSE FOR THE**
4 **PROJECTED TEST YEAR?**

5 A. As discussed above, there is ample evidence that the \$45.6 million is Cash balance is
6 excessive and unnecessary to be included in Working Capital for the projected test year. I
7 recommend that the Commission set the average Case balance for the projected test year
8 at the actual amount of \$18.6 million. This is the amount that the Company demonstrated
9 it needed during the 2023 historical test year and in 2022. Therefore, the Commission
10 should remove \$27.0 million from the Company's projected Working Capital in this rate
11 case.

12 **Q. PLEASE EXPLAIN YOUR \$7.7 MILLION ADJUSTMENT TO ACCRUED**
13 **INTEREST INCLUDED IN WORKING CAPITAL.**

14 A. As the Company's rate base increases from year to year, the amount of debt capital to
15 finance the higher capital additions to rate base increases and the accrued interest to be
16 paid on the higher debt balance also increases. In this rate case, the rate base amount
17 proposed by the Company is increasing from \$13.9 billion in the 2023 historical test year
18 to \$15.6 billion in the projected test year, which is a 12.3% increase.

⁹¹ Exhibit AG-1.29 includes DR AG-CE-0385 with attachment.

1 The Company did not adjust the historical Accrued Interest balance for the projected test
2 year to take into consideration the higher interest it will need to pay on the higher debt
3 outstanding during the projected test year. It is natural for this balance sheet item to
4 increase over time as rate base and debt increases. The Accrued Interest balance in the
5 historical 2023 period was \$62.5 million and a 12.3% increase equals to \$7.7 million in
6 additional interest during the projected test year.

7 **Q. DID THE COMPANY EXPLAIN WHY IT DID NOT INCREASE THE ACCRUED**
8 **INTEREST LIABILITY ACCOUNT FOR THE PROJECTED TEST YEAR?**

9 A. Yes. In response to discovery, the Company admitted that working capital accounts (both
10 assets and liabilities) are subject to change as it projects items in the test year in rate cases.
11 However, it claims that it has been a long-standing practice approved by the Commission
12 for the Company to make minimal adjustments for known, measurable, and material
13 changes.⁹²

14 There are two problems with the Company's position. First, there is no Commission
15 approved practice or limitations as to the adjustments that should be made to historical
16 working capital accounts in forecasting working capital for the projected test year. Second,
17 using the Company's criteria of known, measurable, and material changes, the Accrued
18 Interest account meets those criteria. The increase in debt is known and measurable based

⁹² Id. includes DR AG-CE-0384.

1 on the increase in rate case and the \$7.7 million calculated above is certainly a material
2 amount.

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

4 A. The Company's debt level will rise commensurate with the increase in the electric business
5 rate base. The 12.3% rate of increase I calculated is reasonable given that the amount of
6 debt in the capital structure shown in Schedule D-1 in Exhibit A-4 and Exhibit A-14
7 between 2023 and the projected test year for total company also increases by 18% over
8 that timeframe.

9 Therefore, I recommend that the Commission increase the Accrued Interest liability
10 balance and decreases Working Capital by \$7.7 million.

11 **Q. EXPLAIN YOUR ADJUSTMENT RELATED TO THE PENSION/OPEB**
12 **VOLATILITY MECHANISM.**

13 A. On Exhibit A-12 (JCA-35) Schedule B-4(a), the Company shows in column (j) an increase
14 in assets of \$6.2 million and increase in liabilities of \$8.4 million for the Pension and
15 OPEB Volatility Mechanism, which produces a net decrease in Working Capital of \$2.2
16 million. In response to discovery, the Company confirmed that its calculations were
17 incorrect in this area.⁹³ The Company also confirmed that the correct balances in the

⁹³ Discovery Response AG-CE-400.

1 projected test year should reflect a liability of \$19.5 million for the pension plan and an
2 asset of \$17.1 million for the OPEB plan.

3 These balances less the 2023 average balances of \$5.7 million for pension and \$11.7
4 million for OPEB result in (a) a net liability increase for the pension portion of \$13.8
5 million; and (b) a net asset increase for OPEB of \$5.4 million. These are the amounts that
6 the Company should have included in Exhibit A-12, Schedule B-4a, in column (j). Netting
7 these two changes together results in a Working Capital decrease of \$8.4 million. The
8 Company had calculated a Working Capital decrease of \$2.2 million. Accordingly, an
9 additional decrease should be reflected in Working Capital of \$6.2 million (\$8.4 million
10 less \$2.2 million).

11 The Commission should reduce Working Capital by \$6.2 million to correct the Company's
12 calculated amounts.

13 **Q. PLEASE EXPLAIN THE REMOVAL OF THE \$3.4 MILLION REGULATORY**
14 **ASSET FROM WORKING CAPITAL RELATED TO THE COMPANY'S**
15 **JOINTLY OWNED LUDINGTON PUMPED STORAGE FACILITY.**

16 A. Based on a Commission order in Case U-21310, the Company has been deferring certain
17 costs and the estimated liquidated damages pertaining to defective work by Toshiba at the
18 Ludington generating facility. The net amount of the costs and liquidated damages
19 deferred by the Company and included in a regulatory asset by the Company was
20 \$4,153,000 in 2023. In response to discovery, the Company provided the forecasted costs

1 net of any liquidated damages of \$3,402,000 as of the end of the February 2026 projected
2 test year.⁹⁴

3 The costs pertaining to the power outages, liquidated damages and other costs pertaining
4 to Toshiba work problems at the Ludington facility have been a matter of litigation in
5 several Power Supply Cost Recovery cases. The Attorney General and other parties to the
6 proceedings have taken different positions than the Company as to whether CECo should
7 be responsible to absorb the cost of replacement power from multiple and extended power
8 outages at the plant and how liquidated damages should be apportioned to offset
9 replacement power costs and other costs incurred by the Company. The unsettled dispute
10 and uncertainty as to how much the Company will eventually be allowed to recover, if
11 any, of the deferred amount will eventually be determined when the Commission rules on
12 the appropriate amount to recover in rates.

13 Therefore, I recommend that the Commission remove the \$3.4 million deferred amount
14 from Working Capital in this case. Once the Commission decides the appropriate amount
15 of deferred costs that the Company should be allowed to recover, if any, the appropriate
16 return can be calculated and included with the deferred amount for the period of time that
17 the recoverable portions of the net costs were outstanding.

⁹⁴ Exhibit AG-1.30 includes DR AG-CE-388

1 **Q. WHAT IS THE TOTAL ADJUSTMENT TO WORKING CAPITAL THAT YOU**
2 **RECOMMEND?**

3 A. In summary, the four items discussed above reduce Working Capital by \$44.3 million.
4 The Commission should incorporate these changes into its determination of rate base for
5 the projected test year.

6 **VIII. 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. In Exhibit A-13 (JCA-41), Schedule C-5, the Company shows forecasted O&M expenses
10 of \$675.0 million for the projected test year, which is a decrease of \$19.1 million from the
11 2023 historical year. The decrease primarily reflects substantial expense reductions in four
12 areas (a) \$54.4 million in service restoration costs, (b) \$20.1 million lower forecasted
13 pension and OPEB expenses, (c) \$7.0 million in lower electric generation expense due to
14 retirement of coal plants, and (d) \$5.3 million from lower billing and payment expenses.
15 These expense reductions of \$86.7 million are partially offset by \$67.1 million of cost
16 increases from inflationary adjustments for higher expenses in electric distribution and
17 other areas.

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

1 A. Yes. I have analyzed O&M expenses by major department or area, and I have identified
2 more appropriate and reasonable expense levels that the Commission should consider. In
3 my testimony below, I will recommend that forecasted O&M expenses should be reduced
4 by \$48.0 million. Exhibit AG-1.31 shows a summary of my proposed O&M expense
5 adjustments.

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

7 **Q. HAVE YOU MADE ANY REDUCTIONS TO THE INFLATION INCREASE**
8 **ADJUSTMENTS TO O&M EXPENSES PROPOSED BY THE COMPANY IN**
9 **THIS RATE CASE?**

10 A. No. Where in prior rate cases, the Company proposed to use a different forecasted rate for
11 annual employee salary/merit increases, in this rate case, it proposed to use a rate of
12 increase equal to the CPI forecasted inflation rate.

13 I agree with the Company's use of CPI increases of 2.4% for 2024, and 2.2% for 2025 and
14 2026.

15 **B. Electric Distribution**

16 **Q. WHAT ADJUSTMENTS DID THE COMPANY MAKE TO ITS ELECTRIC**
17 **DISTRIBUTION EXPENSES FROM THE HISTORICAL TEST YEAR TO THE**
18 **PROJECTED TEST YEAR?**

1 A. As shown on line 75 of Exhibit A-106 (MPK-14), Distribution Operations expense was
2 \$276.7 million in 2023 and the Company is forecasting expenses of \$279.9 million for the
3 projected test year. In this exhibit, the Company also shows the historical expense by sub-
4 program for the five years from 2019 to 2023 and the average expense amount during this
5 period. Excluding Service Restoration Costs, the Company forecasted total Distribution
6 O&M expenses to increase from \$88.7 million in 2023 to \$146.4 million in the projected
7 test year, which is a 65% increase. Much of these requested increases are for additional
8 inspections and maintenance of lines and facilities that seemingly require the hiring of
9 additional employees and/or contractors, emanating from the Company's Reliability
10 Roadmap.

11 In his direct testimony, Mr. Kelly explains the projected test year expenses in broad
12 statements with very few specifics. His direct testimony lacks a robust discussion of new
13 work activities, increases in work units to be completed, or specific dollar amounts of
14 expenses that are increasing from either 2023 or from the five-year average amount.
15 Although on occasion he provides forecasted work units and components of programs,
16 there is no comparison to historical quantities or activities to justify increases in costs. The
17 result is that there is very little quantifiable support for some of the increases in expenses
18 at the program or sub-program level.

19 In my testimony below, I will address the increases in expense in some of the programs
20 listed in Exhibit A-106 (MPK-14), including the Service Restoration expense forecasted
21 by the Company for the projected test year, which is sponsored by Company witness

1 Andrew Snider. Exhibit AG-1.32 summarizes the adjustments I propose for Distribution
2 expenses totaling \$32.3 million.

3 **1. Service Restoration Expense**

4 **Q. THE COMPANY PROPOSES SERVICE RESTORATION O&M EXPENSES OF**
5 **\$133.5 MILLION IN THE PROJECTED TEST YEAR. DO YOU AGREE WITH**
6 **THIS LEVEL OF EXPENSE?**

7 A. No. On line 22 of Exhibit A-106 (MPK-14), the Company shows service restoration
8 expense of \$188,041,000 for 2023, \$126,072,000 for the 5-year average, and \$133,500,000
9 for the projected test year ending February 2026. According to the direct testimony of
10 Company witness Andrew Snider, beginning on page 3, the Company determined the
11 projected test year expense amount based on the average expense amount over the five
12 years from 2019 and 2023, and adjusted the result for inflation and the beneficial impact
13 of its aggressive tree trimming program. The Company also proposes a “Service
14 Restoration Cost Sharing Mechanism”. This is a cost deferral and recovery/refund
15 mechanism, which I will discuss later in a separate section of my testimony.

16 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY’S FORECASTED**
17 **RESTORATION EXPENSE FOR THE PROJECTED TEST YEAR?**

1 A. In his testimony, Mr. Snider states that service restoration costs can vary significantly from
2 year to year due to weather events. In the most recent five years, from 2019 to 2023,
3 restoration costs have ranged from \$71.3 million to \$188.0 million.⁹⁵

4 The unpredictable nature of these costs reflects changes in weather (wind and ice) from
5 year to year and the impact of these factors on the Company's costs. To establish a
6 reasonable level of service restoration costs for the projected test year, I used a five-year
7 average of actual expenses from 2019 to 2023 sourced from Exhibit A-106 and as shown
8 on line 1 of Exhibit AG-1.33. This long period of time will smooth the volatility in costs
9 that can occur over a shorter period of time. The resulting amount is \$124,872,000 before
10 any adjustments for future expected inflation and other items. Given the variability of
11 restoration costs, the use of a five-year average is a reasonable approach.

12 **Q. WHAT PROBLEM DO YOU SEE IN MR. SNIDER'S PROPOSED FIVE-YEAR**
13 **AVERAGE AMOUNT FOR SERVICE RESTORATION COSTS?**

14 A. The key problem is that Mr. Snider shows higher Service Restoration costs in the table in
15 Figure 2 on page 5 of his direct testimony than are shown on line 22 of Exhibit A-106
16 (MPK-14). A comparison is shown below.

⁹⁵ Exhibit A-106 (MPK-14) line 22.

Service Restoration Expense (\$ Millions)

<u>Year</u>	Snider <u>Testimony (p. 5)</u>	<u>Exhibit A-106</u>
2019	\$ 92.1	\$ 92.1
2020	75.1	71.3
2021	168.9	159.7
2022	113.3	113.3
2023	188.0	188.0
5 Yr. Avg. Actual	<u>\$ 127.5</u>	<u>\$ 124.9</u>
5 Yr. Avg. Adjusted*	<u>\$ 133.5</u>	<u>\$ 130.7</u>

* Reflects inflation and Forrestry Savings of \$0.5 million

1

2

As discussed on page 6 of his direct testimony, Mr. Snider excludes insurance recoveries received in 2020 and 2021 from his calculation, which reduced service restoration costs.

3

4

In my calculations of the forecasted service restoration expense for the projected test year, I used the actual historical expense amounts from Exhibit A-106, which include the insurance recoveries.

5

6

7

In the Company’s last rate case (Case No. U-21389) the Commission considered the issue of whether insurance costs should be included in the calculation of the service restoration five-year cost average. On page 170 of its March 1, 2024 order, the Commission stated “The Commission agrees with the Attorney General that any insurance proceeds and voluntary refund mechanism credits received by Consumers from 2018-2022 should be included in the five-year average of actual service restoration O&M expense.”

8

9

10

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12

1 Witness Snider raises no new arguments in his testimony in this case that should change
2 the Commission’s decision in Case No. U-21389.

3 **Q. IS THERE AN ADDITIONAL ADJUSTMENT THAT YOU PROPOSE TO THE**
4 **CALCULATION OF SERVICE RESTORATION COSTS FOR THE PROJECTED**
5 **TEST YEAR?**

6 A. Yes. On page 7 of his direct testimony, Mr. Snider discusses an adjustment to service
7 restoration costs from the Company’s forestry management program and in Figure 3 shows
8 an adjustment of \$ 506,000 for the projected test year. Mr. Snider has included this amount
9 as reduction to his calculated service restoration costs for the projected test year.

10 In discovery, the Attorney General asked the Company to provide the underlying
11 calculations and assumptions used to arrive at the cost savings. The information provided
12 in response to the discovery request shows that the Company is assuming only minimal
13 reductions of less than 2% in power outages beginning with 2024 and into future years
14 from the Company’s increased spending in forestry management. Furthermore, the
15 Company could not provide the basis on which it estimated that low rate of decline.⁹⁶ The
16 tree-related power outage data provided by the Company shows that those outages have
17 declined from 11,247 in 2019 to 8,489 in 2023. This represents an average rate of decline
18 of 2.38% over the five-year period. By using this rate of decline, supported by actual data,

⁹⁶ Exhibit AG-1.36 includes DR AG-CE-0518.

1 I calculated a service restoration cost savings benefit of \$1,280,000, which is \$774,000
2 higher than the Company's calculated amount. Exhibit AG-1.35 shows the calculations.

3 After including this adjustment, the appropriate service restoration expense for the
4 projected test year is \$129,882,000. This amount is \$3,618,000 lower than the Company's
5 forecasted amount. Therefore, I recommend that the Commission reduce the Company's
6 O&M expense for the projected test year by \$3,618,000, as shown on Exhibit AG-1.33.

7 **2. Staking and Locating**

8 **Q. THE COMPANY PROPOSES \$6.9 MILLION FOR ITS STAKING AND**
9 **LOCATING PROGRAM. WHAT IS YOUR ASSESSMENT?**

10 A. The forecasted rate of growth for staking requests is too high and needs to be reduced. In
11 his calculations to determine the Staking and Locating expense for the projected test year,
12 Mr. Kelly used a 5% annual growth rate. He used the same assumption in Case No. U-
13 21389.⁹⁷ The basis for the 5% growth rate is MISS DIG statistics which are compiled on
14 a state-wide basis, as shown on page 128 of Mr. Kelly's testimony.

15 However, using the staking requests received only by Consumers Energy the average
16 annual rate of growth over the 2018 to 2023 period has only been 2.5%. Exhibit AG-1.34
17 shows the source data and calculations. The use of the 5% growth rate by the Company

⁹⁷ Michael Kelly direct testimony at page 127, line 11. See also Mr. Kelly's direct testimony in Case U-21389 at page 86, line 6.

1 dates back to at least Case No. U-21224. In that case, Company witness Blumenstock
2 used the same 5% assumption and projected 455,000 staking orders related to 2023.⁹⁸
3 However, the actual 2023 results were approximately 415,000 orders, or 40,000 fewer than
4 projected. The 5% growth rate is stale and inappropriate.

5 **Q. WHAT CHANGE TO THE COMPANY'S STAKING AND LOCATING O&M**
6 **EXPENSE FORECAST DO YOU RECOMMEND DUE TO THE LOWER**
7 **GROWTH RATE?**

8 A. In Exhibit AG-1.34, I calculated a lower expense amount based on 14,549 fewer staking
9 orders, which is the difference between 440,468 forecasted staking using the 2.75% growth
10 rate and the Company's forecast of 455,017 order. By multiplying the 14,549 orders by
11 the \$13.74 cost per order, I calculated a lower forecasted expense of \$200,000 for the
12 projected test year.

13 The Commission should reduce the Company's O&M by \$0.2 million to take into account
14 the lower growth rate in staking and locating orders.

⁹⁸ See Blumenstock testimony, pages 217 and 218 in Case U-21224.

1 **3. Lines Reliability LVD and HVD**

2 **Q. EXHIBIT A-106 (MPK-14), LINE 4, SHOWS LVD LINES RELIABILITY O&M**
3 **EXPENSE INCREASING FROM \$0.7 MILLION IN 2023 TO \$30.2 MILLION IN**
4 **THE PROJECTED TEST YEAR. WHAT IS YOUR ASSESSMENT?**

5 A. The dramatic escalation in O&M expense for LVD Lines Reliability is excessive and
6 should be reduced. As shown on line 4 Exhibit 106, the largest expense amount incurred
7 in this area in the last five years was \$1.1 million in 2022. In response to discovery the
8 Company admitted that it has not followed IEEE recommendations and best practices for
9 inspection and maintenance.⁹⁹ It is not reasonable for the Company to undertake a 30-fold
10 escalation in expense in less than two years to reverse past poor practices.

11 On page 110 of his direct testimony, Mr. Kelly discusses the components of the \$30.2
12 million proposed expense for the projected test year. I will address the major items. For
13 Pole Inspections, the Company proposed to spend \$9.7 million per year by moving to a
14 12-year inspection cycle. Although, a 12-year cycle maybe an improvement in identifying
15 failing poles, reaching that level of performance should be more gradual. I recommend
16 spending only half that amount in the projected test year and increasing it further in the
17 subsequent year. Therefore, I recommend that the Commission remove \$4,850,000 of
18 O&M expense from the projected test year.

⁹⁹ Exhibit AG-1.37 includes DR AG-CE-0430.

1 For Switch Inspections, the Company now wants to spend \$8.0 million in the projected
2 test year when in the past it had only performed minimal visual inspections.¹⁰⁰ Similar to
3 pole inspections, I recommend that the Company reduce spending in this area by half in
4 the projected test year and increase it more in subsequent years to reach the stated
5 inspection cycle. Therefore, I recommend that the Commission remove \$4.0 million of
6 O&M expense for the projected test year.

7 For Metro Inspections, the Company did not perform any inspections from 2021 to 2023.
8 The sudden ramp-up to \$2 million for the projected test year should also be reduced for
9 the same reasons discussed for the other two spending categories. I recommend that the
10 Commission remove \$1.0 million for this program from O&M expense for the projected
11 test year.

12 For Grid Modernization, the Company proposes to spend an additional \$3.0 million for
13 the projected test year, which brings the total forecasted amount to \$4,322,000 according
14 to line 60 of Exhibit A-106. The Company spent nothing in 2021, \$1,959,000 in 2022,
15 and \$1,115,000 in 2023. These costs for planning projects should also be reduced. The
16 average amount spent for the past two years was \$1,537,000. After adjusting for inflation,
17 the forecasted cost of the projected test year should be \$1,609,000. This amount is
18 \$2,713,000 lower than the expense forecasted by the Company. I recommend that the
19 Commission remove this amount from the Company's forecasted O&M expense.

¹⁰⁰ Id.

1 Therefore, in total for the LVD Lines Reliability subprogram, I recommend that the
2 Commission remove \$12,563,000 from the Company’s forecasted O&M expense for the
3 projected test year.

4 **Q. EXHIBIT A-106 (MPK-14) ON LINE 5 SHOWS HVD LINES RELIABILITY**
5 **INCREASING FROM \$261,000 TO \$2,331,000 IN THE PROJECTED TEST YEAR.**
6 **DO YOU AGREE WITH O&M EXPENSE INCREASE?**

7 A. In discovery, the Attorney General asked the Company about the increase in O&M
8 expense for HVD Lines Reliability. In the response, the Company stated that there are no
9 changes to inspection cycles and disclosed that the requested increase was incorrect due to
10 worksheet error. It stated that the projected test year O&M level should be \$116,000 or
11 \$2.2 million lower than the amount shown on Exhibit A-106.¹⁰¹

12 In the discovery response, the Company also stated that the \$2.2 million of expense should
13 be attributed to HVD Lines Demand on line 9 of Exhibit A-106 (MPK-14). However, Mr.
14 Kelly’s testimony on page 119 does not support a \$2.2 million increase in O&M expense
15 for HVD Lines Demand.

16 Therefore, I recommend that the Commission remove \$2.2 million from the Company’s
17 forecasted O&M expense for the projected test year.

¹⁰¹ Exhibit AG-1.38 includes DR AG-CE-431.

1 **4. Substation Reliability – HVD**

2 **Q. THE COMPANY’S O&M EXPENSE FOR SUBSTATION RELIABILITY – HVD**
3 **IS INCREASING FROM \$2.2 MILLION TO \$3.6 MILLION BETWEEN 2023 AND**
4 **THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE PROJECTED**
5 **INCREASE OF \$1.4 MILLION?**

6 A. No. In discovery, the Attorney General asked the Company about this expense increase
7 and requested information regarding the frequency of inspections and the Company’s
8 practices in 2023 and in the projected test year. In its response, the Company stated that
9 the current frequency of inspections is not changing between 2023 and the projected test
10 year but failed to address the part of the question related to work practices.¹⁰² Also, Mr.
11 Kelly’s testimony on pages 117 to 118 is far too general to discern why additional expenses
12 beyond inflation are required in this area. On page 117 of his testimony, he noted that
13 O&M expense in this area was increased by \$1.4 million above the inflation adjustment
14 but provided no additional support.

15 Given the lack of support, I recommend that the Commission remove \$1.4 million from
16 the Company’s forecasted O&M expense.

¹⁰² Id. includes DR AG-CE-432, part (b).

1 **5. Substation Demand LVD and HVD**

2 **Q. FOR THE PROJECTED TEST YEAR, THE COMPANY FORECASTED AN**
3 **INCREASE OF MORE THAN 100% IN THE O&M EXPENSE FOR LVD AND**
4 **HVD SUBSTATION DEMAND. WHAT IS YOUR ASSESSMENT OF THESE**
5 **INCREASED SPENDING LEVELS?**

6 A. The Company's forecasted increases beyond inflation for Substations Demand LVD is
7 \$5.245 million and for Substations Demand HVD is \$4.332 million. In each case, the
8 forecasted increases are more than 100% of the 2023 O&M expense amounts shown on
9 line 10 and 11 of Exhibit A-106. As discussed on page 119 of Mr. Kelly's direct testimony,
10 the work to be performed by the Company in this area is for emergent and unplanned
11 activities resulting from equipment failures.

12 In response to discovery, the Company tries to justify the increase in forecasted O&M
13 expense by claiming that by moving to monthly from bi-monthly inspections there will be
14 an increase in maintenance activity.¹⁰³ This claim has no sound basis. Monthly
15 inspections would not discover more issues to be addressed, they would discover problems
16 sooner before they become perhaps more severe. The result should be lower maintenance
17 and repair costs not more.

¹⁰³ Id. includes DR AG-CE-0433.

1 Given the variability in expense from year to year, the average expense amount during the
2 most recent three-years adjusted for inflation should be sufficient to address unplanned
3 and emergent activities during the projected test year. For LVD facilities, the three-year
4 historical expense was \$3,931,000.¹⁰⁴ Adjusted for inflation, the expense for the projected
5 test year is \$4,129,000.¹⁰⁵ This amount is \$5,308,000 lower than the \$9,437,000 forecasted
6 by the Company.

7 For HVD facilities, the three-year historical expense was \$3,176,000.¹⁰⁶ Adjusted for
8 inflation, the expense for the projected test year is \$3,336,000.¹⁰⁷ This amount is
9 \$4,467,000 lower than the \$7,803,000 forecasted by the Company.

10 I recommend that in total for LVD and HVD Substation Demand the Commission remove
11 \$ 9,775.000 from the Company's forecasted O&M expense for the projected test year.

12 **6. Underground Workforce**

13 **Q. THE COMPANY FORECASTED \$2.5 MILLION FOR TRAINING EMPLOYEES**
14 **TO PERFORM UNDERGROUNDING OF OVERHEAD LINES. WHAT IS YOUR**
15 **ASSESSMENT?**

¹⁰⁴ Exhibit A-106, line 10.

¹⁰⁵ $\$3,931,000 \times 1.024 \times 1.022 \times 1.00367 = \$4,129,000$.

¹⁰⁶ Exhibit A-106, line 11.

¹⁰⁷ $\$3,176,000 \times 1.024 \times 1.022 \times 1.00367 = \$3,336,000$.

1 A. On page 143 of his testimony, Mr. Kelly discusses forecasting of incremental O&M
2 expenses for the Underground Workforce program. The amount of expense forecasted for
3 the projected test year is \$2,517,000.¹⁰⁸ For 2023, the actual expense was \$327,000.

4 In discovery, the Attorney General asked the Company to explain this expense. In
5 response, the Company stated that the forecasted expense was for training employees
6 assigned to the Underground Workforce.¹⁰⁹ As discussed in the Capital Expenditures
7 section of my testimony, the Commission only approved a limited pilot for
8 undergrounding of overhead lines for the 12 months ending February 2025. My
9 recommendation to the Commission is that the expanded undergrounding program
10 proposed by the Company should be rejected as premature. Therefore, any additional
11 O&M expenses for training a larger workforce should also be rejected.

12 Furthermore, the Company or its contractors are already knowledgeable with
13 undergrounding electrical lines because nearly all new housing subdivisions and many
14 other installations entail burying electrical lines underground. Therefore, the Company
15 should already have trained employees or contractors that can perform this work for the
16 pilot and any future expansions approved by the Commission.

17 I recommend that the Commission remove \$2,517,000 from the Company's forecasted
18 O&M expense for the projected test year.

¹⁰⁸ Exhibit A-106, line 32.

¹⁰⁹ Exhibit AG-1.39 includes DR AG-CE-0438.

1 **C. Generation Base O&M Expense**

2 **Q. THE COMPANY FORECASTED \$78.1 MILLION OF BASE O&M EXPENSE**
3 **FOR THE POWER GENERATION AREA. DO YOU AGREE WITH THIS**
4 **LEVEL FOR THE PROJECTED TEST YEAR?**

5 A. No. Exhibit A-43 (RTB-4) shows Generation Base O&M expense of \$93.9 million for
6 2023 and \$78.1 million for the projected test year. Although the projected test year shows
7 a decline of \$15.8 million from 2023, the retirement of coal plants has a significant impact
8 on this decline, and it is necessary to ascertain that the decrease in costs is fully reflected
9 in the projected test year along with adjustments to other power plants.

10 In discovery, the Attorney General asked the Company to provide a breakdown of Base
11 O&M expense by power plant for each year from 2021 through the projected test year.¹¹⁰
12 In reviewing the expense data provided by the Company, I identified two adjustments that
13 reduce O&M expense for the projected test year.

14 The first adjustment pertains to the Croton hydro plant. The Company forecasted O&M
15 expense for the projected test year of \$3,055,000. However, over the most recent historical
16 three years, the average O&M expense for this plant was \$1,664,000. No basis or support
17 was provided by the Company for nearly a tripling of the expense. Based on the historical
18 expense of \$1,664,000 and after adjusting it for inflation through the end of the projected

¹¹⁰ Exhibit AG-1.40 includes DR AG-CE-0519 with ATT 1.

1 test year I forecast an expense amount of \$1,747,000. This amount is \$1,308,000 lower
2 than the Company's forecast of \$3,055,000. I recommend that the Commission remove
3 the \$1,308,000 from the Company's forecasted O&M expense for the projected test year.

4 The second adjustment pertains to the Karn plant. The Company shutdown Karn Units 1
5 and 2 at the end of May 2023. Therefore, during 2023, the plant had five months of
6 operations for Karn 1 and 2 and 12 months of operation for Karn Units 3 and 4. Karn 1
7 and 2 were coal plants and Karn 3&4 are natural gas-fueled plants. The historical expense
8 information provided by the Company shows that during 2021 and 2022 the entire Karn
9 plant had average O&M expense of \$26,761,000. For the year 2023 with only partial
10 operation of Karn 1 and 2, the Company reported \$16,554,000 in O&M expense for the
11 Karn plant, which is a decline of \$10,207,000 from the average expense from the prior two
12 years. This decline can be attributed to Karn 1 and 2 operating for less than six months.
13 By annualizing the \$10,207,000, we should expect a decrease of \$20,414,000
14 (\$10,207,000 x 2) in the annual expense for the Karn plant.

15 Using the average O&M expense of \$26,761,000 from 2021 and 2022 as a benchmark and
16 reducing that expense by the annualized Karn 1 and 2 expense reduction of \$20,414,000,
17 the remaining expense for Karn 3 and 4 for 2024, 2025 and the projected test year should
18 be \$6,347,000 before inflation and \$6,666,000 after inflation.¹¹¹ This amount is
19 \$3,745,000 lower than the \$10,411,000 that the Company forecasted for the Karn plant

¹¹¹ $\$26,761,000 - \$20,414,000 = \$6,347,000 \times 1.024 \times 1.022 \times 1.00367 = \$6,666,000.$

1 expense for the projected test year. The Company's forecasted expense is overstated and
2 should be adjusted. I recommend that the Commission remove \$3,745,000 from the
3 Company's forecasted O&M expense for the projected test year.

4 In total, for Power Generation O&M expense, I recommend that the Commission remove
5 \$5,053,000 from the projected test year O&M expense.

6 **D. Customer Interactions**

7 **Q. THE COMPANY FORECASTED THAT O&M EXPENSE FOR CUSTOMER**
8 **INTERACTIONS WILL INCREASE FROM \$24.1 MILLION IN 2023 TO \$25.4**
9 **MILLION IN THE PROJECTED TEST YEAR. DO YOU AGREE WITH THE**
10 **HIGHER EXPENSE LEVEL?**

11 A. No. On line 9 of Exhibit A-13 (JCA-41), Schedule C-5, the Company shows an increase
12 in O&M expense for Customer Interactions from \$24.1 million in 2023 to \$25.4 million
13 for the projected test year.

14 Witness Steven McLean sponsors the Customer interactions O&M expense and discusses
15 it starting at page 9 of his direct testimony. In his testimony, Mr. McLean states that the
16 Company continues to invest in multiple digital channels to make the customer to company
17 interactions more efficient and effective. In the table at the top of page 9 of his testimony,
18 Mr. McLean also shows expenses and initiatives being undertaken by the Company's IT
19 department to further enhance the Customer Interactions experience.

1 To assess the reasonableness of the forecasted O&M expense for the projected test year,
2 the Attorney General asked in discovery, for the Company to provide the actual O&M
3 expense for Customer Interactions for each of the four quarters ending June 2024 and about
4 other expense matters. The quarterly expense information provided by the Company
5 shows that actual expenses for Customer Interactions in the four quarters ended June 2024
6 were \$5.9 million, \$6.1 million, \$5.7 million and \$5.0 million.¹¹² The total actual expense
7 for 12 months ended June 2024 is \$22.7 million. This expense level is \$1.3 million lower
8 than the 2023 expense and \$2.6 million lower than the projected test year. Additionally, in
9 response to discovery, the Company stated that it had not incorporated any savings in the
10 projected test year from large improvements made the IVR (customer call response)
11 system even though those improvements will be implemented well before the end of the
12 test year.¹¹³

13 Based on the evidence presented above, I consider the Company's O&M expense forecast
14 for Customer Interactions to be overstated. Therefore, I recommend that the Commission
15 set the level of Customer Interactions O&M expense for the projected test year at the actual
16 level for the 12 months ended June 2024 of \$22.7 million and remove \$2.6 million from
17 the Company's forecasted expense.

¹¹² Exhibit AG-1.41 includes DR AG-CE-449 and Attachment 1

¹¹³ Id. includes DR AG-CE-0450.

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E. Demand Response Reconciliation

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**Q. PLEASE EXPLAIN THE O&M EXPENSE REDUCTION YOU HAVE INCLUDED
ON YOUR EXHIBIT AG-1.31 FROM THE DEMAND RESPONSE
RECONCILIATION.**

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5

A. Witness Aponte included a \$6.1 million O&M expense item on line 24 of her Exhibit A-13 (JCA-41), Schedule C-5. The amount represents the Company's filed position for a financial incentive payment in the Demand Response Reconciliation Case U-21410. Subsequent to the filing of this rate case, the Commission ruled on Case U-21410 and disallowed \$0.6 million of the incentive payment amount requested by the Company. The Attorney General asked the Company in discovery if the \$6.1 million should be revised to exclude the \$0.6 million disallowance and the Company agreed.¹¹⁴

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Therefore, I recommend that Commission reduce the Company's forecasted O&M expense for the projected test year by \$0.6 million.

14

F. Corporate - Insurance Expense

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16

In discovery, the Attorney General asked the Company to provide the actual insurance expense from 2019 to 2023 including any premium refunds or rebates. The Company was

¹¹⁴ Discovery Response AG-CE-455.

1 also asked to provide the forecasted expense for the projected test year and show how it
2 determined the forecasted expense.

3 In response to the request, the Company provided the historical information and the
4 amount of forecasted insurance expense for 2024, 2025, 2026 and the projected test year.
5 The Company's forecasted insurance expense for the projected test year is \$16,593,000.
6 The worksheet provided with the discovery response shows the projected test year expense
7 being a proration of the 2025 and 2026 forecasted expense. However, there are no
8 calculations to show how the 2025 and expense amounts were determined. In the
9 discovery response, the Company stated that the property insurance premiums are based
10 on estimated values and rate increases, but no details were provided. According to the
11 discovery response, other premiums were calculated using year over year percent increase.
12 However, no details or calculations were provided.¹¹⁵

13 To determine the reasonableness of the Company's forecasted insurance expense, I
14 calculated the compound rate of change for the five-year historical insurance premiums
15 and applied that rate of increase to the 2023 actual amount to arrive at the forecasted
16 amount for the projected test year. For refund distributions, I used the five-year average
17 amount from 2019 to 2023. These amounts vary significantly from year to year and similar
18 to injuries and damages and the practice used with insurance premium refund in other rate
19 cases, a five-year average approach is appropriate.

¹¹⁵ Exhibit AG-1.42 includes DR AG-CE-0523.

1 The result of my calculations is a forecasted insurance expense of \$10,475,000. This
2 amount is \$6,118,000 lower than the Company's forecasted amount. Exhibit AG-1.43
3 shows the calculations to arrive to this amount. I recommend that the Commission remove
4 \$6,118,000 from the Company's forecasted O&M expense for the projected test year.

5 **G. Incentive Compensation Expense**

6 Through the testimony of witnesses Amy Conrad and Michael Stuart, the Company
7 proposes to recover in rates nearly \$2.6 million of short-term incentive compensation.¹¹⁶

8 In the following pages of my testimony, I will analyze the Company proposal to include
9 in rates the cost of incentive compensation and the alleged benefits to customers provided
10 by Mr. Stuart in his testimony. Over the past few years, the Company has made several
11 changes to the incentive plan that have made it easier for the Company to payout incentive
12 compensation. For example, the operating performance measures that drive the short-term
13 incentive payouts under the plan were revamped since those two rate cases. Beginning in
14 2022, the ability to trigger a payout has been modified to make it much easier for
15 employees to receive incentive compensation payments. I will discuss these changes in
16 more detail later in my testimony.

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

¹¹⁶ Exhibit A-70 (AMC-3).

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

4 The major components of the EICP for non-officer employees are shown in Exhibit A-68
5 (AMC-1). Fifty percent (50%) of the target award in 2023 was based on achieving 9
6 performance measures related to employee safety, customer experience, electric reliability,
7 affordability, as well as employee empowerment and methane reduction. Prior to 2022, to
8 achieve 100% payout of this grouping of “operating” measures, the Company needed to
9 achieve at least 6 performance measures. The other 50% of the target award was based on
10 achieving earnings per share and operating cash flow goals of CMS Energy. The two items
11 had a weight of 70% for earnings per share and 30% for operating cash flow. This
12 50/50 combination of operating and financial measures started in 2012.

13 In 2010 and 2011, the calculation of the non-officer EICP was based solely on achieving
14 operating performance measures. The requirement to achieve 100% payout of target was
15 also stricter with accomplishment of 9 measures out of 11 needed. The Company then
16 adjusted this percentage based on the percent payout of the officers’ EICP. Over the last
17 five years, non-officer employees have received incentive payouts as a percentage of target
18 of 123% in 2018, 111% in 2019, 139% in 2020, and 77% in 2021 and 117% in 2022.¹¹⁷
19 The only year in the past fourteen years where a bonus payout was not made to non-officer

¹¹⁷ U-21490 DR AG-CE-165 with attachment.

1 employees was in 2011 when only 6 of the 11 operating measures were achieved. These
2 consistent payouts indicate that incentive compensation is not at-risk compensation based
3 on achieving superior performance, but it simply supplements base pay.

4 For the officers' EICP, the target payout has been based almost entirely on earnings per
5 share and operating cash flow. However, the percent payout can be adjusted up or down
6 depending on whether there is a payout related to the operating measures.

7 In forecasting the amount of EICP expense of \$2.6 million included in the forecasted test
8 year, the Company assumed that a 100% payout (at target) for both the officer and non-
9 officer EICP will occur.

10 **Q. HAS THE COMPANY MADE ANY CHANGES TO THE EICP FOR 2022**
11 **PAYOUTS?**

12 A. Yes. In their direct testimony, Ms. Conrad and Mr. Stuart discuss how the requirements
13 of the EICP were modified effective in 2022. First 30% of the payout for officers is
14 directly linked to the operational measures, whereas in the past the operational measures
15 have been characterized as a “modifier.”¹¹⁸ Also, the requirement that a minimum number
16 of metrics need to be achieved at threshold level and at target level to trigger a payout has

¹¹⁸ U-20650 testimony of Ms. Conrad on page 22 (lines 15 and 16).

1 been dropped.¹¹⁹ Instead, each individual metric will have its own threshold and target
2 payouts.

3 These changes may focus greater officer interest on certain operational metrics, but it
4 virtually assures an incentive payout even if only one operational metric is achieved since
5 there is no minimum number of performance metrics to be achieved to trigger a payout as
6 in the past.

7 **Q. PLEASE PROVIDE A SUMMARY OF RECENT CHANGES MADE TO THE**
8 **EICP METRICS.**

9 A. A review of Exhibit A-32 (AMC-1) from Case No. U-20650 shows the operating
10 performance measures previously included a customer experience index, a customer on-
11 time delivery measure, and a service on-time commitment metric. These later two
12 performance metrics have been dropped and only the customer experience index remains.
13 As for employee-related performance metrics, the employee safety metric continues, and
14 the Company has added an employee empowerment metric. Also, the previous metric
15 related to replacing vintage services has been dropped and a new metric has been added
16 which is methane reduction from repairing/replacing leaking gas pipes.

17 **Q. WHAT IS YOUR ASSESSMENT OF THE CHANGES TO THE PERFORMANCE**
18 **MEASURES?**

¹¹⁹ Case U-21148 Exhibit AG-52 includes DR AG-CE-0097.

1 A. The previous customer-related performance metrics were somewhat redundant, so going
2 with one overall satisfaction metric is a positive change. As for adding the methane
3 emission reduction metric, this new metric may make sense from an overall corporate
4 viewpoint. However, it is questionable if it belongs within the employee performance
5 metrics or within the electric business performance measures. Most employees have little
6 impact on achieving that metric.

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

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

11 For the 2023 plan cycle, half of the non-officer employee EICP payouts and 70% of the
12 Officer EICP payouts were dependent upon the financial metrics. As such, the officer
13 group that sets the direction of the Company is still far too focused on financial results.
14 Customers do not directly benefit from shareholders achieving a higher return on their
15 investment. Although the Company has argued in the past that happy investors will be
16 more attracted to the Company debt and common stock issues and therefore provide a
17 lower cost of capital, it has not offered direct proof to support this argument. The argument
18 is particularly hollow since the Company has not issued any significant common stock in
19 more than five years. Later in my testimony, I will discuss in more detail the customer
20 benefits put forth by Mr. Stuart.

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

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

10 Additionally, the fact that the performance measures use CMS Energy financial
11 information and comingle electric and gas business measures is a concern. Although the
12 Company is a combined gas and electric utility and makes up 95% of CMS Energy,
13 appropriate cost segregation is required to avoid having electric customers subsidize other
14 businesses, particularly non-utility operations.

15 Lastly, the Company has stated that it continues to pay salary increases each year with
16 2023 increases well above the rate of inflation.¹²⁰

¹²⁰ Discovery Response AG-CE-524

1 **Q. PLEASE BRIEFLY SUMMARIZE AND PROVIDE YOUR ASSESSMENT OF THE**
2 **CUSTOMER BENEFITS PRESENTED BY THE COMPANY TO JUSTIFY**
3 **RECOVERY OF INCENTIVE COMPENSATION COSTS.**

4 A. In his testimony, Mr. Stuart attempts to quantify certain benefits related to three of the
5 operating performance measures that are part of the EICP. In Exhibit A-158 (RMS-2),
6 Mr. Stuart shows the number of Safety Incidents, which have increased from 102 in 2020
7 to 125 in 2023. The exhibit also shows that the Company's 2022 Workers Compensation
8 and other related costs have decreased slightly to \$1.9 million. Clearly, the increase in
9 safety incidents does not show superior performance or an improving trend.

10 In Exhibit A-159 (RMS-3), Mr. Stuart shows the Company's SAIDI Index results as a
11 measure of Electric Reliability. The 176 SAIDI minutes (excluding Major Event Days)
12 for 2023 compares well to the 2021 results of 195, but results in past years have been
13 erratic with no consistent trend of improvement.¹²¹ Therefore, the claimed \$19.6 million
14 of savings based on the Berkley Labs formula are suspect.

15 Mr. Stuart also calculates certain savings related to the Company's Culture Index based
16 on purported cost savings from lower employee turnover. However, Exhibit A-160 shows
17 that employee turnover was 2.7% in 2023 up from 2.0% in 2021 and 1.1% in 2020. Clearly,
18 this is not an improving trend.

¹²¹ In U-21308, Mr. Stuart's Exhibit A-100 shows a SAIDI result for 2018 of 180 with results increasing in the 2019 to 2022 period.

1 In summary, the cost savings calculated by Mr. Stuart are inconsistent with recent trends
2 in performance, speculative and at best transitory. They do not justify the \$2.6 million of
3 incentive compensation that the company seeks to recover in this rate case.

4 **Q. WHAT CONCLUSIONS AND RECOMMENDATIONS HAVE YOU REACHED**
5 **WITH REGARD TO RECOVERY OF INCENTIVE COMPENSATION COSTS IN**
6 **RATES?**

7 A. As discussed above, the focus of the short-term incentive compensation plans is
8 overwhelmingly directed at creating shareholder value, not customer benefits, and the
9 officer group that directs the day-to-day operations is only minimally incentivized to meet
10 operational goals. Certain design flaws with the EICP tend to reward mediocre
11 performance and diminish any real customer benefits. Incentive compensation should be
12 paid for exceptional performance, at least to pass the test of cost recovery in rates.
13 Performance that is ordinary and achieves basic goals and efficient operations is paid for
14 in base salaries.

15 Both management and other employees have received large annual merit salary increases
16 since at least 2009. The Company argues that it must pay a competitive compensation
17 package to retain talented management and employees. Although that may be the case, it
18 does not mean that customers should pay for all or most of that expense. Shareholders
19 also significantly benefit from talented management, perhaps even more so than
20 customers. Customers are paying for higher base pay each year. Shareholders can share

1 the burden by paying for the incentive compensation that disproportionately favors their
2 interests.

3 The Company's proposed incentive compensation expense of \$2.6 million for the
4 projected test year assumes that the Company will achieve target performance for all its
5 goals. There is no track record with the revised performance measures that supports that
6 conclusion. It is probable that the Company may fall short of achieving 100% of the
7 performance measures. In response to discovery, the Company stated if it achieved only
8 the lower threshold level of performance that the incentive compensation would be \$1.3
9 million for the projected test year.¹²²

10 I do not believe the Company has made a compelling case to justify recovery of any
11 amount of incentive compensation and therefore no incentive compensation should be
12 included in rates. However, in recent rate cases the Commission has approved a portion of
13 incentive compensation pertaining to operating measures and if it decides to do so in this
14 case, I recommend that the Commission approve at most recovery of the \$1.3 million
15 incentive compensation amount related to potential achievement of operating measures at
16 the threshold level and remove the remaining \$1.3 million from O&M expense for the
17 projected test year.

¹²² Exhibit AG-1.44 includes DR AG-CE-460.

1

I. O&M Adjustments - Summary

2 **Q. PLEASE SUMMARIZE YOUR RECOMMENDED O&M ADJUSTMENTS.**

3 A. Operations and maintenance expenses represent a large part of the Company's cost
4 structure. My analysis of the expense level proposed by the Company has shown that in
5 the following areas these expenses are excessive or not needed and should be removed.

Summary of O&M Expense Reductions	Amount (\$ Millions)
Electric Distribution	\$ 32.3
Power Generation	\$ 5.1
Customer Interactions	2.6
Demand Response Program	0.6
Insurance Expense	6.1
Incentive Compensation	1.3
Total	\$ 48.0

6

7 As such, I recommend that the Commission reduce the amount of total O&M costs
8 proposed by the Company by \$48.0 million and reduce the revenue deficiency accordingly.

9 Exhibit AG-1.31 provides further details.

1 **IX. Service Restoration Cost Sharing Mechanism**

2 **Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED SERVICE**
3 **RESTORATION COST SHARING MECHANISM FOR SERVICE**
4 **RESTORATION COSTS.**

5 A. The Company is proposing another reiteration of a cost recovery mechanism to insulate
6 itself from any financial risk or exposure from higher service restoration costs incurred
7 above the amount set in rates. The current proposal is the fifth proposal in the last five
8 rate cases. In this rate case, Witnesses Snider and Foster propose a 50% cost recovery or
9 refund mechanism. Although the percentage of cost sharing with customers has changed
10 the basic mechanism has not changed much from previous proposals other than the
11 percentage of cost recovery.

12 **Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S DEFERRAL**
13 **PROPOSAL?**

14 A. The proposed deferral mechanism is not necessary and should be rejected by the
15 Commission. In Case Nos. U-21389, U-21224, U-20963, and U-20697, the Commission
16 rejected similar proposals.

17 Figure 1 on page 5 of Mr. Snider's testimony shows that service restoration costs peaked
18 in 2023 at \$188 million. In my testimony above, I proposed to set the service restoration
19 expense at nearly \$130 million, including inflation adjustments for 2024, 2025, and two

1 months in 2026. This is a significantly higher amount than the Company has received in
2 prior rate cases. Therefore, there is no compelling need for a cost deferral and recovery
3 mechanism. The average amount of expense that I have proposed for the projected test
4 year captures both high and low annual service restoration costs. The law of averages
5 dictates that costs in future years will likely be less than the highest amount included in
6 the average.

7 Furthermore, a large portion of the increase in service restoration expense since 2021 has
8 been driven by the addition of more people for storm preparedness. As discussed in my
9 testimony in Case Nos. U-21389 and U-21224, the Company has added hundreds of people
10 to manage the Incident Command System both on an on-going basis and during significant
11 weather emergencies. The number of people involved in the ICS skyrocketed in 2019 from
12 600 to 900 people with the Company assigning fewer tasks to more individuals and
13 supervisory groups. In response to discovery, the Company reported that it utilized at least
14 883 employees in Storm Pre-Staging activities in 2020 and forecasted that it would exceed
15 2,300 employees in 2021 and 2022.¹²³ The Company needs to better justify this large
16 escalation in resources and the related increase in service restoration costs. By approving
17 a cost deferral and recovery mechanism, the Commission would remove the incentive for
18 the Company to control such costs in future years because the Company would be able to
19 pass through large cost increases to customers. The proposed cost recovery mechanism
20 would also diminish the incentive for the Company to reduce power outages because it

¹²³ Case No. U-20963 CEC Co response to discovery response AG-CE-869.

1 would recover 50% of any incremental service restoration costs. The mechanism runs
2 counter to the objective of incentivizing the Company to reduce power outages or face
3 penalties.

4 In summary, I recommend that the Commission reject the Company's proposal for a cost
5 recovery and deferral mechanism for service restoration costs. However, if the
6 Commission were inclined to approve a similar mechanism, it should be asymmetrical
7 where customers receive 100% of any underspent amounts for the privilege given to the
8 Company to recover 50% of any cost increases above those amounts set in rates.

9 **X. Adjustments To Revenue Deficiency**

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

12 A. Exhibit AG-1.45 summarizes the adjustments to rate base and operating income. The net
13 result is a jurisdictional revenue deficiency of \$82.9 million, which is a reduction of \$219.7
14 million from the Company's requested level of \$302.6 million.

15 I recommend the Commission adopt my proposed adjustments and issue an order granting
16 rate relief to the Company no greater than \$82.9 million.

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

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

Experience and Qualifications of Sebastian Coppola

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

EMPLOYMENT BACKGROUND

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

ENERGY INDUSTRY EXPERTISE

During his 27-year career at SEMCO Energy, MCN Energy and MichCon, Mr. Coppola held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports, and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing and Manager of Materials Inventory and Warehousing Accounting. In many

Experience and Qualifications of Sebastian Coppola

of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

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

ENERGY INDUSTRY AND REGULATORY EXPERIENCE

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

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

**Experience and Qualifications
of Sebastian Coppola**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

➤ Specific Regulatory Proceedings and Related Experience:

- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2024 gas rate case U-21534 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2024 gas rate case U-21540 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2024 gas rate case U-21291 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.

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- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2022-2023 GCR plan in case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Power Company 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.

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- Filed testimony on behalf of the Michigan Attorney General in CEC0 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Act 9 application in Case No. U-20993 by Saginaw Bay Pipeline Company to set transportation rates for services to DTE Gas Company.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 electric rate Case U-20836 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.

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- Filed rebuttal testimony on behalf the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gaslight & Coke Company (Peoples Gas) in Docket 17-0137.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan reconciliation case No. U-20554.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2020-2021 GCR plan reconciliation case No. U-20552.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR plan reconciliation case No. U-20236.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Ameren Illinois Company (Ameren) in Docket 20-0323.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan case No. U-20822.

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- Filed testimony on behalf of the Michigan Attorney General in CEC0 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2020 electric rate Case U-20697 on several issues, including operation

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

- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 PSCR Reconciliation in case U-20202.

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- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.

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- Filed testimony on behalf of the Michigan Attorney General in CEC0 2017-2018 GCR reconciliation case U-20075.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 Integrated Resource Plan in case U-20165.

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- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 Tax Credit B refund case U-20287 for the natural gas business.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue,

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operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.

- Filed testimony on behalf of the Michigan Attorney General in CEC0 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.

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- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CECO Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.

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- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CEC Co Gas Choice and End-User Transportation tariff changes case U-17900.

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- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.

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- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.
- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CEC0's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.

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- Filed testimony on behalf of the Michigan Attorney General in CEC0 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CEC0's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.

Experience and Qualifications of Sebastian Coppola

- Filed testimony in MichCon’s 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors’ compensation in the 2012 Avista general rate case.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company’s 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio’s power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company’s 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation’s 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo’s gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo’s electric business Pilot Revenue Decoupling Mechanism in case U-16566.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.
- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.

**Experience and Qualifications
of Sebastian Coppola**

- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.
- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the “Massachusetts Formula” at MichCon and at SEMCO in 1975 and 2000.

Experience and Qualifications of Sebastian Coppola

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

EDUCATIONAL BACKGROUND

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



Attorney General's Exhibits (U-21585)

Witness Coppola

AG-1.1	DR Response – Capex U-21389 Path vs. Reliability Roadmap
AG-1.2	DR Response – Reliability Goal Achievement Timeframe
AG-1.3	DR Response – Inflation factors
AG-1.4	DR Response – Contractor Service Installation vs. Employees
AG-1.5	DR Response – LVD Lines Demand Failures
AG-1.6	DR Response – LVD Lines Reliability
AG-1.7	DR Response – LVD Substation Reliability
AG-1.8	DR Response – Fractionalization
AG-1.9	DR Response – Undergrounding
AG-1.10	DR Response – LVD Projects over \$1 million
AG-1.11	DR Response – Wildfire Program
AG-1.12	DR Response – HVD Lines and Substation Rehab
AG-1.13	DR Response – HVD Large Transformer Pre-Purchase
AG-1.14	DR Response – Grif Modernization Programs
AG-1.15	Summary Cap Ex, Rate Base, Depreciation & Tax Expense
AG-1.16	Overall Cost of Capital
AG-1.17	Cost of Common Equity
AG-1.18	Cost of Common Equity-DCF
AG-1.19	Cost of Common Equity-CAPM
AG-1.20	Cost of Common Equity-Risk Premium
AG-1.21	ROE Decisions by Regulatory Commissions
AG-1.22	Peer Group Selection Screening
AG-1.23	Pro-Forma Cash Flow Coverage Ratios
AG-1.24	Market to Book Ratios
AG-1.25	DR Response – Moody’s Rating Report May 31, 2024
AG-1.26	DR Response – S&P Rating Report August 17, 2023
AG-1.27	DR Response – August 2024 10-Year U.S. Treasury Rates
AG-1.28	Values Line Report on Market Volatility vs. Risk
AG-1.29	Working Capital Interest Accrual
AG-1.30	DR Response – Ludington/Toshiba Deferral
AG-1.31	O&M Adjustments Summary
AG-1.32	O&M Adjustments - Distribution Operations
AG-1.33	Service Restoration Cost Adjustment
AG-1.34	Staking & Locating O&M Adjustments
AG-1.35	Forestry Cost Savings for Service Restoration
AG-1.36	DR Response – CECo Calculation of Forestry Savings
AG-1.37	DR Response – Distribution LVD O&M expense increases
AG-1.38	DR Response – Distribution HVD O&M Expense increases
AG-1.39	DR Response – Underground Workforce
AG-1.40	DR Response – Generation Base O&M Expense Analysis
AG-1.41	DR Response – Customer Interactions Cost Trends
AG-1.42	DR Response – Insurance Forecast
AG-1.43	AF Recalculation of Insurance Expense

AG-1.44 | DR Response – Incentive Compensation at Threshold
AG-1.45 | AG Revenue Deficiency Calculation

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Question:

90. Refer to Figure 6 on page 23 of Mr. Kelly's direct testimony on SAIDI Reliability Projections. Please:

- a. Confirm that the SAIDI projections are for SAIDI excluding MEDs. If not confirming, explain.
- b. Explain what year the historical SAIDI represents or show how it was calculated and for which years.
- c. Explain what Net SAIDI represents and show how it is calculated.
- d. Provide the number of total sustained customer power outages that occurred in the historical year from all events, the actual number experienced in 2023, and the number forecasted for each year 2023 to 2032 based on the Resilient Grid Plan and the Rate Case Level spending plans, separately, in Excel.
- e. Provide the number of total sustained customer power outages that occurred in the historical year from all events excluding MEDs, the actual number experienced in 2023, and the number forecasted for each year 2023 to 2032 based on the Resilient Grid Plan and the Rate Case Level spending plans, separately, in Excel.
- f. Provide the spending amount (Capex and O&M expense separately) for the Resilient Grid Plan and the Rate Case Level for each year 2013 to 2032 in Excel and show the difference in spending between the two alternatives.
- g. For the incremental Reliability Roadmap or Resilient Grid Plan spending level, identify specifically for which items the additional spending would occur by year and explain in detail how this additional spending for those items will achieve the 116 minutes SAIDI goal in 2032 and the other goals identified on lines 5-8 of page 24 of your testimony.
- h. Provide the incremental spending on the Distribution system (Capex and O&M expense, separately) that occurred from 2016 to 2023 in Excel and show how that incremental spending improved SAIDI and other reliability measures over that timeframe.
- i. Provide the number of total sustained customer power outages that occurred each year 2016 to 2023 from all events and separately excluding MEDs in Excel.
- j. Confirm that the Resilient Grid Plan is the same as the Reliability Roadmap plan. If not confirming, explain the difference and where each are presented.

Response:

- a. Yes, the SAIDI projections are excluding MEDs.
- b. It is the historical baseline used in Reliability Performance Glidepath from my testimony in Case No. U-21389, Page 23, Figure 13.
- c. Net SAIDI is calculated as follows: $\text{Net SAIDI} = \text{Net SAIFI} * \text{Net CAIDI}$. Net SAIDI, as referenced in Figure 40 of my testimony, refers to the System Average Interruption Duration Index (SAIDI) that accounts for both the reliability improvements from the Company's proposed investments and the assumed degradation in reliability due to system deterioration. This methodology is used to provide a more accurate projection of system performance by considering both positive and negative factors affecting reliability. The reliability improvement includes the expected benefits from planned investments aimed at improving the reliability of the electric distribution system,

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and degradation accounts for the natural deterioration of the system over time if no investments were made.

- d. See attachment U21585-AG-CE-405_Kelly_ATT_1
- e. See attachment U21585-AG-CE-405_Kelly_ATT_1
- f. See the following:
 - o Attachment U21585-AG-CE-405_Kelly_ATT_2 for capital projections from 2024 through 2032 and O&M projections from 2024 to 2028. The EDIIP is a 5-year plan and O&M was not forecasted beyond 2028.
 - o Exhibit No.: A-95 (MPK-3) for historical capital for 2019 through 2023.
 - o Exhibit No.: A-106 (MPK-14) for historical O&M for 2019 through 2023.
 - o Case No. U-20697, Exhibit No.: A-29 (RTB-2), Page 1, columns (c) – (g) for historical capital for 2014 through 2018. This exhibit has is attached as U21585-AG-CE-405_Kelly_ATT_3 for convenience.
 - o Case No. U-20697, Exhibit No.: A-39 (RTB-12), Page 1, columns (b) – (f) for historical O&M for 2014 through 2018 This exhibit has is attached as U21585-AG-CE-405_Kelly_ATT_4 for convenience.
 - o Case No. U-20134, Exhibit No.: A-38 (ABJ-4) Page 1, column (c) for the 2013 historical capital. This exhibit has is attached as U21585-AG-CE-405_Kelly_ATT_5 for convenience.
 - o Case No. U-20134, Exhibit No.: A-28 (JRA-13) Page 1, column (b) and Exhibit No.: A-50 (AJB-17) Page 1, column (b) for the 2013 historical O&M. These exhibits are attached as U21585-AG-CE-405_Kelly_ATT_6 and U21585-AG-CE-405_Kelly_ATT_7, respectively.
- g. See attachment U21585-AG-CE-405_Kelly_ATT_8 for the investment categories for which incremental spending results in SAIFI improvements needed to achieve the 116 minutes of SAIDI excluding MEDs.
- h. It is unclear what is meant by “incremental spending” in this part of the request. See the response to subpart (f) for actual historical spending.
- i. See attachment U21585-AG-CE-405_Kelly_ATT_1
- j. Yes, in Figure 6 on page 23 of my direct testimony, “Resilient Grid Plan” refers to the spending included in the Reliability Roadmap.

Revised Response

Please see attached U21585-AG-CE-405_Kelly_ATT_2.Revised. The attachment was revised to correct a formula error in the attachment originally provided, which impacts the totals on line 89 in the EDIIP O&M and O&M Variance tabs.

Witness: Michael P. Kelly

Date: September 9, 2024

CECo Response to AG-CE-0405 (Revised)

Electric Distribution Capital: EDIIP

(\$ thousands)	2024	2025	2026	2027	2028	2029	2030	2031	2032
1.01 - Lines New Business - LVD	\$107,674	\$110,085	\$112,397	\$114,757	\$117,167	\$119,628	\$122,140	\$124,705	\$127,324
1.03 - Lines Strategic Cust - HVD	\$31,796	\$79,682	\$31,029	\$23,708	\$17,328	\$17,692	\$18,064	\$18,443	\$18,830
1.05 - Metering New Business - LVD	\$17,459	\$17,351	\$18,811	\$62,106	\$62,521	\$62,944	\$63,377	\$63,818	\$64,269
1.06 - Transfmrs New Business - LVD	\$16,738	\$31,856	\$40,260	\$43,472	\$46,948	\$46,948	\$46,948	\$46,948	\$46,948
1.07 - Metro New Business	\$2,424	\$4,000	\$3,500	\$3,000	\$3,000	\$3,063	\$3,127	\$3,193	\$3,260
1.08 - Streetlights New Business	\$3,974	\$4,023	\$4,107	\$4,193	\$4,282	\$4,371	\$4,463	\$4,557	\$4,653
New Business	\$180,065	\$246,997	\$210,104	\$251,237	\$251,246	\$254,647	\$258,119	\$261,664	\$265,283
2.01 - Lines Reliability - LVD	\$41,351	\$222,999	\$293,302	\$346,503	\$347,327	\$346,970	\$347,932	\$348,915	\$349,918
2.02 - Lines Reliability - HVD	\$36,327	\$89,007	\$100,936	\$105,991	\$105,715	\$103,206	\$104,727	\$106,280	\$107,865
2.04 - Substations Reliability - LVD	\$15,500	\$43,992	\$42,392	\$43,992	\$42,817	\$44,750	\$46,578	\$45,435	\$44,189
2.05 - Substations Reliability - HVD	\$5,400	\$5,400	\$5,400	\$5,400	\$5,400	\$5,513	\$5,629	\$5,747	\$5,868
2.07 - SCADA	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.09 - Grid Capabilities - Automation	\$36,432	\$14,771	\$7,646	\$0	\$0	\$0	\$0	\$0	\$0
2.10 - System Protection	\$3,473	\$3,995	\$4,078	\$4,165	\$4,252	\$4,341	\$4,432	\$4,526	\$4,621
2.12 - Repetitive Outages - LVD	\$3,857	\$38,893	\$40,340	\$38,830	\$43,949	\$44,176	\$44,408	\$44,645	\$44,887
2.13 - Metro Reliability	\$4,000	\$4,000	\$4,000	\$4,000	\$4,084	\$4,170	\$4,257	\$4,347	\$4,438
2.14 - Lines and Subs Rehab HVD	\$37,052	\$76,900	\$76,900	\$76,900	\$77,710	\$78,536	\$79,381	\$80,243	\$81,123
2.15 - Substations Rehab LVD	\$9,400	\$30,600	\$31,000	\$31,500	\$31,689	\$33,682	\$36,579	\$36,780	\$36,986
2.16 - Lines Rehabilitation - LVD	\$32,080	\$60,097	\$105,720	\$158,855	\$159,566	\$160,291	\$161,032	\$161,789	\$162,561
2.17 - Metro Rehabilitation	\$6,000	\$6,000	\$6,000	\$6,000	\$6,000	\$6,126	\$6,255	\$6,386	\$6,520
2.19 - Grid Capabilities - Advanced Tech	\$12,122	\$23,098	\$29,147	\$34,220	\$18,599	\$18,990	\$19,388	\$19,796	\$20,211
2.20 - Lines Resiliency - LVD	\$11,400	\$22,600	\$93,150	\$173,100	\$171,357	\$171,721	\$172,094	\$172,474	\$172,862
2.21 - Substation Resiliency - LVD	\$0	\$4,100	\$4,100	\$4,100	\$4,100	\$4,186	\$4,274	\$4,364	\$4,455
Reliability	\$254,394	\$646,452	\$844,111	\$1,033,556	\$1,022,565	\$1,026,659	\$1,036,967	\$1,041,725	\$1,046,503
3.01 - Lines Capacity - LVD	\$14,900	\$56,886	\$55,908	\$54,934	\$53,968	\$54,262	\$54,561	\$54,867	\$55,179
3.02 - Lines & Subs Capacity - HVD	\$45,692	\$33,004	\$18,000	\$18,000	\$18,000	\$18,378	\$18,764	\$19,158	\$19,560
3.04 - Substations Capacity - LVD	\$13,150	\$22,270	\$22,270	\$22,270	\$22,270	\$22,738	\$23,216	\$23,703	\$24,201
3.05 - Transformers Capacity - LVD	\$1,216	\$2,172	\$2,745	\$2,964	\$3,201	\$3,201	\$3,201	\$3,201	\$3,201
3.06 - New Business Cap - LVD	\$20,511	\$20,351	\$20,156	\$19,551	\$18,963	\$19,361	\$19,768	\$20,183	\$20,607
3.07 - CVR	\$3,877	\$4,391	\$4,105	\$4,018	\$4,033	\$4,118	\$4,204	\$4,292	\$4,383
3.08 - Lines Solar Interconns - LVD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.09 - Lines Solar Interconns - HVD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.10 - Subs Solar Interconns - LVD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.11 - Subs Solar Interconns - HVD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Capacity	\$99,346	\$139,074	\$123,184	\$121,738	\$120,436	\$122,058	\$123,714	\$125,404	\$127,131
4.01 - Lines Failures - LVD	\$84,152	\$150,745	\$130,725	\$126,671	\$122,794	\$125,373	\$128,006	\$130,694	\$133,438
4.02 - Lines & Subs Failures - HVD	\$4,120	\$5,000	\$5,000	\$5,000	\$5,000	\$5,105	\$5,212	\$5,322	\$5,433
4.04 - Substations Failures - LVD	\$7,468	\$9,000	\$9,000	\$9,000	\$9,000	\$9,189	\$9,382	\$9,579	\$9,780
4.05 - Metering Failures - LVD	\$36,216	\$39,457	\$37,314	\$38,453	\$39,587	\$40,418	\$41,267	\$42,134	\$43,018
4.06 - Transfmrs Failures - LVD	\$19,988	\$38,372	\$48,495	\$52,364	\$56,551	\$56,551	\$56,551	\$56,551	\$56,551
4.07 - Streetlight Failures	\$12,341	\$12,250	\$12,372	\$12,496	\$12,621	\$12,886	\$13,157	\$13,433	\$13,715
4.08 - Metro Failures	\$550	\$550	\$550	\$550	\$550	\$562	\$573	\$585	\$598
Demand Failures	\$164,835	\$255,374	\$243,457	\$244,534	\$246,103	\$250,084	\$254,148	\$258,297	\$262,534
5.01 - Lines Relocations - LVD	\$45,167	\$46,131	\$47,200	\$48,195	\$49,206	\$50,239	\$51,294	\$52,372	\$53,471
5.02 - Lines Relocations - HVD	\$900	\$900	\$900	\$900	\$900	\$919	\$938	\$958	\$978
5.04 - Metro Relocations	\$6,400	\$10,300	\$6,400	\$5,000	\$5,000	\$5,105	\$5,212	\$5,322	\$5,433
Asset Relocations	\$52,467	\$57,331	\$54,500	\$54,095	\$55,106	\$56,263	\$57,445	\$58,651	\$59,883
6.01 - Computer & Equipment	\$75	\$75	\$75	\$75	\$75	\$77	\$78	\$80	\$82
6.02 - Tools	\$8,116	\$8,004	\$8,188	\$8,434	\$8,687	\$8,869	\$9,056	\$9,246	\$9,440
6.03 - System Control Projects	\$343	\$279	\$279	\$0	\$0	\$0	\$0	\$0	\$0
11562- Enterprise Corrective Action Plan	\$450	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
6.0X - Streetlight Conversions	\$3,728	\$3,806	\$3,887	\$3,968	\$3,008	\$3,071	\$3,136	\$3,202	\$3,269
Electric Other	\$12,712	\$12,164	\$12,429	\$12,477	\$11,770	\$12,017	\$12,269	\$12,527	\$12,790
Total Electric Distribution Capital	\$763,819	\$1,357,392	\$1,487,784	\$1,717,637	\$1,707,225	\$1,721,727	\$1,742,661	\$1,758,269	\$1,774,124

CECo Response to AG-CE-0405 (Revised)

Electric Distribution Capital: Variance

(\$ thousands)	2024	2025	2026	2027	2028	2029	2030	2031	2032
1.01 - Lines New Business - LVD	(\$1,000)	\$1,411	\$3,723	\$6,083	\$8,493	\$10,954	\$13,466	\$16,031	\$18,650
1.03 - Lines Strategic Cust - HVD	\$0	\$47,886	(\$767)	(\$8,088)	(\$14,468)	(\$14,104)	(\$13,732)	(\$13,353)	(\$12,966)
1.05 - Metering New Business - LVD	\$18	(\$90)	\$1,370	\$44,665	\$45,080	\$45,503	\$45,936	\$46,377	\$46,828
1.06 - Transfmrs New Business - LVD	(\$58)	\$15,060	\$23,464	\$26,676	\$30,152	\$30,152	\$30,152	\$30,152	\$30,152
1.07 - Metro New Business	\$0	\$1,576	\$1,076	\$576	\$576	\$639	\$703	\$769	\$836
1.08 - Streetlights New Business	\$0	\$49	\$133	\$219	\$308	\$397	\$489	\$583	\$679
New Business	(\$1,040)	\$65,892	\$28,999	\$70,132	\$70,141	\$73,542	\$77,014	\$80,559	\$84,178
2.01 - Lines Reliability - LVD	\$0	\$181,648	\$251,951	\$305,152	\$305,976	\$305,619	\$306,581	\$307,564	\$308,567
2.02 - Lines Reliability - HVD	\$0	\$52,680	\$64,609	\$69,664	\$69,388	\$66,879	\$68,400	\$69,953	\$71,538
2.04 - Substations Reliability - LVD	\$0	\$28,492	\$26,892	\$28,492	\$27,317	\$29,250	\$31,078	\$29,935	\$28,689
2.05 - Substations Reliability - HVD	\$0	\$0	\$0	\$0	\$0	\$113	\$229	\$347	\$468
2.07 - SCADA	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2.09 - Grid Capabilities - Automation	\$0	(\$21,661)	(\$28,786)	(\$36,432)	(\$36,432)	(\$36,432)	(\$36,432)	(\$36,432)	(\$36,432)
2.10 - System Protection	\$0	\$522	\$605	\$692	\$779	\$868	\$959	\$1,053	\$1,148
2.12 - Repetitive Outages - LVD	(\$5,999)	\$29,037	\$30,484	\$28,974	\$34,093	\$34,320	\$34,552	\$34,789	\$35,031
2.13 - Metro Reliability	\$0	\$0	\$0	\$0	\$84	\$170	\$257	\$347	\$438
2.14 - Lines and Subs Rehab HVD	\$0	\$39,848	\$39,848	\$39,848	\$40,658	\$41,484	\$42,329	\$43,191	\$44,071
2.15 - Substations Rehab LVD	\$0	\$21,200	\$21,600	\$22,100	\$22,289	\$24,282	\$27,179	\$27,380	\$27,586
2.16 - Lines Rehabilitation - LVD	\$0	\$28,017	\$73,640	\$126,775	\$127,486	\$128,211	\$128,952	\$129,709	\$130,481
2.17 - Metro Rehabilitation	\$0	\$0	\$0	\$0	\$0	\$126	\$255	\$386	\$520
2.19 - Grid Capabilities - Advanced Tech	\$0	\$10,976	\$17,025	\$22,098	\$6,477	\$6,868	\$7,266	\$7,674	\$8,089
2.20 - Lines Resiliency - LVD	(\$1,703)	\$9,497	\$80,047	\$159,997	\$158,254	\$158,618	\$158,991	\$159,371	\$159,759
2.21 - Substation Resiliency - LVD	\$0	\$4,100	\$4,100	\$4,100	\$4,100	\$4,186	\$4,274	\$4,364	\$4,455
Reliability	(\$7,702)	\$384,356	\$582,015	\$771,460	\$760,469	\$764,563	\$774,871	\$779,629	\$784,407
3.01 - Lines Capacity - LVD	\$0	\$41,986	\$41,008	\$40,034	\$39,068	\$39,362	\$39,661	\$39,967	\$40,279
3.02 - Lines & Subs Capacity - HVD	\$0	(\$12,688)	(\$27,692)	(\$27,692)	(\$27,692)	(\$27,314)	(\$26,928)	(\$26,534)	(\$26,132)
3.04 - Substations Capacity - LVD	\$0	\$9,120	\$9,120	\$9,120	\$9,120	\$9,588	\$10,066	\$10,553	\$11,051
3.05 - Transformers Capacity - LVD	\$0	\$956	\$1,529	\$1,748	\$1,985	\$1,985	\$1,985	\$1,985	\$1,985
3.06 - New Business Cap - LVD	\$0	(\$160)	(\$355)	(\$960)	(\$1,548)	(\$1,150)	(\$743)	(\$328)	\$96
3.07 - CVR	\$0	\$514	\$228	\$141	\$156	\$241	\$327	\$415	\$506
3.08 - Lines Solar Interconns - LVD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.09 - Lines Solar Interconns - HVD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.10 - Subs Solar Interconns - LVD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3.11 - Subs Solar Interconns - HVD	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Capacity	\$0	\$39,728	\$23,838	\$22,392	\$21,090	\$22,712	\$24,368	\$26,058	\$27,785
4.01 - Lines Failures - LVD	\$0	\$66,593	\$46,573	\$42,519	\$38,642	\$41,221	\$43,854	\$46,542	\$49,286
4.02 - Lines & Subs Failures - HVD	\$0	\$880	\$880	\$880	\$880	\$985	\$1,092	\$1,202	\$1,313
4.04 - Substations Failures - LVD	\$0	\$1,532	\$1,532	\$1,532	\$1,532	\$1,721	\$1,914	\$2,111	\$2,312
4.05 - Metering Failures - LVD	\$0	\$3,241	\$1,098	\$2,237	\$3,371	\$4,202	\$5,051	\$5,918	\$6,802
4.06 - Transfmrs Failures - LVD	\$0	\$18,384	\$28,507	\$32,376	\$36,563	\$36,563	\$36,563	\$36,563	\$36,563
4.07 - Streetlight Failures	\$0	(\$91)	\$31	\$155	\$280	\$545	\$816	\$1,092	\$1,374
4.08 - Metro Failures	\$0	\$0	\$0	\$0	\$0	\$12	\$23	\$35	\$48
Demand Failures	\$0	\$90,539	\$78,622	\$79,699	\$81,268	\$85,249	\$89,313	\$93,462	\$97,699
5.01 - Lines Relocations - LVD	\$0	\$964	\$2,033	\$3,028	\$4,039	\$5,072	\$6,127	\$7,205	\$8,304
5.02 - Lines Relocations - HVD	\$0	\$0	\$0	\$0	\$0	\$19	\$38	\$58	\$78
5.04 - Metro Relocations	\$0	\$3,900	\$0	(\$1,400)	(\$1,400)	(\$1,295)	(\$1,188)	(\$1,078)	(\$967)
Asset Relocations	\$0	\$4,864	\$2,033	\$1,628	\$2,639	\$3,796	\$4,978	\$6,184	\$7,416
6.01 - Computer & Equipment	\$0	\$0	\$0	\$0	\$0	\$2	\$3	\$5	\$7
6.02 - Tools	\$0	(\$112)	\$72	\$318	\$571	\$753	\$940	\$1,130	\$1,324
6.03 - System Control Projects	\$0	(\$64)	(\$64)	(\$343)	(\$343)	(\$343)	(\$343)	(\$343)	(\$343)
11562- Enterprise Corrective Action Plan	\$0	(\$450)	(\$450)	(\$450)	(\$450)	(\$450)	(\$450)	(\$450)	(\$450)
6.0X - Streetlight Conversions	\$0	\$78	\$159	\$240	(\$720)	(\$657)	(\$592)	(\$526)	(\$459)
Electric Other	\$0	(\$548)	(\$283)	(\$235)	(\$942)	(\$695)	(\$443)	(\$185)	\$78
Total Electric Distribution Capital	(\$8,742)	\$584,831	\$715,223	\$945,076	\$934,664	\$949,166	\$970,100	\$985,708	\$1,001,563

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Rate Case O&M (\$ thousands)	Inflation					0.0%
Elec Ops O&M \$K	2024	2025	2026	2027	2028	
1.01 - O&M Assoc w/Construction	0	0	0	0	0	0
1.02 - Transformer Credits	0	0	0	0	0	0
1.0 - O&M Assoc w/Construction	0	0	0	0	0	0
2.01 - Lines Reliability - LVD	1,166	1,166	1,166	1,166	1,166	1,166
2.02 - Lines Reliability - HVD	305	305	305	305	305	305
2.04 - Substations Reliability - LVD	3,179	3,179	3,179	3,179	3,179	3,179
2.05 - Substations Reliability - HVD	2,143	2,143	2,143	2,143	2,143	2,143
2.0A - Non-Forestry Reliability	6,793	6,793	6,793	6,793	6,793	6,793
2.07 - Forestry (ERev 4,13,22)	105,371	112,792	113,122	113,428	113,752	113,752
2.08 - Forestry - HVD	12,279	12,294	11,972	11,646	11,300	11,300
2.0B - Forestry Reliability	117,650	125,086	125,094	125,074	125,052	125,052
3.01 - Lines Demand - HVD	784	784	784	784	784	784
3.03 - Substations Demand - LVD	5,001	5,001	5,001	5,001	5,001	5,001
3.04 - Substations Demand - HVD	3,357	3,357	3,357	3,357	3,357	3,357
3.07 - Corrective Maintenance	4,154	4,154	4,154	4,154	4,154	4,154
3.09 - Staking	5,282	5,282	5,282	5,282	5,282	5,282
3.10 - Meter Services (ERev 2,11,20)	916	916	916	916	916	916
3.10a - Meter Credits	0	0	0	0	0	0
3.11 - Streetlighting	1,627	1,627	1,627	1,627	1,627	1,627
3.12 - Service Calls	4,518	4,518	4,518	4,518	4,518	4,518
3.13 - Alma Equipment Repair	566	566	566	566	566	566
3.14 - Meter Reading (ERev 3,12,21)	1,859	1,859	1,859	1,859	1,859	1,859
3.15 - Meter Tech & Mgmt Sys Support	1,230	1,230	1,230	1,230	1,230	1,230
3.16 - Smart Energy MTC - Elec	9,492	9,492	9,492	9,492	9,492	9,492
3.0A - Ops, Mtc & Mtr w/o Svc Rest	38,785	38,785	38,785	38,785	38,785	38,785
3.06 - Service Restoration - LVD	107,317	107,317	107,317	107,317	107,317	107,317
3.0B - Service Restoration	107,317	107,317	107,317	107,317	107,317	107,317
4.01 - Training	10,691	10,691	10,691	10,691	10,691	10,691
4.02 - Facilities Building Opers & Maint	0	0	0	0	0	0
4.03 - Tools	1,549	1,549	1,549	1,549	1,549	1,549
4.04 - Field Operations Expenses	2,491	2,491	2,491	2,491	2,491	2,491
4.05 - Energy Operations Indirect Labor	0	0	0	0	0	0
4.06 - Labor Variation	0	0	0	0	0	0
4.07 - Supervision / Admin Staff - T&WM	5,941	5,941	5,941	5,941	5,941	5,941
4.07a - Supervision / Admin Staff - LVD	0	0	0	0	0	0
4.07b - Supervision / Admin Staff - HVD	0	0	0	0	0	0
4.09 - Smart Energy Operations Center	0	0	0	0	0	0
4.10 - Underground Workforce	292	292	292	292	292	292
4.11 - Grid Management - Distr	6,923	6,923	6,923	6,923	6,923	6,923
HVD Lines Construction Workforce	607	607	607	607	607	607
4.0 - Field Operations	28,494	28,494	28,494	28,494	28,494	28,494
5.01 - Compliance and Controls	1,606	1,606	1,606	1,606	1,606	1,606
5.01 - Compliance and Controls	1,606	1,606	1,606	1,606	1,606	1,606
6.01 - Resource Planning & Closeout	0	0	0	0	0	0
6.02 - Scheduling & Dispatch	0	0	0	0	0	0
6.03 - Contract Administration	0	0	0	0	0	0
6.0 - Planning & Scheduling	0	0	0	0	0	0
7.01 - OP Distribution & Generation	3,860	3,860	3,860	3,860	3,860	3,860
7.02 - OP Business Services	0	0	0	0	0	0
7.0 - Operations Performance	3,860	3,860	3,860	3,860	3,860	3,860
8.01 - DCO Business Support	513	513	513	513	513	513
8.02 - DCO Chargebacks	1,392	1,392	1,392	1,392	1,392	1,392
Electric Operations EICP	0	0	0	0	0	0
8.03 - DCO Accruals (Ops)-Injury & Damages	3,062	3,062	3,062	3,062	3,062	3,062
8.0 - Operations Management	4,967	4,967	4,967	4,967	4,967	4,967
9.01 - Unallocated Emergent Fund (Ops)	(43)	(43)	(43)	(43)	(43)	(43)
9.02 - IT Projects (Ops)	0	0	0	0	0	0
9.0 - Unallocated	(43)	(43)	(43)	(43)	(43)	(43)
Electric Transmission	0	0	0	0	0	0
Total Ops OM	309,429	316,865	316,873	316,853	316,831	316,831
Engineering Dist O&M (\$k)	2,024	2,025	2,026	2,027	2,028	
1.03 - Customer Energy Mgmt	449	449	449	449	449	449
1.0 - Engineering Support	449	449	449	449	449	449
1.10 - Electric Distribution Management	145	145	145	145	145	145
1.1 - Electric Distribution Management	145	145	145	145	145	145
2.03 - Planning - LVD System	3,826	3,826	3,826	3,826	3,826	3,826
2.04 - Planning - HVD System	3,348	3,348	3,348	3,348	3,348	3,348
2.06 - System Protection - Distr	1,513	1,513	1,513	1,513	1,513	1,513
2.07 - Planning Analytics	559	559	559	559	559	559
2.08 - Planning Projects	2,946	2,946	2,946	2,946	2,946	2,946
2.0 - Electric Distribution Planning	12,192	12,192	12,192	12,192	12,192	12,192
3.03 - Design - LVD	493	493	493	493	493	493
3.04 - Design - HVD	703	703	703	703	703	703
3.05 - Joint Pole Rental	2,351	2,351	2,351	2,351	2,351	2,351
3.06 - Standards	653	653	653	653	653	653
3.0 - Electric Distribution Design	4,200	4,200	4,200	4,200	4,200	4,200
4.01 - Electric Regulatory & Asset Strategy	36	36	36	36	36	36
4.0 - Electric Distribution Strategy	36	36	36	36	36	36
8.01 - EEO Forecast Challenge / UEF	0	0	0	0	0	0
8.02 - EEO IT Projects	0	0	0	0	0	0
8.0 - Unallocated	0	0	0	0	0	0
Total Engr OM	17,022	17,022	17,022	17,022	17,022	17,022
TOTAL ELEC DIST O&M	\$326,451	\$333,887	\$333,895	\$333,875	\$333,853	

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EDIIP O&M (\$ thousands)					
Elec Ops O&M (\$k)	2024	2025	2026	2027	2028
1.01 - O&M Assoc w/Construction	0	0	0	0	0
1.02 - Transformer Credits	0	0	0	0	0
1.0 - O&M Assoc w/Construction	0	0	0	0	0
2.01 - Lines Reliability - LVD	1,166	30,027	30,727	30,527	30,427
2.02 - Lines Reliability - HVD	305	2,300	3,100	3,100	3,100
2.04 - Substations Reliability - LVD	3,179	14,500	14,500	14,500	14,500
2.05 - Substations Reliability - HVD	2,143	13,700	13,700	13,700	13,700
2.0A - Non-Forestry Reliability	6,793	60,527	62,027	61,827	61,727
2.07 - Forestry (ERev 4,13,22)	105,371	112,792	113,122	113,428	113,752
2.08 - Forestry - HVD	12,279	12,294	11,972	11,646	11,300
2.0B - Forestry Reliability	117,650	125,086	125,094	125,074	125,052
3.01 - Lines Demand - HVD	784	784	784	784	784
3.03 - Substations Demand - LVD	5,001	5,001	5,001	5,001	5,001
3.04 - Substations Demand - HVD	3,357	3,357	3,357	3,357	3,357
3.07 - Corrective Maintenance	4,154	4,154	4,154	4,154	4,154
3.09 - Staking	5,282	5,282	5,282	5,282	5,282
3.10 - Meter Services (ERev 2,11,20)	916	916	916	916	916
3.10a - Meter Credits	0	0	0	0	0
3.11 - Streetlighting	1,627	1,627	1,627	1,627	1,627
3.12 - Service Calls	4,518	4,518	4,518	4,518	4,518
3.13 - Alma Equipment Repair	566	566	566	566	566
3.14 - Meter Reading (ERev 3,12,21)	1,859	1,859	1,859	1,859	1,859
3.15 - Meter Tech & Mgmt Sys Support	1,230	1,230	1,230	1,230	1,230
3.16 - Smart Energy MTC - Elec	9,492	9,492	9,492	9,492	9,492
3.0A - Ops, Mtc & Mtr w/o Svc Rest	38,785	38,785	38,785	38,785	38,785
3.06 - Service Restoration - LVD	96,057	96,057	96,057	96,057	96,057
3.0B - Service Restoration	96,057	96,057	96,057	96,057	96,057
4.01 - Training	9,615	9,615	9,615	9,615	9,615
4.02 - Facilities Building Opers & Maint	4,781	4,781	4,781	4,781	4,781
4.03 - Tools	1,497	1,497	1,497	1,497	1,497
4.04 - Field Operations Expenses	2,287	2,287	2,287	2,287	2,287
4.05 - Energy Operations Indirect Labor	0	0	0	0	0
4.06 - Labor Variation	0	0	0	0	0
4.07 - Supervision / Admin Staff - T&WM	669	669	669	669	669
4.07a - Supervision / Admin Staff - LVD	3,767	3,767	3,767	3,767	3,767
4.07b - Supervision / Admin Staff - HVD	958	958	958	958	958
4.09 - Smart Energy Operations Center	0	0	0	0	0
4.10 - Underground Workforce	292	292	292	292	292
4.11 - Grid Management - Distr	5,947	5,947	5,947	5,947	5,947
HVD Lines Construction Workforce	0	0	0	0	0
4.0 - Field Operations	29,813	29,813	29,813	29,813	29,813
5.01 - Compliance and Controls	1,263	1,263	1,263	1,263	1,263
5.01 - Compliance and Controls	1,263	1,263	1,263	1,263	1,263
6.01 - Resource Planning & Closeout	0	0	0	0	0
6.02 - Scheduling & Dispatch	0	0	0	0	0
6.03 - Contract Administration	0	0	0	0	0
6.0 - Planning & Scheduling	0	0	0	0	0
7.01 - OP Distribution & Generation	3,860	3,860	3,860	3,860	3,860
7.02 - OP Business Services	0	0	0	0	0
7.0 - Operations Performance	3,860	3,860	3,860	3,860	3,860
8.01 - DCO Business Support	513	513	513	513	513
8.02 - DCO Chargebacks	1,392	1,392	1,392	1,392	1,392
Electric Operations EICP	0	0	0	0	0
8.03 - DCO Accruals (Ops)-Injury & Damages	3,062	3,062	3,062	3,062	3,062
8.0 - Operations Management	4,967	4,967	4,967	4,967	4,967
9.01 - Unallocated Emergent Fund (Ops)	(43)	(43)	(43)	(43)	(43)
9.02 - IT Projects (Ops)	0	0	0	0	0
9.0 - Unallocated	(43)	(43)	(43)	(43)	(43)
Electric Transmission	0	0	0	0	0
Total Ops OM	299,146	360,315	361,823	361,603	361,481
Engineering Dist O&M (\$k)	2024	2025	2026	2027	2028
1.03 - Customer Energy Mgmt	434	434	434	434	434
1.0 - Engineering Support	434	434	434	434	434
1.10 - Electric Distribution Management	203	203	203	203	203
1.1 - Electric Distribution Management	203	203	203	203	203
2.03 - Planning - LVD System	2,827	2,827	2,827	2,827	2,827
2.04 - Planning - HVD System	3,591	3,591	3,591	3,591	3,591
2.06 - System Protection - Distr	1,503	1,503	1,503	1,503	1,503
2.07 - Planning Analytics	546	546	546	546	546
2.08 - Planning Projects	2,124	2,124	2,124	2,124	2,124
2.0 - Electric Distribution Planning	10,591	10,591	10,591	10,591	10,591
3.03 - Design - LVD	504	504	504	504	504
3.04 - Design - HVD	808	808	808	808	808
3.05 - Joint Pole Rental	2,351	2,351	2,351	2,351	2,351
3.06 - Standards	492	492	492	492	492
3.0 - Electric Distribution Design	4,155	4,155	4,155	4,155	4,155
4.01 - Electric Regulatory & Asset Strategy	(40)	(40)	(40)	(40)	(40)
4.0 - Electric Distribution Strategy	(40)	(40)	(40)	(40)	(40)
8.01 - EEO Forecast Challenge / UEF	0	0	0	0	0
8.02 - EEO IT Projects	0	0	0	0	0
8.0 - Unallocated	0	0	0	0	0
Total Engr OM	15,343	15,343	15,343	15,343	15,343
TOTAL ELEC DIST O&M	314,489	375,658	377,166	376,946	376,824

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Variance O&M					
(\$ thousands)					
Elec Ops O&M (\$k)	2024	2025	2026	2027	2028
1.01 - O&M Assoc w/Construction	\$0	\$0	\$0	\$0	\$0
1.02 - Transformer Credits	\$0	\$0	\$0	\$0	\$0
1.0 - O&M Assoc w/Construction	\$0	\$0	\$0	\$0	\$0
2.01 - Lines Reliability - LVD	\$0	\$28,861	\$29,561	\$29,361	\$29,261
2.02 - Lines Reliability - HVD	\$0	\$1,995	\$2,795	\$2,795	\$2,795
2.04 - Substations Reliability - LVD	\$0	\$11,321	\$11,321	\$11,321	\$11,321
2.05 - Substations Reliability - HVD	\$0	\$11,557	\$11,557	\$11,557	\$11,557
2.0A - Non-Forestry Reliability	0	53,734	55,234	55,034	54,934
2.07 - Forestry (ERev 4,13,22)	\$0	\$0	\$0	\$0	\$0
2.08 - Forestry - HVD	\$0	\$0	\$0	\$0	\$0
2.0B - Forestry Reliability	0	0	0	0	0
3.01 - Lines Demand - HVD	\$0	\$0	\$0	\$0	\$0
3.03 - Substations Demand - LVD	\$0	\$0	\$0	\$0	\$0
3.04 - Substations Demand - HVD	\$0	\$0	\$0	\$0	\$0
3.07 - Corrective Maintenance	\$0	\$0	\$0	\$0	\$0
3.09 - Staking	\$0	\$0	\$0	\$0	\$0
3.10 - Meter Services (ERev 2,11,20)	\$0	\$0	\$0	\$0	\$0
3.10a - Meter Credits	\$0	\$0	\$0	\$0	\$0
3.11 - Streetlighting	\$0	\$0	\$0	\$0	\$0
3.12 - Service Calls	\$0	\$0	\$0	\$0	\$0
3.13 - Alma Equipment Repair	\$0	\$0	\$0	\$0	\$0
3.14 - Meter Reading (ERev 3,12,21)	\$0	\$0	\$0	\$0	\$0
3.15 - Meter Tech & Mgmt Sys Support	\$0	\$0	\$0	\$0	\$0
3.16 - Smart Energy MTC - Elec	\$0	\$0	\$0	\$0	\$0
3.0A - Ops, Mtc & Mtr w/o Svc Rest	\$0	\$0	\$0	\$0	\$0
3.06 - Service Restoration - LVD	(\$11,260)	(\$11,260)	(\$11,260)	(\$11,260)	(\$11,260)
3.0B - Service Restoration	(\$11,260)	(\$11,260)	(\$11,260)	(\$11,260)	(\$11,260)
4.01 - Training	(\$1,076)	(\$1,076)	(\$1,076)	(\$1,076)	(\$1,076)
4.02 - Facilities Building Opers & Maint	\$4,781	\$4,781	\$4,781	\$4,781	\$4,781
4.03 - Tools	(\$52)	(\$52)	(\$52)	(\$52)	(\$52)
4.04 - Field Operations Expenses	(\$204)	(\$204)	(\$204)	(\$204)	(\$204)
4.05 - Energy Operations Indirect Labor	\$0	\$0	\$0	\$0	\$0
4.06 - Labor Variation	\$0	\$0	\$0	\$0	\$0
4.07 - Supervision / Admin Staff - T&WM	(\$5,272)	(\$5,272)	(\$5,272)	(\$5,272)	(\$5,272)
4.07a - Supervision / Admin Staff - LVD	\$3,767	\$3,767	\$3,767	\$3,767	\$3,767
4.07b - Supervision / Admin Staff - HVD	\$958	\$958	\$958	\$958	\$958
4.09 - Smart Energy Operations Center	\$0	\$0	\$0	\$0	\$0
4.10 - Underground Workforce	\$0	\$0	\$0	\$0	\$0
4.11 - Grid Management - Distr	(\$976)	(\$976)	(\$976)	(\$976)	(\$976)
HVD Lines Construction Workforce	(\$607)	(\$607)	(\$607)	(\$607)	(\$607)
4.0 - Field Operations	\$1,319	\$1,319	\$1,319	\$1,319	\$1,319
5.01 - Compliance and Controls	(\$343)	(\$343)	(\$343)	(\$343)	(\$343)
5.01 - Compliance and Controls	(\$343)	(\$343)	(\$343)	(\$343)	(\$343)
6.01 - Resource Planning & Closeout	\$0	\$0	\$0	\$0	\$0
6.02 - Scheduling & Dispatch	\$0	\$0	\$0	\$0	\$0
6.03 - Contract Administration	\$0	\$0	\$0	\$0	\$0
6.0 - Planning & Scheduling	\$0	\$0	\$0	\$0	\$0
7.01 - OP Distribution & Generation	\$0	\$0	\$0	\$0	\$0
7.02 - OP Business Services	\$0	\$0	\$0	\$0	\$0
7.0 - Operations Performance	\$0	\$0	\$0	\$0	\$0
8.01 - DCO Business Support	\$0	\$0	\$0	\$0	\$0
8.02 - DCO Chargebacks	\$0	\$0	\$0	\$0	\$0
Electric Operations EICP	\$0	\$0	\$0	\$0	\$0
8.03 - DCO Accruals (Ops)-Injury & Damages	\$0	\$0	\$0	\$0	\$0
8.0 - Operations Management	\$0	\$0	\$0	\$0	\$0
9.01 - Unallocated Emergent Fund (Ops)	\$0	\$0	\$0	\$0	\$0
9.02 - IT Projects (Ops)	\$0	\$0	\$0	\$0	\$0
9.0 - Unallocated	\$0	\$0	\$0	\$0	\$0
Electric Transmission	\$0	\$0	\$0	\$0	\$0
Total Ops OM	(\$10,283)	\$43,450	\$44,950	\$44,750	\$44,650
Engineering Dist O&M (\$k)	2024	2025	2026	2027	2028
1.03 - Customer Energy Mgmt	(15)	(15)	(15)	(15)	(15)
1.0 - Engineering Support	(15)	(15)	(15)	(15)	(15)
1.10 - Electric Distribution Management	58	58	58	58	58
1.1 - Electric Distribution Management	58	58	58	58	58
2.03 - Planning - LVD System	(999)	(999)	(999)	(999)	(999)
2.04 - Planning - HVD System	243	243	243	243	243
2.06 - System Protection - Distr	(10)	(10)	(10)	(10)	(10)
2.07 - Planning Analytics	(13)	(13)	(13)	(13)	(13)
2.08 - Planning Projects	(822)	(822)	(822)	(822)	(822)
2.0 - Electric Distribution Planning	(1,601)	(1,601)	(1,601)	(1,601)	(1,601)
3.03 - Design - LVD	11	11	11	11	11
3.04 - Design - HVD	105	105	105	105	105
3.05 - Joint Pole Rental	(0)	(0)	(0)	(0)	(0)
3.06 - Standards	(161)	(161)	(161)	(161)	(161)
3.0 - Electric Distribution Design	(45)	(45)	(45)	(45)	(45)
4.01 - Electric Regulatory & Asset Strategy	(76)	(76)	(76)	(76)	(76)
4.0 - Electric Distribution Strategy	(76)	(76)	(76)	(76)	(76)
8.01 - EEO Forecast Challenge / UEF	0	0	0	0	0
8.02 - EEO IT Projects	0	0	0	0	0
8.0 - Unallocated	0	0	0	0	0
Total Engr OM	(1,679)	(1,679)	(1,679)	(1,679)	(1,679)
TOTAL ELEC DIST O&M	(\$11,962)	\$41,771	\$43,271	\$43,071	\$42,971

CECo Response to AG-CE-0405 (revised)

U21585-AG-CE-0405_Kelly_ATT_1	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Actual All Weather Customers Interrupted	2,079,821	2,373,331	2,346,681	2,893,155	2,485,737	2,973,272	2,395,548	2,565,577									
Net Customers Interrupted Including MEDs (EDIIP)								2,341,483	2,298,702	2,258,753	2,202,032	2,141,116	2,081,961	2,032,252	1,986,080	1,941,188	1,931,351
Net Customers Interrupted including MEDs (Rate Case)								2,341,530	2,299,425	2,265,475	2,247,206	2,227,898	2,210,022	2,191,800	2,177,188	2,163,935	2,183,195
Actual Customers Interrupted Excluding MEDs	1,819,153	1,614,474	1,842,714	2,054,912	1,906,511	1,956,567	1,789,263	1,788,165									
Net Customers Interrupted Excluding MEDs (EDIIP)								1,734,432	1,702,742	1,673,150	1,631,135	1,586,012	1,542,193	1,505,371	1,471,170	1,437,917	1,430,631
Net Customers Interrupted Excluding MEDs (Rate Case)								1,734,467	1,703,278	1,678,129	1,664,597	1,650,295	1,637,053	1,623,555	1,612,732	1,602,915	1,617,182

U21585-AG-CE-0406
Page 1 of 1

Question:

91. Refer to lines 1-9 on page 24 of Mr. Kelly's direct testimony on the Company's three reliability goals. Please identify the year when the Company expects to achieve all three goals.

Response:

Please refer to discovery response U21585-MNSC-CE-0301.

Witness: Michael P. Kelly
Date: August 23, 2024

U21585-MNSC-CE-0301

Page 1 of 1

Question:

16. Refer to Kelly, p. 24, which states, "Investment as outlined in the Reliability Roadmap will set the Company on a path to building a grid that will deliver on three reliability goals."

- a. Please clarify if the Company expects the proposed Reliability Roadmap investments to reach the three listed reliability goals or only to set the Company on the path to doing so.
- b. Please explain by what year the Company will achieve the three reliability goals under the proposed Reliability Roadmap investments.
- c. Please provide what level of confidence (and/or margin of error) the Company has that the proposed investments will achieve these goals by the year provided in Part b of this question, or at all. Please provide any corresponding analyses that support this level of confidence.

Response:

- a. The proposed investment plan for 2024-2028 is not expected to, on its own, be sufficient to achieve the three reliability goals, but will set the Company on the path to doing so.
- b. Provided approval of the 2024-2028 O&M and Capital outlined in the Reliability Roadmap and a continuation of the 2028 investments into 2029, the Company expects to achieve better than the 131 minutes of SAIDI that defined the threshold of the second quartile for SAIDI excluding MEDs in 2023 by IEEE¹. The Company has not yet determined a projected year in which the other two reliability goals will be achieved.
- c. The Company has not conducted an analysis to determine a specific level of confidence and/or margin of error. The Company expects that the proposed investments will result in a SAIDI better than 131 minutes in 2029 given the recent accuracy of the modeling the Company has conducted since SAIDI glidepath conveyed in U-20697 and in each subsequent rate case where the actual system performance compared to forecasted/modeled system performance has averaged a variance of 2.5%.

Witness: Michael P. Kelly

Date: August 20, 2024

CECo WP-JCA-51

Consumers Energy Company
Inflation Factors
For the Projected Year Ending February 28, 2026

Case No.: U-21585
WP-JCA-51

Forecast at a glance

Base forecast (October 2023) 2023:Q3 - 2027:Q4

	Major economic indicators																	
	% ch. from prior quarter, annual rate						% ch. from prior year, or annual average						% ch. from fourth quarter of prior year, or fourth-quarter average					
	2023.1	2023.2	2023.3	2023.4	2024.1	2024.2	2022	2023	2024	2025	2026	2027	2022.4	2023.4	2024.4	2025.4	2026.4	2027.4
Key Indicators of real activity																		
Real gross domestic product	2.2	2.1	5.2	1.7	0.5	1.0	1.9	2.5	1.6	1.2	1.6	1.8	0.7	2.8	1.0	1.3	1.8	1.8
Contributions to growth (% points):																		
Final sales to domestic purchasers	3.9	2.0	3.6	1.9	1.0	1.2	1.8	2.2	1.6	1.4	1.8	1.9	0.8	2.9	1.2	1.5	1.9	1.9
Net exports of goods & services	0.6	0.0	1.2	0.0	-0.5	-0.2	-0.5	0.7	-0.1	-0.2	-0.2	-0.1	0.2	0.4	-0.3	-0.3	-0.2	-0.1
Change in private inventories	-2.2	0.0	0.4	-0.2	0.0	0.0	0.6	-0.5	0.0	0.1	0.1	0.0	-0.3	-0.6	0.1	0.1	0.1	0.0
Major components of real GDP																		
Personal consumption expend.	3.8	0.8	4.0	2.1	1.3	1.3	2.5	2.3	1.8	1.5	2.0	2.3	1.2	2.6	1.3	1.7	2.2	2.2
Nonres. fixed investment	5.7	7.4	1.3	2.4	1.1	0.8	5.2	4.4	1.6	0.9	1.4	1.9	5.6	4.2	0.9	1.0	1.7	2.0
Residential investment	-5.3	-2.2	5.3	-2.3	-4.2	1.0	-9.0	-11.0	-0.4	3.6	2.7	1.4	-17.4	-1.2	0.5	4.0	1.5	2.0
Change in private inventories *	27.2	14.9	37.8	25.2	23.8	21.9	128.1	26.3	28.0	50.7	63.5	70.9	151.9	25.2	39.3	54.9	68.7	72.1
Exports of goods & services	6.8	-9.3	8.7	6.2	1.1	4.2	7.0	3.1	3.4	3.5	3.6	3.5	4.3	2.8	3.3	3.3	3.7	3.4
Imports of goods & services	1.3	-7.6	-1.5	5.0	4.8	4.6	8.6	-2.2	3.2	4.7	4.4	3.7	2.1	-0.8	4.8	4.6	4.2	3.4
Gov't consump. & gross invest.	4.8	3.3	3.2	1.8	0.9	0.8	-0.9	3.6	1.4	0.5	0.4	0.2	0.8	3.3	0.7	0.5	0.4	0.1
Pvt. housing starts (thous. units)																		
Pvt. housing starts (thous. units)	1385	1450	1383	1384	1377	1381	1551	1401	1385	1404	1397	1383	1405	1384	1392	1407	1385	1378
Light vehicle sales (mil. units)																		
Light vehicle sales (mil. units)	15.3	15.6	15.6	15.3	15.2	15.5	13.8	15.5	15.7	16.5	16.6	16.4	14.3	15.3	16.2	16.6	16.6	16.2
Industrial production, total																		
Industrial production, total	-0.3	0.7	1.3	-3.4	-2.3	-1.2	3.4	0.0	-1.3	0.2	1.0	1.2	1.8	-0.4	-1.0	0.6	1.1	1.2
Industrial production, mfg																		
Industrial production, mfg	-0.2	0.4	-1.0	-3.2	-1.8	-0.3	2.7	-0.8	-1.1	0.7	1.0	1.3	0.6	-1.0	-0.2	0.8	1.2	1.3
Capacity utilization (mfg, %)																		
Capacity utilization (mfg, %)	78.2	78.0	77.6	76.7	76.1	75.7	79.2	77.6	75.7	75.3	75.2	75.2	78.5	76.7	75.5	75.2	75.2	75.2
Nonfarm payroll employ. (mil.)																		
Nonfarm payroll employ. (mil.)	155.2	155.9	156.6	157.2	157.4	157.4	152.6	156.2	157.3	156.9	156.8	157.4	154.3	157.2	157.1	156.7	157.0	157.7
Average monthly chg. (thous.)																		
Average monthly chg. (thous.)	312	201	266	141	34	-18	399	230	-16	-31	26	60	284	141	-42	-8	44	68
Private nonfarm hours																		
Private nonfarm hours	2.6	-1.5	1.4	2.0	0.3	-0.1	4.0	1.4	0.5	-0.3	0.1	0.5	2.5	1.1	-0.1	-0.2	0.3	0.6
Civilian unemployment rate (%)																		
Civilian unemployment rate (%)	3.5	3.5	3.7	3.7	3.7	3.8	3.6	3.6	3.8	4.4	4.7	4.6	3.6	3.7	4.0	4.6	4.7	4.6
Prices, Productivity, & Costs																		
CPI, all items, all urban																		
CPI, all items, all urban	3.8	2.7	3.4	2.4	1.3	2.6	8.0	4.1	2.4	2.2	2.2	2.2	7.1	3.1	2.4	2.0	2.2	2.2
CPI excl food & energy, all urban																		
CPI excl food & energy, all urban	5.0	4.7	2.8	3.2	2.7	2.8	6.1	4.8	2.9	2.4	2.2	2.2	6.0	3.9	2.6	2.3	2.2	2.2
PCE price index																		
PCE price index	4.2	2.5	2.9	2.3	1.8	2.4	6.5	3.8	2.3	2.1	2.0	2.0	5.9	2.9	2.3	1.9	2.0	2.0
PCE price excl food & energy																		
PCE price excl food & energy	5.0	3.7	2.5	2.8	2.5	2.5	5.2	4.2	2.6	2.2	2.0	2.0	5.1	3.5	2.4	2.1	2.0	2.0
PPI finished goods																		
PPI finished goods	0.6	-6.0	5.7	3.3	0.1	1.5	13.4	1.8	1.6	1.3	1.5	1.9	10.2	0.8	1.4	1.1	1.6	2.0
Compensation per hour																		
Compensation per hour	7.2	6.9	3.7	2.9	3.8	4.0	3.3	4.5	3.9	3.7	3.5	3.6	1.9	5.2	3.9	3.6	3.5	3.7
Output per hour																		
Output per hour	-0.8	3.5	4.5	-0.5	-0.3	0.9	-1.9	1.1	1.0	1.5	1.7	1.5	-2.1	1.6	0.9	1.6	1.6	1.5
Unit labor cost																		
Unit labor cost	8.0	3.3	-0.7	3.4	4.0	3.1	5.3	3.4	2.8	2.2	1.8	2.1	4.1	3.5	3.0	1.9	1.8	2.2
Fed Financial Accounts house price index **																		
Fed Financial Accounts house price index **	-0.9	4.2	1.4	1.2	1.1	1.0	16.4	1.8	5.3	3.6	3.5	3.5	8.8	6.1	4.0	3.5	3.5	3.5
Price of WTI crude oil (\$/barrel)																		
Price of WTI crude oil (\$/barrel)	76.08	73.76	82.32	83.98	77.71	79.47	94.78	79.03	81.58	78.30	77.80	80.26	82.79	83.98	84.18	77.04	78.34	81.35
Price of Brent crude oil (\$/barrel)																		
Price of Brent crude oil (\$/barrel)	81.27	78.39	86.51	88.33	82.33	84.00	100.72	83.63	86.25	83.92	85.24	86.97	88.58	88.33	89.00	83.00	85.88	87.63
Selected Financial Variables																		
Federal funds rate (%)																		
Federal funds rate (%)	4.52	4.99	5.26	5.39	5.60	5.56	1.68	5.04	5.38	4.05	2.86	2.62	3.65	5.39	5.05	3.56	2.62	2.62
Yield on 10-Yr Treasury Notes (%)																		
Yield on 10-Yr Treasury Notes (%)	3.65	3.59	4.15	4.67	4.42	4.23	2.95	4.02	4.13	3.53	3.28	3.24	3.83	4.67	3.85	3.39	3.25	3.24
Baa corporate bond yield (%)																		
Baa corporate bond yield (%)	5.65	5.76	6.03	6.57	6.38	6.27	5.14	6.00	6.21	5.78	5.53	5.40	5.99	6.57	6.03	5.66	5.47	5.37
Broad trade-wtd US\$ (Jan 2006=100)																		
Broad trade-wtd US\$ (Jan 2006=100)	120.3	119.7	121.9	122.0	122.6	122.6	120.7	121.0	122.2	120.2	117.7	115.6	124.8	122.0	121.5	119.2	116.8	114.9
S&P 500 stock index, period end																		
S&P 500 stock index, period end	4109	4450	4287	4073	3896	3869	3839	4073	3865	4039	4169	4286	3839	4073	3865	4039	4169	4286
S&P 500 stock index, average																		
S&P 500 stock index, average	4003	4204	4458	4180	3985	3882	4101	4211	3901	3935	4112	4221	3852	4180	3867	4011	4156	4268
Incomes & Related Measures																		
Corporate profits w/ IVA & CCA[d]																		
Corporate profits w/ IVA & CCA[d]	-9.9	0.9	16.8	-4.4	-7.0	-4.9	9.8	0.5	-2.4	-2.3	1.5	2.5	8.6	0.4	-4.9	-0.8	2.4	2.7
Real disposable personal income																		
Real disposable personal income	10.8	3.5	-0.8	2.4	4.4	3.0	-6.0	4.1	2.7	2.7	2.3	2.4	-1.5	3.9	3.1	2.5	2.3	2.4
Personal saving rate (%)																		
Personal saving rate (%)	4.8	5.2	3.9	3.7	4.4	4.8	3.3	4.4	4.9	5.9	6.2	6.3	3.2	3.7	5.3	6.0	6.1	6.3
Fed. surplus (unified, FY, bil. \$)																		
Fed. surplus (unified, FY, bil. \$)	-2717	-1168	-1291	-1689	-2254	-456	-1375	-1715	-1483	-1702	-1817	-1893	-1686	-1689	-1955	-2089	-2172	-2361

**billions of chained 2017 \$

**% change, not annualized

Source: S&P Global Market Intelligence

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U21389-AG-CE-0441

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Question:

102. Refer to lines 1-9 on page 15 of Mr. Lynd's direct testimony on service line installations. Please:

- a. Explain why contractor costs increased by 75% over a two-year period from 2020 to 2022. Explain why the Company would agree to such a large increase in contractor rates.
- b. If the Company offered fewer units to contractors, who performed the remaining installations?
- c. Provide the number of units installed by contractors and related cost for each year 2018-2022.
- d. Provide the remaining units installed by the Company or other party than contractors and related cost for each year 2018 to 2022. If the cost of installation by the Company is significantly lower than contractors, why did the Company not hire more workers to perform the work and release all contractors.
- e. Provide the calculation of the 75% and 30% in Excel with supporting data.
- f. What is the expected percentage increase in wire and cable costs, as well as contractor costs for 2023, 2024 and 2025? Provide the basis for those cost increase percentages.

Response:

- a. The increase in contractor costs are due to several factors including inflation, labor shortages, and scope of work that contractors have been hired to perform. Contractors are also hired to provide specialized equipment, as needed, which can increase the cost for a specific project. The Company maintains a working relationship with contractors to meet the demand for new business work. Refer also to the direct testimony of Company witness Slieff who discusses the importance of both Company and contracted resources.
- b. Company crews perform the installations not performed by contractors.
- c. The Company does not have a breakout of contractor units prior to 2020. The direct contractor cost from 2018 to 2022 and LVD Lines New Business units from 2020 to 2022 are provided below.

	2018	2019	2020	2021	2022
Direct	9,999,581	15,434,640	24,683,244	33,283,541	32,790,307
CTR Unit (planning)			4,054	4,892	3,059

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- d. As noted in subpart (b), Company crews complete LVD Lines New Business installations not completed by contracted lineworkers. As noted in subpart (c), the Company does not have a breakout of contractor units prior to 2020. Contractor costs also support units completed by Company crews. Examples include, but are not limited to, the use of contractors for soft digging or traffic control. Accordingly, not all contractor cost can be solely attributed to contractor installed units. Please refer to the direct testimony of Company witness Slieff for the decisions the Company makes when selecting electric line work contactors and utilization or expansion of Company lineworkers.

	2020	2021	2022
Contractor	4,054	4,892	3,059
Company	5,134	5,760	6,603
Total Units	9,188	10,652	9,662

- e. The 75% increase referenced in my direct testimony, page 15, line 7, is: $(\$17,064/9761)-1$ (these costs include Company overheads). The 30% increase referenced in my direct testimony, page 15, line 9, at a higher degree of precision, utilizing the costs provided in subpart (c) is 32.8%: $(\$32,790,307/\$24,683,244)-1$.
- f. Refer to discovery response U21389-AG-CE-0446, subpart (a), for information on expected costs of wire and cable. The Company did not develop a projection of contractor cost percentage increases as part of projecting the LVD Lines New Business program costs.

Witness: DONALD A. LYND
Date: August 3, 2023

U21585-AG-CE-0469
Page 1 of 1

Question:

154. Refer to line 12 on page 28 of Mr. Lynd's direct testimony on LVD Lines Demand Failures. Please provide the basis and show how you determined the \$5,300 average unit cost.

Response:

The \$5,300 average unit cost for LVD Lines Demand Failures is determined by analyzing historical data, considering variations in unit costs, and projecting future expenditures based on anticipated needs. As stated in my direct testimony, page 30, lines 1 through 7, Consumers Energy continues to see an increased unit cost due to increased cost of materials and increased amount of materials used in proactively addressing failures. Additional discussion of increased material costs is provided in my direct testimony, page 15, lines 1 through 5.

Witness: DONALD A. LYND

Date: August 27, 2024

U21585-AG-CE-0477

Page 1 of 2

Question:

162. Refer to Figure 39 on page 82 of Mr. Lynd's direct testimony on LVD Lines Reliability. Please:

- a. Expand the table to include the same information for each year 2019 to 2023 and provide it in Excel.
- b. Explain whether the units of ATR Loops represent the number of loops created or the number of reclosers installed.
- c. What do the units for Zonal Health, Secondary, and Voltage Conversions represent?
- d. Explain why for Secondary the cost for 4 units in the bridge period is so high relative to the test year activity.
- e. Explain why there is a significant decline in the number and cost for Pole replacements in the test year in comparison to the bridge period.
- f. Identify the projects that require right of way easements and the related cost in Excel for 2023, the bridge period, and the projected test year. Provide the number of miles or length of easements being paid for each project.

Response:

- a. The requested information is provided in Exhibit A-112 (MPK-20), lines 15 through 19 and line 55. Secondary and Voltage Conversions are new investment categories and to the extent this type of work was completed, it is included in line 16, Targeted Circuit Improvements.
- b. Units of ATR loops represent the number of loop schemes created.
- c. The units for Zonal Health represent fuses, miles, and projects. The units for Secondary and Voltage Conversions are miles.
- d. The units for Secondary is miles. The cost per unit for the bridge period is \$260,500, and the test year is \$299,800, which is approximately 15% higher. Therefore, the cost for the bridge period is less than the test year. More weight should be given to the test year unit cost given that the bridge period has a small number of units being completed.

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- e. The quantity of poles is based on known and identified poles for replacement. The Company also replaces failed poles as identified in the LVD Lines Demand Failures section of my direct testimony. Nearly every LVD Lines Reliability project receives a review to determine if new easements are required. Acquisition costs (labor, documentation, travel, etc) for LVD easements are accrued in a single account which is why the Company identifies easement costs as a single line item within testimony and exhibits. Forecasted easement payment information is not available. The Company made specific payments for LVD easements to third parties for just three projects in 2023 for a total of \$7,400. The Company made specific payments for LVD easements for one project so far in the bridge period for \$9,100. The Company does not retain the data on the length or miles of those easements where payments are made.

Witness: DONALD A. LYND

Date: August 27, 2024

U21585-AG-CE-0480

Page 1 of 1

Question:

165. Refer to lines 1-10 on page 90 of Mr. Lynd's direct testimony on LVD Substation Reliability. For each of the three bulleted items, please provide the costs for each year 2019-2024 and the line number where the costs were previously included.

Response:

For DSCADA, the investments were formerly part of Grid Modernization. Please refer to discovery response U21585-ST-CE-0006, subpart (a), which provided the historical costs for that investment category.

The other two investment categories itemized in my direct testimony, page 90, HVD line work associated with new and existing LVD substations projects; and ROW procurement, were historically part of the HVD Lines and Substations Capacity subprogram. In prior years, the costs in these categories specific to LVD substations were not tracked separately so historical costs are not available.

Calendar year 2024 is included in the bridge period for this case; those forecasted expenditures are provided in my direct testimony, page 94, Figure 45.

Witness: DONALD A. LYND

Date: August 27, 2024

U21585-ST-CE-0006

Page 1 of 1

Question:

6. Regarding the LVD Substation Reliability Investment Category and Expenditure and Units, page 94, Figure 45:

- a. Please provide the historical (2019 to 2023) expenditure as the same category list as the Figure 45; however, in excel format.
- b. Please explain the items of New or rebuilt substation for Bridge Period and Test Year Capital Expenses, how the 8 units is needed \$8,985,000 for Bridge Period, while the 12 units is needed \$25,442,000 for Test year?

Response:

- a. The historical expenditures for the categories in Figure 45 of my direct testimony are provided in Exhibit A-112 (MPK-20), lines 28 through 33, and line 54. As explained in my direct testimony, page 90, lines 13 through 15, DSCADA projects were previously included in the Automation subprogram instead of LVD Substations Reliability. For ease of comparison, the requested information is being provided in Attachment 1 to this discovery response in the requested Excel format. In this attachment, the dollars reflect the amount invested in the given time period, while the units reflect the number of units completed in that time period, which is why there are some instances where there are dollars but no units.
- b. The increased spending from the bridge period to the test year in the New or Rebuilt Substation investment category is partially due to the four additional substation projects in the test year, and partially due to a new work item within the subprogram. As noted in my direct testimony, page 90, lines 1 through 12, HVD line work associated with new and existing LVD substation projects was previously included in HVD Lines and Substation Capacity subprogram expenditures. Starting in 2024, HVD line work associated with projects in the New or Rebuilt Substation investment category is now included the LVD Substation Reliability subprogram. For example, the \$7,461,000 projected spending for the Houghton Lake project in Exhibit A-128 (DAL-2), page 25, line 5, includes \$2,860,000 in spending for the substation itself and \$4,781,000 in spending for associated HVD line work.

Witness: DONALD A. LYND

Date: July 1, 2024

CECo Response to ST-CE-0006

U21585-ST-CE-0006											
Attachment 1											
LVD Substation Reliability Investment Category Expenditures and Units (2019-2023)											
Investment Categories	2019		2020		2021		2022		2023		Ex. A-112 (MPK-20) line
	2019 Capital	# of Units	2020 Capital	# of Units	2021 Capital	# of Units	2022 Capital	# of Units	2023 Capital	# of Units	
New or rebuilt substations	\$ 6,471,136	6	\$ 4,680,033	4	\$ 1,124,659	2	\$ 4,628,403	4	\$6,067,843	3	28
New mobile substations	\$ 709,830	1	\$ 4,333,957	3	\$ 4,745,155	1	\$ 3,333,542	1	\$2,250,653	2	29
Animal mitigation	\$ 2,276,747	42	\$ 2,327,943	19	\$ 4,655,023	50	\$ 4,701,094	31	\$1,026,099	6	30
Regulator replacements	\$ 601,493	32	\$ 43,434	1	\$ 879,762	15	\$ 728,105	31	\$ 5,481	0	31
Transformer replacements	\$ 300,160	1	\$ 108,389	0	\$ 5,115,612	7	\$ 3,287,007	3	\$5,245,914	3	32
DSCADA Projects (Automation subprogram)	\$10,580,115	42	\$18,184,037	64	\$19,213,429	84	\$13,954,409	64	\$5,446,740	11	54

U21585-AG-CE-0490
Page 1 of 3

Question:

175. Refer to lines 1-5 on page 141 of Mr. Lynd's direct testimony on Fractionalization. Please:

- a. Provide the number of circuits that fall in the top tier for fractionalization and the percentage of total circuits that this number represents.
- b. Provide the total number of subparts that the top circuits will be fractionalized into.
- c. Provide the number of projects and related cost by year to complete the fractionalization.
- d. Provide the percentage of total company customer interruptions and customer outage minutes that the 848,539 customer interruptions and the 402,278,560 customer-outage-minutes represent.

Response:

- a. The three tiers of circuits discussed in my direct testimony, page 141, lines 1 through 5, are illustrated in Figures 69 and 70 on pages 140 and 141. In the filed version of my direct testimony the figures appear to have reduced quality; therefore, they are reproduced and enlarged below. The three top tiers consist of 142 circuits with more than 2,000 customers and 135 circuits that have more than 75 miles. The Company is most focused on the top 3% of circuits, as described in the Reliability Roadmap, Exhibit A-111 (MPK-19), page 81 (of 183). These circuits serve more than 2,400 customers or have more than 90 miles of line. The top tier, displayed in red in Figures 69 and 70, includes 21 circuits with more than 125 miles and 20 circuits with more than 3,000 customers for 40 unique circuits (1 circuit has both more than 125 miles and more than 3,000 customers). The Company has more than 2,000 LVD circuits, as stated in my direct testimony, page 6, lines 3 through 7. Figures 69 and 70 include 2,386 circuits; therefore, the top tier (red) represents 1.7% of the total circuits.

FIGURE 69
CIRCUITS RANKED BY OVERHEAD PRIMARY LINE EXPOSURE

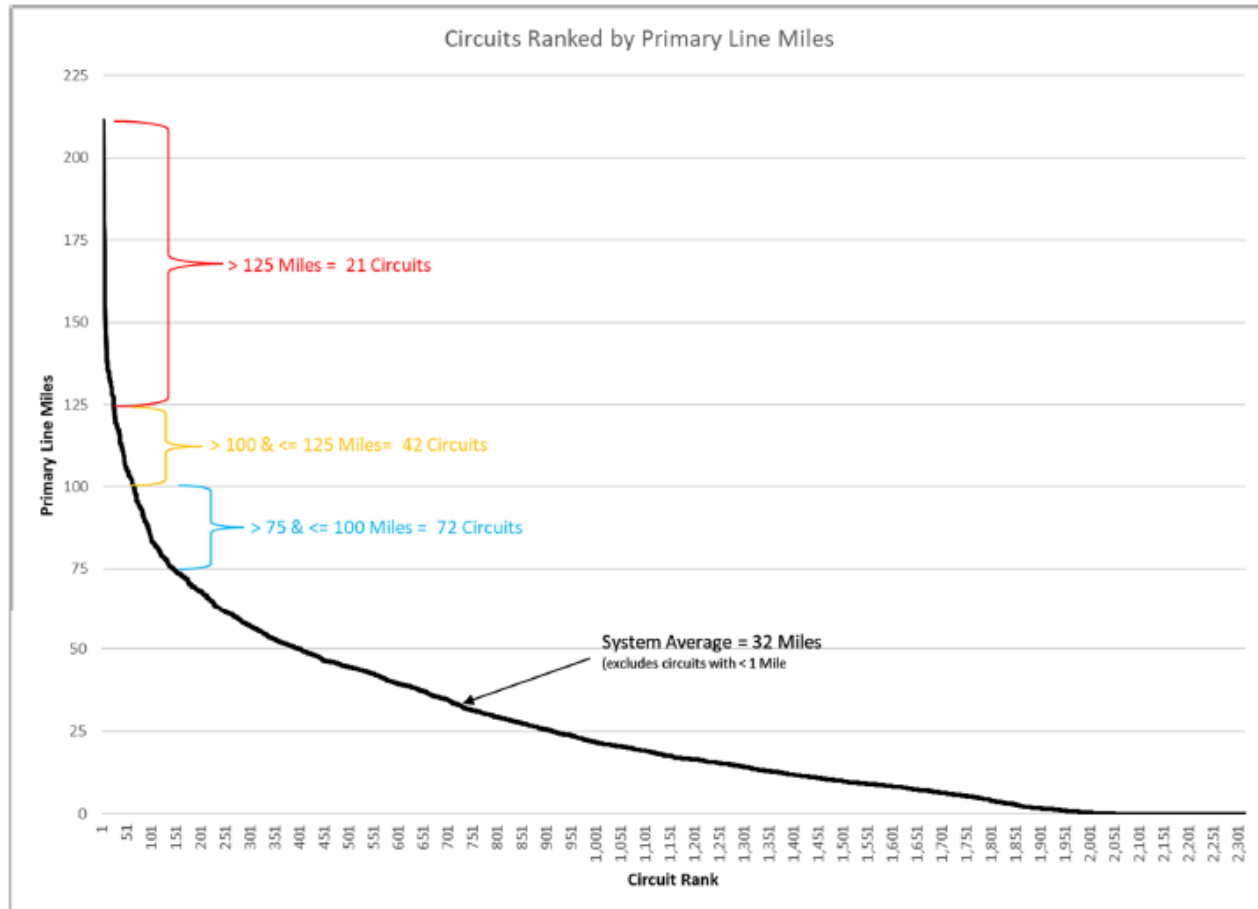
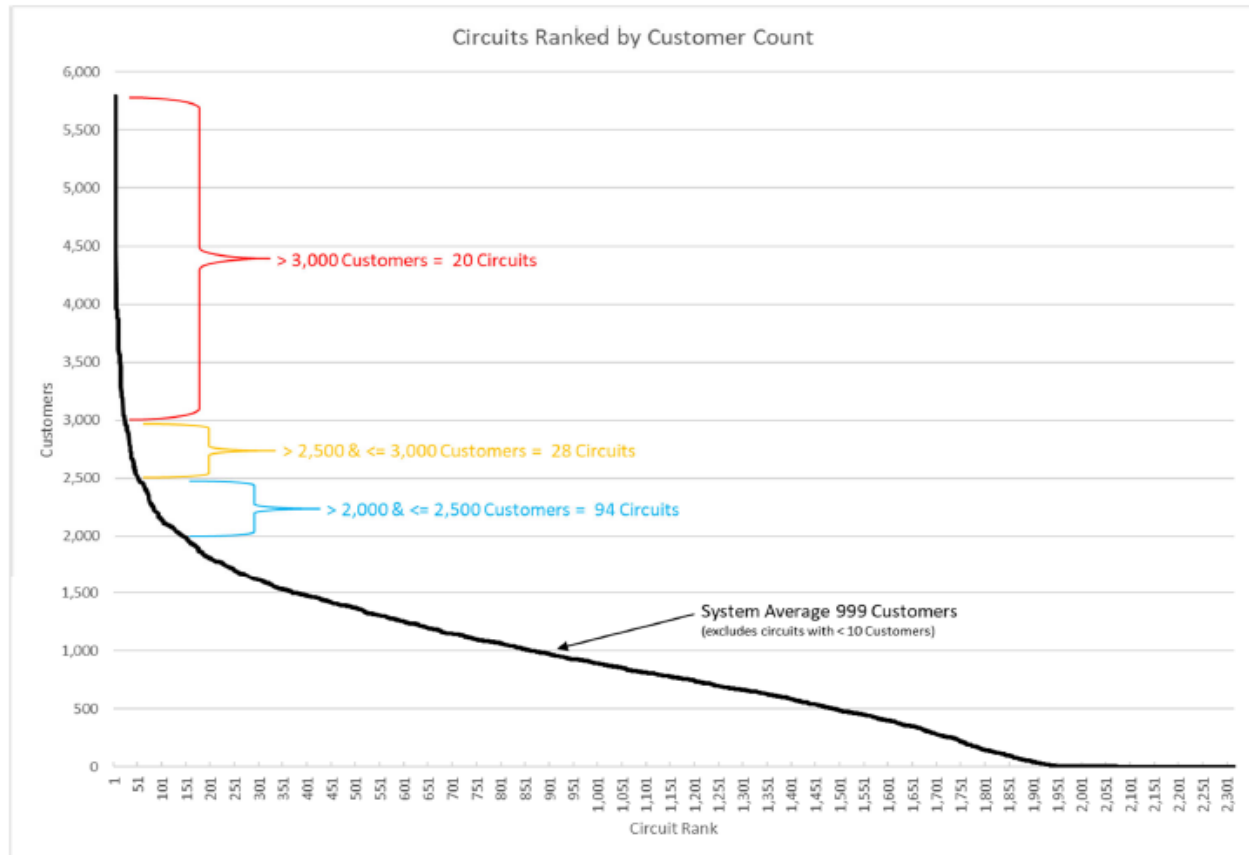


FIGURE 70
CIRCUITS RANKED BY CUSTOMER COUNT



- b. Fractionalizing is a relatively new concept at the Company and a final goal has not been established. My direct testimony, page 145, Figure 72, illustrates the pre- and post-investment configuration by circuit for the bridge period and test year fractionalizing investments. Fractionalization plans beyond the test year have not been established to this detail.
- c. As noted in subpart (b) above, a final goal has not been established for Fractionalization.
- d. For 2019 to 2023 combined, for the three tiers displayed in Figures 69 and 70, the 848,539 customer interruptions were 6% of the total system; the 402,278,560 customer-outage-minutes were 6% of the total system. Both numbers include major event days (MEDs).

Witness: DONALD A. LYND
Date: August 27, 2024

U21585-AG-CE-0495

Page 1 of 1

Question:

180. Refer to Figure 72 on page 145 of Mr. Lynd's direct testimony on fractionalization projects. It appears that some of the circuits listed in the table are not being fractionalized give that the same number of customers are retained on the lines after fractionalization as they were pre-fractionalization. For examples: Backus Substation-Maple Valley with 1,001 customers pre and post; Bennington Substation-Manitou 759 customers; Eagle Substation-Chicago 1,892 customers, Pioneer 1,171 customers, Cottonwood 2,083 customers. Other circuits show only minimal fractionalization of customers to different circuits or lines. Explain what the purpose of fractionalization is if no changes or no significant changes are being made to these circuits.

Response:

Figure 72 shows all substations impacted by the Fractionalization project plan in the bridge period and test year even though some of the circuits for those substations will not be impacted. While the Company has not set a definitive fractionalizing end-state, as noted in discovery response U21585-AG-CE-0490, it is focused on reducing the number of circuits in top tiers, accordingly a Fractionalizing project may not address every circuit at a substation.

For the Backus Substation project, the work scope is focused on fractionalizing the 116 miles of the present Springbrook Circuit.

For the Bennington Substation project, the work scope is focused on fractionalizing the 114 miles of the Grand River Circuit.

For the Eagle Substation project, the work scope is primarily focused on fractionalizing circuits at Hager Park, Van Buren, and Chicago substations. The new Eagle Substation circuitry adjusts electrical loading, customer count, and circuit miles. The project will also add a distribution automation loop for Rosewood Substation, Lamplighter Circuit to minimize the number of customers interrupted. The project's adjustment of electrical loading will reduce the risk of overloaded lines and equipment.

Witness: DONALD A. LYND

Date: August 27, 2024

U21585-AG-CE-0496

Page 1 of 1

Question:

181. Refer to Figure 74 on page 148 of Mr. Lynd's direct testimony on fractionalization projects. For 2023, the bridge period and the test year, please:

- a. Provide the number customers benefiting from the fractionalization projects.
- b. The number of power outages avoided.
- c. The number of outages that occurred on the fractionalized circuits in each year 2019 to 2023, and forecasted to occur after the fractionalization in each year 2024, 2025, and 2026.

Response:

The customer-outage-minute benefit is the most quantifiable project benefit for the LVD Reliability subprograms including Resiliency. These benefits for the Fractionalization projects are provided in Exhibit A-127 (DAL-1), page 41, lines 12 through 14, and Exhibit A-128 (DAL-2), page 40, lines 23 through 26, in the Benefit Type and Benefit columns.

As noted in discovery response U21585-AG-CE-0493, no Fractionalization projects were complete in 2023, therefore, there are no benefits or outages avoided that can be provided for that year.

- a. The number of customers benefiting from the identified bridge period fractionalization projects is 7,630 customers and for the identified test year fractionalization projects it is 13,722 customers.
- b. Reducing the number of unique outage incidents is not the intended purpose of the program. As I stated in my direct testimony, page 146, lines 9 through 13, the investments will reduce the number of customers experiencing a given outage. The estimated reduction in customer-outages, based on the statistics provided in my direct testimony, page 145, Figure 72, is provided in Attachment 1. These benefits will not be realized until the project is completed.
- c. See Attachment 2 for the number of outages on the first zone of each of the pre-investment configuration circuits provided in my direct testimony, page 145, Figure 72. Customer-outages on the first zone are directly impacted by the Fractionalizing projects. The Company's estimate of customer-outages avoided each year is provided in the response to subpart (b) above. As noted, an overall reduction in outage incidents is not anticipated for Fractionalizing projects.

Witness: DONALD A. LYND**Date:** August 27, 2024

CECo Response to AG-CE-0480

U21585-AG-CE-0496			
Attachment 1			
Line No.	Resiliency Project	Customer-Outage-Minute Benefit	Customer- Interruption Benefit
1	Backus	217,331	1,035
2	Bennington	76,750	365
3	Broughwell	129,556	617
4	Eagle	249,309	1,187
5	Greenwood	361,337	1,721
6	Whittemore	107,599	512

CECo Response to AG-CE-0480

U21585-AG-CE-0496								
Attachment 2								
	Pre-Investment Configuration			Number of Outage Incidents				
Line No.	FeederID	Substation	Circuit	2019	2020	2021	2022	2023
1	141201	Backus	Springbrook	1	0	0	0	2
2	141202	Backus	Maple Valley	0	0	0	0	0
3	136001	Bennington	Manitou	1	1	0	1	0
4	136002	Bennington	Grand River	0	1	0	0	0
5	129401	Broughwell	Minard	0	0	0	1	1
6	129402	Broughwell	Onondaga	2	3	0	1	1
7	157201	Maines Road	Town Road	0	0	0	0	2
8	157202	Maines Road	Wellman Road	0	0	1	0	1
9	058801	Chicago	Chicago	1	0	0	0	0
10	058802	Chicago	Pinebrook	0	1	0	2	0
11	027901	Hager Park	Wellington	0	0	0	2	0
12	027902	Hager Park	Hager Park	2	2	0	2	2
13	133201	Rosewood	Pioneer	0	0	0	0	0
14	133202	Rosewood	Cottonwood	0	0	0	0	0
15	133203	Rosewood	Lamplighter	0	1	0	0	0
16	033101	Van Buren	Van Buren	2	0	0	1	1
17	033102	Van Buren	Moss Lake	0	0	0	1	1
18	033103	Van Buren	Rush Lake	0	0	0	0	0
19	140401	Alger	Skidway	4	1	4	1	1
20	140402	Alger	Forest Lake	1	0	0	2	0
21	002001	Greenwood	Rau Road	1	0	3	1	0
22	002002	Greenwood	Indian Lake	1	2	4	1	0
23	127301	Whittemore	M-65	0	0	0	1	1
24	127302	Whittemore	Sand Lake	3	0	0	0	0

U21585-AG-CE-0208
Page 1 of 2

Question:

30. Please refer to the Direct Testimony of Heidi Myers at 10:12-18, where Witness Myers discusses the Company's proposed undergrounding of distribution lines.

- a. Please provide the following information associated with each line the Company proposes to underground:
 - i. Description of distribution line;
 - ii. Expected in-service date associated with undergrounded line; and
 - iii. Expected cost associated with proposed undergrounding.
- b. Please provide all analyses conducted by the Company or by a third party on its behalf examining the costs and benefits of undergrounding the proposed distribution lines.

Response:

- a. Additional discussion of the Overhead to Underground Conversion projects is contained in my direct testimony, in the Resiliency section, pages 136 to 148. The requested data is largely contained in this section of testimony and Exhibit A-127 (DAL-1), page 41, and Exhibit A-128 (DAL-2), pages 40 and 51. Requested items (i), (ii), and (iii) are provided in Attachment 1 to this discovery response.
- b. Please see Attachment 2 to this discovery response for the Company's data for outages in the LVD zones for which the Company has proposed overhead to underground projects. Benefits of overhead to underground conversions are estimated based on industry research such as this article: [Remote-Area Reliability at a Reasonable Cost | T&D World \(tdworld.com\)](#), combined with historical reliability performance of the project areas. The Company estimates that its overhead to underground conversion projects in the Resiliency subprogram will eliminate, on average, 90% of the customer-outage-minutes previously experienced on the zones converted. The Company did not provide a reliability benefit for the projects selected for wildfire mitigation as the key benefit is reduction of wildfire risk; however, a reliability improvement, though not quantified would be expected.

Please see Attachment 3 to this discovery response for the analysis conducted by Company Witness Kelly for the original request to pilot overhead to underground conversions in Case No. U-21389.

The Company projected \$400,000 per mile for both the bridge and test year projects consistent with my testimony filed in Case No. U-21389, which was informed by work completed for Case No. U-21222, in the Company's report filed on October 1, 2021 (<https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000UcQE2AAN>), particularly pages 119 to 121. The chart of costs presented in that report is duplicated below. The Company's estimated cost of overhead to underground conversion projects has also been informed by discussions with other utilities.

FIGURE 29

COSTS FOR MOVING OVERHEAD CIRCUITS TO UNDERGROUND

	Rural Overhead to Underground	Urban Overhead to Underground
Minimum	\$277,000 <i>Labor = \$179,000</i> <i>Material = \$98,000</i>	\$757,000 <i>Labor = \$514,000</i> <i>Material = \$243,000</i>
Average	\$626,000 <i>Labor = \$285,000</i> <i>Material = \$341,000</i>	\$1,342,000 <i>Labor = \$908,000</i> <i>Material = \$434,000</i>
Maximum	\$974,000 <i>Labor = \$390,000</i> <i>Material = \$584,000</i>	\$1,926,000 <i>Labor = \$1,301,000</i> <i>Material = \$625,000</i>

Witness: DONALD A. LYND

Date: August 8, 2024

U21585-AG-CE-0492

Page 1 of 1

Question:

177. Refer to lines 12-20 on page 142 of Mr. Lynd's direct testimony on the criteria for undergrounding overhead lines.

- a. Explain why the Company has set a low threshold of at least one outage in the last 24 months and between 10 and 100 customers served on the target line.
- b. By excluding lines that do not supply an overhead system is the Company only targeting end of line projects for undergrounding?
- c. Explain why a cost/benefit analysis against other alternatives is not part of the selection criteria to make sound economic decisions.
- d. Provide the number of projects and miles of overhead lines that would meet the Company 9-point criteria in 2023, the related cost to achieve the undergrounding of these lines in future years, and time period over which they would be completed.

Response:

- a. I further explain these selection criteria in my direct testimony, page 142, line 21, through page 143, line 18.
- b. Yes. The overhead to underground projects included within Exhibit A-127 (DAL-1), page 41, and Exhibit A-128 (DAL-2), page 40, start at the beginning of the selected zone and proceed downstream to the end of the circuit.
- c. The selection criteria align with the analysis discussed by the direct testimony of Company witness Kelly, page 42, line 16 through page 43, through 6. The criteria is used for the initial project selection; however, the Company does consider physical barriers to construction which could significantly increase cost. Not all projects are selected to move forward due to barriers in the field or significant additional cost expected to overcome those barriers. Additionally, traditional reliability solutions will not have the same resiliency benefit of an undergrounding project.
- d. The Company has not determined the number of projects and miles of overhead lines that would meet all nine criteria in 2023. When the overhead to underground program was initially developed in 2022, there were 2,694 zones totaling 3,795 miles that met at least five of the nine selection criteria. The remaining four criteria require individual review through use of load flow modeling software, GIS and imagery maps, and review of other project lists and are determined at the time project lists are created. Some of the 2,694 zones will not meet all nine selection criteria and, therefore, will not move forward as an undergrounding project. In the Reliability Roadmap, filed as Exhibit A-111 (MPK-19), page 79 (of 183), the Company estimated that 3,200 miles of the LVD system were a candidate for targeted undergrounding and that it plans to ramp up to 400 miles per year of undergrounding. Specific future year project lists have not been developed beyond the test year of this case, but see Exhibit A-111 (MPK-19), page 80 of 183, Figure 60 for the 5-year investment plan and associated miles.

Witness: DONALD A. LYND

Date: August 27, 2024

U21585-AG-CE-0411

Page 1 of 2

Question:

96. Refer to lines 1-15 on page 42 of Mr. Kelly's direct testimony on undergrounding overhead lines. Please:

a. Explain why and how the Company can begin a multi-year initiative to perform more undergrounding work and complete 25 miles of undergrounding in the projected test year when the results of the current undergrounding pilot project have not yet been evaluated.

b. Provide the capital expenditures and related miles of undergrounding performed in each year 2023, 2024, 2025, and the projected test year along with the economic analysis that shows these installations were justified.

c. Explain why the Company proposes to underground 5 miles of overhead lines in EJ communities. Is there evidence that these communities have sustained more power outages than adjacent non-EJ communities? Please identify the EJ communities and provide supporting evidence of higher power outages or other service reliability problems above other adjacent communities. Provide also the capital expenditures for the 5 miles of undergrounding and the period where those expenditures are included in this rate case.

d. Explain why the Company plans to underground 10.1 miles of overhead lines to prevent wildfires and identify specifically in which areas. Is there evidence that the Company's electrical lines or related facilities have caused wildfires in those areas or there is a high likelihood that they may cause wildfires? If yes, please provide the evidence. Provide also the capital expenditures and the period where they are included.

Response:

- a. Please refer page 42, lines 1 through 15 of my testimony. The Company wants to ensure equity in providing the reliability benefits of the undergrounding of overhead lines and has proposed 5 miles targeted in environmental justice communities that were not chosen as part of the pilot approved in Case No. U-21389. Additionally, the Company wanted to use the resources that have been ramped up to gain easements, procure materials, and construct the undergrounded lines to perform additional undergrounding, rather than reassign or redeploy them as the Company waits for pilot results to test cost effectiveness.
- b. The Company's had minimal spending of \$9,000 in 2023 in preparation for the overhead to underground pilot. This amount is included within the historical spending presented in Exhibit A-95 (MPK-3), line 22, column (g). The Company has not completed any projects to-date for 2024 or 2025. See U21585-AG-CE-0208_Lynd_ATT_3 for the analysis that was initially produced for Case No. U-21389. See also Company witness Lynd's direct testimony, page 144.
- c. Please refer to part (a) for the Company's reason for proposing to conduct overhead to underground conversions in EJ communities. These projects, the communities, and proposed capital expenditures are found in Exhibit No.: A-128 (DAL-2), Page 40, Lines 15 – 22. The Company does not necessarily evaluate reliability in EJ communities by solely comparing them to "adjacent communities," but compares them to the broader non-EJ system and against IEEE SAIDI quartiles.

U21585-AG-CE-0411
Page 2 of 2

70% of the project mileage for the test period are for circuits that performed in the third or fourth quartile over the past five years.

- d. Please refer to my response to U21585-MNSC-CE-303 subpart (a) for why the Company plans to underground 10.1 miles of overhead lines to prevent wildfires and specifically in which areas. Please also refer to my responses to U21585-AG-CE-0209 subpart (a) and U21585-AG-CE-0417 subpart (b). Please refer to page 39 lines 6 through 12 of my testimony for the wildfire risk mitigation undergrounding capital expenditures and the period where they are included.

Witness: Michael P. Kelly
Date: August 26, 2024

U21585-AG-CE-0412
Page 1 of 4

Question:

97. Refer to lines 16-22 on page 42, Figure 10, and lines 1-6 on page 43 of Mr. Kelly's direct testimony on undergrounding overhead lines. Please:

- a. Explain each of the two hardening alternatives using Aerial Spacing Cable and Tree Wire, what they entail, where the Company has installed this equipment, the effectiveness in preventing falling wires, power outages, and fires, and the incremental cost per mile to install this equipment over other standard wire the Company currently installs or plans to install over the next five years. Provide photos of typical installations of Aerial Spacing Cable, Tree Wire, and standard electrical wire to show the difference in equipment and installation.
- b. If Aerial Spacing Cable and Tree Wire are effective in preventing falling wires and power outages, explain why the Company has not used this equipment more frequently.
- c. For each of the PVRR in Figure 10, provide the cost/benefit analysis in Excel with formulas intact and all supporting data and assumptions clearly explained and cited to a source along with any narrative that explain the analysis. Explain what assumptions the Company has made and the basis for those assumptions about installation costs in different terrain, urban vs. rural installations, repair costs, and maintenance costs for undergrounding overhead lines.
- d. Figure 10 seems to show that continued vegetation management is the least costly alternative by nearly 50% over the other options including undergrounding. If true, explain why the Company would spend capital on underground projects and other alternatives given this evidence.
- e. By stating that any conductor that is not undergrounded is always susceptible to tree damage, is the Company proposing that ultimately all overhead lines should be undergrounded? If no, what is the point of the statement? Are all conductors located near trees?

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request because it is argumentative and mischaracterizes the Company's filed testimony. Without waiving this objection, Consumers Energy responds as follows:

- a. See discussion on Exhibit No.: A-114 (MPK-22), page 24 regarding the benefits of covered conductor over traditional conductor, as well as Figure 15 in that exhibit for a comparative photo of covered conductor versus traditional bare conductor. See below for additional discussion from the Company's Electric Distribution Engineering Manual regarding the use of tree wire and aerial spacer. The incremental cost per mile of tree wire and aerial spacer cable is 52% more per mile and 66% more per mile, respectively. See attachment U21585-AG-CE-0412_Kelly_ATT_1 for locations where this equipment has been installed.

U21585-AG-CE-0412

Page 2 of 4

29-5 Introduction

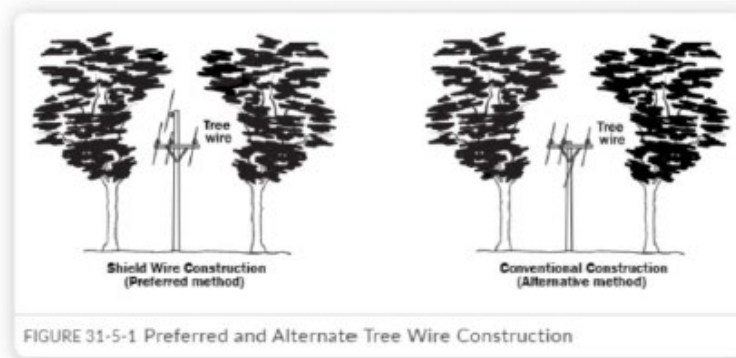
General

- An aerial spacer cable (ASC) system is an option available as an alternative to bare wire construction. Its main advantage over bare wire construction is that it can be used in heavily wooded areas with a reduction in tree trimming, while improving reliability. Storm related outages caused by tree intervention can be reduced and the cable covering helps prevent faults caused by animals or trees. It can also be used where obstructions might prevent the use of open wire construction. Its compact configuration allows it to be used to increase the quantity of circuits on a pole. It can also be used as an alternative method for narrow rights of way and also for aesthetic appearance.
- The designer must locate the poles and conductor where it is bucket accessible, for construction and maintenance purposes.
- Use the 25 kV ASC standard for all voltages 25 kV and below.

31-5 Introduction

General

- Tree wire is a type of construction that uses covered conductors, but unlike aerial spacer cable (ASC), it is built similar to conventional or shield wire construction. Depending on the design requirements, tree wire construction may be designed with the system neutral either above the primary as a shield wire, or below the primary in the normal neutral position. The shield wire position is preferred. This is to further protect the line from damage caused by fallen limbs and trees. Use 052 ASC messenger for the shield wire neutral conductor. Tree wire is intended to be used where there are tree conditions and ASC generally cannot be used, i.e., deep right-of-way (ROW), over swamps, etc., see [figure 31-5-1](#).
- Tree wire is classified as a covered, not an insulated conductor. All working clearance requirements are the same as bare wire.
- The conductor and other materials used in tree wire designs must be special ordered; anticipate long lead times.



CECo Response to AG-CE-0208

U21585-AG-CE-0208_Lynd_ATT_3-Corrected by AG			
Present Value of the Revenue Requirement	Cost to Cust.	incl. ICE Calculator	
Undergrounding	\$ 5,654,271	\$ 5,681,342	
Ariel Space Cable	\$ 5,079,840	\$ 5,201,608	
Tree Wire	\$ 5,048,622	\$ 5,187,689	
Vegetation Management	\$ 3,271,198	\$ 3,413,882	
Undergrounding			
Current Undergrounding Estimate	\$ 400,000.00	Witness Lynd Testimony	
Efficiency Gain (% of Original Estimate)	100%	PG&E level of forecast efficiencies is expected at 50% - Role of Undergrounding in Resilience, Public Utilities Fortnightly, 9/29/2022	
Undergrounding Cost per Mile	\$ 400,000.00		
Improvement in Reliability Post-Investment	93%	WEC commentary - Role of Undergrounding in Resilience, Public Utilities Fortnightly, 9/29/2022	
Hardening Options			
Ariel Spacer Cable	\$ 227,617.00	Engineering Estimate	
Improvement beyond Trimming	64%	Don Lynd Testimony for Targeted Zone Improvements	
Tree Wire	\$ 208,139.00	Engineering Estimate	
Improvement in Reliability Post-Investment	59%	Ratio to cost of ASC	
Rebuild of Traditional Single Phase at End of Life			
Rebuild Costs	\$ 137,500.00	Engineering Estimate	

U21585-AG-CE-0504
Page 1 of 1

Question:

189. Refer to Exhibits A-127 and A-128. Please provide the following information:

- a. For each project of \$1.0 million or greater, please provide the current phase of development of the project (i.e., Initial scoping, conceptual analysis, engineering design, out for bid, construction, completed), and the next phase of development with start and completion dates.
- b. For each program category: asset relocations, Lines Reliability and subcategories, repetitive outages, lines rehabilitations, resiliency, lines capacity, new business capacity, and CVR projects, how many projects can the Company complete in a week and how many workload hours have been planned for the bridge period and the projected test year?

Response:

- a. See Attachment 1 to this response for the requested information. Since the time of filing, a few LVD Lines Capacity projects were deferred based on updated loads and forecasts. One LVD Lines Reliability project on the list was deferred to accommodate higher priority zonal health work; additional smaller projects were added to the workplan to fulfill the projected subprogram spending.
- b. As discussed in numerous places in my testimony project units can vary in scope and complexity; accordingly, there is not a defined number of projects that can be completed in a week. With regards to Metro Asset Relocations and Resiliency-Fractionalization projects, the Company is planning to complete the projects listed in Exhibits A-127 (DAL-1) and A-128 (DAL-2); a specific workload hour for this subprogram is not available as the work is predominately specific bid to contractors. See Attachment 2 to this response for the Company's projections of workload hours for the remainder of requested subprograms.

Witness: DONALD A. LYND
Date: August 28, 2024

CECo Response to AG-CE-0504

U21585-AG-CE-0504													
Attachment 1 Page 1 of 2													
Bridge Period													
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)				
Line No.	Sub-Program	Project Description, Line, Substation, or Location	Projected Spending	Units	Unit Type	Investment Category	Location	Benefit Type	Benefit	Current Phase	Next Phase	Start Date	Construction Complete Date
1	Metro New Business	GR AMPHITHEATER CIVIL	2,250	1	Project	Metro New Business	Grand Rapids	Primary Service; Estimated Added Load, kVA	-	Construction	Complete	9/16/2024	5/30/2025
2		KZO EVENT CENTER CIVIL	2,350	1	Project	Metro New Business	Kalamazoo	Primary Service; Estimated Added Load, kVA	-	Construction	Complete	6/3/2024	11/1/2024
3	LVD Asset Relocations	Hodenpyl	1,141	4.6	Miles	LVD Underbuild	Harrietta	Obligation to serve		Scheduling	Construction	1/15/2025	4/30/2025
4		Hodenpyl #2	1,770	3.9	Miles	LVD Underbuild	Mesick	Obligation to serve		Design	Scheduling	11/1/2024	6/1/2025
5		Rosebush	1,127	9.0	Miles	LVD Underbuild	Rosebush	Obligation to serve		Construction	Complete	11/1/2023	9/4/2024
6	Metro Relocations	GR DIVISION FNTN CRES CIVIL	3,000	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilities; customers impacted	257	Construction	Complete	3/4/2024	8/30/2024
7		GR DIVISION FULTON FOUNTN CIVIL	1,000	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilities; customers impacted	257	Construction	Complete	3/4/2024	11/1/2024
8		GR PRJ WATERMARK CVL PH3	1,000	1	Project	Metro Relocations	Grand Rapids	Substation Coordination; customers impacted	800	Construction	Complete	9/3/2024	11/1/2024
9	LVD Lines Reliability	POLE KAWKAWLIN_RUSSELL - 1	1,292	51	Poles	Pole Replacements	KAWKAWLIN	Customer-outage-minutes avoided	325,000	Planning	Design	7/1/2025	9/30/2025
10		POLE LETTIS RD/MONROE RD #1	2,130	122	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	300,000	Planning	Design	7/1/2025	9/30/2025
11		POLE MIDDLETON/NORTHWOOD #1	3,331	183	poles	Pole Replacements	PERRINTON	Customer-outage-minutes avoided	743	Planning	Design	7/1/2025	9/30/2025
12		POLE MIDLAND/NORTHWOOD #1	2,931	161	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	2,898,000	Planning	Design	7/1/2025	9/30/2025
13		POLE Russelville / Vassar Road #1	1,329	95	Poles	Pole Replacements	DAVISON	Customer-outage-minutes avoided	1,330,000	Design	Scheduling	7/1/2025	9/30/2025
14		POLE STADIUM NORMAL 1	1,550	67	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	1,000	Scheduling	Construction	7/1/2025	9/30/2025
15		RLBY EDMORE/CEDAR LAKE VOLT CONV-PT 4	2,252	1.0	miles	Voltage Conversions	EDMORE	Customer-outage-minutes avoided	85	Design	Scheduling	1/1/2025	3/31/2025
16		RLBY GERRISH SUB VOLTAGE CONVERSION 2	1,568	3.9	Miles	Voltage Conversions	GERRISH TOWNSHIP	Customer-outage-minutes avoided	318,084	Design	Scheduling	1/1/2025	3/31/2025
17		RLBY Houghtn Hts-Merritt Volt Conv LCP 680 P1	1,011	4.0	Miles	Voltage Conversions	HOUGHTON LAKE	Service Quality; number of customers	767	Complete	-	4/16/2024	7/23/2024
18		RLBY CEDAR SPRINGS_EDGERTON LCP 814	1,052	1.7	Miles	Zonal Health Improvements	CEDAR SPRINGS	Customer-outage-minutes avoided	419,401	Planning	Design	7/1/2025	9/30/2025
19		UINJ Cable Injection Flint	1,091	4.6	Miles	Zonal Health Improvements	Flint Area	Customer-outage-minutes avoided	51,210	Complete	-	5/1/2024	8/9/2024
20		UINJ Cable Injection Grand Rapids	1,091	4.6	Miles	Zonal Health Improvements	Grand Rapids Area	Customer-outage-minutes avoided	138,870	Construction	Complete	2/1/2024	11/30/2024
21	LVD Substations Reliability	BUSSFIELD	1,403	1	Project	New or Rebuilt Substations	Village of Blissfield, Lenawee Co.	Customer-outage-minutes avoided	2,025,000	Complete	-	1/1/2024	4/29/2024
22		FELLOWSHIP	1,345	1	Project	New or Rebuilt Substations	Battle Creek Twp, Cahoun Co.	Customer-outage-minutes avoided	2,728,080	Complete	-	3/1/2023	5/26/2024
23		HOUGHTON LAKE	3,032	-	Project	New or Rebuilt Substations	Roscommon Twp, Roscommon Co.	Customer-outage-minutes avoided	-	Scheduling	Construction	4/1/2025	1/30/2026
24		WAMPLERS	2,351	1	Project	New or Rebuilt Substations	Franklin Twp, Lenawee Co.	Customer-outage-minutes avoided	2,257,200	Construction	Complete	3/1/2024	9/30/2024
25		BEALS ROAD	1,122	1	Project	Transformer Replacements	Wyoming Twp, Kent Co.	Customer-outage-minutes avoided	428,220	Construction	Complete	6/1/2024	5/15/2025
26	Metro Reliability	GRA RANSOM CIVIL	1,060	1	Project	Obsolete or Needed Civil	Grand Rapids	Customer-outage-minutes avoided	13,048	Complete	-	10/30/2023	5/31/2024
27	LVD Substations Rehabilitation	WAGER	1,815	1	Project	Allis Chalmers Substation Transformers	Genesee Twp, Genesee Co.	Customer-outage-minutes avoided	2,522,880	Construction	Complete	1/1/2024	8/31/2024
28		CONVIS	1,430	1	Project	Equipment Replacement and Regulatory	Convis Twp, Calhoun Co.	Regulatory Compliance	-	Construction	Complete	2/1/2023	12/15/2024
29	Metro Rehabilitation	SAG FRANKLIN DUCT REPLACEMENT CIVIL	1,000	1	Project	Crushed Duct	Saginaw	Customer-outage-minutes avoided	-	Planning	Design	4/7/2025	7/5/2025
30		FU W 1ST STREET VAULT CIVIL	1,000	1	Project	Vault or Manhole Rehabilitation	Flint	Customer-outage-minutes avoided	-	Scheduling	Construction	9/16/2024	11/1/2024
31		FU W 1ST STREET VAULT ELEC	1,000	1	Project	Vault or Manhole Rehabilitation	Flint	Customer-outage-minutes avoided	30,310	Scheduling	Construction	11/4/2024	12/31/2024
32		JAC CORTLAND ST MECH TO JACKSON CIVIL	1,500	1	Project	Vault or Manhole Rehabilitation	Jackson	Customer-outage-minutes avoided	-	Design	Scheduling	4/7/2025	8/9/2025
33	Resiliency	BACKUS	2,550	-	Project	Resiliency - Fractionalization	Backus Twp, Roscommon Co.	Customer-outage-minutes avoided	-	Engineering	Scheduling	9/15/2025	12/15/2025
34		BROUGHWELL	1,189	1	Project	Resiliency - Fractionalization	Rives Twp, Jackson Co.	Customer-outage-minutes avoided	129,556	Complete	-	9/1/2023	6/19/2024
35		WHITTEMORE	4,450	1	Project	Resiliency - Fractionalization	Grant Twp, Iosco Co.	Customer-outage-minutes avoided	107,599	Construction	Complete	8/1/2024	3/1/2025
36	LVD Lines Capacity	HASTINGS BROADWAY	1,435	1	Project	Overloaded Equipment Upgrades	HASTINGS	Overload Failure Reduction; Customers	677	Construction	Complete	7/1/2024	10/31/2024
37		SARANAC RIVERSIDE LCP 989 PH2 PT1	1,479	1	Project	Overloaded Equipment Upgrades	SARANAC	Overload Failure Reduction; Customers	196	Construction	Complete	5/13/2024	9/30/2024
38		GREENBUSH_GREENBUSH LLRP PH1 SHT1	1,891	-	Project	Sub Capacity-associated Line Work	HARRISVILLE TOWNSHIP	Overload Failure Reduction; Customers	-	Design	Scheduling	4/1/2025	6/30/2025
39		LINCOLN_LOST LAKE LLRP PH1 SUB	1,907	1	Project	Sub Capacity-associated Line Work	GUSTIN TOWNSHIP	Overload Failure Reduction; Customers	1,410	Scheduling	Construction	7/1/2024	12/30/2024
40		PEACH RIDGE/BALLARD CONV PT4	1,134	1	Project	Sub Capacity-associated Line Work	SPARTA	Overload Failure Reduction; Customers	380	Planning	Design	4/1/2025	6/30/2025
41		STANDISH_STERLING LOAD XFER - PH2	1,128	1	Project	Sub Capacity-associated Line Work	STANDISH	Overload Failure Reduction; Customers	2,238	Deferred	Scoping	N/A	N/A
42		TAMARACK-AMBLE PH 2	3,032	1	Project	Sub Capacity-associated Line Work	LAKEVIEW	Overload Failure Reduction; Customers	474	Design	Scheduling	1/1/2025	3/31/2025
43		TAMARACK-LAKEVIEW PH 2.1	1,486	1	Project	Sub Capacity-associated Line Work	LAKEVIEW	Overload Failure Reduction; Customers	538	Design	Scheduling	7/1/2024	9/30/2024
44		TAMARACK-LAKEVIEW PH 2.2	1,004	1	Project	Sub Capacity-associated Line Work	LAKEVIEW	Overload Failure Reduction; Customers	538	Scheduling	Construction	10/1/2024	12/31/2024
45	LVD Subs Capacity	HAWTHORNE	1,073	1	Project	New Substations	Walker Twp, Kent Co.	Obligation To Serve - Customers Impacted	224	Construction	Complete	9/12/2022	9/30/2024
46		RIVERBEND	3,565	1	Project	New Substations	Arenac Twp, Arenac Co.	Obligation To Serve - Customers Impacted	677	Construction	Complete	5/20/2024	10/31/2024
47		SANTIAGO	13,176	1	Project	New Substations	Au Gres Twp, Arenac Co.	Obligation To Serve - Customers Impacted	1,930	Construction	Complete	3/4/2024	12/30/2024
48		BIL MAR	2,145	1	Project	Increase Capacity at Existing Substation	Blendon Twp, Ottawa Co.	Obligation To Serve - Customers Impacted	1,467	Construction	Complete	3/1/2024	12/31/2024
49		COOLEY	2,208	-	Project	Increase Capacity at Existing Substation	City of Kalamazoo, Kalamazoo Co.	Obligation To Serve - Customers Impacted	-	Scheduling	Construction	11/1/2024	12/31/2025
50		EAST JACKSON	2,112	-	Project	Increase Capacity at Existing Substation	Leoni Twp, Jackson Co.	Obligation To Serve - Customers Impacted	-	Scheduling	Construction	1/1/2025	5/15/2025
51		FOUR MILE	1,544	1	Project	Increase Capacity at Existing Substation	Walker Twp, Kent Co.	Obligation To Serve - Customers Impacted	4,923	Scheduling	Construction	1/6/2025	10/31/2025
AG Total Disallowed			\$	14,428									

CECo Response to AG-CE-0504

U21585-AG-CE-0504																	
Attachment 1 Page 2 of 2		Projected Test Year		U21585-AG-CE-0504_Lynd_ATT_1													
(a)		(b)		(c)		(d)		(e)		(f)		(g)		(h)		(i)	
Line No.	Sub-Program	Project Description, Line, Substation, or Location	Period Spending	Units	Unit Type	Investment Category	Location	Benefit Type	Benefit	Current Phase	Next Phase	Start Date	Complete Date	Construction	Construction		
1	Metro New Business	GR MT VERNON SOCCER CIVIL	1,000	1	Project	Metro New Business	Grand Rapids	Primary Service; Estimated Added Load, kV	-	Design	Scheduling	6/2/2025	8/9/2025				
2		KZO PARKING GARAGE ELEC	1,117	1	Project	Metro New Business	Kalamazoo	Secondary Service; Estimated Added Load, kV	1,000	Design	Scheduling	4/7/2025	5/24/2025				
3	LVD Asset Relocations	Dontz	1,300	1.3	Miles	LVD Underbuild	Manistee	Obligation to serve	-	Design	Scheduling	9/15/2025	12/30/2025				
4		Maple City	1,764	7.2	Miles	LVD Underbuild	Glen Arbor	Obligation to serve	-	Scheduling	Construction	10/7/2024	5/31/2025				
5	Metro Relocations	JAC INGHAM SUB DELTA CONVERSATION	2,000	1	Project	Metro Relocations	Jackson	Substation Coordination; customers impact	149	Planning	Design	9/1/2025	11/22/2025				
6		KZO KALAMAZOO AVE CIVIL	3,883	1	Project	Metro Relocations	Kalamazoo	Coordination of Utilities; customers impact	21	Design	Scheduling	4/7/2025	11/15/2025				
7		KZO KALAMAZOO AVE ELEC	3,000	1	Project	Metro Relocations	Kalamazoo	Coordination of Utilities; customers impact	21	Planning	Design	6/2/2025	12/13/2025				
8	LVD Lines Reliability	AUBURN02_AUBURN01	1,022	1	Loop	Automation - ATR Loops	AUBURN	Customer-outage-minutes avoided	431	Design	Scheduling	10/1/2025	12/30/2025				
9		DUNHAM02_WEBSTER01	1,375	1	Loop	Automation - ATR Loops	FLUSHING TWP/MT MORRIS TWP	Customer-outage-minutes avoided	560	Design	Scheduling	5/30/2025	12/30/2025				
10		MONTROSE02_FIELD ROAD01	1,213	1	Loop	Automation - ATR Loops	MONTROSE/VIENNA TWP	Customer-outage-minutes avoided	327	Design	Scheduling	5/30/2025	12/30/2025				
11		SCDY College Park/Madison	1,620	5.4	Miles	Secondary	ADRIAN	Service Quality; number of customers	130	Planning	Design	4/1/2025	6/30/2025				
12		SCDY Elm Street/Porter	3,300	11.0	Miles	Secondary	BATTLE CREEK	Service Quality; number of customers	1,430	Planning	Design	4/1/2025	6/30/2025				
13		SCDY Elm Street/Verona	4,680	15.6	Miles	Secondary	BATTLE CREEK	Service Quality; number of customers	2,303	Design	Scheduling	4/1/2025	6/30/2025				
14		SCDY Kendall/Westwood	1,890	6.3	Miles	Secondary	KALAMAZOO	Service Quality; number of customers	938	Design	Scheduling	1/1/2025	3/31/2025				
15		SCDY Kinderhook/Gilead	1,170	3.9	Miles	Secondary	COLDWATER	Service Quality; number of customers	317	Design	Scheduling	4/1/2025	6/30/2025				
16		SCDY Liberty/Washington	2,340	7.8	Miles	Secondary	BATTLE CREEK	Service Quality; number of customers	599	Design	Scheduling	4/1/2025	6/30/2025				
17		SCDY Lombard/Sheridan	1,800	6.0	Miles	Secondary	ALBION	Service Quality; number of customers	531	Design	Scheduling	4/1/2025	6/30/2025				
18		SCDY Oakwood/Parkview	1,260	4.2	Miles	Secondary	KALAMAZOO	Service Quality; number of customers	421	Design	Scheduling	1/1/2025	3/31/2025				
19		SCDY Oriole/Whittier	1,590	5.3	Miles	Secondary	LUDINGTON	Service Quality; number of customers	554	Design	Scheduling	1/1/2025	12/30/2025				
20		SCDY Phillips/Milwood	2,040	6.8	Miles	Secondary	KALAMAZOO	Service Quality; number of customers	1,055	Design	Scheduling	1/1/2025	3/31/2025				
21		SCDY Sloan/Longfellow	2,490	8.3	Miles	Secondary	FLINT	Service Quality; number of customers	820	Planning	Design	1/1/2025	3/31/2025				
22		RLBY PEWAMO SUB VOLT CONVERSION SUB EXIT	1,657	1.0	Miles	Voltage Conversions	PEWAMO	Service Quality; number of customers	784	Design	Scheduling	4/1/2025	6/30/2025				
23		DIMONDALE-DIMONDALE-PH1	2,355	5.9	Miles	Zonal Health Improvements	DIMONDALE	Customer-outage-minutes avoided	170,025	Design	Scheduling	1/1/2025	3/31/2025				
24		RLBY ALGER_FOREST LAKE LCP 720_784 P1	1,412	3.5	Miles	Zonal Health Improvements	ALGER	Customer-outage-minutes avoided	25,620	Planning	Design	1/1/2026	3/31/2026				
25		RLBY Batteese_Coon_Hill_LCP_0978	1,005	0.9	Miles	Zonal Health Improvements	PLEASANT LAKE	Customer-outage-minutes avoided	640,000	Planning	Design	4/1/2025	6/30/2025				
26		RLBY CAMBRIDGE-IRISHHILLS-RCND #2 MS0 1	1,037	2.3	Miles	Zonal Health Improvements	COLUMBIA TOWNSHIP	Customer-outage-minutes avoided	3,131,944	Scheduling	Construction	4/1/2025	6/30/2025				
27		RLBY CONKLIN PARK/CROTON LCP 946	1,137	1.0	Miles	Zonal Health Improvements	CROTON	Customer-outage-minutes avoided	386,427	Design	Scheduling	1/1/2025	3/31/2025				
28		RLBY CONVIS_CONVIS LCP 363	1,000	1.0	Miles	Zonal Health Improvements	MARSHALL	Customer-outage-minutes avoided	22,876	Planning	Design	1/1/2025	3/31/2025				
29		RLBY DUQUITE_SAGANING SUB	1,180	1.5	Miles	Zonal Health Improvements	STANDISH	Customer-outage-minutes avoided	1,115,899	Planning	Design	1/1/2025	3/31/2025				
30		RLBY EAGLE SUB-LINE WORK	2,964	2.6	Miles	Zonal Health Improvements	JENISON	Service Quality; number of customers	3,897	Planning	Design	4/1/2025	6/30/2025				
31		RLBY FIFTEEN MILE ROAD/15 MILE 018	1,296	2.5	Miles	Zonal Health Improvements	MARSHALL	Customer-outage-minutes avoided	146,352	Design	Scheduling	4/1/2025	6/30/2025				
32		RLBY FROST LONG LK LCP 267	1,147	1.0	Miles	Zonal Health Improvements	HARRISON	Service Quality; number of customers	348	Design	Scheduling	4/1/2025	6/30/2025				
33		RLBY GETTY_SUB REBUILD	1,000	1.2	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	602,641	Design	Scheduling	1/1/2026	3/31/2026				
34		RLBY GREGORY UNADILLA LCP 934	1,280	9.0	Miles	Zonal Health Improvements	STOCKBRIDGE	Customer-outage-minutes avoided	74,466	Planning	Design	4/1/2025	6/30/2025				
35		RLBY Harvey St/Sunshine Lcp 057 & 089	1,736	0.4	Miles	Zonal Health Improvements	GRAND RAPIDS	Customer-outage-minutes avoided	164,000	Complete	-	5/2/2024	5/14/2024				
36		RLBY Honor/Platte LCP 6835 Zone	4,469	3.0	Miles	Zonal Health Improvements	HONOR	Customer-outage-minutes avoided	60,787	Deferred	Scoping	N/A	N/A				
37		RLBY HOUGHTON HTS SUB RELO	5,911	15.0	Miles	Zonal Health Improvements	HOUGHTON LAKE	Customer-outage-minutes avoided	84,632	Design	Scheduling	1/1/2025	3/31/2025				
38		RLBY HOWARD CITY - MORLEY SUB	1,342	1.8	Miles	Zonal Health Improvements	HOWARD CITY	Customer-outage-minutes avoided	159,083	Design	Scheduling	4/1/2025	6/30/2025				
39		RLBY LAKE MITCHELL-GLF CLB LCP 6001 1A	1,349	1.3	Miles	Zonal Health Improvements	CADILLAC	Customer-outage-minutes avoided	77,696	Design	Scheduling	1/1/2026	3/31/2026				
40		RLBY Leffingwell/Nottingham EB & Cascade	1,434	1.6	Miles	Zonal Health Improvements	GRAND RAPIDS	Customer-outage-minutes avoided	1,104,262	Design	Scheduling	1/1/2025	3/31/2025				
41		RLBY MCBAIN-VOGEL CENTER LCP 064 (EXEC)	1,800	3.5	Miles	Zonal Health Improvements	MCBAIN	Customer-outage-minutes avoided	145,202	Design	Scheduling	1/1/2026	3/31/2026				
42		RLBY MESICK-SPRINGVILLE LCP 413 1-28	1,608	2.3	Miles	Zonal Health Improvements	MESICK	Customer-outage-minutes avoided	126,244	Design	Scheduling	4/1/2025	6/30/2025				
43		RLBY New Wolf Lake Sub	2,000	3.0	Miles	Zonal Health Improvements	ALAMO	Customer-outage-minutes avoided	3,347,741	Design	Scheduling	4/1/2025	6/30/2025				
44		RLBY NOBLE_WHITNEY LCP 521	1,580	4.9	Miles	Zonal Health Improvements	AUGRES	Customer-outage-minutes avoided	73,885	Planning	Design	1/1/2025	3/31/2025				
45		RLBY OBERLIN BENMARK LCP 841 CEMI	1,128	1.8	Miles	Zonal Health Improvements	GLADWIN	Customer-outage-minutes avoided	4,554	Planning	Design	1/1/2026	3/31/2026				
46		RLBY Pennfield Pennfield LCP 306	1,419	0.8	Miles	Zonal Health Improvements	BATTLE CREEK	Customer-outage-minutes avoided	36,290	Design	Scheduling	4/1/2025	6/30/2025				
47		RLBY PIGEON LAKE_PIGEON LCP 146	1,080	1.7	Miles	Zonal Health Improvements	HOLLAND	Customer-outage-minutes avoided	80,336	Design	Scheduling	4/1/2025	6/30/2025				
48		RLBY PRICE ROAD_PRICE LCP 0031	1,003	1.0	Miles	Zonal Health Improvements	HOMER TOWNSHIP	Customer-outage-minutes avoided	49,587	Design	Scheduling	1/1/2025	3/31/2025				
49		RLBY RYNO_MAPES SUB PART 1A	3,094	3.8	Miles	Zonal Health Improvements	MIO	Customer-outage-minutes avoided	237,191	Design	Scheduling	4/1/2025	6/30/2025				
50		RLBY Stanwood-Riversway Ph 3 - Part 1	3,114	13.0	Miles	Zonal Health Improvements	STANWOOD	Customer-outage-minutes avoided	525,008	Design	Scheduling	1/1/2025	3/31/2025				
51		RLBY WIRTZ ROAD_BOWMANVILL LCP 321	1,220	3.0	Miles	Zonal Health Improvements	GLADWIN	Customer-outage-minutes avoided	190,600	Planning	Design	1/1/2025	3/31/2025				
52		UINJ Cable Injection Traverse City	6,304	23.0	Miles	Zonal Health Improvements	Traverse City Area	Customer-outage-minutes avoided	464,870	Planning	Design	4/1/2025	12/31/2025				
53		UINJ Flint	6,304	26.0	Miles	Zonal Health Improvements	Flint Area	Customer-outage-minutes avoided	537,183	Design	Scheduling	2/1/2025	6/30/2025				

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Question:

94. Refer to lines 22-24 on page 36 of Mr. Kelly's direct testimony on the Wildfire Risk Mitigation program.

- a. Is the elevated wildfire risk in the north-central Lower Peninsula identified by FEMA mainly from electrical lines or from other sources.
- b. What is causing wildfires started by powerlines? Describe the medium that the charged electric lines come in contact with that ignite a fire and in turn becomes a wildfire.
- c. Provide the number of wildfires started by Company's electric lines or equipment in the past 20 years and provided details of each incident, such as location, date, what company equipment started the fire and how, acres burned, damaged sustained, repair and liability costs incurred by the Company, insurance proceeds, etc.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request because it calls for an analysis that the Company has not performed. Subject to this objection, and without waiving it, the Company provides the following response:

- a. The elevated wildfire risk in the north-central Lower Peninsula identified by FEMA is from all sources.
- b. Pacific Gas & Electric identifies several risk drivers for wildfires started by powerlines including vegetation contact, equipment/facility failure, contact from object, and wire to wire contact¹. According to the State of Michigan, "most wildfires occur in the spring here in Michigan when days are dry and windy with abundant dead vegetation left after the snow melts. These conditions can spread a wildfire quickly because there is less moisture in the air and the wind carries burning debris to other areas. The dead vegetation makes for good wildfire fuel."²
- c. The Company has not performed the requested analysis. However, please refer to my responses to U21585-AG-CE-0209 subpart (a) and U21585-AG-CE-0417 subpart (b).

Witness: Michael P. Kelly

Date: August 26, 2024

¹ Pacific Gas and Electric Company 2023-2025 Wildfire Mitigation Plan R6 dated July 5, 2024. [pge-wmp-r6-07052024.pdf](https://www.pge.com/content/dam/pge-na/us-ca/wildfire/PGE-Wildfire-Mitigation-Plan-R6-2023-2025.pdf)

² State of Michigan Wildfire webpage. <https://www.michigan.gov/michiganprepares/be-informed/wildfire>

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Question:

95. Refer to lines 5-22 on page 39 of Mr. Kelly's direct testimony on the Wildfire Risk Mitigation program spending. Please:

- a. Confirm that the \$12 million of capital expenditures in the projected test year will grow to \$73 million in 2028 and will likely continue to grow above that amount in subsequent years. If not confirming, explain.
- b. Confirm that O&M costs will escalate each year to exceed \$4 million in 2028 and will likely continue to increase above that amount in subsequent years. If not confirming, explain.

Response:

- a. Yes, the Company capital expenditures outlined in Exhibit A-114 (MPK-22) would grow to \$73 million in 2028. The Company has not made spending plans beyond 2028 in this area and cannot say whether expenditures will continue to grow above that amount in subsequent years as the Company will continue to evaluate and develop projected spending based on wildfire risk mitigation needs, and learnings from benchmarking and industry best practices going forward.
- b. Yes, O&M costs as outlined in Exhibit A-114 (MPK-22) escalate each year to exceed \$4 million in 2028. The Company has not made spending plans beyond 2028 in this area and cannot say whether expenses will continue to grow above that amount in subsequent years as the Company will continue to evaluate and adjust projected spending based on wildfire risk mitigation needs, and learnings from benchmarking and industry best practices going forward.

Witness: Michael P. Kelly

Date: August 26, 2024

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Question:

102. Refer to Figure 5 on page 9 of Exhibit A-114 on the Wildfire plan. Please:

- a. Provide the data in the charts in Excel.
- b. For the wildfires started by powerlines during 2012 to 2023, provide the information by year, and by month within each year, and identify the locations and the reason for the powerline ignition in Excel.

Response:

- a. See U21585-AG-CE-0417_Kelly_ATT_1.
- b. See U21585-AG-CE-0417_Kelly_ATT_2 for wildfires started by powerlines during 2012 to 2023 including year, month, and locations. This data was provided to the Company by the Michigan Department of Natural Resources, and the Company does not have the reason for the powerline ignition.

Witness: Michael P. Kelly
Date: August 26, 2024

Figure 5 - Wildfire Ignition Sources in Michigan's Lower Peninsula (2012-2023)					
Ignition Sources by Count			Ignition Sources by Acres Burned		
Ignition Source	Count		Ignition Source	Acres	
Debris Burning	813		Miscellaneous	6844	
Equipment	298		Campfire	3882	
Miscellaneous	288		Debris Burning	3133	
Campfire	251		Lightning	2931	
Powerline	242	9.5%	Equipment	1999	
Undetermined	209		Arson	1490	
Arson	147		Undetermined	1279	
Children	76		Powerline	671	2.9%
Other	213		Other	633	
Total	2,537		Total	22,862	
AG Calculations					

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Question:

208. Refer to Figure 26 on page 53 of Mr. Kurdziel's direct testimony on HVD Lines and Substation Rehabilitation. Please:

- a. Provide the same information for each year 2019-2023 in Excel.
- b. Provide the number of stations replacement projects for each year 2019-2023, bridge period and test year.
- c. Explain what justifies increasing spending on this program by 78% to \$70.9 million in the test year over the bridge period spending amount of \$39.9 million.
- d. For the number of minutes of SAIDI reduction benefits in the bridge and test year periods, relate this information in reduction of number of outages and restoration time for the customers affected, and provide the number of customers who will benefit.
- e. Explain what differentiates HVD Lines and Substation rehabilitation from reliability. What is the difference in work completed, etc.? When is a project included in one or the other of the two programs?
- f. Provide the same information in subpart (e) also for LVD Lines and Substations.

Response:

- a. The historical actual amounts are provided in Exhibit A-112 (MPK-20). Actual, historical customer outage minutes avoided cannot be provided. There is no way to conclusively quantify outages which might have happened in the past, but did not. Please see also discovery response U21585-MNSC-CE-0317.
- b. Station replacements are listed as substation rebuilds below.

	2019	2020	2021	2022	2023	Bridge	Test
Rebuild	0	1	0	0	4	2	2

- c. The HVD Lines and Substation Rehabilitation subprogram addresses assets that have been identified through inspections of HVD lines and substations that are not addressed in HVD Lines and Substations Demand Failures. For HVD lines, this rehabilitation subprogram focuses largely on Priority 3 anomalies. As noted in my direct testimony on page 42, the Company is identifying a growing number of priority 3 anomalies in HVD lines inspections. As can be seen in Figures 24 and 25 on page 46, Priority 3 anomalies can degrade quickly. Addressing these pole tops proactively prevents these locations from getting worse and failing outright, potentially causing interruptions to customers and requiring more expensive repairs in Demand Failures. The Company plans to address this increasing asset degradation, which can be seen in the increased proposed investment levels from the bridge period to the test year, going from a projection of 233 pole tops during the bridge period to 1,130

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pole tops in the test year. As noted in my direct testimony on page 20, lines 20-21, pole top rehabilitation projects directly address poor insulator health, which is the leading cause of HVD line outage events over the past 5 years. As indicated on page 21, line 16-19, of my direct testimony, a substantial percentage of the Company’s HVD lines insulator assets are at risk, with 44% falling into the higher-risk vintage and victor categories. Increasing spending in this area directly improves insulator health and prevents outages from occurring due to asset degradation.

The increased investment from the bridge period to the test year also addresses the 32% of HVD Substations that are at a moderate to high risk, as shown in Figure 15 on page 33 of my direct testimony. As stated starting on page 47, line 18, of my direct testimony, this program also addresses the increasing number of substation component issues identified through inspections and substation transformers in failing health as determined through diagnostic testing. Maintaining HVD substations is critical to being able to operate the grid and maintain a level of redundancy that allows customers to not experience an outage where system configuration can support isolation of faults. Failure to address these assets will result in increased Demand Failures spending, possible failures of major equipment like a transformer bank, and remove a layer of redundancy that benefits customers.

- d. The customer minute benefit for each project can be seen in Exhibits A-125 (KMK 3) and A-126 (KMK-4) for the bridge period and test year, respectively. Customer outage minutes avoided are calculated as described on page 80, lines 1 through 15, of Company witness Kelly’s testimony. Customer outage minutes saved is calculated based on assumptions for number of impacted customers, outage duration, failure rate, and the amount of units impacted. Assumptions are based on actual failures vs asset population, average number of customers impacted by Lines or subs events, and traditional response duration. See table below for assumptions used in bridge and test period calculations.

Project Type	Assumed Impacted Customers	Assumed Duration (minutes)	Assumed Failure Rate
Circuit breakers	3900	240	0.000666667
Bushings	2300	1080	0.028
HVD sub rebuilds	11700	240	0.028
TRF replacement	5850	240	0.005
Rehab pole replacements	3900	250	0.042
Switch replacements	3900	250	0.021
Rehab PTA per mile	3900	250	0.04
Other HVD projects	3900	250	0.02
HVD animal mitigation	5850	120	0.067
PT replacements	2000	240	0.01

- e. Page 40 of my direct testimony explains the purpose of the HVD Lines and Substations Rehabilitation subprogram, which is part of our overall reliability approach. This subprogram specifically addresses

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issues where failure has not yet occurred, but where the Company has judged there is an increased risk of failure that would threaten customer reliability or system operability in a shorter timeframe than the HVD Lines and HVD Substation Reliability subprograms.

- f. Please refer to the direct testimony of Company witness Lynd, page 85, line 19, through page 86, line 11, which explains the purpose of the LVD Substations Reliability subprogram and page 111, line 16, through page 112, line 18, which explains the purpose of the LVD Substations Rehabilitation subprogram.

Witness: Keith M Kurdziel

Date: August 28, 2024

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Question:

211. Refer to the advance purchase of transformers for “high probability projects” discussed beginning on line 19 of page 93 of Mr. Kurdziel’s direct testimony. Please:

- a. Identify the probability percentage that these new projects will come to pass? Explain on what information you base your conclusion.
- b. Confirm that the long lead time with transformers is an industry-wide problems that also affect utilities in other states and in that regard utilities in Michigan are not at a disadvantage. If not confirming, provide evidence otherwise.
- c. To avoid having customers pay for the cost of carrying risky assets which may not be used soon after purchase, is the Company willing to record the purchase cost of the desired transformers in a regulatory asset account with no return on the balance of the account until after the transformer are installed and the cost is transferred to rate base? If no, explain why not.

Response:

- a. Recent history has shown increased inquires for large scale projects since 2022 as described in my direct testimony on page 95 starting on line 22. Through the end of the test year in this case, the Company is tracking several large high-probability projects. There is no specific percentage probability for these projects, but two particular projects that would require several very large transformers and would easily cover the investment amounts included in the bridge period and test year help illustrate the issue. For one of these projects, the Company has indications that the customer will commit, with an anticipated commitment date and with the Company and customer nearing finalization of contract negotiation and agreement. For the other project, the customer is in contract negotiations with the Company and has narrowed their interest down to a single site.
- b. While it is true that lead time for large transformers has been an industry-wide issue, the Company is proposing to purchase long lead transformers proactively to gain an advantage for Michigan, making it a leading candidate in attracting these large transformational new business opportunities to the state.
- c. No, because the Company needs to be able to cover the financing costs related to this spending and the proposed transformer purchases are reasonable and prudent. Furthermore, as stated on page 95, line 29, through page 96, line 7, of my direct testimony, these transformers could be used for other substation projects in other investment programs if ultimately not needed for New Business.

Witness: Keith M Kurdziel
Date: August 28, 2024

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Question:

218. Refer to the Electric Distribution Asset Management section of Mr. McPhail's direct testimony beginning on page 60 and the Planning System Modernization section beginning on page 73. Please:

- a. Explain why these optimization systems are needed at this time when the focus and resources should be concentrated on replacing failing infrastructure, reducing power outages, and the duration of outages.
- b. Identify and explain what systems the Company is currently using to manage assets and perform planning and why those systems cannot be improved at a lower cost instead of being replaced with new more costly systems.
- c. Explain what alternatives the Company evaluated that could accomplish most of the objectives at a lower cost. Provide details and related costs.
- d. Provide a copy of the cost benefit analysis (CBA) performed that justifies undertaking each of the systems proposed. Provide the CBA in Excel with formulas intact and all supporting data and assumptions referenced to a source and explained.
- e. Refer to Figure 14 on page 62. For each system or project provide the cost of the project from inception to completion by year for both capital expenditures and O&M expense, separately.
- f. Refer to Figure 15 on page 75. For each system or project, provide the cost of the project from inception to completion by year for both capital expenditures and O&M expense, separately.
- g. For each project listed in Figures 14 and 15, provide the current phase of development of the project (i.e., Initial scoping, conceptual analysis, system requirements determination, vendor/system selection, implementation, completed), and the next phase of development with start and completion dates.

Response:

a.

Distribution Asset Management (DistAM)

Replacing infrastructure to reduce outage frequency and duration are key benefits for customers. Some factors that are considered with Distribution Asset Management include: what infrastructure is replaced, when does the asset get replaced, and should replacement happen before the asset fails or on a schedule. When DistAM is at full deployment, infrastructure replacement will be optimized. This will include asset health monitoring and predictive analytics, which will be used to provide a workplan that supports the greatest benefits for customers.

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Planning Systems Modernization

The ability to optimize the system is considered an auxiliary benefit of the proposed investments in Planning Systems Modernization. At its core, this investment is required to provide planners with the modeling, simulation, and prediction capabilities needed to know which infrastructure to replace and when, so that both the number and duration of future outages can be reduced. To prevent customers from experiencing the reliability and power quality issues mentioned in the Non-Load Challenges from the Customer Technology Adoption section of Exhibit No. A-111 (MPK-19), planning tools must be able to perform complex, time-series simulations to identify constraints or violations that traditional modeling practices and tools cannot account for. A few examples of this include unanticipated peaks caused by mass EV charging on the days before or after a significant weather event, power quality issues such as overvoltage introduced by inverter-based generation during minimum load hours, or protection schemes that fail to operate as intended due to generator fault current contributions.

In addition to the above, investments in planning tools will enable the Company to streamline the majority of the fast track initial and supplemental review screens specified in R 460.946 and R 460.950 of the Michigan Interconnection and Distributed Generation Standards, will increase the accuracy and value of the Company's hosting capacity maps, will support Company compliance with the various distribution system impact analyses and data reporting requirements of the Michigan Transportation Electrification Plan, pursuant to Case No. U-21492, and will provide planning and interconnection SMEs with the insights needed to successfully navigate the increased Distributed Generation program cap required by PA 235.

b.

DistAM

The Company currently uses SAP, GIS, ADMS, PI Historian, Cascade, and stand-alone Microsoft excel spreadsheets to manage assets. The Company uses a Quarterly Operating Review (QOR) for the subject matter experts (SMEs) to report on asset health and prioritization. The SMEs extract the information out of the source systems and process the data manually for the QOR. DistAM is establishing consistent automated processes to standardize how data is interchanged between source systems and how data flows between Asset Repository (AR), Asset Performance Management (APM), and Asset Investment Planning (AIP) systems.

The Asset Repository (AR) will be the central repository for key asset information. Asset information will be accumulated from multiple source systems and will act as the source of truth for information that is not available in existing systems. The AR will feed asset information into APM which will calculate asset health scores and additionally feed AIP to evaluate project value. The Asset Repository is being built in-house in an agile software development project to be cost-effective.

The Asset Performance Management (APM) requirements will be released as an RFP. The RFP will be available for vendor proposals including the Company Information Technology (IT) staff and vendors that

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supply existing systems. The RFP process ensures that all solutions are evaluated and the most cost-effective solution is implemented.

The Asset Investment Planning (AIP) went through the Company RFP process and was evaluated and awarded to a company that provides decision analytics software. Their solutions are based off Value Frameworks that optimize investment planning, asset management, and business strategies.

Planning System Modernization

For nearly 25 years, the Company has relied on an industry-standard suite of CYME Power Engineering software products to perform planning on the LVD system. This suite includes:

- CYME – Power flow software used for capacity planning, protective device analysis, power quality analysis, DER interconnection studies, system optimization studies, and more. CYME is the “bread and butter” analysis tool used by various planning departments across the Company to identify current or future constraints on the system, and to evaluate mitigation alternatives that alleviate those constraints.
- CYME Gateway – Extraction engine that maps to the Company’s GIS and other data sources importing circuit models, device characteristics, settings and load information into the CYME databases.
- CYMTCC – Protective device analysis software used for advanced clearing and coordination studies, as well as identification and development of protective device settings.

Referred to singularly as CYME, this suite of industry leading applications is deeply embedded into the Company’s existing planning processes and IT systems, and the Company is not proposing to replace it with a new solution. The intent of the Load Flow Tool Upgrade project is to build upon and adjacent to the existing CYME implementation to deliver the planning capabilities to maintain a reliable, safe, and efficient distribution system as DER and EV penetration increases.

c.

DistAM

The Asset Repository (AR) project utilized industry experts, Black & Veatch, and internal Company scoping meetings, to decide to build AR internally integrating with established systems in use. Data not available in source systems will be maintained in AR as the primary data source and available for other systems and to support data analytics. Building the AR internally using Company resources in an agile methodology allows the Company to build the solution incrementally and to add assets over time, ensuring the correct minimum solution is used to satisfy the requirements.

The Asset Performance Management (APM) solution is more technologically advanced due to the complexity in calculating health scores and assessing risk and the need to combine the different data sources together. Due to the complexity of the requirements and the robust industry offerings, the APM requirements will be released as an RFP. The RFP will be available for vendor proposals including the

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Company Information Technology (IT) staff and vendors that supply existing systems. The RFP process ensures that all solutions are evaluated and the most cost-effective solution is implemented.

For the Asset Investment Planning (AIP), bids were solicited through the Company RFP process to over 10 companies. The vendor proposals were evaluated, and the bid was awarded to a company that provides decision analytics software.

Planning System Modernization

As discussed in the response to parts a. and b. above, the Load Flow Tool Upgrade project leverages the existing CYME implementation as a foundation on which to build the capabilities that are already or will soon be needed as DERs and electrification accelerates. This includes advanced forecasting capabilities that will be built adjacent to and integrated with CYME planning models. It also includes time-series simulation and reporting, and automated interconnection screening capabilities that will be developed or enabled within CYME.

The only alternate path identified that comes at a lower cost would be to do nothing, continuing to rely on a planning toolset that was designed to meet the traditional needs of LVD circuit, substation, and system protection planners maintaining the health of a distribution system absent high levels of DER and EV penetration. Staying on this path would jeopardize the future safety, reliability, and efficiency of the distribution system, and would prevent the Company from performing accurate and efficient analyses that support and inform hosting capacity, the Michigan Transportation Electrification Plan, the Michigan Interconnection and Distributed Generation Standards, and the 10% the Distributed Generation program cap that the Michigan Clean Energy Law (PA 235) requires.

RAMP

The Company explored many internal and external resources. It was determined the Company has limited capabilities to predict and identify the types of adverse conditions on the electric distribution system that, if left uncorrected, could result in outages for customers. As stated on page 75, line 14 through page 76, line 1, the RAMP software and methodology is new to the industry and not yet commercially available. This opportunity allows the Company to work with the vendor to build a sustainable, reliable, and cost-effective solution that utilizes the existing line sensor assets already purchased and managed by the same vendor. Utilizing the existing line sensor assets with another vendor's analytics software that has the same capabilities as RAMP would be significantly more costly given that it would require a significant amount of IT infrastructure hours and investment to build the necessary integrations between the different software.

CECo Response to AG-CE-0543

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d.

DistAM

- Please refer to the response to U21585-MNSC-CE-0348 for quantitative benefits for the DistAM program as a whole.

Planning System Modernization

- Please see response to part b. above for why this is the most prudent path forward, and these capabilities are required. A CBA has not been performed.

RAMP

- Please refer to the response to U21585-MNSC-CE-0351.

e.

(\$000) (Calendar Year)	2022		2023		2024		2025		2026	
	Cap	O&M	Cap	O&M	Cap	O&M	Cap	O&M	Cap	O&M
Asset Repository	282	414	300	108	-	-	500	100	500	270
Asset Performance Management	-	-	1,501	51	200	200	6,525	600	3,706	0
Asset Investment Planning	-	-	-	-	3,675	85	369	40	0	40

f.

(\$000) (Calendar Year)	2022		2023		2024		2025		2026	
	Cap	O&M	Cap	O&M	Cap	O&M	Cap	O&M	Cap	O&M
Reliability Analytics Monitoring Program (RAMP)	-	-	-	-	-	-	2,083	-	-	-
Load Flow Tool Upgrade	-	-	-	-	-	-	2,500	180	2,500	180
Grid Mod Analytics	-	-	-	-	-	-	333	-	-	-

g.

DistAM

System	Current Phase	Next Phase	Next Phase Start Date	Next Phase End Date
Asset Repository	In Development (Agile Project)	Implementation (Agile Project)	5/8/2024	1/23/2025
Asset Performance Management	Initial Scoping	System Requirements	Q3/2024	Q4/2024
Asset Investment Planning	In Production	Maintenance	Complete	Complete

Planning System Modernization

System	Current Phase	Next Phase	Next Phase Start Date	Next Phase End Date
Reliability Analytics Monitoring Program (RAMP)	Concept use case execution	Large scale implementation	Q1/2025	Q1/2028 or Q1/2030
Load Flow Tool Upgrade	System Requirements Determination	Implementation	Q1/2025	Q3/2026
Grid Modernization Analytics	Initial Scoping	Implementation	Q3/2025	Q1/2026

Witness: Scott A. Mcphail

Date: August 29, 2024

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Question:

63. Please refer to McPhail, p. 63-64, which discusses the benefits of the Asset Repository. For each item in the bulleted list, please provide a quantitative estimate of the benefit listed.

Response:

The benefits outlined in the referenced testimony state the primary benefits of DistAM, and are not solely representative of the Asset Repository. Each component of the DistAM program shares similar benefits, which are foundational to the program as a whole. The DistAM program contains the Asset Repository, which feeds the Asset Investment Planning and Asset Performance Management tools as described on page 63 lines 12-13. Any benefits not quantified are planned to be included when an updated BCA is completed.

- Reduced capital and maintenance costs: \$2.7M Capital and \$900k O&M per year.
- Reduced customer outages and restoration cost: 344 outages avoided per year.
- Reduced power quality issues and system losses: The Company has not quantified a value for system losses.
- Increased asset availability: The Company has not quantified a value for asset availability.
- Reduced asset degradation risk, and
- Improved resilience of the electric distribution system: The Company has not quantified a value for asset degradation and Improved resilience of the electric distribution system.

Witness: Scott A. Mcphail

Date: August 20, 2024

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Question:

66. Please refer to McPhail, p. 76, which discusses the benefits of RAMP. Please provide a quantitative estimate of the outages avoided and cost savings from the RAMP and CAAP tool.

Response:

Since RAMP's inception in 2022 through August 16, 2024, 396,818 customer outage minutes have been prevented. The Company has not determined a cost savings from RAMP and CAAP.

Witness: Scott A. Mcphail

Date: August 23, 2024

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Question:

219. Refer to the Operational Systems Modernization section of Mr. McPhail's direct testimony beginning on page 81. Please:

- a. Explain why these optimization systems are needed at this time when the focus and resources should be concentrated on replacing failing infrastructure, reducing power outages, and the duration of outages.
- b. Provide a copy of the CBA performed that justifies undertaken each of the systems proposed. Provide the CBA in Excel with formulas intact and all supporting data and assumptions referenced to a source and explained.
- c. Refer to Figure 16 on page 82. For each system or project, provide the cost of the project from inception to completion by year for both capital expenditures and O&M expense, separately.
- d. For each project listed in Figure 16, provide the current phase of development of the project (i.e., Initial scoping, conceptual analysis, system requirements determination, vendor/system selection, implementation, completed), and the next phase of development with start and completion dates.

Response:

a.

Operational Systems Modernization

Replacing infrastructure to reduce outage frequency and duration are benefits to customers. Operational Systems Modernization projects focus on leveraging technologies to establish and enhance operational procedures to improve outage response and prepare for the requirements of the grid of the future. As explained in response to U21585-AG-CE-0541, the Company must remain proactive in its efforts to enable new technologies for the benefit of customers.

FLISR

FLISR directly impacts both the number and length of power outages on circuits with FLISR capability. FLISR intelligently sectionalizes faulted areas to avoid unnecessary customer outages. By auto sectionalizing, FLISR also narrows down a potential fault to a specific zone, allowing field crews to find the issue in less time. With a functional FLISR system, faults will be immediately isolated, and any available downstream customers can automatically be transferred to adjacent circuits. This greatly impacts travel and switching time for field operations, reducing outage minutes. New and upgraded equipment will be installed to support this effort, improving current failing or obsolete equipment.

DER Optimization

The DER Optimization initiative will directly influence the prioritization and selection of infrastructure that needs to be replaced using traditional alternatives versus infrastructure investments that can be deferred

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or avoided through the management and control of Company, customer, and third-party owned DERs. Reducing the number and duration of power outages, and avoiding other reliability or power quality related issues, is a benefit of the DER Optimization program.

The increase of the Distributed Generation program cap to 10% of the utility’s average five-year in state peak load introduced by Public Act 235 not only escalates the reliability concern, but accelerates the timeline for needing to have a DERMS designed, implemented, and fully integrated with operational systems and processes to avoid reliability challenges that can be caused by DER penetration.

b.

FLISR

Please refer to U21585-MNSC-CE-0321 for the outage minutes expected to be avoided with FLISR. A formal CBA will be completed once the project is kicked off later this year.

DER Optimization

As described in part a., justification for investments in the DER Optimization program are based on critical functionalities it provides related to managing bi-directional power flows, power quality concerns, and interconnections with third party and customer owned DER. It is also considered a mandatory system to enable future compliance with FERC 2222 and PA 235. The comprehensive scope, costs, and full-scale benefits of the DER Optimization initiative will be further defined following the launch of the benchmarking and learning sessions with key stakeholders, including the working group described by the MPSC in Case No. U-21389.

c.

(\$000) (Calendar year)	2022		2023		2024		2025		2026	
	Cap	O&M	Cap	O&M	Cap	O&M	Cap	O&M	Cap	O&M
Fault Location Isolation & Service Restoration (FLISR)	-	-	-	-	-	-	2,500	375	2,500	375
DER Optimization	187	63	2	2	-	-	4,953	510	14,842	1,640

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d.

System	Current Phase	Next Phase	Next Phase Start Date	Next Phase End Date
FLISR	Initial Scoping/Conceptual Analysis	Implementation	Q1/2025	Q2/2026
DER Optimization	System Requirements Determination	Vendor/System Selection	Q2/2025	Q3/2025

Witness: Scott A. Mcphail
Date: August 29, 2024

AG Adjustments to Capital Expenditures, Rate Base, Depreciation Expense, and Property Tax

(\$000)

Line	Description (a)	Property taxes		Total (d)	Rate Base Reduction (e)	Depreciation Rate ³ (f)	Reduction in Depreciation Expense (g)	Property taxes	
		14 Months Ending 2/28/2025 (b)	12 Months Ending 2/28/2026 (c)					Rate ⁴ (h)	Adjustment (i)
Distribution:¹									
1	LVD Lines-New Business	11,352	10,358	21,710	16,531	2.98%	493	\$ 0.0115540	\$ 95
2	LVD Lines Demand Failures	17,839	14,357	32,196	25,018	2.98%	746	\$ 0.0115540	145
3	LVD Lines Reliability - Zonal Health Improvements		178,189	178,189	89,095	2.98%	2,655	\$ 0.0115540	515
4	LVD Lines Reliability - Secondary		14,090	14,090	7,045	2.98%	210	\$ 0.0115540	41
5	LVD Lines Reliability - Right-of-Way	2,859	7,359	10,218	6,539	2.98%	195	\$ 0.0115540	38
6	LVD Substation Reliability - New or Rebuilt Substation:		14,410	14,410	7,205	2.98%	215	\$ 0.0115540	42
7	LVD Substation Reliability - DSCADA	1,599	1,880	3,479	2,539	2.98%	76	\$ 0.0115540	15
8	LVD Repetitive Outages	5,409	6,453	11,862	8,636	2.98%	257	\$ 0.0115540	50
9	LVD Lines Rehabilitation	4,062	5,405	9,467	6,765	2.98%	202	\$ 0.0115540	39
10	Resiliency	10,068	22,623	32,691	21,380	2.98%	637	\$ 0.0115540	124
11	LVD Lines Capacity	13,485	37,714	51,199	32,342	2.98%	964	\$ 0.0115540	187
12	LVD Premature Projects	14,428	14,144	28,572	21,500	2.98%	641	\$ 0.0115540	124
13	Wildfire Risk Mitigation Program		12,000	12,000	6,000	2.98%	179	\$ 0.0115540	35
14	HVD Lines Reliability	7,205	6,930	14,135	10,670	2.98%	318	\$ 0.0115540	62
15	HVD Lines and Substations Rehabilitation	9,303	31,189	40,492	24,898	2.98%	742	\$ 0.0115540	144
16	Large Transformer Pre-Purchases	10,200	10,200	20,400	15,300	2.98%	456	\$ 0.0115540	88
17	Grid Modernization	8,960	25,178	34,138	21,549	2.98%	642	\$ 0.0115540	124
18 Generation (Solar, Hydro, Battery Storage)²									
19	Washtenaw Solar Project		24,233	24,233	12,117	3.64%	441	\$ 0.0115540	70
20	Muskegon Solar Project	141,387	128,907	270,294	205,841	3.64%	7,493	\$ 0.0115540	1,189
21	Spring Creek Solar Project	108,185	122,819	231,004	169,595	3.64%	6,173	\$ 0.0115540	980
22	Hydro Facilities	42,376	92,258	134,634	88,505	17.80%	15,754	\$ 0.0115540	511
23	Battery Storage	39,672	78,921	118,593	79,133	3.64%	2,880	\$ 0.0115540	457
24 Operations Support:²									
25	Lansing Service Center	3,405	13,967	17,372	10,389	2.56%	266	\$ 0.0115540	60
26	Hastings Service Center	136		136	136	2.56%	3	\$ 0.0115540	1
27	Kalamazoo Service Center	4,815	9,424	14,239	9,527	2.56%	244	\$ 0.0115540	55
28	Control/Dispatch Center	4,903	5,570	10,473	7,688	2.56%	197	\$ 0.0115540	44
29	Total	\$ 461,648	\$ 888,578	\$ 1,350,226	\$ 905,937		\$ 43,077		\$ 3,368
30	Working Capital Reduction⁵				44,300				
31	Total Rate Base Reduction				\$ 950,237				

Source:

- (1) Sponsored by Sebastian Coppola in direct testimony.
- (2) Sponsored by David Dismukes in direct testimony
- (3) Depreciation Rate - WP-JCA-26
- (4) Exhibit A-161 (BJV-1).
- (5) Coppola testimony.

Recommended Capital Structure & Cost Rates for
Projected Year Ending February 2026 (Millions of Dollars)

Line	Description (a)	Note	Consumers Energy Capital Structure			Cost Rate* (e)	Total Cost (d) x (e) (f)	Conversion Factors** (g)	Pre-Tax Wtd. Cost (f) x (g) (h)
			Capital Balances (b)	% Permanent Capital (c)	% Total Capital (d)				
1	Long Term Debt	(A)	\$ 12,139	49.85%	41.60%	4.26%	1.77%	1.0000	1.77%
2	Preferred Stock		37	0.15%	0.13%	4.50%	0.01%	1.3381	0.01%
3	Common Equity	(A)	<u>12,177</u>	<u>50.00%</u>	<u>41.73%</u>	9.80%	<u>4.09%</u>	1.3381	<u>5.47%</u>
4	Total Permanent Capital	(B)	24,353	<u>100.00%</u>	83.46%		5.87%		7.25%
5	Short Term Debt	(B)	281		0.96%	4.28%	0.04%	1.0000	0.04%
6	Deferred Income Taxes	(B)	4,430		15.18%	0.00%	0.00%	1.0000	0.00%
7	JDITC								
8	Long Term Debt	(A)	58		0.20%	4.26%	0.01%	1.0000	0.01%
9	Preferred Stock		-		0.00%	4.50%	0.00%	1.3381	0.00%
10	Common Equity	(A)	<u>58</u>		0.20%	9.80%	0.02%	1.3381	<u>0.03%</u>
11	Total JDITC	(B)	<u>116</u>						
12	Total Capitalization & Cost Rates		<u>\$ 29,180</u>		<u>100.00%</u>		5.94%		7.33%

Notes

- * All Cost rates per Exhibit A-14 (MRB-1), Schedule D1 except for Common Equity which is set forth on Exhibit AG-1.17. and long-term debt as explained on page 2 of this exhibit
- ** From Company Exhibit A-14 (MRB-1), Schedule D1, column (h).
- (A) Reflects the permanent capital of CECO per Exhibit A-14 (MRB-1), Sched. D1, with common equity set at 50%.
- (B) Capital balances per Company Exhibit A-14 (MRB-1), Schedule D1.

Recommended Capital Structure & Cost Rates
Cost of Long Term Debt

<u>Line</u>	<u>Caption or Item</u> (a)	<u>Millions of Dollars</u>		<u>Average</u>	<u>Comment or Explanation</u> (e)
		<u>LT Debt</u> <u>Amount</u> (b)	<u>Interest</u> <u>Cost</u> (c)	<u>Interest</u> <u>Rate</u> (d)	
1	Cost of Long Term Debt per Company-See Exhibit A-14 (MRB - 4)	<u>\$ 11,958.0</u>	<u>\$ 519.8</u>	<u>4.35%</u>	Exhibit Lines 58 and 62
	<u>AG Changes</u>				
2	Adjustment for Actual August 2024 issue				
3	Subtract Projected Issuance in August 2024 at 5.9%	(665.0)	(39.2)		Exhibit A-14 (MRB-4) Line 43
4	Addition of Actual Issuance in August 2024 at 4.9%	<u>700.0</u>	<u>34.3</u>		From DR AG-CE-274
5	Net Change (L 3 + L 4)	<u>35.0</u>	<u>(4.9)</u>		
6	Revise Interest Rate on 2025 Debt Issued				
7	Subtract Projected Issuances in 2025 at 5.89%	(612.0)	(36.3)		Exhibit A-14 (MRB-4) Lines 44 & 45
8	Addition of Projected Issuances in 2025 at 5.43%	<u>612.0</u>	<u>32.9</u>		See Note 1 Below
9	Net Change (L 6 + L 7)	<u>-</u>	<u>(3.4)</u>		
10	AG Revised Cost of Long Term Debt (Sum of Lines 1, 5 and 9)	<u>\$ 11,993.0</u>	<u>\$ 511.5</u>	<u>4.26%</u>	

Note 1 Long Term Debt Rate and Cost for Line 8

Projected 30 Year U.S. Treasury (see AG CAPM analysis)	3.95%	From AG CAPM Analysis
"A" rated bond spread vs. U.S. Treasury	<u>1.34%</u>	Per Exhibit A-35 (MRB-9), line 44
Sub Total	5.29%	
Amort. Of Financing costs	<u>0.08%</u>	Existing Financing Differential per Ex. A-14 (MRB-4)
Total Cost Rate	<u>5.37%</u>	
Amount to Finance per Company	<u>\$ 612.0</u>	
Amount - Line 8, Col. (c)	<u>\$ 32.9</u>	5.56% x Amt. to Finance

Short-Term Debt Cost Rate Revised

<u>Line</u>	<u>Month and Year</u> (a)		<u>Bloomberg Forward SOFR Rates*</u>		<u>Variable Cost Rate Reduction (c) less (b) (d)</u>	<u>Company Short Term Debt Rate** (e)</u>	<u>Revised Short Term Debt Rate (d) plus (e) (f)</u>
			<u>Company Case (b)</u>	<u>Revised Information (c)</u>			
1	Feb	2024	4.55%	3.97%			
2	Mar	2024	4.48%	3.83%			
3	Apr	2024	4.40%	3.72%			
4	May	2024	4.32%	3.62%			
5	Jun	2024	4.25%	3.57%			
6	Jul	2024	4.18%	3.53%			
7	Aug	2024	4.13%	3.49%			
8	Sep	2024	4.10%	3.40%			
9	Oct	2024	4.06%	3.30%			
10	Nov	2024	4.00%	3.20%			
11	Dec	2024	3.94%	3.18%			
12	Jan	2025	3.90%	3.20%			
13	Feb	2025	<u>3.93%</u>	<u>3.24%</u>			
14	Average Rate		<u>4.17%</u>	<u>3.48%</u>	<u>-0.69%</u>	<u>4.97%</u>	<u>4.28%</u>

* Rates provided in attachments to AG-CE-395 as of April 2, 2024 (Company Case) and August 23, 2024 as Revised above

** See Exhibit A-14 (MRB-1), line 10, column (e)

Summary of Cost of Common Equity Analysis

<u>Line</u>	<u>Description</u> (a)	<u>Relative Weighting</u> (b)	<u>Consumers Energy Proxy Rates</u> (c)	<u>Note</u> (d)
1	Discounted Cash Flow Approach (DCF)	50.00%	9.27%	1
2	Capital Asset Pricing Model Approach (CAPM)	25.00%	10.58%	2
3	Utility Equity Risk Premium Approach	25.00%	<u>9.72%</u>	3
4	Calc. Cost of Common Equity (Sum of Col. (b) x (c) for Lines 1, 2 and 3)		9.71%	
5	Adjustment for other factors		<u>0.09%</u>	4
6	Recommended ROE		9.80%	

Note 1 See Exhibit AG-1.18

Note 2 See Exhibit AG-1.19

Note 3 See Exhibit AG-1.20

Note 4 Reflects the potential of higher interest rates

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Capital Asset Pricing Model Application
(See Equation Below)

<u>Line</u>	<u>Company</u>	<u>Ticker</u>	<u>Common Equity to Capital %</u>	<u>Current Beta (B)</u>	<u>Risk Premium (Rp)</u>	<u>Beta x Risk Premium Col. (d) x (e)</u>	<u>Risk Free Rate (Rf)</u>	<u>Ke or CAPM ROE for Proxy Co. Col. (e) + (g)</u>
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Alliant Energy	LNT	42.3%	0.90	7.17%	6.45%	3.95%	10.40%
2	Ameren	AEE	41.3%	0.90	7.17%	6.45%	3.95%	10.40%
3	Avista	AVA	49.2%	0.95	7.17%	6.81%	3.95%	10.76%
4	Black Hills	BKH	41.5%	1.05	7.17%	7.53%	3.95%	11.48%
5	Consolidated Edison	ED	48.9%	0.80	7.17%	5.74%	3.95%	9.69%
6	DTE Energy	DTE	34.8%	1.00	7.17%	7.17%	3.95%	11.12%
7	IDACORP	IDA	51.3%	0.85	7.17%	6.09%	3.95%	10.04%
8	Northwestern	NWE	50.4%	0.95	7.17%	6.81%	3.95%	10.76%
9	PNM Resources	PNM	33.4%	0.90	7.17%	6.45%	3.95%	10.40%
10	Public Service Enterprise Group	PEG	43.9%	0.95	7.17%	6.81%	3.95%	10.76%
11	Average		<u>43.7%</u>	<u>0.93</u>	<u>7.17%</u>	<u>6.63%</u>	<u>3.95%</u>	<u>10.58%</u>
12	High							11.48%
13	Low							9.69%

Sources: Column (c) From Data included in SEC filings - Average of four quarters ended June 2024
 Column (d) From the Value Line Investment Survey Publications of June 7, July 19 and Aug.9, 2024.
 Column (e) Historic average - 1926 to 2022 Ibbotson returns of Stock Market vs. Yield on Government Bonds (Co. Exh A-14 (TAW-1)), page 7, line 51, col. (I)
 Column (g) Average 30 Year Treasury Rate Developed (based on 10 Yr Treasury from AG-CE-403)

	<u>Beg. of Test Yr.</u>	<u>End of Test Year</u>	<u>Average</u>
10 Yr. Treasury Rate per S&P Global (45th Qtr. 2024 and 2025)	3.99%	3.45%	
Less pro-rated reductions (2/12) of 4th qt. 2024 at 3.99% to 4th qt. 2025 at 3.45% and 2026 at 3.24%.			
10-Year forecasted treasury rates from DR AG-CE-0403.	<u>0.09%</u>	<u>0.03%</u>	
Sub Total	3.90%	3.42%	
August 2024 Spread (30. vs. 10 Yr.) per U.S. Treasury	<u>0.29%</u>	<u>0.29%</u>	
Est. 30 Year Treasury Rate	<u>4.19%</u>	<u>3.71%</u>	<u>3.95%</u>

Equation for CAPM

$$K_e = R_f + (B \times R_p)$$

Where K_e = the Cost of Common Equity; R_f = the Risk Free Rate of Return;
 B = the Beta or covariance of the stocks price to overall market ; and
 R_p = the Expected Risk Premium of the overall market

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Utility Equity Risk Premium Approach

<u>Line</u>	<u>Description</u> (a)	<u>Rate Developed</u> (b)	<u>Note</u> (c)
1	Number of Companies in proxy group	10	
2	Average Rating	A/BBB	1
3	Projected Average of "A" and "BBB" Bonds New Issue Rate	5.65%	2
4	Historical Spread - Elec. Util. Common Stocks vs. "A" Rated Utility Bonds	<u>4.07%</u>	3
5	Total - Rate for "A" and "BBB" rated companies (lines 3 + 4)	<u>9.72%</u>	

Notes:

1	All of the peer companies are rated in the A and BBB categories or are split rated	
2	New Issue Rates with Spreads per Exh A-35 (MRB-9), page 9, lines 44 to 47.	
	"BBB" Rated Spread to 30 Yr, Treasuries	2.20%
	"BBB+" Rated Spread to 30 Yr, Treasuries	1.68%
	"A-" Rated Spread to 30 Yr. Treasuries	1.56%
	"A" Rated Spread to 30 Yr. Treasuries	<u>1.34%</u>
	Average Spread per Company	1.70%
	Assumed 30 Year US Treasury Bond Rate (per CAPM Analysis)	<u>3.95%</u>
	Projected Average of "A" / "BBB" 30 Year bonds	<u>5.65%</u>
3	Risk Premium per Company Exhibit A-14 (TAW-1) page 8, line 94 Substitute Ex. A-14 (TAW-1) page 9 rates for page 8 rates	4.37%
	2021 (-7.88% vs -24.1%) / 92 Years	-0.18%
	2002 (-10.91% vs -22.42%) / 92 Years	<u>-0.12%</u>
	Adjusted Spread over "A" rated utility bonds	<u>4.07%</u>

30 BP Differential

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Electric Rate Case Return on Equity (ROE) - 24 Months Ended June 2024*

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Line	Electric Company	Jurisdiction & Order Date			ROE Awarded in		Parent Company	Pub. Finan'ls Avail.	Long Term Debt Issued Since Date of Rate Order	
					2023	2024				
1	Green Mountain Power	VT	Aug. 31	2022	8.57%		Energir	Private		
2	Oklahoma Gas & Electric	OK	Sep. 8	2022	9.50%		OGE	Yes	Jan 3, 2023 \$450M, 10 Yr. at 5.4%	
3	El Paso Electric	TX	Sep. 15	2022	9.35%		JP Mrgn Chase TII Fund	Private		
4	Kingsport Power	TN	Oct. 25	2022	9.50%		American Electric Power	Yes	Feb 27, 2023 \$850M, 10 Yr. at 5.625%	
5	Commenwealth Edison	IL	Nov. 17	2022	7.85%		Exelon	Yes	Jan 3, 2023 \$975M, 10 Yr. and 30 Yr at 4.9% & 5.3%	
6	NSTAR Electric	MA	Nov. 30	2022	9.80%		Eversource	Yes	May 8, 2023 \$1.8Bil. 3Yr, 5Yr., 10Yr at 4.75% to 5.45%	
7	Ameren Illinois	IL	Dec. 1	2022	7.85%		Ameren	Yes	May 2023 \$500M 10 Yr. at 4.95%	
8	Delmarva Power & Light	MD	Dec. 14	2022	9.60%		Exelon	Yes	Jan 3, 2023 \$975M, 10 Yr. and 30 Yr at 4.9% & 5.3%	
9	Duke Energy Ohio	OH	Dec. 14	2022	9.50%		Duke	Yes	March 2023 \$750M 10 Yr & 30 Yr at 5.25% & 5.65%	
10	Pacificorp	OR	Dec. 16	2022	9.50%		Berkshire Hathaway Energy	Yes	May 15, 2023 \$1.2Bil. 31 Yr at 5.5%	
11	Pudget Sound Energy	WA	Dec. 22	2022	9.40%		Alberta Investment Mgt. Co.	Private		
12	Wisconsin Public Service	WI	Dec. 22	2022	9.80%		WEC Energy	Yes	Jan. 9, 2023 - \$1.1 B; 3 and 5 Yr. at 4.75	
13	Sierra Pacific Power	NV	Dec. 27	2022	9.56%		Berkshire Hathaway Energy	Yes		
14	Enpire District Electric	OK	Dec. 29	2022	9.30%		Algonquin Power & Utilities	Foreign		
15	Wisconsin Electric Power	WI	Dec. 29	2022	9.80%		WEC Energy	Yes	Jan. 9, 2023 - \$1.1 B; 3 and 5 Yr. at 4.75	
16	Minnesota Power Enterpr.	MN	Jan. 23	2023	9.65%		Allete	Yes	Apr. 27, 2023 \$125M 10 Yr. at 4.9%	
17	Cheyenne Light Fuel & Pwr.	WY	Jan. 26	2023	9.75%		Black Hills	Yes	Sep. 15, 2023 \$\$450M 10.5 Yr. at 6.15%	
18	Duke Energy Progress	SC	Feb. 9	2023	9.60%		Duke Energy	Yes	Mar. 2023 \$500M (10 Yr), \$500M (30 Yr.) at 5.25% & 5.35%	
19	Southwestern Electric Power	LA	Feb. 17	2023	9.50%		Xcel Energy	Yes	Jul. 31, 2023, \$800M 10 Yr at 5.45%	
20	Oncor Elec. Delivery	TX	Mar. 9	2023	9.70%		Sempra Energy	Yes	Jun. 2023 \$550M (3 Yr), \$700M (10 Yr.) at 5.4% & 5.5%	
21	Versant Power	ME	May. 31	2023	9.35%		Enmax (City of Alberta, Can.)	Private		
22	Northern States Power	MN	Jun 1	2023	9.25%		Xcel Energy	Yes	Jul. 31, 2023, \$800M 10 Yr at 5.45%	
23	Central Maine Power	ME	Jun 6	2023	9.35%		Avangrid	Yes		
24	MDU Resources	ND	Jun 6	2023	9.75%		MDU Resources	Yes		
25	Average-12 Mo. Ended June 2023				9.37%					
26	Consolidated Edison of NY	NY	Jul. 20	2023	9.25%		Consolidated Edison	Yes	Nov 2023 \$600M (10 Yr.) at 5.5%	
27	Northern Indiana P. S.	IN	Aug. 2	2023	9.80%		NIPSCO	Yes	Jun 2024 \$600M (5 Yr) at 5.2%	
28	Energry Texas	TX	Aug. 3	2023	9.57%		Energry	Yes	May 2024 \$1.2B (30 Yr.) at 7.125%	
29	Duke Energy Progress	NC	Aug. 18	2023	9.80%		Duke Energy	Yes	Sep. 2023 \$600M (10 Yr), \$750M (30 Yr.) at 5.75% & 6.10%	
30	Green Mountain Power	VT	Aug. 23	2023	9.58%		Eniger	Private		
31	United Illuminating Group	CT	Aug. 25	2023	8.63%		Avangrid	Yes	Oct. 2023 \$65M 10 Yr. 4.5% (Remarketed)	
32	Tuscon Electric Power	AZ	Aug. 25	2023	9.55%		Fortis	Canada		
33	Avista	ID	Aug. 31	2023	9.40%		Avista	Yes		
34	Sub Total				9.45%					

* All ROE data from Regulatory Research Associates & excludes Limited Issue Rider cases

** A summary of all ROEs including those at 9.9% and above is included on page 3 of this exhibit

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Electric Rate Case Return on Equity (ROE) - 24 Months Ended June 2024*

Line	Electric Company	Jurisdiction & Order Date			ROE Awarded in		Parent Company	Pub. Finan'ls Avail.	Long Term Debt Issued Since Date of Rate Order
					2023	2024			
1	Sub Total from Page 1					9.45%			
2	Public Service of Colorado	CO	Sep. 6	2023		9.30%	Xcel Energy	Yes	Feb 2024 \$800M (10 Yr.) at 5.5%
3	MDU Resources	MT	Sep. 21	2023		9.65%	MDU Resources	Yes	
4	Duke Energy KY	KY	Oct. 12	2023		9.75%	Duke Energy	Yes	Jun 2024 \$1.5B (10 Yr & 30 Yr) at 5.45 & 5.80
5	New York State Elec. & Gas	NY	Oct. 12	2023		9.20%	Avangrid	Yes	July 2024 \$600M (3 Yr.) 5.48%
6	Rochester Gas & Electric	NY	Oct. 12	2023		9.20%	Avangrid	Yes	July 2024 \$600M (3 Yr.) 5.48%
7	Potomac Edison	MD	Oct. 18	2023		9.50%	Exelon	Yes	Feb 2024 \$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
8	Southwestern Public Service	NM	Oct. 19	2023		9.50%	Xcel Energy	Yes	Feb 2024 \$800M (10 Yr.) at 5.5%
9	NorthWestern Energy Group	MT	Oct. 25	2023		9.65%	NorthWestern Energy Group	Yes	
10	Madison Gas & Electric	WI	Nov. 3	2023		9.70%	MGE Energy	Yes	
11	Public Service of Oklahoma	OK	Nov. 3	2023		9.30%	American Electric Power	Yes	Jun 2024 \$1.0B (30 Yr.) 7%
12	Northern States Power	WI	Nov. 9	2023		9.80%	Xcel Energy	Yes	Feb 2024 \$800M (10 Yr.) at 5.5%
13	Wisconsin Power & Light	WI	Nov. 9	2023		9.80%	Alliant Energy	Yes	
14	Atlantic City Electric	NJ	Nov. 17	2023		9.60%	Exelon	Yes	Feb 2024 \$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
15	Pacificorp	WY	Nov. 28	2023		9.35%	Berkshire Hathaway	Yes	
16	Empire District Electric	AR	Dec. 7	2023		9.70%	Algonquin Power & Utilities	Canada	
17	Ameren Illinois	IL	Dec. 14	2023		8.72%	Ameren	Yes	
18	Baltimore Gas & Electric	MD	Dec. 14	2023		9.50%	Exelon	Yes	Feb 2024 \$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
19	Commonwealth Edison	IL	Dec. 14	2023		8.91%	Exelon	Yes	Feb 2024 \$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
20	Portland General Electric	OR	Dec. 18	2023		9.50%	Portland General Electric	Yes	
21	Nevada Power	NV	Dec. 26	2023		9.52%	Berkshire Hathaway	Yes	
22	Idaho Power	ID	Dec. 28	2023		9.60%	IDACORP	Yes	
23	Public Service of New Mexico	NM	Jan. 3	2024		9.26%	PNM Resources	Yes	
24	Kentucky Power	KY	Jan. 19	2024		9.75%	American Electric Power	Yes	Jun 2024 \$1.0B (30 Yr.) 7%
25	UNS Electric-Tuscon Electric	AZ	Jan. 30	2024		9.75%	UNS Energy & Fortis	Canada	
26	Jersey Central Power & Light	NJ	Feb. 14	2024		9.60%	First Energy	Yes	
27	Virginia Electric	VA	Feb. 28	2024		9.70%	Dominion Energy	Yes	May 2024 \$2.0B (30 Yr & 31 Yr) at 7% & 6.875%
28	Arizona Public Service	AZ	Mar. 5	2024		9.55%	Pinnacle West	Yes	June 2024 \$350M (2 Yr.) SOFR
29	Monongahela Power	WV	Mar. 26	2024		9.80%	First Energy	Yes	
30	Dalmarva Power	DE	Apr. 18	2024		9.60%	Exelon	Yes	
31	Indiana Michigan Electric	IN	May. 8	2024		9.85%	American Electric Power	Yes	Jun 2024 \$1.0B (30 Yr.) 7%
32	Patomac Electric	MD	Jun. 10	2024		9.50%	Exelon	Yes	
33	Fitzburg Gas & Electric	MA	Jun. 28	2024		9.40%	Unitil	Yes	
34	Average-12 Mo. Ended June 2024					9.50%			

* All ROE data from Regulatory Research Associates & excludes Limited Issue Rider cases
 ** A summary of all ROEs including those at 9.9% and above is included on page 3 of this exhibit

**MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case**

**Case No. U-21585
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Electric Rate Case Return on Equity (ROE) - 24 Months Ended June 2024*

Line	Caption or State and Company		No. of Cases		ROEs 12 Mo. Ended June		Explanations & Commentary
			2023	2024	2023	2024	
All Cases							
1	Average ROE - Cases Under 9.90%		33	40	9.37%	9.50%	From Pages 1 and 2
2	Average ROE - Cases at 9.9% or Greater (below)		11	10	10.10%	10.33%	Line 21 Below
3	Total Cases and Average ROEs		<u>44</u>	<u>50</u>	<u>9.55%</u>	<u>9.67%</u>	9.61% 2-Year Average
<hr/>							
Cases with ROEs at 9.90% or Greater							
4	Michigan	DTE Electric	1	1	9.90%	9.90%	
5	Michigan	Consumer Energy Co.		1		9.90%	
6	Michigan	Upper Peninsula Power	1		9.90%		
7	California	Pacific Gas & Electric	1	1	10.25%	10.70%	Wild Fire Risk
8	California	Pacific Gas & Electric	1		10.00%		Wild Fire Risk
9	California	San Diego Gas & Electric	1	1	10.20%	10.65%	Wild Fire Risk Due to Shared Funding Risk
10	California	San Diego Gas & Electric	1		9.95%		Wild Fire Risk Due to Shared Funding Risk
11	California	So. California Edison	1	1	10.30%	10.75%	Wild Fire Risk
12	California	So. California Edison	1		10.05%		Wild Fire Risk
13	California	Pacificorp		1		10.00%	
14	California	Liberty Utilities (CalPeco Elec.)	1		10.00%		Small Utility - Lake Tahoe (Rate Base of Approx. \$350M)**
Other States							
15	Alaska	Alaska Elec. Light & Power		1		11.45%	Small Juneau Alaska utility (17,600 customers)***
16	Georgia	Georgia Power	1		10.50%		Troubled Nuclear Plant Construction
17	Indiana	AES Indiana		1		9.90%	
18	N. Carolina	Duke Energy Carolinas		1		10.10%	3 Year Rate Plan under appeal by AG & Others
19	Ohio	Dayton Power & Light	1		10.00%		Distrib. ROE Only; Smaller Utility (536K customers)****
20	S. Carolina	Duke Energy S. Carolina	-	1	-	9.94%	Multi Year Agrmt. w/100% Flow-through of Unprot. DIT
21	Sub Total for Cases w/ROEs at 9.9% Plus		<u>11</u>	<u>10</u>	<u>10.10%</u>	<u>10.33%</u>	

* All ROE data from Regulatory Research Associates & excludes Limited Issue Rider cases

** Per Algonquin Nov. 10, 2023 Investor Presentation

*** See page 24 of 2022 Avista Form 10-K filed in early 2023

**** 100% of Customers may select an alternative energy provider - AES 2023 Form 10-K, pages 25 and 26.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case

Case No. U-21585
Exhibit AG-1.22
September 27, 2024
Page 1 of 2

Comparisson of AG and DTEE Peer Groups

Line	Value Line Electric Utilities	2023 Revs. (\$M)	Elimination Factors							Large NU Ops & CMS	Total Factors	Peer Group per	
			Revs. Over Under	Reorg.	EPS	OS Wind	Foreign	M & A	Fall-Off			& Wldfr.	AG
			20 B +	1 B	No Div. Grth								
1	AVANGRID	\$ 8,309			Yes		Yes				2		
2	Consolidated Edison	14,663										x	
3	Dominion Energy	14,393			Yes		Yes				2		
4	Duke Energy	29,060	Yes								1		
5	Eversource Energy	11,911					Yes		Yes		2		
6	Exelon	21,727	Yes								1		
7	FirstEnergy	12,870					Yes				1		x
8	NextEra Energy	28,114	Yes							Yes	2		
9	PPL Corp.	8,312						Yes			1		x
10	Public Service Enterp. Group	11,237										x	
11	Southern Co.	25,253	Yes								1		
12	ALLETE	1,880					Yes				1		
13	Alliant Energy	4,027										x	x
14	Ameren	7,500										x	x
15	American Electric Power	18,882					Yes				1		
16	CMS Energy	7,462								Yes	1		
17	CenterPoint Energy	8,646					Yes				1		
18	DTE Energy	12,745										x	x
19	Entergy	12,147					Yes	Yes			2		x
20	Fortis	11,517				Yes					1		
21	Eergy	5,508						Yes			1		x
22	MGE Energy	670		Yes							1		
23	OGE Energy	2,674						Yes			1		x
24	Otter Tail	1,349								Yes	1		
25	WEC Energy	8,893					Yes				1		x
26	Avista	1,752										x	
27	Black Hills	2,331										x	
28	Edison International	16,338								Yes	1		
29	Hawaiian Electric	3,682			Yes			Yes	Yes		3		
30	IDACORP	1,766										X	
31	Northwestern	1,422										x	
32	PNM Resources	1,939										x	
33	Pacific Gas & Electric	24,438	Yes							Yes	2		
34	Pinnacle West Capital	4,696						Yes			1		x
35	Portland General Electric	2,923						Yes			1		x
36	Sempra Energy	16,720				Yes					1		
37	Xcel Energy	14,206								Yes	1		x
38	Unitil	557		Yes							1		
	Totals		5	2	3	2	9	7	5	3	36	10	12

Companies Eliminated from Peer Group Consideration
(due to M & A, Reorg. and EPS Growth Concerns)

<u>Line</u>	<u>Company involved in M & A, Reorg.</u>
1	Avangrid
2	Dominion Energy
3	Eversource
4	First Energy*
5	Allele
6	American Electric Power
7	CenterPoint Energy
8	Entergy*
9	WEC Energy*

<u>Anticipated Actions to be Taken per Value Line</u>
Iberdola of Spain looking to acquire remainder of Company
Selling various assets to reduce debt
Looking to sell Off-Shore Wind and Water Distribution assets
Selling \$3.5 Billion in Transmission Assets
Being acquired by Global Infrastructure Partners
Selling AEP OnSite Partners for \$0.3 billion
Sale of two gas units pending for \$1.2 B to Bernhard Capital Ptns.
Looking to sell shut-down nuclear assets
Purchasing \$0.5 billion stake in Texas solar project

		<u>EPS per Value Line</u>			
<u>Company with Earnings Disruption</u>		<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>
10	PPL Corp*	\$ 2.04	\$ 0.53	\$ 1.41	\$ 1.60
11	Entergy*	6.90	6.87	5.35	11.10
12	Evergy*		3.83	3.26	3.17
13	OGE Energy*		2.36	2.25	2.07
14	Hawaiian Electric		2.25	2.20	1.81
15	Pinnacle West*		5.47	4.26	4.41
16	Portland General Electric*			2.74	2.38

<u>Comments based on Value Line and Company Documents</u>
Effects of Restructuring
Hurricanes Ida and Zeta (2020-22); Favorable IRS Audit Outcome (2023)
Impairment Loss in 2022
Wildfires - Value Line estimates 2028 EPS at \$1.00 per share
Disruptive Rate Case Outcome in late 2021 - EPS to recover
Mild Weather in 2023 and higher costs

* These companies have been included in the Company's peer group

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Rating Agency Cash Flow Ratios
(With ROE at 9.80% and a 50% Common Equity Ratio)

Line	Caption	2023 Adjusted Moody's Cash Flow Ratio (\$ Millions)			Note
		Cash From Operations	Debt	Ratio	
	(a)	Pre-Wkg. Cap. (b)	(c)	(b) / (c) (d)	
1	2022 Actual Ratio Results	\$ 2,190	\$ 11,454	19.1%	1
2	Reduce Common Equity (to 50% vs 50.7%)	(12)	144		2
3	Increase ROE (to 9.80% vs 8.26% Actual)	159			3
4	Pro Forma w/50% Common Equity, 9.80% ROE	<u>\$ 2,337</u>	<u>\$ 11,598</u>	20.2%	L 1 + L 2 + L 3
5	Ratings Downgrade Risk			Below 18%	4

Notes

- From page 2 of Moody's May 31, 2024 report on Consumers Energy (see AG-CE-273 Attachment)
- As noted under "Average 2023 Capitalization" below, the Company's Common Equity was 50.7% in 2023. Adjusting to 50% shifts \$144 million from common equity to long-term debt (0.7% x \$20.6 billion = \$144 million).
Lower Common Equity of \$144 million x the Company's earned ROE of 8.26% = \$12 million in lower Net Income.
- Increasing the ROE from 8.26% (actual) to 9.80% produces a \$159 million increase in total Company earnings (1.54% x \$10.3 billion = \$159 million).
Note: Consumers 2023 Net Income of \$ 865 million (p. 102, of 2023 Form 10-K) / \$10.5 billion (below) = a 8.26% ROE
- Page 3 of Moody's May 31, 2024 report on Consumers Energy (see AG-CE-273 Attachment) indicates "below 18% on a sustained basis" as a risk.

Average 2023 Capitalization (\$ Millions) (from Ex. A-14 (JCA-22, Sch. D1, pg.1)	Actual 2023		Rebalancing Adjustmts.	2023 Rebalanced	
	Amount	% Capital		Amount	% Capital
Long-Term Debt	\$ 10,135	49.1%	\$ 144	\$ 10,279	49.8%
Preferred Stock	37	0.2%		37	0.2%
Common Equity	<u>10,470</u>	<u>50.7%</u>	(144)	<u>10,326</u>	<u>50.0%</u>
Total	<u>\$ 20,642</u>	<u>100.0%</u>		<u>\$ 20,642</u>	<u>100.0%</u>

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case
Peer Group Market to Book Equity Ratios Jun. 30, 2024

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<u>Line</u>	<u>Company</u> (a)	<u>Ticker</u> (b)	<u>Mkt. Val. p/Sh.</u> <u>Of Com. Equity</u> <u>Jun. 30, 2024*</u> (c)	<u>Millions**</u>		<u>Book</u> <u>Value per</u> <u>Share</u> <u>(d) / (e)</u> (f)	<u>Market</u> <u>to Book</u> <u>Ratio</u> <u>(c) / (f)</u> (g)
				<u>Book</u> <u>Value of</u> <u>Com. Equity</u> (d)	<u>Common</u> <u>Shares</u> (e)		
1	Alliant Energy	LNT	\$ 50.90	\$ 6,791	256.5	26.48	1.92
2	Ameren	AEE	71.11	11,539	266.8	43.25	1.64
3	Avista	AVA	34.61	2,527	78.7	32.11	1.08
4	Black Hills	BKH	54.38	3,357	69.7	48.16	1.13
5	Consolidated Edison	IDA	89.42	21,560	312.0	69.10	1.29
6	DTE Energy	DTE	111.01	11,105	207.0	53.65	2.07
7	IDACORP	IDA	93.15	3,196	53.3	59.96	1.55
8	Northwestern Energy Group	NWE	50.08	2,807	64.8	43.32	1.16
9	PNM Resources	WEC	34.40	2,403	90.2	26.64	1.29
10	Public Service Enterprise Group	PEG	73.70	15,824	515.0	30.73	2.40
11	Average						1.55

* Per Yahoo

** Per SEC Filings on Form 10-Q for quarter ended June 30, 2024

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Question:

55. Refer to Mr. Bleckman's testimony discussing the credit ratings of CEC and the infusion of equity capital from CMS Energy. Please provide a copy of all rating agency reports covering CMS Energy and Consumers Energy for the most recent two years (2022 through 2024).

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that information regarding CMS Energy is irrelevant to this matter as CMS Energy is not a party to this case. Subject to the Company's objection, and without waiving that objection, Consumers Energy responds as follows:

Please find the requested ratings agency credit opinions for Consumers Energy attached.

Witness: MARC R. BLECKMAN

Date: August 19, 2024

THE REST OF THIS EXHIBIT CONSISTS OF 12 PAGES FOR
THE MOODY'S REPORT DATED MAY 31, 2024

CREDIT OPINION

31 May 2024

Update



Send Your Feedback

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	(P)A3
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the [ratings section](#) at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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CLIENT SERVICES

Americas 1-212-553-1653

Asia Pacific 852-3551-3077

Japan 81-3-5408-4100

EMEA 44-20-7772-5454

Consumers Energy Company

Update to credit analysis

Summary

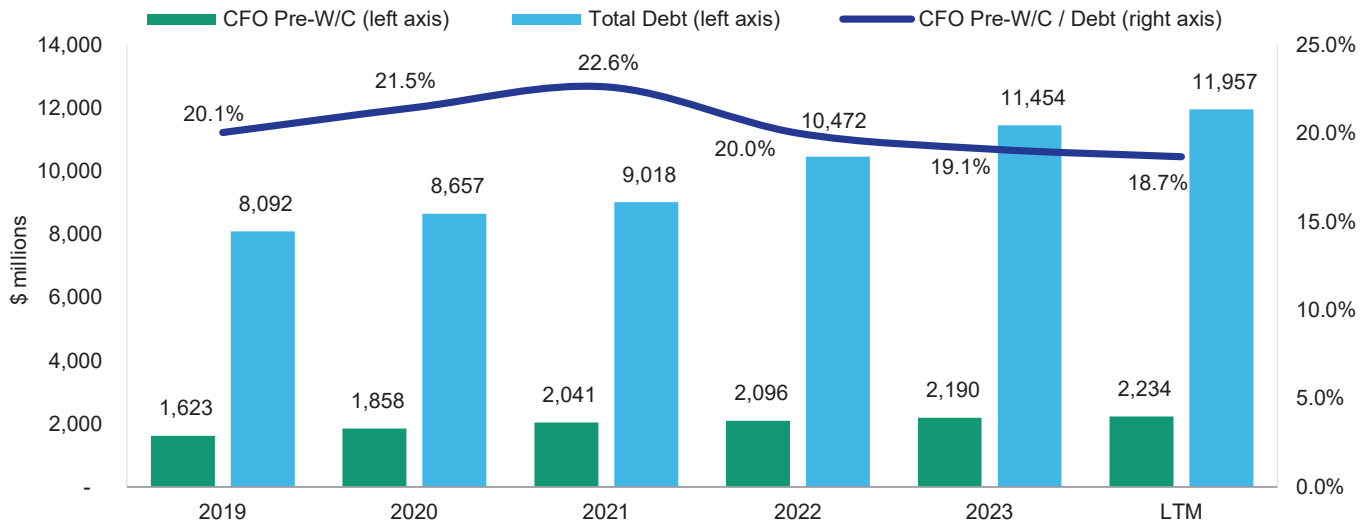
Consumers Energy Company's (Consumers Energy) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in the credit supportive regulatory environment of Michigan. We expect the utility to maintain a stable financial profile with cash flow from operations before changes in working capital (CFO pre-WC) to debt averaging around 20-21%, including an adjustment to exclude securitization debt, over the next 2-3 years. At the end of the latest twelve month (LTM) period ending 31 March 2024, Consumers Energy's CFO pre-WC to debt ratio was 20%, including the adjustment to exclude securitization bonds. The company will continue to execute its robust capital investment plan and have an active regulatory calendar over this period. Based on the Michigan regulatory framework, we expect the utility to recover its investment costs on a timely basis and to earn an appropriate return on its investments.

Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). However, CMS has made notable progress in reducing the percentage of parent debt in its capital structure in recent years. We now estimate that the percentage of parent debt will remain below 25% of total consolidated debt. All of Consumer Energy's outstanding debt obligations are secured.

Recent development

In November 2023, Michigan enacted a new energy law (2023 Energy Law), which raised the state's renewable energy standard while providing additional authority to the Michigan Public Service Commission (MPSC). Consumer Energy's operations are under the purview of MPSC. In general, we view this development to be constructive because the utilities in the state will now outline a renewable energy plan with greater transparency, and the MPSC will have an expanded scope of consideration for various factors influencing Consumers Energy's plan to decarbonize.

Exhibit 1
 Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.3%, 20.4% and 20.0% in 2022, 2023 and LTM ending 31 March 2024, respectively.

Source: Moody's Financial Metrics

Credit strengths

- » Credit supportive regulatory environment in Michigan
- » Transparent and timely cost recovery
- » Stable financial profile

Credit challenges

- » Robust capital investment plan
- » Maintaining regulatory support for these capital investments
- » Lack of geographic and regulatory diversity with single state service territory

Rating outlook

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

Factors that could lead to an upgrade

A rating upgrade could be considered if credit metrics improve such that CFO pre-WC to debt is above 21% on a sustained basis. In addition, if the Michigan regulatory framework becomes even more formulaic, transparent or timely with its suite of cost recovery mechanisms for Consumers Energy, a rating upgrade could be possible.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on <https://ratings.moodys.com> for the most updated credit rating action information and rating history.

Factors that could lead to a downgrade

A rating downgrade could be considered if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment; or if the CFO pre-WC to debt ratio declines below 18% on a sustained basis.

Key indicators

Exhibit 2

Consumers Energy Company

	2019	2020	2021	2022	2023	LTM
CFO Pre-W/C + Interest / Interest	6.2x	6.6x	7.5x	7.1x	5.8x	5.6x
CFO Pre-W/C / Debt	20.1%	21.5%	22.6%	20.0%	19.1%	18.7%
CFO Pre-W/C – Dividends / Debt	12.7%	14.1%	14.6%	12.7%	13.0%	13.0%
Debt / Capitalization	46.0%	44.9%	43.7%	45.1%	45.8%	46.7%

All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

Credit metrics included in the exhibit include securitization bonds. When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.3%, 20.5% and 20.0% in 2022, 2023 and LTM ending 31 March 2024, respectively.

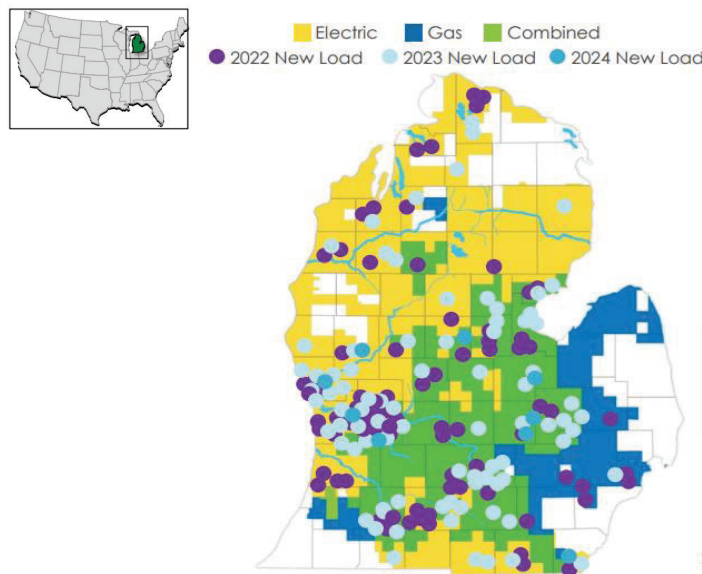
Source: Moody's Financial Metrics

Profile

Consumers Energy is a vertically integrated electric and gas utility serving approximately 1.9 million electric and 1.8 million gas customers in the state of Michigan with an average rate base of \$25 billion in 2023. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. The utility is a wholly-owned subsidiary of CMS and, as the primary subsidiary of the parent company, it represents over 95% of CMS's consolidated earnings. In addition to Consumers Energy, CMS has a subsidiary called NorthStar Clean Energy, a non-utility domestic independent power producer and marketer.

Exhibit 3

Consumers Energy's Service Territory



Source: Company Presentations

Detailed credit considerations

Credit supportive regulatory environment

Consumers Energy is regulated by the MPSC, which has a regulatory framework that we view to be more credit supportive than most other states. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework has been streamlined, improving both the rate case process and the timeliness of cost recovery. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which had already included pre-construction approval for large

generating resources, into an integrated resource planning (IRP) process. The IRP process considers a wide range of factors including fuel costs, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before the construction of major projects.

In November 2023, new energy legislation (2023 Energy Law) was enacted. Under the new law, the state's renewable energy standards were raised to 50% by 2030 and 60% by 2035 from the previous 15% by 2021 requirement. It also set a clean energy standard of 80% by 2035 and 100% by 2040. Under the law, zero to low-carbon emitting sources, such as nuclear generation and natural gas generation with carbon capture, are considered clean energy sources. Along with these new standards, the new legislation expanded the authority of the MPSC to oversee their implementation. CMS's utility subsidiary Consumers Energy will file updates to its renewable energy plans in 2024 and its Clean Energy Plan in or before 2027. Given the existing regulatory framework in Michigan, we expect the company's collaborative dialogue with both stakeholders and regulator to continue under the new legislation.

In June 2022, Consumers Energy and key stakeholders in Michigan reached a settlement related to the company's latest IRP. The settlement included the retirement of all of its remaining coal power plants (all three units at the Campbell power plant site) in 2025 as a result of the 2021 IRP. Consumers Energy will be able to record approximately \$1.3 billion of the remaining book value of these power plants as a regulatory asset and earn a 9% return on equity (ROE) through the remaining life. Instead of securitizing the remaining book value, the settlement will minimize the impact of the accelerated coal retirements on Consumers Energy's credit metrics. We view this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

Timeliness of cost recovery based on a prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous formulaic rate adjustment mechanisms that provide a high degree of cash flow stability and assurance of recovery. For example, Consumers Energy has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/under recoveries, although interim gas inventory buildup could substantially increase the company's working capital financing when gas prices increase sharply.

Gas utilities in the state also benefit from programs designed to assure recovery of needed infrastructure improvements. Consumers Energy's RDM compares and adjusts for differences between weather normalized actual and authorized revenues. The company's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing less than 250 miles of cast iron pipe and other high-risk components.

Active rate case filing cadence

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. The utility currently has its gas rate case pending before the MPSC, and filed its request for an electric rate increase on 31 May 2024. Over the last three years, Consumers Energy experienced downward pressure on its allowed ROE in its rate cases although the company was able to maintain a 9.9% allowed ROE. We expect Consumers Energy to maintain a stable financial profile because there are other offsetting mechanisms such as usage of forward test year to allow the utility to earn appropriate returns and to recover investment costs on a timely basis. However, further deterioration of the allowed ROE is likely to put negative pressure on the company's overall financial profile.

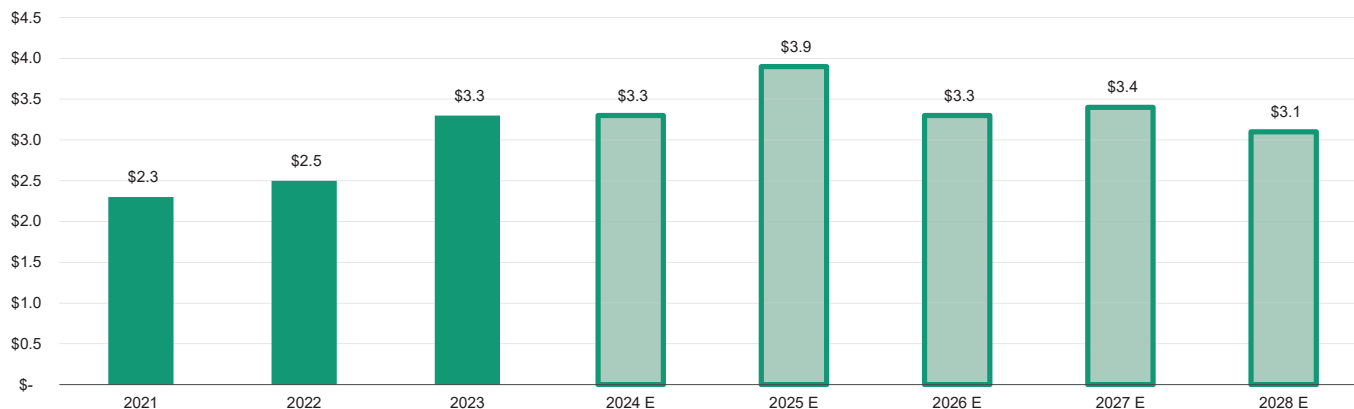
On 1 March 2024, the commission authorized a \$92 million increase based on a 9.9% ROE, 50.02% equity capital structure and a \$13.67 billion rate base value. Also, the final order approved an Investment Recovery Mechanism (IRM) rider for distribution reliability projects totaling \$99 million over two years.

On 15 December 2023, the utility filed a gas rate case, seeking a \$136 million increase based on a projected test year for the 12-month period ending 30 September 2025, requesting a 10.25% ROE, 51.5% equity capital structure and a rate base value estimated around \$10.97 billion. In April 2024, the MPSC Staff recommended an \$70.77 million increase based on a 9.85% ROE, 49.92% equity capital structure and a \$10.88 billion rate base value. A final decision is expected by 15 October 2024.

Stable credit metrics expected to be maintained through its high capital investment cycle

Consumers Energy's capital spending continues to be robust as it is currently in the midst of a large capital investment plan. The company increased its five-year capital expenditure plan through 2028 to \$17 billion, approximately \$1.5 billion higher than the previous plan. Consumers Energy will invest approximately \$6.3 billion primarily to maintain and upgrade its gas utility infrastructure; \$7.3 billion related to its electric distribution and other infrastructure; and \$3.4 billion related to clean energy generation. These investments should enhance the company's reliability and safety as well as help it execute its decarbonization plan.

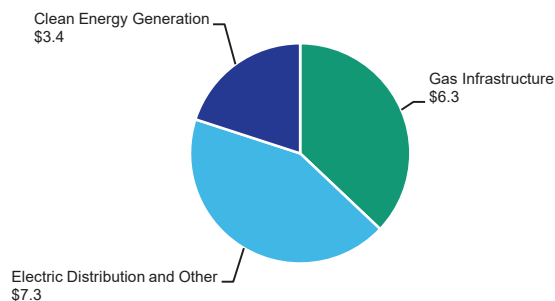
Exhibit 4
Consumers Energy's elevated capital program will extend at least through 2028
 \$ billions



Source: Company 10K

Through this period, Consumers Energy plans to keep rate increases modest, which should help to maintain regulatory support for investment cost recovery. Funding for these investments will be provided by internally generated cash flow, the issuance of debt at Consumers Energy and equity contributions from CMS. We expect Consumers Energy to maintain its CFO pre-WC to debt at around 20%-21% on average over the next 2-3 years. At the end of 2023 and for the LTM period ending 31 March 2024, Consumers Energy produced a CFO pre-WC to debt ratio of 20.5% and 20%, respectively, excluding securitization debt.

Exhibit 5
Planned Capital Expenditures 2024 - 2028
 \$ billions



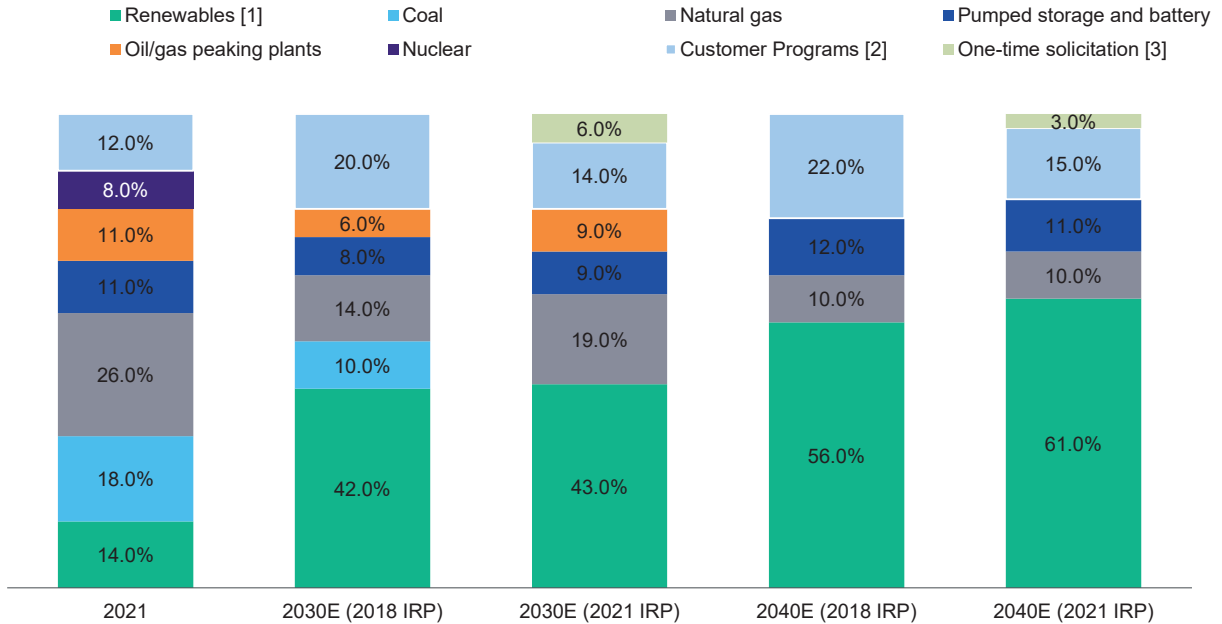
Source: Company 10K

Based on Consumers' latest IRP approved in 2022, the utility will add up to 8 GW of solar power, which is 2 GW more than what was approved in the company's 2018 IRP. As a result, by 2040, more than 60% of Consumers Energy's generation capacity will be from renewable sources. In order to replace the retiring coal capacity, the utility acquired the Covert natural gas-fired power plant for

approximately \$815 million in 2023. It issued requests for proposals (RFP) for two purchased power agreements (PPA) for 500 MW of dispatchable generation and 200 MW of clean energy sources.

Exhibit 6

Based on the latest IRP settlement, more than 60% of Consumers Energy's generation sources will be renewables by 2040



[1] Does not include renewable RECs.

[2] Includes energy waste reduction, demand response, and conservation voltage reduction program.

[3] One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.

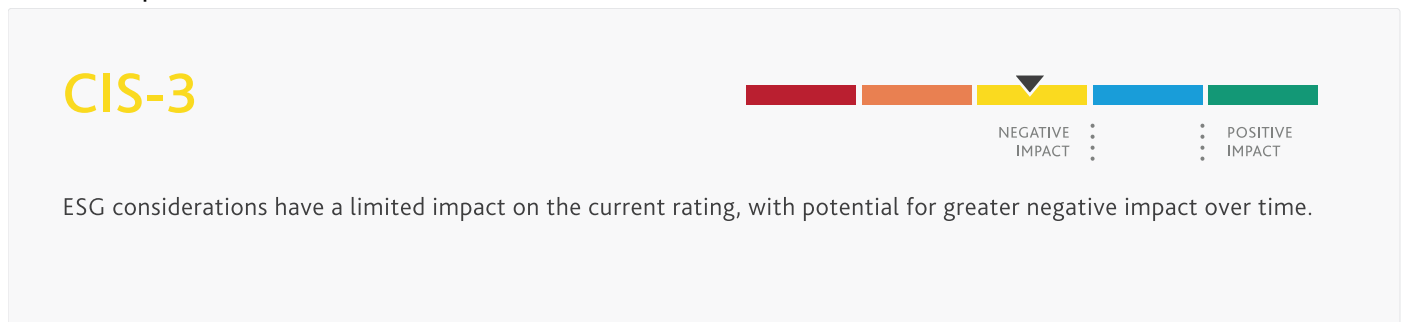
Source: Company's 10-K in 2022 and 2021, and latest investor presentation

ESG considerations

Consumers Energy Company's ESG credit impact score is CIS-3

Exhibit 7

ESG credit impact score

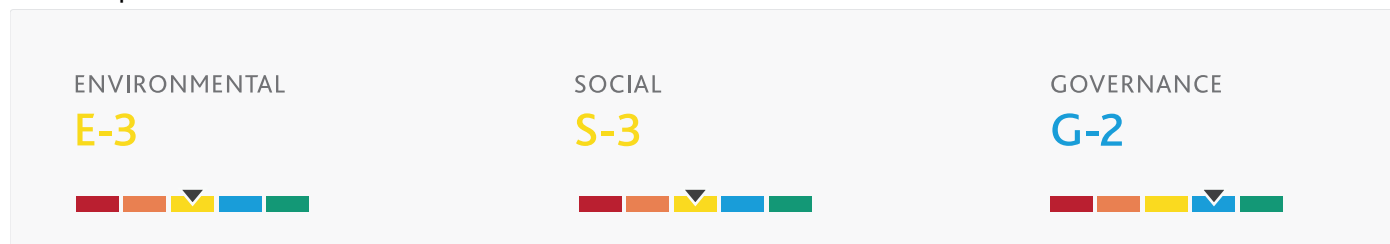


Source: Moody's Ratings

Consumers Energy's **CIS-3** indicates that ESG considerations have limited impact on the current credit rating with greater potential for negative impact over time. It reflects some exposure to physical climate risk and moderating carbon transition risk. It also incorporates social risks stemming from inherent risk associated with regulated utilities and governance risk that is not a material driver.

Exhibit 8

ESG issuer profile scores



Source: Moody's Ratings

Environmental

Consumers Energy's **E-3** issuer profile score reflects its moderate position for the carbon transition with tangible strategies and plans in place that substantially mitigate its carbon transition exposure. The utility is currently in a transition to phase out its coal-fired generation and targets zero coal-fired generation output in 2025, accelerated from its prior target of 2039. The utility also established a goal of net zero methane emission for its gas delivery system by 2030; net zero carbon emissions for its electric business by 2040, including MISO market purchases and PPAs; and net zero greenhouse gas emissions for its entire business, including customer and supplier emissions, by 2050. Michigan's regulatory framework supports the utility's transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Social

S-3 issuer profile score for Consumers Energy is primarily related to its customer and regulatory relations as well as demographic and societal trends. The utility's regulatory environment, as well as its interaction with the Michigan Public Service Commission, are important in considering the utility's social risk. Also, the safety and reliability of its operations are important social considerations.

Governance

Consumers Energy's **G-2** issuer profile score reflects our view that its governance does not pose a particular risk and is not a material driver in the company's overall credit profile. It also incorporates its position as a subsidiary of CMS whose corporate governance considerations including financial policy and risk management influence Consumers Energy.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click [here](#) to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumers Energy's external liquidity sources include a \$1.1 billion secured revolving credit facility expiring in December 2027 and, as of 31 March 2024, net availability was \$1.073 billion with \$27 million of letters of credit outstanding. Consumers Energy also maintains a \$250 million secured credit facility terminating in November 2025 and had \$197 million available as of 31 March 2024. Both facilities are secured by first mortgage bonds. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's \$500 million commercial paper program. At 31 March 2024, the company had no commercial paper notes outstanding under the program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at 65%. At 31 March 2024, debt to capital was 50%.

These facilities includes sustainability linked pricing metrics, which permits pricing adjustments for meeting targets related to sustainability. Targets include renewable generation and diverse supplier spend, highlighting its commitment to shifting its exposure to a greater renewable content and to supplier diversity.

The utility's continuing capital expenditure program and dividend policy will result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent.

For the LTM period ended 31 March 2024, Consumers generated approximately \$2.3 billion of cash from operations, invested \$3.2 billion and distributed \$673 million of dividends to CMS, resulting in negative free cash flow of approximately \$1.6 billion. Given its robust investment plan, we expect Consumers Energy to maintain its negative free cash flow position over the 12-18 months.

In January 2024, Consumers Energy issued \$600 million first mortgage bonds with 4.6% rate maturing in May 2029.

Rating methodology and scorecard factors

Exhibit 9

Methodology Scoring Factors

Consumers Energy Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2024		Moody's 12-18 Month Forward View As of 5/19/2024 [3]	
	Measure	Score	Measure	Score
Factor 1 : Regulatory Framework (25%)				
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.5x	Aa	5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	20.4%	Baa	20% - 21%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	13.4%	Baa	13% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	44.5%	A	45% - 46%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A2		A3
b) Actual Rating Assigned				A3

* Senior Secured Rating.

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

[2] As of 3/31/2024.

[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

Source: Moody's Financial Metrics

Appendix

Exhibit 10

Cash Flow and Credit Metrics

CF Metrics (In \$ millions)	2019	2020	2021	2022	2023	LTM
FFO	1,752	1,994	2,054	2,125	2,065	2,136
+/- Other	(129)	(136)	(13)	(29)	125	98
CFO Pre-WC	1,623	1,858	2,041	2,096	2,190	2,234
+/- ΔWC	(15)	25	(53)	(1,098)	243	108
CFO	1,608	1,883	1,988	998	2,433	2,342
- Div	593	638	723	770	696	674
- Capex	2,100	2,184	2,066	2,256	2,260	2,289
FCF	(1,085)	(939)	(801)	(2,028)	(523)	(621)
(CFO Pre-W/C) / Debt	20.1%	21.5%	22.6%	20.0%	19.1%	18.7%
(CFO Pre-W/C - Dividends) / Debt	12.7%	14.1%	14.6%	12.7%	13.0%	13.0%
FFO / Debt	21.6%	23.0%	22.8%	20.3%	18.0%	17.9%
RCF / Debt	14.3%	15.7%	14.8%	12.9%	12.0%	12.2%
Revenue	6,376	6,189	7,021	8,151	7,166	7,053
Interest Expense	312	332	315	342	455	482
Net Income	725	798	838	883	802	842
Total Assets	23,699	25,399	27,140	29,916	31,852	32,209
Total Liabilities	16,053	16,862	17,880	19,780	21,071	21,418
Total Equity	7,647	8,538	9,261	10,137	10,782	10,792

All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months

Source: Moody's Financial Metrics

Exhibit 11

Peer Comparison Table

(In \$ millions)	Consumers Energy Company (P)A3 Stable			DTE Electric Company (P)A2 Stable			DTE Gas Company A3 Stable			Northern States Power Company (Minnesota) A2 Stable			Wisconsin Power and Light Company Baa1 Stable		
	FY	FY	LTM	FY	FY	LTM	FY	FY	LTM	FY	FY	LTM	FY	FY	LTM
	Dec-22	Dec-23	Mar-24	Dec-22	Dec-23	Mar-24	Dec-22	Dec-23	Mar-24	Dec-22	Dec-23	Mar-24	Dec-22	Dec-23	Mar-24
Revenue	8,151	7,166	7,053	6,397	5,804	5,895	1,894	1,726	1,736	6,684	6,043	5,913	1,856	1,827	1,817
CFO Pre-W/C	2,096	2,190	2,234	2,164	2,565	2,726	575	638	580	2,034	2,259	2,306	317	602	595
Total Debt	10,472	11,454	11,957	11,408	12,523	12,612	2,602	2,642	2,565	7,292	7,692	8,212	3,323	3,700	3,679
CFO Pre-W/C + Interest / Interest	7.1x	5.8x	5.6x	6.5x	6.7x	6.8x	7.2x	7.2x	6.4x	8.2x	7.8x	7.7x	4.5x	7.4x	6.6x
CFO Pre-W/C / Debt	20.0%	19.1%	18.7%	19.0%	20.5%	21.6%	22.1%	24.1%	22.6%	27.9%	29.4%	28.1%	9.5%	16.3%	16.2%
CFO Pre-W/C - Dividends / Debt	12.7%	13.0%	13.0%	12.3%	12.5%	13.6%	15.8%	16.9%	14.9%	20.2%	21.0%	20.2%	4.2%	11.3%	11.1%
Debt / Capitalization	45.1%	45.8%	46.7%	47.4%	48.4%	48.6%	44.5%	42.3%	39.4%	43.4%	43.0%	43.2%	43.8%	44.0%	43.5%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End; LTM = Last Twelve Months.

Source: Moody's Financial Metrics

Ratings

Exhibit 12

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
LT IRB/PC	A3
Pref. Stock	Baa1
Commercial Paper	P-2
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Pref. Stock	Ba1

Source: Moody's Ratings

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Moody's Ratings

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

U21585-AG-CE-0273

Page 1 of 1

Question:

55. Refer to Mr. Bleckman's testimony discussing the credit ratings of CEC and the infusion of equity capital from CMS Energy. Please provide a copy of all rating agency reports covering CMS Energy and Consumers Energy for the most recent two years (2022 through 2024).

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that information regarding CMS Energy is irrelevant to this matter as CMS Energy is not a party to this case. Subject to the Company's objection, and without waiving that objection, Consumers Energy responds as follows:

Please find the requested ratings agency credit opinions for Consumers Energy attached.

Witness: MARC R. BLECKMAN

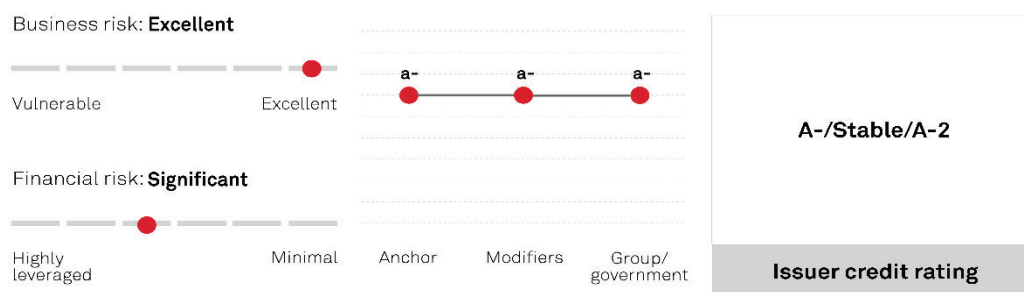
Date: August 19, 2024

THE REST OF THIS EXHIBIT CONSISTS OF 15 PAGES FOR
THE S&P REPORT DATED AUGUST 17, 2023

Consumers Energy Co.

August 17, 2023

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Monopolistic vertically integrated electric utility and gas distribution utility operations.	Lack of operating diversity makes the company largely depend on Michigan regulators to sustain its credit quality.
Favorable regulatory construct in Michigan.	Exposure to environmental risks due to its dependence on natural gas and coal-fired generation (about 70% of electricity generated or purchased in 2022), though this is partially mitigated by a plan to retire coal by 2025.
Large customer base of 1.9 million electric and 1.8 million gas customers.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.
The company is an insulated subsidiary of its parent, CMS Energy, allowing us to rate it one notch above the parent.	Susceptibility to adverse weather events, including winter storms.
	Exposure to cyclical commercial and industrial customers, which account for about 47% of electric revenues and 20% of gas revenues.

We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk.

We view Michigan's regulatory construct as above average compared to peers because of the benefit of a streamlined 10-month rate case process and various constructive rate mechanisms, such as the use of forward test-years, power supply and natural gas cost rider adjustments, and partial decoupling for the gas business. These mechanisms help the company earn its allowed ROE and minimize regulatory lag.

CE is currently in the middle of both an electric rate case and a gas rate case. The company filed for a \$207.1 million electric rate increase based on a 10.25% return on equity (ROE) in May and reached a settlement with various intervenors for a \$95 million gas rate increase based on a 9.90% ROE in July. We expect final rate orders by the end of 2023 and continue to monitor related developments.

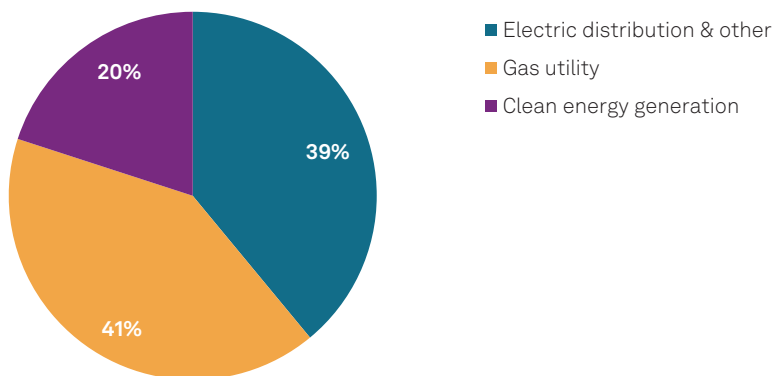
Consumers Energy Co. rate case details

	Present electric rate case: requested by company 5/1/2023	Previous electric rate case: authorized by Commission 1/19/2023	Present gas rate case: settlement filed 7/21/2023	Previous gas rate case: authorized by Commission 7/7/2022
Rate change amount (\$ mil.)	207.1	155.0	95.0	170.0
Rate base (\$ mil)	14,354.2	N/A	N/A	N/A
Rate base valuation method	Average	Average	Average	Average
Return on equity (%)	10.25	9.90	9.90	9.90
Common equity to total capital (%)	42.58	N/A	N/A	N/A
Rate of return (%)	6.11	N/A	N/A	N/A
Rate case test year end date	2/28/2025	12/31/2023	N/A	9/30/2023

Source: S&P CapitalIQ Pro. N/A—Not applicable.

The company's elevated capital spending plan prioritizes infrastructure upgrades, and its energy transition plans. Over the next five years, CE plans to spend about \$15.5 billion to maintain and upgrade its gas infrastructure and electric distribution systems and reduce its carbon emission. The capital plan includes investment of about \$6.3 billion in the gas segment and about \$9.2 billion in the electric segment. The company also intends to reduce its carbon exposure in line with its Integrated Resource Plan (IRP), which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 for CE's electric division and a goal to retire CE's owned coal-fired generation plants by 2025. Furthermore, the company's IRP targets a gradual reduction in its gas-fired generation dependence after 2025 as well as a target to meet 90% of its customer needs with clean energy sources by 2040. In addition, the company also announced a net-zero greenhouse gas emissions target for its gas distribution system by 2050.

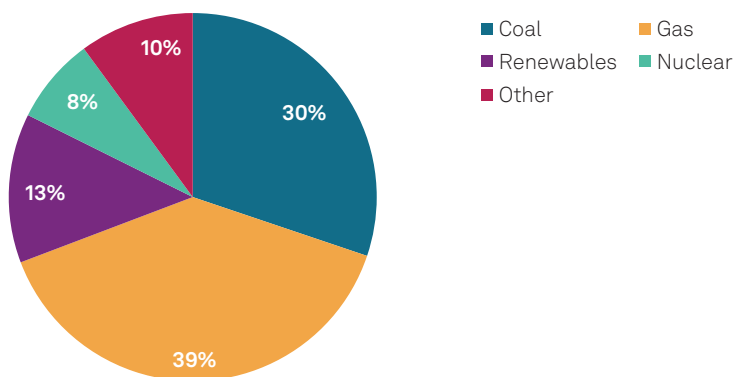
Consumers Energy Co.'s investment plan



Source: Company filings.

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Consumers Energy Co.'s electricity generated and purchased by source



Source: Company filings.

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The MPSC is currently investigating CE for malfunctioning meters and estimated billings. The company informed investors during its earnings call that meter vendors faced supply-chain issues since the start of the pandemic, which delayed the deployment of the company's updated meters moving to 5G from 3G. Given these delays, there were some issues with meter reads as more wireless carriers moved to 5G. This said, the company expects more consistent meter reads by the end of August. We continue to monitor the developments surrounding this investigation.

We expect CE's credit measures to remain within the significant financial risk profile category. Throughout our base-case scenario, we expect CE's funds from operations (FFO) to debt to be between 18%-20%.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of about 18%-20%.

Downside scenario

We could lower our rating on Consumers Energy if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or
- We could also lower our rating on Consumers Energy if we lower our rating on parent CMS Energy Corp.

Upside scenario

Although less likely, we could raise our rating on Consumer's Energy if we raise our rating on CMS Energy and Consumers Energy's stand-alone financial measures improve, reflecting FFO to debt consistently above 20%.

Our Base-Case Scenario

Assumptions

- Consistent rate case filings and use of existing regulatory mechanisms;
- Elevated capital spending over the forecast period averaging about \$3 billion annually;
- Annual dividends averaging about \$960 million annually;
- All debt maturities are refinanced; and
- Continued negative discretionary cash flow will be financed in a balanced manner to support the regulated capital structure.

Key metrics

Consumers Energy Inc.—Forecast summary

Period ending (Mil. \$)	2021a	2022a	2023e	2024f	2025f	2026f	2027f
Revenue	6,987	8,117	7,932	8,376	8,896	9,428	9,985
EBITDA (reported)	2,252	2,321	2,653	2,902	3,143	3,392	3,655
Plus: Operating lease adjustment (OLA) rent	8	6	6	6	6	6	6
Plus/(less): Other	146	70	51	(47)	(58)	(58)	(65)
EBITDA	2,406	2,397	2,710	2,861	3,092	3,340	3,595
Less: Cash interest paid	(375)	(342)	(406)	(478)	(533)	(573)	(605)
Less: Cash taxes paid	10	2	--	(102)	(41)	(92)	(66)

Consumers Energy Inc.—Forecast summary

Funds from operations (FFO)	2,041	2,058	2,303	2,281	2,518	2,675	2,925
Cash flow from operations (CFO)	2,014	985	2,717	2,221	2,471	2,585	2,798
Capital expenditure (capex)	2,136	2,275	3,707	2,823	3,117	2,765	2,737
Free operating cash flow (FOCF)	(123)	(1,290)	(990)	(602)	(647)	(180)	61
Dividends	724	771	788	913	968	1,044	1,099
Discretionary cash flow (DCF)	(847)	(2,061)	(1,778)	(1,515)	(1,615)	(1,224)	(1,038)
Debt (reported)	8,810	10,287	11,585	12,402	13,217	13,838	14,354
Plus: Lease liabilities debt	74	81	89	99	110	124	140
Plus: Pension and other postretirement debt	--	--	--	--	--	--	--
Less: Accessible cash and liquid Investments	(22)	(43)	(43)	(43)	(43)	(43)	(43)
Plus/(less): Other	535	680	27	98	180	267	355
Debt	9,397	11,005	11,658	12,556	13,465	14,186	14,807
Equity	9,279	10,155	10,885	11,687	12,603	13,369	14,096
Cash and short-term investments (reported)	22	43	43	43	43	43	43
Adjusted ratios							
Debt/EBITDA (x)	3.9	4.6	4.3	4.4	4.4	4.2	4.1
FFO/debt (%)	21.7	18.7	19.8	18.2	18.7	18.9	19.8
FFO cash interest coverage (x)	6.4	7.0	6.7	5.8	5.7	5.7	5.8
EBITDA interest coverage (x)	6.3	6.4	6.2	5.7	5.5	5.6	5.7
CFO/debt (%)	21.4	8.9	23.3	17.7	18.3	18.2	18.9
FOCF/debt (%)	(1.3)	(11.7)	(8.5)	(4.8)	(4.8)	(1.3)	0.4
DCF/debt (%)	(9.0)	(18.7)	(15.3)	(12.1)	(12.0)	(8.6)	(7.0)
Debt/debt and equity (%)	50.3	52.0	51.7	51.8	51.7	51.5	51.2

All figures adjusted by S&P Global Ratings. a—Actual. e—Estimate. f—Forecast.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE's electric business operates as a vertically integrated utility that generates, distributes, and sells electricity. The electric utility sources about half of its generation from purchased power, rather than from its own plants. The company also sells, stores, and transports natural gas. It is based in Jackson, Mich. CE contributes to about 95% of CMS' EBITDA.

Peer Comparison

Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Wisconsin Power & Light Co.	Wisconsin Electric Power Co.	Consolidated Edison Co. of New York Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31	2022-12-31	2022-12-31
Mil.	\$	\$	\$	\$	\$
Revenue	8,117	6,353	1,856	4,070	13,268
EBITDA	2,397	2,715	742	1,614	4,048
Funds from operations (FFO)	2,058	2,389	562	986	3,140
Interest	374	551	123	230	890
Cash interest paid	342	359	124	540	821
Operating cash flow (OCF)	985	1,654	286	726	3,264
Capital expenditure	2,275	2,617	1,007	1,018	3,563
Free operating cash flow (FOCF)	(1,290)	(964)	(721)	(293)	(299)
Discretionary cash flow (DCF)	(2,061)	(1,727)	(926)	(922)	(1,277)
Cash and short-term investments	43	15	5	6	1,056
Gross available cash	43	15	5	6	1,056
Debt	11,005	11,528	3,406	5,843	21,344
Equity	10,155	9,695	3,491	4,152	16,878
EBITDA margin (%)	29.5	42.7	40.0	39.7	30.5
Return on capital (%)	6.3	7.6	8.1	11.8	5.8
EBITDA interest coverage (x)	6.4	4.9	6.0	7.0	4.5
FFO cash interest coverage (x)	7.0	7.6	5.5	2.8	4.8
Debt/EBITDA (x)	4.6	4.2	4.6	3.6	5.3
FFO/debt (%)	18.7	20.7	16.5	16.9	14.7
OCF/debt (%)	8.9	14.3	8.4	12.4	15.3
FOCF/debt (%)	(11.7)	(8.4)	(21.2)	(5.0)	(1.4)
DCF/debt (%)	(18.7)	(15.0)	(27.2)	(15.8)	(6.0)

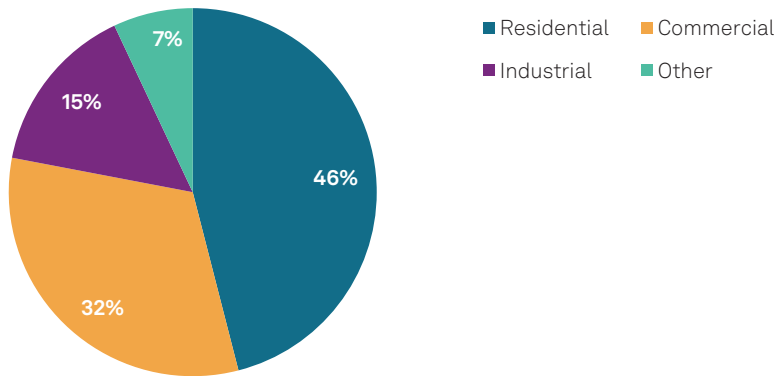
Business Risk

Our assessment of CE's business risk profile reflects the company's monopolistic electric and natural gas utility operations and effective management of regulatory risk. The Michigan Public Service Commission (MPSC) regulates CE and we view the regulatory environment in Michigan as above average compared to peers. This is demonstrated through the company's use of forward-looking test years and a streamlined 10-month rate case process. Furthermore, CE benefits from other constructive rate mechanisms, such as the Power Supply Cost Recovery and Gas Cost Recovery adjustment riders, as well as partial decoupling for the gas business, which annually reconciles actual weather-normalized nonfuel revenues with the revenues approved by the MPSC. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag. The company also actively manages its gas supply for its gas system as it injects natural gas into storage during the summer months for use during the winter months. During 2022, 48 percent of the natural gas supplied to all customers during

Consumers Energy Co.

the winter months was supplied from storage. Furthermore, CE's business risk profile is bolstered by the company's large customer base of about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan. This said, the company is exposed to cyclical commercial and industrial customers for its electric operations which contribute about 47% of the company's electric revenues.

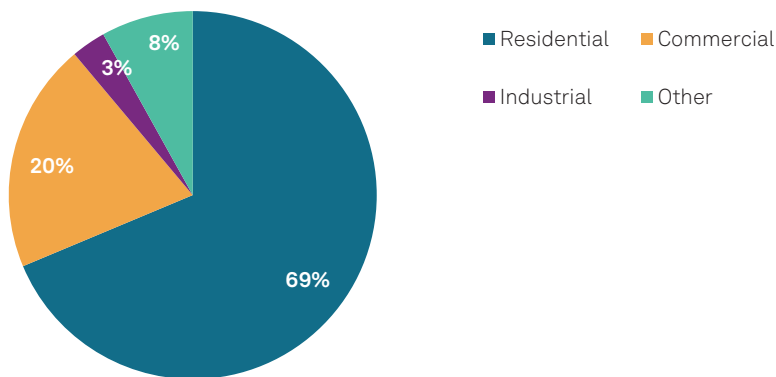
Consumers Energy Co.'s electrical revenue by customer class



Source: Company filings.

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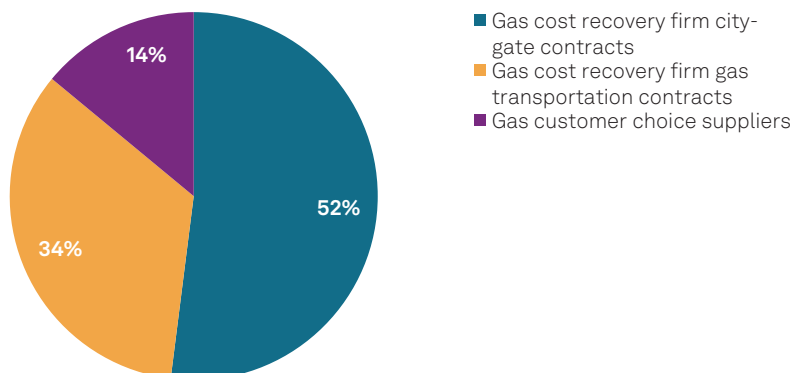
Consumers Energy Co.'s gas revenue by customer class



Source: Company filings.

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Consumers Energy Co.'s gas supply sources



Source: Company filings.

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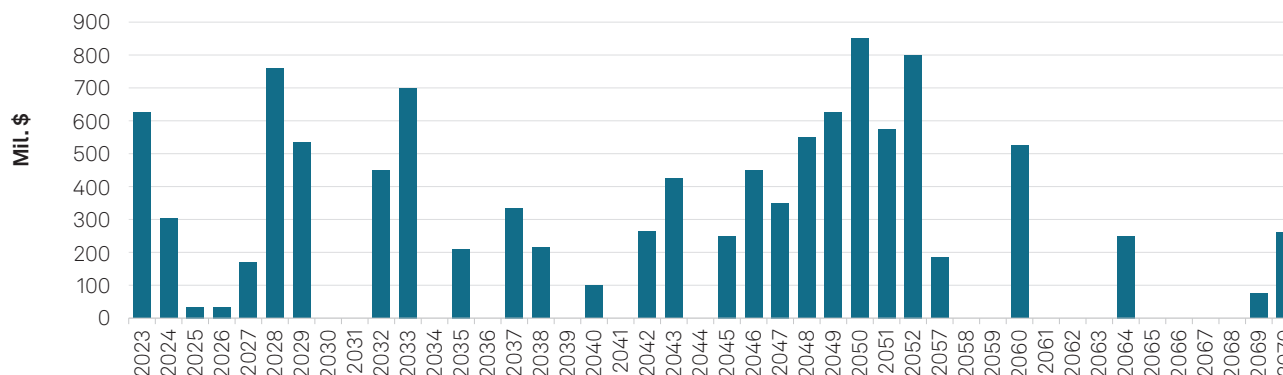
Financial Risk

We assess CE's financial measures using our medial volatility table, reflecting the company's lower-risk regulated electric and gas utility operations and its effective management of regulatory risk. Under our base-case scenario, we expect elevated capital spending averaging around \$3 billion annually over the forecast period (inclusive of the company's acquisition of the Covert gas plant), dividends averaging about \$960 million annually, equity injections by the parent to maintain the company's capital structure, securitization issuance related to the retirement costs of the company's Karn coal plant units 1 and 2, continued use of existing regulatory mechanisms, negative discretionary cash flow, and refinancing of all debt maturities. As such, we anticipate financial measures to be consistent with the middle of the range for the significant financial risk category. Specifically, we forecast FFO to debt between 18%-20%.

Debt maturities

Debt Maturities

As of June 2023



Source. Company filings

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Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022
Reporting period	2017a	2018a	2019a	2020a	2021a	2022a
Display currency (mil.)	\$	\$	\$	\$	\$	\$
Revenues	6,187	6,430	6,341	6,155	6,987	8,117
EBITDA	2,267	2,152	2,252	2,392	2,406	2,397
Funds from operations (FFO)	1,954	1,665	1,823	1,968	2,041	2,058
Interest expense	347	355	335	393	380	374
Cash interest paid	314	331	296	373	375	342
Operating cash flow (OCF)	1,792	1,533	1,688	1,265	2,014	985
Capital expenditure	1,721	1,920	2,191	2,254	2,136	2,275
Free operating cash flow (FOCF)	71	(387)	(502)	(989)	(123)	(1,290)
Discretionary cash flow (DCF)	(453)	(918)	(1,094)	(1,628)	(847)	(2,061)
Cash and short-term investments	44	39	11	20	22	43
Gross available cash	44	39	11	20	22	43
Debt	7,037	7,774	8,238	9,113	9,397	11,005
Common equity	6,488	6,920	7,737	8,556	9,279	10,155
Adjusted ratios						
EBITDA margin (%)	36.6	33.5	35.5	38.9	34.4	29.5
Return on capital (%)	9.8	7.9	7.7	7.5	6.9	6.3
EBITDA interest coverage (x)	6.5	6.1	6.7	6.1	6.3	6.4
FFO cash interest coverage (x)	7.2	6.0	7.2	6.3	6.4	7.0
Debt/EBITDA (x)	3.1	3.6	3.7	3.8	3.9	4.6
FFO/debt (%)	27.8	21.4	22.1	21.6	21.7	18.7
OCF/debt (%)	25.5	19.7	20.5	13.9	21.4	8.9

Consumers Energy Co.--Financial Summary

FOCF/debt (%)	1.0	(5.0)	(6.1)	(10.9)	(1.3)	(11.7)
DCF/debt (%)	(6.4)	(11.8)	(13.3)	(17.9)	(9.0)	(18.7)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. \$)

Financial year	Dec-31-2022	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Company reported amounts		10,287	10,155	8,151	2,321	1,233	335	2,397	994	771	2,239
Cash taxes paid		-	-	-	-	-	-	2	-	-	-
Cash interest paid		-	-	-	-	-	-	(331)	-	-	-
Lease liabilities		81	-	-	-	-	-	-	-	-	-
Operating leases		-	-	-	6	1	1	(1)	5	-	-
Accessible cash and liquid investments		(43)	-	-	-	-	-	-	-	-	-
Capitalized interest		-	-	-	-	-	2	(2)	(2)	-	(2)
Share-based compensation expense		-	-	-	25	-	-	-	-	-	-
Securitized stranded costs		(170)	-	(34)	(34)	(6)	(6)	6	(28)	-	-
Power purchase agreements		356	-	-	51	14	14	(14)	38	-	38
Asset-retirement obligations		589	-	-	28	28	28	-	-	-	-
Nonoperating income (expense)		-	-	-	-	(8)	-	-	-	-	-
Reclassification of interest and dividend cash flows		-	-	-	-	-	-	-	(22)	-	-
Debt: other		(95)	-	-	-	-	-	-	-	-	-
Total adjustments		718	-	(34)	76	29	39	(340)	(9)	-	36
S&P Global Ratings adjusted		Debt	Equity	Revenue	EBITDA	EBIT	Interest expense	Funds from Operations	Operating cash flow	Dividends	Capital expenditure
		11,005	10,155	8,117	2,397	1,262	374	2,058	985	771	2,275

Liquidity

We assess CE's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecasted consolidated EBITDA declines by 10%. We believe the supportive regulatory framework provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, CE has the ability to absorb high-impact, low-probability events, in our view, as the company maintains about \$1.1 billion in committed credit facilities through 2027, maintains another \$250 million in committed credit facilities through

November 2024, and can likely lower its capital spending (averaging about \$3 billion annually) during stressful periods, indicative of a limited need for refinancing under such conditions. CE can borrow \$500 million from the parent CMS Energy as per its renewed credit agreement in December 2022. Furthermore, our assessment reflects the company's prudent risk management and sound relationships with its banking group. Overall, we believe that the company should be able to withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has around \$300 million of long-term debt maturities coming up in 2024 and we expect the company to proactively address these maturities well in advance of their scheduled due dates.

Principal liquidity sources

- Cash FFO of about \$2.3 billion;
- Credit facilities of about \$1.3 billion;
- Working capital inflows of about \$150 million; and
- Available cash of about \$100 million.

Principal liquidity uses

- Debt maturities of about \$700 million over the next 12 months;
- Estimated maintenance capital spending of about \$1.9 billion; and
- Dividends of about \$850 million.

Environmental, Social, And Governance

Environmental factors are a moderately negative consideration in our credit rating analysis of CE. The company's use of above-average fossil fuel generation sources exposes it to heightened climate transition risk. The utility's generation capacity portfolio consists of 24% natural gas, 33% coal, 22% renewables, and 21% oil/gas as of Dec. 31, 2022. Slightly mitigating this risk is the utility's accelerated coal retirement plan, which includes a goal to be coal-free by 2025 and have 90% of its capacity portfolio sourced from clean energy resources by 2040.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy because we view the utility as integral to the group's identity, highly unlikely to be sold and having a strong commitment from management, given the company's emphasis on maintaining the size of the regulated utility operations relative to the nonutility businesses.

Because CE is operationally separate and sufficient insulating measures are in place, we rate the utility one notch above the GCP. Some of the key insulating measures are:

- CE is a separate and stand-alone legal entity that functions independently (both financially and operationally), files its own rate cases, and is independently regulated by MPSC.
- CE has its own records and books, including stand-alone audited financial statements.
- The utility has its own funding arrangements, including issuing its own long-term debt, and it has a separate committed credit facility to cover its short-term funding needs.
- CE does not comingle funds, assets, or cash flow with parent CMS Energy or its other subsidiaries, and it does not participate in a money pool.

- We believe there is a strong economic basis for CMS Energy to preserve CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE is also a significant portion of CMS Energy, accounting for about 95% of the consolidated company.
- There are no cross-default provisions between parent CMS Energy and CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

CE's capital structure consists of about \$10.9 billion of long-term debt, including about \$10.8 billion in first-mortgage bonds (FMBs) and about \$110 million of tax-exempt revenue bonds.

Analytical conclusions

We rate the company's senior unsecured debt 'A-', in-line with the long-term issuer credit rating on CE as the rated issuances are senior unsecured debt issued by a qualifying investment grade utility as per our criteria.

We base our 'A-2' short-term rating on CE on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- We assign recovery ratings to FMBs issued by U.S. utilities, which can result in issue ratings being notched above an issuer credit rating on a utility, depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of secured utility bonds that qualify for a recovery rating as defined in our criteria.
- CE's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Rating Component Scores

Foreign currency issuer credit rating	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2
Business risk	Excellent
Country risk	Very Low
Industry risk	Very Low
Competitive position	Excellent
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	a-
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)

Rating Component Scores

Liquidity	Adequate (no impact)
Management and governance	Satisfactory (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	a-
Group credit profile	bbb+
Entity status within group	Insulated (no impact on SACP)

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of August 17, 2023)*

Consumers Energy Co.

Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
<i>Local Currency</i>	A-2

Consumers Energy Co.

Ratings Detail (as of August 17, 2023)*

Senior Secured A

Issuer Credit Ratings History

30-Oct-2019	A-/Stable/A-2
03-Dec-2014	BBB+/Stable/A-2
11-Sep-2014	BBB/Positive/A-2

Related Entities

CMS Energy Corp.

Issuer Credit Rating	BBB+/Stable/A-2
Junior Subordinated	BBB-
Preferred Stock	BBB-
Senior Unsecured	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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Question:

88. Refer to WP-JCA-51 on the S&P Global forecast of economic data. Please provide a copy of the latest report available to the Company.

Response:

Please see attachment U21585-AG-CE-0403_ATT_1

Witness: JOSNELLY C APONTE

Date: August 19, 2024

Forecast at a glance

Base forecast (August 2024) 2024:Q3 - 2028:Q4

	Major economic indicators																	
	% ch. from prior quarter, annual rate						% ch. from prior year, or annual average						% ch. from fourth quarter of prior year, or fourth-quarter average					
	2024.1	2024.2	2024.3	2024.4	2025.1	2025.2	2023	2024	2025	2026	2027	2028	2023.4	2024.4	2025.4	2026.4	2027.4	2028.4
Key indicators of real activity																		
Real gross domestic product	1.4	2.8	1.8	1.4	1.4	1.8	2.5	2.6	1.7	1.7	1.8	1.8	3.1	1.9	1.6	1.6	1.9	1.8
Contributions to growth (% points):																		
Final sales to domestic purchasers	2.5	2.7	1.8	1.5	1.6	1.8	2.3	2.7	1.7	1.7	1.9	1.9	3.3	2.1	1.7	1.8	1.9	1.9
Net exports of goods & services	-0.7	-0.7	0.1	0.0	-0.2	-0.1	0.6	-0.2	-0.1	-0.1	-0.1	-0.1	0.2	-0.3	-0.1	-0.1	-0.1	-0.1
Change in private inventories	-0.4	0.8	-0.1	-0.1	0.0	0.1	-0.3	0.1	0.1	0.0	0.0	0.0	-0.5	0.0	0.1	0.0	0.0	0.0
Major components of real GDP																		
Personal consumption expend.	1.5	2.3	2.7	1.9	1.7	1.8	2.2	2.3	1.9	1.9	2.3	2.4	2.7	2.1	1.7	2.1	2.4	2.4
Nonres. fixed investment	4.4	5.2	2.1	2.6	2.1	2.3	4.5	3.8	2.3	1.3	1.1	1.5	4.6	3.6	1.9	1.0	1.3	1.7
Residential investment	16.0	-1.4	-11.6	-7.0	1.1	4.0	-10.6	2.7	-1.0	4.3	2.8	3.0	0.4	-1.5	3.9	3.5	2.7	3.3
Change in private inventories *	28.6	71.3	64.4	60.0	58.9	66.7	43.7	56.1	69.0	78.3	77.0	77.6	54.9	60.0	77.1	76.4	78.3	76.7
Exports of goods & services	1.6	2.0	4.2	3.9	3.4	3.9	2.6	2.5	3.7	3.9	4.0	3.7	1.8	2.9	3.8	3.9	4.1	3.5
Imports of goods & services	6.1	6.9	2.4	3.4	4.2	4.0	-1.7	3.7	3.9	3.7	3.9	3.7	-0.1	4.7	3.9	3.9	3.8	3.6
GovT consump. & gross invest.	1.8	3.1	0.8	1.1	0.6	0.5	4.1	3.0	0.8	0.4	0.1	0.0	4.6	1.7	0.5	0.3	0.0	-0.1
Pvt. housing starts (thous. units)																		
	1407	1348	1315	1314	1340	1359	1421	1346	1362	1411	1440	1471	1481	1314	1382	1419	1450	1482
Light vehicle sales (mil. units)																		
	15.3	15.7	16.4	16.2	16.4	16.5	15.5	15.9	16.5	16.7	16.6	16.3	15.7	16.2	16.7	16.7	16.5	16.2
Industrial production, total																		
	-2.1	4.3	0.7	-0.6	0.1	0.7	0.2	0.2	0.6	1.0	1.0	1.2	-0.1	0.6	0.7	0.9	1.1	1.3
Industrial production, mfg																		
	-1.3	3.4	0.4	-0.4	0.5	1.4	-0.5	0.0	0.9	1.4	1.2	1.4	-0.4	0.5	1.3	1.1	1.3	1.4
Capacity utilization (mfg. %)																		
	77.1	77.5	77.3	77.0	76.8	76.7	78.2	77.2	76.7	76.5	76.3	76.1	77.6	77.0	76.7	76.4	76.2	76.1
Nonfarm payroll employ. (mil.)																		
	157.8	158.4	159.0	159.5	159.7	159.8	156.1	158.7	159.8	160.1	160.5	161.2	157.1	159.5	159.9	160.2	160.7	161.5
Average monthly chg. (thous.)																		
	267	177	168	146	39	37	251	190	29	24	47	63	212	146	21	32	54	69
Private nonfarm hours																		
	0.6	0.9	0.7	0.6	-0.1	0.0	1.1	0.6	0.2	-0.1	0.2	0.4	0.6	0.7	-0.1	-0.1	0.3	0.5
Civilian unemployment rate (%)																		
	3.8	4.0	4.0	4.1	4.2	4.2	3.6	4.0	4.3	4.5	4.6	4.5	3.8	4.1	4.4	4.6	4.6	4.4
Prices, Productivity, & Costs																		
CPI, all items, all urban																		
	3.8	2.8	2.1	2.2	1.8	2.1	4.1	3.0	2.2	2.6	2.1	2.3	3.2	2.7	2.3	2.4	2.2	2.4
CPI excl food & energy, all urban																		
	4.2	3.2	2.4	2.6	2.4	2.4	4.8	3.4	2.5	2.4	2.3	2.3	4.0	3.1	2.4	2.3	2.3	2.3
PCE price index																		
	3.4	2.6	2.0	2.1	1.9	2.0	3.7	2.5	2.1	2.2	2.0	2.1	2.8	2.5	2.1	2.2	2.0	2.1
PCE price excl food & energy																		
	3.7	2.9	2.3	2.3	2.2	2.2	4.1	2.8	2.3	2.1	2.0	2.0	3.2	2.8	2.2	2.1	2.0	2.0
PPI finished goods																		
	3.6	-0.3	-1.5	0.3	0.9	0.8	1.5	0.7	0.5	1.9	1.9	2.0	-0.4	0.5	1.3	2.0	1.9	2.0
Compensation per hour																		
	4.2	2.9	3.8	3.3	4.0	3.7	4.3	3.3	3.7	4.1	3.7	3.7	4.4	3.5	3.9	4.0	3.7	3.8
Output per hour																		
	0.4	2.4	0.8	0.6	1.3	1.8	1.5	2.1	1.4	1.9	1.8	1.7	2.7	1.0	1.7	1.9	1.8	1.6
Unit labor cost																		
	3.9	0.5	3.0	2.6	2.7	1.8	2.8	1.2	2.3	2.1	1.9	2.0	1.7	2.5	2.1	2.1	1.9	2.1
Fed Financial Accounts HPI **																		
	1.4	1.1	0.8	0.9	0.9	0.9	1.7	5.0	3.6	3.7	3.7	3.6	5.0	4.2	3.6	3.8	3.6	3.6
Price of WTI crude oil (\$/barrel)																		
	77.55	81.40	81.34	77.70	73.87	72.29	77.62	79.50	72.81	75.03	77.88	81.01	78.34	77.70	72.39	76.13	79.05	81.97
Price of Brent crude oil (\$/barrel)																		
	82.97	84.65	85.53	82.67	79.00	77.83	82.50	83.95	78.71	81.91	83.67	85.34	83.77	82.67	79.00	82.91	84.23	86.01
Selected Financial Variables																		
Federal funds rate (%)																		
	5.33	5.33	5.33	5.31	5.06	4.80	5.02	5.32	4.54	2.89	2.63	2.63	5.33	5.31	3.92	2.63	2.63	2.63
Yield on 10-Yr Treasury Notes (%)																		
	4.16	4.44	4.25	3.99	3.83	3.67	3.96	4.21	3.62	3.29	3.20	3.21	4.44	3.99	3.45	3.24	3.20	3.23
Baa corporate bond yield (%)																		
	5.75	5.97	5.90	5.82	5.78	5.75	5.92	5.86	5.74	5.65	5.55	5.43	6.23	5.82	5.71	5.63	5.50	5.40
Broad trade-wtd US\$ (Jan 2006=100)																		
	121.0	122.9	123.5	123.5	123.0	122.4	120.5	122.7	122.0	119.3	116.9	115.2	121.8	123.5	120.8	118.4	116.2	114.8
S&P 500 stock index, period end																		
	5254	5460	5456	5389	5348	5321	4770	5389	5261	5121	4953	4995	4770	5389	5261	5121	4953	4995
S&P 500 stock index, average																		
	4996	5254	5483	5422	5368	5335	4284	5289	5322	5207	5016	4961	4472	5422	5277	5147	4960	4984
Incomes & Related Measures																		
Corporate profits w/ IVA & CCAdj																		
	-5.4	25.7	6.4	2.6	0.7	3.7	1.5	8.9	3.9	0.6	1.0	2.0	5.1	6.7	1.9	0.0	1.6	2.4
Real disposable personal income																		
	1.3	1.0	2.4	2.5	4.0	3.1	4.1	1.4	2.9	3.1	2.9	2.6	3.8	1.8	3.3	3.0	2.8	2.6
Personal saving rate (%)																		
	3.8	3.5	3.4	3.5	4.0	4.3	4.5	3.5	4.5	5.5	6.1	6.3	3.7	3.5	4.9	5.7	6.1	6.3
Fed. surplus (unified, FY, bil. \$)																		
	-2219	-814	-1578	-1946	-2432	-607	-1695	-1663	-1659	-1751	-1847	-2029	-2040	-1946	-2036	-2116	-2321	-2113

* billions of chained 2017 \$

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

Source: S&P Global Market Intelligence

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VLFAAlert



ValueLinefunds

4th Quarter 2018

Volume VII, Issue IV

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Mitchell Appel
President
Value Line Funds

Dear Fellow Shareholder,

Thank you for choosing Value Line Funds as a part of your diversified investment portfolio. For over half a century, Value Line Funds has championed sound investment principles and helped thousands of investors accomplish their financial goals with our actively managed family of mutual funds.

We hope you enjoy this edition of the VLFAAlert and thank you for your continued support.

Volatility is Not Risk:

Why the Difference is Critical to Long-Term Results

2017 lulled many equity investors into a comfort zone based on historically low volatility. 2018 has been more volatile—with tighter monetary policy and geopolitical and trade policy uncertainty among the drivers of the increase. But volatility levels in 2018 are actually historically normal—even with the bouts of volatility anticipated ahead of the November mid-term elections. But volatility is not risk. And recognizing the difference can be critical to your long-term investment returns.

Defining Our Terms

Volatility is simply the measure of the up and down movements of the market. For example, since 1950, when the Value Line Funds were first established, the average maximum drawdown in the broad U.S. equity market during midterm election years has been -17%, with weakness tending to be concentrated in the pre-election days. However, the good news is that there has been a consistent tendency historically for post-drawdown rallies, averaging +32% in the subsequent year.¹ Volatility? Yes! Uncertainty? Yes! But volatility is only risk if you act during down times—that is, only if you sell. To which the often-invoked quip may well be the most prudent answer: "Don't just do something, sit there."

Risk, on the other hand, is the probability of a permanent loss. You might think of risk as the possibility of having to lower your quality of life in the future.

"Volatility is not synonymous of risk but—for those who truly understand it—of wealth."

- Francois Rochon*

Recognizing the Difference

Volatility is independent of risk. Too many investors let an investment's short-term price movements, or perceptions of short-term price movements, drive their buying and selling decisions. Too often volatility is regarded as something to be

avoided. But since short-term price moves are unknowable and independent of underlying fundamentals and value, such volatility should not be a determinant.

And ALL investments have risk of some kind, including cash and CDs. One just needs to pick the risks that are best to take based on your individual tolerance level, time horizon and financial needs and goals.

As famed investor and Berkshire Hathaway CEO Warren Buffet wrote:

"Stock prices will always be far more *volatile* than cash-equivalent holdings. *Over the long term*, however, currency-denominated instruments are *riskier* investments — far riskier investments — than widely diversified stock portfolios that are bought over time and that are owned in a manner invoking only token fees and commissions. **That lesson has not customarily been taught in business schools, where volatility is almost universally used as a proxy for risk. Though this pedagogic assumption makes for easy teaching, it is dead wrong: Volatility is far from synonymous with risk.** Popular formulas that equate the two terms lead students, investors and CEOs astray."²

**"Volatility is our friend.
Volatility has nothing to do with risk."**

- Mohnish Pabrai*

(continued on back)

Value Line Article on Volatility vs. Risk

It's a Matter of Time, Not Timing

Most experienced investors do not fear volatility, only unrecoverable loss. But most losses, as measured by a day, a week, a quarter or a year, are recoverable over time. Declines in principal value have historically been temporary. Of course, there are true risks. A company could go totally out of business. An innovation could transform an industry so profoundly to make a once "blue chip" company a relic. A geopolitical event could happen to negate all assumptions. But these occurrences are rare. For the vast majority of investors, maintaining a long-term perspective is the real key to attaining gains over their investing lifetime. Historically, since World War II, the longer you hold stocks, the narrower the range of returns.³ In other words, even if volatility is a concern, it decreases the longer you hold stocks. It's the old adage: what matters is time in the market, not market timing.

"You can't overlook the volatility, but you don't let it push you around in the market."

*- Boone Pickens**

solutions designed to meet a broad array of investment goals. Whether you are looking for income or long-term capital appreciation, whether you choose to invest in equities, taxable or tax-exempt fixed income or a hybrid fund of multiple asset classes, you can rely on the solid fundamentals of Value Line Funds.

Value Line Funds Include:
Equity Funds
Premier Growth Fund
Larger Companies Focused Fund
Mid Cap Focused Fund
Small Cap Opportunities Fund
Hybrid Funds
Asset Allocation Fund
Capital Appreciation Fund
Fixed Income Funds
Tax Exempt Fund
Core Bond Fund

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Question:

69. Refer to Exhibit A-12 (JCA-34), Schedule B4. The Company shows Accrued Interest of \$62.5 million for the projected test year, which is the same as the historic 2023 balance. Given the Company's projected increase in its debt level, please explain why the interest accrual is being held constant to the 2023 historic balance and not increasing commensurate with the increase in the amount of debt for the projected test year.

Response:

Working capital accounts (both assets and liabilities) are subject to change as the Company projects its test year in rate cases. However, it has been a long-standing practice approved by the Commission, that the Company makes minimal adjustments to its projected working capital which is based on a 13-month average. The adjustments are limited to known, measurable and material changes such as adjustments to pension and other post-employment benefit accounts that are supported by actuarial reports or other third-party resources.

Witness: JOSNELLY C APONTE

Date: August 20, 2024

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Question:

70. The cash balance in working capital for 2023 in Case U-21224, Exhibit A-12, Schedule B4, was projected by the Company at \$43.8 million. In this rate case, the same exhibit schedule shows that the actual 2023 cash balance was \$18.6 million, which is lower by \$25.2 million, or 58%, of the amount proposed in case U-21224. Please:

- a. Explain why the actual cash balance for 2023 was \$25.2 million less than the amount proposed by the Company in Case U-21224.
- b. Explain whether the Company invested any of its excess cash in 2023 in short-term investments, and if so, identify the amount and the income achieved each month during 2023.
- c. Explain why borrowing under the large lines of credit that the Company's holds is not a suitable alternative to stockpiling cash.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request because it is argumentative and mischaracterizes the Company's approach to managing cash balances. Without waiving this objection, Consumers Energy responds as follows:

- a. While actual cash balances may be higher or lower, the Company consistently projects normal cash levels which equates to approximately 1% of test year revenues. The Commission considered this as a reasonable approach in Case No. U-21389. While there are myriad factors that affect cash balances at any point in time, it was a key factor that the Company experienced unfavorable weather in 2023, as well as storm restoration activity well beyond the 5-year historical average. Both of these conditions negatively affected the Company's operating cash flows.
- b. Yes, see attached. Note that short-term investments are not included in rate base.
- c. Refer to part a. of this response. The Company has not argued for carrying large cash balances, but rather a normal and reasonable minimum average cash balance. Please refer to my direct testimony with regards to managing cash balances and short-term borrowing, particularly beginning on page 25. In addition, please be aware that the Company did borrow on its short-term borrowing facilities in 2023.

Witness: MARC R. BLECKMAN

Date: August 27, 2024

CECo Response to AG-CE-0385

Consumers Energy Company			
Monthly Short Term Investment & Interest Income Balances - Electric Portion			
U21585-AG-CE-0385(b)_Bleckman_Attachment 1			
	(a)	(b)	(c)
Line No.	Date	Short-Term Investments	Interest Income
1	Jan-2023	-	17,598
2	Feb-2023	20,487,397	22,917
3	Mar-2023	167,655,202	248,309
4	Apr-2023	274,121,377	808,794
5	May-2023	285,457,737	1,723,544
6	Jun-2023	28,750,648	426,895
7	Jul-2023	-	190,594
8	Aug-2023	-	523,794
9	Sep-2023	-	-
10	Oct-2023	-	-
11	Nov-2023	-	-
12	Dec-2023	-	40,664
	AG calculated total	155,294,472	4,003,109
			2.58%

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Question:

73. Refer to page 35 of Ms. Aponte's direct testimony on the Distribution Deferral. Please:

- a. Provide a page reference where the distribution deferral and cap were approved by the Commission in the orders in Case Nos. U-21224 and U-21389.
- b. Provide a list of all cost deferral and regulatory asset cost recovery mechanisms that will be in effect for the projected test year with a brief description of the mechanism and the asset balance to be recovered as of December 31, 2023 and as of the end of the projected test year.

Response:

- a. Please refer to the Commission's order approving the settlement agreement in Case No. U-21224, on January 19, 2023, Exhibit A, page 5, item number 9; and final order in Case No. U-21389, pages 294 through 296.
- b. See table on next page (13-month balances in \$000s):

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Regulatory Asset	Description	12/31/2023	02/28/2026
PowerMIDrive - Exhibit No. A-17 (JCA-52)	Deferred accounting for expenditures associated with the PowerMIDrive program, approved by the Commission in Case No. U-20134	7,464	6,247
PowerMiFleet - Exhibit No. A-18 (JCA-53)	Deferred accounting for expenditures associated with the PowerMiFleet program, approved by the Commission in Case No. U-20697	3,047	3,039
Karn Decommissioning Costs - Exhibit No. A-23 (JCA-58)	In depreciation case U-20849, the Commission approved regulatory asset treatment of Karn Units 1 & 2 decommissioning costs	20,115	31,655
Karn 1-2, Classic 7, and Campbell Ash Disposal - Exhibit No. A-25 (JCA-60)	In depreciation case U-20849, the Commission approved regulatory asset treatment for Karn Units 1 & 2 and Classic 7 ash disposal costs	17,128	26,284
Electric Plant in Service - Campbell 1&2 - Exhibit No. A-21 (JCA-56)	The settlement agreement approved by the Commission in Case No. U-21090 on June 23, 2022, established that in the next rate case filed after the conclusion of the IRP case, the actual remaining net book value of Campbell Units 1, 2, and 3 would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset to be recovered through their design lives	418,573	395,620
Electric Plant in Service - Campbell 3 - Exhibit No. A-22 (JCA-57)	See above	845,523	839,854
JHC 1,2,3 Decommissioning Costs - Exhibit No. A-24 (JCA-59)	Decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 were approved to be recorded, as spent, to a regulatory asset, in the settlement agreement approved by the Commission in Case No. U-21090	6,445	15,841
Karn-Bonus Deferral - Exhibit No. A-19 (JCA-54)	Deferral of employee retention costs related to the decommissioning of the Karn 1-2 plants, as ordered by the Commission in Case No. U-20697.	8,607	1,338
Campbell-Bonus Deferral - Exhibit No. A-20 (JCA-55)	Deferral of employee retention costs related to the decommissioning of the Campbell plants, per the settlement agreement approved by the Commission in Case No. U-21090	28,202	21,404
Toshiba Restoration LPS	On May 18, 2023, the Commission approved the use of a regulatory asset and deferral of "all costs associated with the allegedly defective work performed by" Toshiba on the Ludington Pumped Storage Plant. The balance will also include "all amounts recovered from" Toshiba via litigation or otherwise, including liquidated damages, if any	4,153	3,402
Pension Volatility Mechanism Electric - Exhibit No. A-26 (JCA-61), page 1	Differences between what is included in rates and the Company's actual electric utility Pension costs, pursuant to the settlement agreement in electric rate case No. U-21224	(5,741)	(14,175)
OPEB Volatility Mechanism Electric - Exhibit No. A-26 (JCA-61), page 2	Differences between what is included in rates and the Company's actual electric utility OPEB costs, pursuant to the settlement agreement in electric rate case No. U-21224	11,618	17,865

Witness: JOSNELLY C APONTE

Date: August 23, 2024

Operations & Maintenance - Summary

<u>Line</u>	<u>Description</u> (a)	<u>Millions Of Dollars</u> (b)	<u>Note or Ref.</u> (c)
1	O&M Per Company	<u>\$ 675.0</u>	1
	<u>Attorney General Changes</u>		
2	Electric Distribution	(32.3)	Ex. AG-1.32
3	Power Generation	(5.1)	Testimony
4	Customer Interactions	(2.6)	Testimony
5	DR Reconciliation Disallowance	(0.6)	Testimony
6	Insurance Expense	(6.1)	Ex. AG-1.43
7	Incentive Compensation	(1.3)	Testimony
8	Total Change	<u>\$ (48.0)</u>	(Sum of L2 to L5)
9	AG Revised O&M Level	<u>\$ 627.0</u>	(L1 + L6)
10	Change in O&M	<u>\$ (48.0)</u>	(L7 less L6)

Note 1 Per Company Exhibit A-13 (JCA-41), Sched. C-5, page 1, Line 25

Electric Distribution

<u>Line</u>	<u>Caption or Description</u>	<u>Amount in Millions</u>	<u>Note</u>
	(a)	(b)	(c)
1	Company Estimate	\$ 279.9	1
	<u>AG Adjustments</u>		
2	Service Restoration	(3.6)	Exhibit AG-1.33
3	Staking	(0.2)	Exhibit AG-1.34
4	Lines Reliability - LVD	(12.6)	Testimony
5	Lines Reliability - HVD	(2.2)	Testimony
6	Substation Reliability - HVD	(1.4)	Testimony
7	Substation Demand - HVD and LVD	(9.8)	Testimony
8	Underground Workforce	(2.5)	Testimony
9	Total Adjustments	<u>\$ (32.3)</u> <u>\$ (32.3)</u>	2
9	Attorney General Estimate	<u>\$ 247.6</u>	3
	Testimony+A13:A21		
10	Reduction in O & M	<u>\$ (32.3)</u>	4

1 Per Exhibit A-104 (MKP-12) Line 4
2 Sum of Lines 2 to 7
3 Line 1 less Line 8
4 Line 9 less Line 1

Service Restoration O&M

(Thousands of Dollars)

<u>Line</u>	<u>Caption or Item</u> (a)	<u>2019</u> (b)	<u>2020</u> (c)	<u>2021</u> (d)	<u>2022</u> (e)	<u>2023</u> (f)	<u>Five Yr. Average</u> (g)
1	Service Restoration*	\$ 92,129	\$ 71,262	\$ 159,659	\$ 113,271	\$ 188,041	<u>\$ 124,872</u>
<hr/>							
		<u>Five Year</u>	<u>2024</u>	<u>2025</u>	<u>Projected</u>		
		<u>Average</u>			<u>Test Yr. Ended</u>		
2	Inflation Factors**		2.40%	2.20%	<u>Feb. 2026</u>	0.367%	<u>Notes</u>
3	Five Yr. Avg.(From Line 1) + Inflation	\$ 124,872	\$ 127,869	\$ 130,682	\$ 131,162		
4	Savings From Tree Trimming Program***				<u>(1,280)</u>		
5	AG Expense Level				\$ 129,882	L 3 + L 4	
6	Company Estimate (pg. 5 Snider Testimony)				<u>133,500</u>		
7	Service Restoration O&M Reduction				<u>\$ (3,618)</u>	L 5 less L 6	

* Per Exhibit A-108 (MPK-14), Line 23
** Per Exhibit A-110 (MPK-18), Line 57
*** Exhibit AG-1.35.

Staking & Locating

<u>Line</u>	<u>Caption</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>Reference</u>	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(g)	
<u>Historic Information</u>									
1	Consumers Electric Staking Orders	387,139	387,139	388,989	408,970	411,008	415,303	Note 1	
2	Avg. Annualized Increase (5 Yrs.)	2.75% annualized over 5 yrs.							
<u>O&M Projected Expense Information</u>									
			<u>2023</u>	<u>2024</u>	<u>2025</u>	Projected Test Yr. Ending <u>Feb. 2026</u>			
3	Staking Orders per AG Case		415,303	426,724	438,459	440,468		Note 2	
4	Staking Orders Projected by Company					455,017		Note 3	
5	Difference in Staking Orders					(14,549)		L 3 less L 4	
6	Projected Cost per Staking Order					\$ 13.74		Note 3	
7	Reduction in Staking & Locating O&M Expense					\$ (199,899)		L 5 x L 6	

Notes 1 Per U-21224 DR AG-CE-365 for 2018 - 2021 and Kelly testimony (page 127 in this case and page 88 in Case U-21389)
2 2023 escalated at 2.75% per year
3 See AG-CE-434 Attachment

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Line Clearing Ramp-up Plan Estimated Potential Service Restoration Cost Avoidance

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	<u>Year</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2019-23</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>
		Actual	Actual	Actual	Actual	Actual	Average	Projected	Projected	Projected	Projected	Projected
2	Line Clearing Program Funding Level (\$M)	\$53.3	\$54.8	\$86.6	\$102.0	\$109.1	\$81.2	\$117.6	\$125.1	\$125.1	\$125.1	\$125.1
3	Actual Tree-Related Primary Outage Incidents with MED	11,247	9,337	12,665	8,256	8,489	9,999					
	AG Calculated Compound Decline rate 2019 to 2023							2.38%	2.38%	2.38%	2.38%	2.38%
4	Projected Tree-Related Primary Outage Incidents with MED							9,761	9,528	9,302	9,080	8,864
5	Cumulative Primary Voltage Outage Incidents Reduced with MED from 5-Year Average (Column g, Line 3)							238	470	697	919	1,135
6	Cumulative Outage Incident Reduction Percent from 5-Year Compound Decline Rate							2.38%	4.70%	6.97%	9.19%	11.35%
7	Annual Potential Service Restoration Cost Avoidance - Cumulative (\$M)*							\$0.600	\$1.185	\$1.757	\$2.315	\$2.859
8	Projected Test Year Ending February 2026 - O&M Expense Savings (\$M)										\$1.280	
9	CECo Calculated Savings**										<u>\$0.506</u>	
10	Incremental Cost Savings (\$M)										\$0.774	

Source: Exhibit A-48 (PLB-2)

* Assumes Five-year average cost per incident of \$2,519.51 per DR AG-CE-0518

** Witness Andrew Snider direct testimony at 7.

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Page 1 of 1

Question:

193. Refer to Figure 3 on page 7 of Mr. Snider’s direct testimony and Exhibit A-48 (PLB-2) on Forestry-related service restoration cost savings. Please:

- a. Show how the Company determined the projected tree-related outage incidents with MEDs on line 4 of Exhibit A-48. Explain why the projected outages with MEDs for 2024, 2025, 2026 and future years are considerably higher than the number of power outages for 2022 and 2023 when the Company experienced several major event days, particularly in 2023.
- b. Explain what the \$2,519.51 included in the calculation of cost savings on line 7 represents and show how it was determined.

Response:

- a) The Company determined the projected tree-related outage incidents with MEDs on line 4 of Exhibit A-48 by using an expected annual improvement from the 5-year average and Years Since Last Cleared (YSLC) Low Voltage Distribution (“LVD”) system condition projections. As the LVD system becomes more on-cycle, tree-caused outage incidents including MEDs reduce. The years of 2022 and 2023 were lower than the 5-year average, resulting in 2024 and future years projections being higher than 2022 and 2023. Additionally, 2019 and 2021 are higher than the 5-year average.
- b) The \$2,519.51 used in line 7 represents an average cost per outage incident, which is calculated by dividing a 5-year sum of service restoration Operating and Maintenance (“O&M”) expense by the total outage incidents over the same period, resulting in a 5-year average O&M cost per outage incident across all outage causes.

5-Year Sum of O&M Spend	5-Year Sum of Incidents	5-Year Average Cost per Outage Incident
\$637,205,614.90	252,909	\$2,519.51

Witness: PAMELA L. BOLDEN
Date: August 30, 2024

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Question:

115. Refer to Exhibit A-106 (MPK-14), lines 4 and 5, and pages 109 and 110 of Mr. Kelly's direct testimony on O&M expense for Lines Reliability LVD and HVD. Please:

- a. Explain why the proposed large increase in O&M expense from \$651,000 in 2023 to \$30.2 million in the projected test year must be undertaken over a two-year period and a more gradual increase is not more appropriate to achieve the stated objectives.
- b. If the Company now wants to follow the Institute of Electrical Electronics Engineers (IEEE) recommendation and best practices for inspections and maintenance, what type of practices has it followed up to now?
- c. For Pole Inspections:
 - i. Provide the amount spent and numbers completed in each year 2021 to 2023 and identify the current inspection cycle followed.
 - ii. Provide the number of inspections planned for the \$9.7 million.
 - iii. How much incremental value will the more frequent inspections generate and how many fewer outages will be achieved annually over future years?
 - iv. Provide evidence that a 12-year inspection cycle will reduce the historical number of outages or reduce SAIDI by a significant factor.
 - v. If the "stepped up" pole inspections and switch inspections noted on page 110 of Mr. Kelly's testimony are of such critical importance, explain why the Company is not ramping up these inspections and incurring additional costs in 2024.
- d. For Switch Inspections:
 - i. Provide the amount spent and numbers completed in each year 2021 to 2023 and identify the current inspection cycle followed.
 - ii. Provide the inspection cycle proposed going forward, and the number of inspections planned for the \$8.0 million annually.
 - iii. How much incremental value will the more frequent inspections generate and how many fewer outages will be achieved annually over future years?
 - iv. Provide evidence that the new inspection cycle will reduce the historical number of outages or reduce SAIDI by a significant factor.
- e. For Metro Inspections:
 - i. Provide the amount spent and numbers completed in each year 2021 to 2023 and the current inspection cycle followed.
 - ii. Provide the inspection cycle proposed going forward, and the number of inspections planned for the \$2.0 million annually.
 - iii. How much incremental value will the more frequent inspections generate and how many fewer outages will be achieved annually over future years?
 - iv. Provide evidence that the new inspection cycle will reduce the historical number of outages or reduce SAIDI by a significant factor.
- f. For Grid Modernization:
 - i. Provide the amount spent in each year 2021 to 2023.

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- ii. Identify the incremental value the incremental spending of \$3 million will generate and how many fewer outages will be achieved annually over future years?
- iii. Provide evidence that the grid modernization spending will reduce the historical number of outages or reduce SAIDI by a significant factor.
- g. For Digital Analysis:
 - i. Identify the types of tools currently used and the cost of performing the digital analysis.
 - ii. Identify the incremental value that the incremental spending of \$4 million will generate and how many fewer outages will be achieved annually over future years?
 - iii. Provide evidence that the Digital Analytics spending will reduce the historical number of outages or reduce SAIDI by a significant factor.

Response:

While the question references Exhibit A-106 (MPK-14), line 5, which contains HVD O&M, pages 109 and 110 of my testimony, and the subsequent questions in this request, discuss only LVD assets.

- a. The increase identified is consistent with the Reliability Roadmap. The Company could undertake a more gradual approach, but with delayed results. The need to undertake this increase over a two-year period rather than a more gradual increase is to address the identified deficiencies and improve system reliability and safety. Delaying could result in continued or increased outages, equipment failures, and safety hazards, which would ultimately be more costly and detrimental to customers.
- b. Up to now, the Company has not fully adhered to the IEEE recommendations and best practices for inspections and maintenance of LVD assets. Instead, the Company has followed a less rigorous inspection and maintenance schedule while still operating a safe system. However, the Company has determined that a more rigorous approach is needed to reduce the risk of equipment failures and outages. Additionally, the Company has not had visibility into the condition of Metro assets without inspections, risking catastrophic failures and increases in outages. The shift to following IEEE recommendations and best practices is intended to improve the overall reliability and safety of the electric distribution system.
- c. The Company presently visually inspects LVD primary poles and line assets on a two-year cycle, as described by Company witness Lynd in his direct testimony, particularly page 23, line 4, through page 24, line 10. The pole inspections being discussed in my direct testimony, page 110, are an incremental level of inspection predominantly focused on bore testing of poles, similar to what is completed on HVD poles. Company witness Kurdziel's direct testimony, page 24, line 5 through 11, describes these inspections on HVD poles.
 - i. This level of inspection was not performed on the LVD system from 2021 to 2023, accordingly, there are no historical costs for this activity and there is no effective cycle.

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- ii. As noted in my direct testimony, page 110, lines 6 through 10, the plan is to inspect poles on a 12-year cycle. The Company's Reliability Roadmap, Exhibit A-111 (MPK-19), page 71 (of 183), states that the Company would inspect 125,000 poles each year.
 - iii. Completing this additional level of inspection of LVD poles will reduce the safety risk of poles falling and creating hazards. The Company provided its SAIDI estimates relative to the number of poles replaced in the Reliability Roadmap, Exhibit A-111 (MPK-19), page 72 (of 183), Figure 54.
 - iv. See the response to subpart (c)(iii), above.
 - v. The Company is not "ramping up and incurring additional costs" in 2024 because the need for increased maintenance work in this area was first identified in the 2023 Reliability Roadmap, and this is the first electric rate case to include this information, so the test year in this case is the Company's first opportunity to seek recovery for increased spending.
- d. For switch inspections:
- i. No additional inspections have been completed on this equipment other than the visual inspections discussed above in subpart (c), above.
 - ii. The Company's Reliability Roadmap, Exhibit A-111 (MPK-19), page 66 (of 183), Figure 47 outlines the LVD inspection cadence for reclosers, capacitor banks, gang operated switches, and disconnect switches.
 - iii. The Company has not calculated a value for the number of outages prevented; however, this work is based on good engineering practice and will identify and correct problems before outages occur.
 - iv. The Company has not calculated the impact of switch inspections on SAIDI.
- e. For Metro inspections:
- i. This level of inspection was not performed on the Metro system from 2021 to 2023, accordingly, there are no historical costs for this activity and there is no effective cycle.
 - ii. See Company witness Lynd's direct testimony, page 104, lines 8 through 12, and page 132, lines 3 through 6. The inspection plan is identified through a process to access multiple components of each vault. The Company's Reliability Roadmap, Exhibit A-111 (MPK-19), page 102 (of 183), states that the Company would follow recommendations by the IEEE and would inspect vaults and manholes on a 4-year cadence, 'hi rise' vaults on an annual cadence, and using infrared inspections as needed.

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- iii. The Company has not calculated a value for the number of outages prevented; however, this work is based on good engineering practice and will identify and correct problems before outages occur and create safer working conditions.
 - iv. The Company has not calculated the impact of Metro inspections on SAIDI.
- f. For Grid Modernization:
- i. Actual O&M spend for Grid Modernization projects can be found in Exhibit A-106 (MPK-14, line 60).
 - ii. The increased spending in Grid Modernization will support a variety of projects outlined by Company witness McPhail in his direct testimony. For specific benefit analysis, see exhibits: Exhibit A-135 (SAM-4), Exhibit A-136 (SAM-5), Exhibit A-137 (SAM-6), Exhibit A-138 (SAM-7), Exhibit A-139 (SAM-8).
 - iii. See response to U21585-AG-CE-0541.
- g. For Digital Analysis:
- i. The Company currently uses Forestry WISE (refer to page 85 of Exhibit A-111 (MPK-19)).
 - ii. Please refer to Pages 140-143 of Exhibit A-111 (MPK-19)
 - iii. Please refer to Pages 140-143 of Exhibit A-111 (MPK-19)

Witness: Michael P. Kelly

Date: August 27, 2024

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Page 1 of 1

Question:

116. Refer to page 111 of Mr. Kelly's direct testimony and line 5 of Exhibit A-106 on HVD Lines Reliability O&M expense. Please:

- a. Explain what the current inspection cycle is and to what cycle the Company wants to move.
- b. Provide evidence that the more frequent pole and switch inspections, and MOABS testing with repairs and replacements will significantly reduce the number of power outages.
- c. Identify and explain what level of activity the \$261,000 in 2023 entailed and similarly the level of activity the \$2.3 million for the projected test year will entail. Provide numbers and metrics for each period and for each activity within the program.

Response:

- a. The current inspection cycle for HVD poles is a 12-year cycle, as stated on page 24, line 9 of Company witness Kurdziel's testimony. The Company is not planning to change this cycle at this time.
- b. As stated above, the Company is not planning to increase the frequency of these inspections.
- c. The Company has determined that it made an Excel formula error in populating Exhibit A-106 (MPK-14), line 5, column (I). This error also applies to the equivalent cells in my other O&M exhibits that include the HVD Lines Reliability O&M subprogram. Projected test year spending for HVD Lines Reliability O&M should have remained flat, at \$116,000. Because of the formula error, the Company erroneously included increased test year funding that was intended for the HVD Lines *Demand* O&M subprogram (Exhibit A-106 (MPK-14), line 9, column (I)) in HVD Lines Reliability O&M instead. Consequently, Exhibit A-106 (MPK-14) indicates that HVD Lines Demand O&M spending remains flat at \$784,000, when it should have increased. The error amounts to \$2,215,000 (\$2,331,000 - \$116,000). This amount should instead be included in HVD Lines Demand O&M for the test year, which would make that line item \$2,999,000 (\$784,000 + \$2,215,000).

The Company plans to increase HVD Lines Demand O&M spending because recently improved HVD lines inspection technology – particularly infrared cameras – have allowed the Company to identify more anomalies on HVD lines. This has led to a backlog of HVD anomalies that need to be addressed to prevent customer outages while spending in this O&M subprogram has been relatively flat over recent years. Increased O&M spending will allow the Company to clear this backlog and address newly identified anomalies as they occur.

Witness: Michael P. Kelly
Date: August 26, 2024

U21585-AG-CE-0432

Page 1 of 1

Question:

117. Refer to pages 114 to 116 of Mr. Kelly's direct testimony on LVD and HVD Substation Reliability O&M expense. Please:

- a. For the LVD bi-monthly patrol inspections, identify the current inspection cycle and the proposed inspection cycle for the projected test year.
- b. For the HVD on lines 10 through 17 on page 116, identify the current inspection cycle and practices for each activity and the proposed inspection cycle and practices for the projected test year.

Response:

- a. The current inspection cycle is bi-monthly, i.e. every other month. For the test year, the Company plans to move to a monthly cycle as stated on Page 118 (of 183) of Exhibit No.: A-111 (MPK-19), the Company's Reliability Roadmap.
- b. The current cycle is monthly for the referenced inspections and maintenance activities. The Company does not plan to make any cycle changes in the test year.

Witness: Michael P. Kelly

Date: August 26, 2024

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Question:

118. Refer to pages 121 and 122 of Mr. Kelly's direct testimony and lines 10 and 11 of Exhibit A-106 (MPK-14) for Substation Demand LVD and HVD O&M expense.

- a. Given that the forecasted LVD O&M expense represents work for potentially emergent and unplanned restorations, explain and show how you determined the increase in the expense from \$4.1 million in 2023 to \$9.4 million in the projected test year.
- b. Explain (a) what problems (if any) that the Company is seeking to remedy with this 129% increase in LVD O&M expense; and (b) explain the apparent lack of urgency on this program given that the 2024 expense level is only \$4.1 million, which is the same as for 2023.
- c. Similarly, with the HVD O&M expense representing work for potentially emergent and unplanned restorations, explain and show how you determined to increase the expense from \$3.4 million in 2023 to \$7.8 million in the projected test year.
- d. Explain (a) what problems (if any) that the Company is seeking to remedy with this 129% increase in HVD O&M expense; and (b) further explain the apparent lack of urgency on this matter given that the 2024 expense level is only \$3.3 million, which is slightly less than in 2023.

Response:

- a. As noted in discovery response U21585-AG-CE-0432, the Company plans to double its LVD substation inspection cadence in the test year (from bi-monthly to monthly), which leads the Company to anticipate a commensurate increase in the number of LVD substation maintenance issues to address. As noted on page 121 of 183 of the 2023 Reliability Roadmap (Exhibit A-111 (MPK-19)), the Company also plans to increase LVD substations O&M to better adhere to the ESR-1 recommended maintenance intervals (see next subpart).
- b. In addition to the previously noted shift from a bi-monthly to a monthly inspection cadence, the Company's current O&M funding levels have not been sufficient to adequately perform the following LVD substation maintenance activities outlined in Figure 94 of the Reliability Roadmap:
 - Single-phase regulator maintenance
 - Single-phase regulator oil samples and dissolved gas analysis (5-year program)
 - Metro vault inspections
 - Metro cable testing
 - Power transformer inspections and maintenance (limited by outage availability)
 - Infrared repairs (Priority 2 and 3)
 - Switch repairs
 - Facilities O&M repairs

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In 2023, the Company performed more detailed asset health assessments of its LVD substations while developing the Reliability Roadmap, indicating the need for increased maintenance. This is the first electric rate case to include this information.

- c. This increase is based on increased inspection levels on HVD substations in order to better adhere to the ESR-1 recommended maintenance levels, as detailed in the next subpart.
- d. The Company is requesting an increase in O&M funding levels to adequately perform the following HVD substation maintenance activities outlined in Figure 94 of the Reliability Roadmap:
 - HVD Breaker Inspections and Maintenance
 - Circuit switcher inspections and maintenance
 - Spring operated ground switch inspections and maintenance
 - Capacitor bank inspections and maintenance
 - Transformer Load Tap Changer inspections and maintenance

In 2023, the Company performed more detailed asset health assessments of its HVD substations while developing the Reliability Roadmap, indicating the need for increased maintenance. This is the first electric rate case to include this information.

Witness: Michael P. Kelly

Date: August 26, 2024

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Question:

123. Refer to lines 17-23 on page 143 of Mr. Kelly's direct testimony for O&M expense for the Underground Workforce program. Please explain what the O&M expense costs for this program are for and why these costs are not capitalized with undergrounding capital projects.

Response:

These O&M expenses reflect 100% of the training costs for underground workforce employees and 5% of the salaries, expenses, and tools for those employees. The other 95% of salaries, expenses, and tools that are not included in this program are capitalized as suggested by this question. The 5% that is treated as an O&M expense represents working time at the start and end of the day that is not spent doing capital work in the field. Training costs are treated as O&M expenses but they are not part of capital work in the field.

Witness: Michael P. Kelly

Date: August 26, 2024

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Question:

194. Exhibit A-43 (RTB-4) shows Generation Base O&M expense of \$93.9 million for 2023 and \$78.1 million in the projected test year. Please:

- a. Provide a break-down of Base O&M by generating facility for each year 2021 to 2023, and forecasted for 2024, 2025, 2026, and for the projected test year in Excel.
- b. Show in Excel how you determined the forecasted expense amount for each forecasted period, including any reductions pertaining to the retirement of coal plants and any other costs and assumptions clearly explained.

Response:

- a. Please see attachment U21585-AG-CE-0519_ATT_1 for a break-down of Base O&M by generating facility for each year 2021 to 2023, and forecasted for 2024, 2025, 2026, and for the projected test year in Excel.
- b. Please see attachment U21585-AG-CE-0519_ATT_1 for a comparison of the historical year 2023 versus the test year and a comparison of 2022 versus the test year. The comments identify basis for the changes in base O&M associated with the actual retirement of Karn Units 1 and 2 on May 31, 2023, the planned retirement of Campbell Units 1, 2 and 3 on May 31, 2025, and the addition of the Covert plant on June 1, 2023.

In addition, a detailed discussion of O&M expense for Karn Units 1 and 2, Campbell Units 1, 2 and 3, and Covert Units 1, 2 and 3 can be found in my direct testimony beginning on page 108, line 7. With respect to forecasting the expense amount for each forecasted period, please see my direct testimony beginning on page 105, line 20.

Witness: RICHARD T. BLUMENSTOCK

Date: August 27, 2024

CECo Response to AG-CE-0519

U21585-AG-CE-0519_ATT_1	(\$/1000)	(\$/1000)	(\$/1000)	(\$/1000)	(\$/1000)	(\$/1000)	(\$/1000)	(\$/1000)	(\$/1000)	(\$/1000)
	Actuals	Actuals	Actuals	Forecast	Forecast	Forecast	Forecast	Projected Bridge Period	Projected Test Year	Historical year
	12 Months Ending	12 Months Ending	12 Months Ending	12 Months Ending	12 Months Ending	12 Months Ending	12 Months Ending	14 Months Ending	12 Months Ending	versus test year
	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025	12/31/2026	02/29/2025	02/28/2026		
1 BASE O&M	\$ 106,195	\$ 106,818	\$ 93,864	\$ 102,626	\$ 85,050	\$ 68,813	\$ 121,165	\$ 78,063	\$ 15,802	
Admin/Generation Commons	\$ (1,173)	\$ 4,302	\$ 873	\$ 7,580	\$ 7,562	\$ 7,563	\$ 8,854	\$ 7,638	\$ (6,765)	
Adjustment	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Alcona (Hydros)	\$ 728	\$ 231	\$ 639	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 639	
Allegan (Hydros)	\$ 766	\$ 183	\$ 752	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 752	
Battery	\$ -	\$ -	\$ 30	\$ 100	\$ 144	\$ 264	\$ 124	\$ 164	\$ (134)	
Cadillac (Solar)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Campbell	\$ 37,751	\$ 36,060	\$ 34,858	\$ 37,584	\$ 18,674	\$ -	\$ 45,054	\$ 11,204	\$ 23,653	
Circuit West (Solar)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Cobb (Classic 7)	\$ 49	\$ 751	\$ 34	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 34	
Combustion Turbines	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Cooke (Hydros)	\$ 754	\$ 209	\$ 683	\$ -	\$ (60)	\$ (20)	\$ (10)	\$ (53)	\$ 736	
Covert	\$ -	\$ 4	\$ 5,196	\$ 8,415	\$ 9,122	\$ 9,072	\$ 9,935	\$ 9,114	\$ (3,917)	
Croton (Hydros)	\$ 1,055	\$ 2,507	\$ 1,431	\$ 3,001	\$ 3,061	\$ 3,023	\$ 3,511	\$ 3,055	\$ (1,624)	
Electric Grid Integration	\$ 15,248	\$ 16,780	\$ 11,276	\$ 12,704	\$ 12,404	\$ 11,668	\$ 14,772	\$ 12,282	\$ (1,006)	
Five Channels (Hydros)	\$ 790	\$ 890	\$ 717	\$ 2,226	\$ 2,214	\$ 2,203	\$ 2,595	\$ 2,212	\$ (1,494)	
Foote (Hydros)	\$ 688	\$ 246	\$ 614	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 614	
GVSU (Solar)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Hardy (Hydros)	\$ 910	\$ 347	\$ 836	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 836	
Hodenpyl (Hydros)	\$ 641	\$ 266	\$ 708	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 708	
Hydro Commons	\$ (3,123)	\$ 760	\$ (2,698)	\$ 1,092	\$ 1,099	\$ 1,107	\$ 1,275	\$ 1,100	\$ (3,798)	
Jackson	\$ 6,219	\$ 2,851	\$ 5,860	\$ 5,377	\$ 5,390	\$ 5,398	\$ 6,276	\$ 5,391	\$ 469	
Karn	\$ 28,482	\$ 27,039	\$ 16,554	\$ 10,416	\$ 10,411	\$ 10,411	\$ 12,151	\$ 10,411	\$ 6,143	
Loud (Hydros)	\$ 690	\$ 201	\$ 509	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 509	
Ludington	\$ 4,827	\$ 3,360	\$ 5,433	\$ 5,351	\$ 5,374	\$ 5,374	\$ 6,246	\$ 5,374	\$ 60	
Mio (Hydros)	\$ 675	\$ 197	\$ 648	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 648	
Muskegon (Solar)	\$ -	\$ -	\$ 68	\$ 100	\$ 588	\$ 2,205	\$ 198	\$ 858	\$ (790)	
Mustang Mile (Solar)	\$ -	\$ -	\$ 68	\$ 1,300	\$ 2,212	\$ 1,987	\$ 1,669	\$ 2,175	\$ (2,107)	
Renewables Development	\$ -	\$ -	\$ 734	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 734	
Rogers (Hydros)	\$ 854	\$ 206	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Solar Commons	\$ -	\$ 387	\$ -	\$ (300)	\$ (747)	\$ 943	\$ (432)	\$ (466)	\$ 466	
Tippy (Hydros)	\$ 1,100	\$ 759	\$ 1,003	\$ 1,103	\$ 1,032	\$ 1,032	\$ 1,275	\$ 1,032	\$ (29)	
Washtenaw (Solar)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 11	\$ -	\$ 2	\$ (2)	
Weadock (Classic 7)	\$ 6	\$ 18	\$ 3	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3	
Webber (Hydros)	\$ 892	\$ 195	\$ 726	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 726	
Whiting (Classic 7)	\$ 85	\$ 95	\$ 25	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 25	
WMU (Solar)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Zeeland	\$ 7,282	\$ 7,972	\$ 6,284	\$ 6,577	\$ 6,572	\$ 6,572	\$ 7,672	\$ 6,572	\$ (288)	

CECo Response to AG-CE-0519

U21585-AG-CE-0519_ATT_1			
	Historical year versus test year comments	2022 versus test year	2022 versus test year comments
1 BASE O&M	In total, base O&M is down due to the retirement of the coal plants and offset by the addition of Covert	\$ 28,755	In total, base O&M is down due to the retirement of the coal plants and offset by the addition of Covert
Admin/Generation Commons Adjustment	Increase due to the fact that this O&M gets allocated to the generation units throughout the year	\$ (3,336)	Increase due to the fact that this O&M gets allocated to the generation units throughout the year
Alcona (Hydros)		\$ 231	
Allegan (Hydros)		\$ 183	
Battery		\$ (164)	
Cadillac (Solar)			
Campbell	Reduction due to Campbell shutdown on 5/31/2025, the test year O&M covers only three months of the forecasted test year	\$ 24,856	Reduction due to Campbell shutdown on 5/31/2025, the test year O&M covers only three months of the forecasted test year
Circuit West (Solar)			
Cobb (Classic 7)		\$ 751	
Combustion Turbines			
Cooke (Hydros)		\$ 262	
Covert	Increase due to full year of operation, Covert came online 6/1/2023	\$ (9,110)	Increase due to full year of operation, Covert came online 6/1/2023
Croton (Hydros)		\$ (548)	
Electric Grid Integration		\$ 4,498	
Five Channels (Hydros)		\$ (1,322)	
Foote (Hydros)		\$ 246	
GVSU (Solar)			
Hardy (Hydros)		\$ 347	
Hodenpyl (Hydros)		\$ 266	
Hydro Commons	Increase due to the fact that this O&M gets allocated to the River Hydros throughout the year	\$ (340)	Increase due to the fact that this O&M gets allocated to the River Hydros throughout the year
Jackson		\$ (2,540)	
Karn	Reduction due to Karn 1&2 shutdown on 5/31/2023.	\$ 16,628	Reduction due to Karn 1&2 shutdown on 5/31/2023. 2022 was the last full year of operation for Karn Units 1&2.
Loud (Hydros)		\$ 201	
Ludington		\$ (2,013)	
Mio (Hydros)		\$ 197	
Muskegon (Solar)		\$ (858)	
Mustang Mile (Solar)	Increase due training of certified technicians for solar projects	\$ (2,175)	Increase due training of certified technicians for solar projects
Renewables Development			
Rogers (Hydros)		\$ 206	
Solar Commons		\$ 853	
Tippy (Hydros)		\$ (273)	
Washtenaw (Solar)		\$ (2)	
Weadock (Classic 7)		\$ 18	
Webber (Hydros)		\$ 195	
Whiting (Classic 7)		\$ 95	
WMU (Solar)			
Zeeland		\$ 1,400	

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Question:

134. Refer to Exhibit A-130 (SQM-2) and provide a schedule in Excel in the same format showing expenses for each quarter for the four quarters ended June 2024.

Response:

Please see U-21585_AG_CE_0449_McLean_ATT_1 for the requested data.

Witness: Steven Q. McLean

Date: August 27, 2024

CECo Response to AG-CE-0449

MICHIGAN PUBLIC SERVICE COMMISSION		Case No.:	U-2xxxx		
Consumers Energy Company		Exhibit No.:	A-___ (xxx-xx)		
Summary of Actual & Projected O&M Expenses		Page:	1 of 2		
		Witness:			
(\$000)		Date:			
	(a)	(b)	(c)		
Line No.	Description	2023 Q3	2023 Q4	2024 Q1	2024 Q2
1	Billing & Payment	4,281,394	2,129,116	2,563,589	2,610,353
	Labor	587,060	553,253	617,685	616,740
	Material	499,836	-45,410	235,610	151,499
	Contractor	1,981,067	290,481	307,345	480,154
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	1,213,431	1,330,791	1,402,948	1,361,960
2	Customer Interactions	5,932,338	6,131,930	5,696,187	4,983,362
	Labor	4,525,821	4,485,664	4,151,255	3,976,936
	Material	822	10,409	12,509	33,563
	Contractor	1,130,610	1,312,377	1,181,870	866,187
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	275,086	323,481	350,552	106,676
3	Total CXCO O&M Expenses	\$ 10,213,732	\$ 8,261,046	\$ 8,259,775	\$ 7,593,715
	Labor	5,112,882	5,038,917	4,768,940	4,593,676
	Material	500,658	-35,002	248,119	185,062
	Contractor	3,111,677	1,602,858	1,489,216	1,346,341
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	1,488,516	1,654,273	1,753,500	1,468,637

CECo Response to AG-CE-0449

MICHIGAN PUBLIC SERVICE COMMISSION		Case No.:	U-2xxxx		
Consumers Energy Company		Exhibit No.:	A-____(xxx-xx)		
Summary of Actual & Projected O&M Expenses		Page:	1 of 2		
(\$000)		Witness:			
		Date:			
	(a)	(b)	(c)		
Line No.	Description	2023 Q3	2023 Q4	2024 Q1	2024 Q2
1	Analytics & Outreach	1,132,733	1,076,151	826,856	317,025
	Labor	1,013,379	901,432	619,464	411,250
	Material	-1,126	1,907	2,349	-1,194
	Contractor	106,341	151,650	178,546	76,487
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	14,139	21,163	26,496	-169,518
2	Business Customer Care	443,365	422,405	402,203	389,063
	Labor	367,887	368,444	353,217	360,421
	Material	0	136	2	387
	Contractor	67,477	42,883	38,409	16,228
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	8,002	10,942	10,575	12,027
3	Credit & Assistance	572,360	657,894	605,221	614,062
	Labor	384,153	379,974	390,477	397,455
	Material	1,509	3,660	5,442	34,174
	Contractor	170,572	223,202	184,710	172,984
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	16,126	51,059	24,591	9,450
4	Customer Contact Center	3,435,465	3,448,598	3,608,809	3,447,906
	Labor	2,637,021	2,696,429	2,654,652	2,654,749
	Material	439	4,706	4,715	161
	Contractor	571,014	514,626	687,082	549,787
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	226,990	232,837	262,360	243,208
5	Digital Customer Operations	348,415	526,882	253,098	215,306
	Labor	123,380	139,386	133,445	153,060
	Material	0	0	0	35
	Contractor	215,207	380,017	93,123	50,701
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	9,828	7,479	26,530	11,509
6	Total Customer Interactions O&M Expenses	\$ 5,932,338	\$ 6,131,930	\$ 5,696,187	\$ 4,983,362
	Labor	4,525,821	4,485,664	4,151,255	3,976,936
	Material	822	10,409	12,509	33,563
	Contractor	1,130,610	1,312,377	1,181,870	866,187
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	275,086	323,481	350,552	106,676

MICHIGAN PUBLIC SERVICE COMMISSION Consumers Energy Company Summary of Actual & Projected O&M Expenses		Case No.:	U-2xxxx		
		Exhibit No.:	A-___ (xxx-xx)		
		Page:	1 of 2		
		Witness:			
(\$000)		Date:			
	(a)	(b)	(c)		
Line No.	Description	2023 Q3	2023 Q4	2024 Q1	2024 Q2
1	Customer Billing	2,488,269	1,894,954	2,371,893	2,338,077
	Labor	532,902	481,844	545,781	545,922
	Material	507,582	-46,138	235,094	114,178
	Contractor	228,963	178,518	165,429	317,639
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	1,218,822	1,280,729	1,425,588	1,360,338
2	Customer Payment Programs	1,793,125	234,162	191,696	272,276
	Labor	54,158	71,409	71,904	70,818
	Material	-7,746	727	516	37,321
	Contractor	1,752,104	111,963	141,917	162,516
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	-5,391	50,062	-22,640	1,622
3	Total Billing & Payment O&M Expenses	\$ 4,281,394	\$ 2,129,116	\$ 2,563,589	\$ 2,610,353
	Labor	587,060	553,253	617,685	616,740
	Material	499,836	-45,410	235,610	151,499
	Contractor	1,981,067	290,481	307,345	480,154
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	1,213,431	1,330,791	1,402,948	1,361,960

U21585-AG-CE-0450
Page 1 of 1

Question:

135. On pages 18 and 19 of his direct testimony, Mr. McLean discusses improvements to the Company's Interactive Voice Response system. Please state when these improvements will be completed and what is the cost reduction impact on the projected test year. If the cost savings have been included in the O&M expense forecast for the projected test year in this rate case, provide the amount and the exhibit and line number where they have been included.

Response:

Improvements will be deployed through a phased approach beginning with authentication support in September 2025 and call disposition to CSRs in November 2025.

There will be cost avoidance immediately following the deployment of the virtual agent, please see Company witness Kandan's Exhibit A-89 (SK-7), Page 83 of 126 for detailed avoided costs.

Since the objective is to improve IVR containment, reducing duration of calls, call abandonment, and repeat calls, there is no savings included in the O&M expense forecast for the projected test year in this rate case.

Witness: Steven Q. McLean
Date: August 27, 2024

CECo Response to AG-CE-0450

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Business Case Executive Summaries for Historical, Bridge Period, and Test Year Projects

Case No.: U-21585
Exhibit No.: A-89 (5K-7)
Page No.: 83 of 126
Witness: Skandan
Date: March 2024

Interactive Voice Response (IVR) Authentication Automation		Report Pulled: 3/22/2024	Item ID: 13930							
EXECUTIVE SUMMARY										
BASIC INFORMATION										
Work Category	Strategic/Grow				Work Type					Project
Alias	Generative AI Technology in CCC, Generative Artificial Intelligence (GenAI) Technology in Customer Contact Center Phase 1, Interactive Voice Response (IVR) Enhancements for Customer Contact Center, Interactive Voice Response (IVR) Authentication Automation									
Description	The project will implement a virtual agent bot, run with generative artificial intelligence to support the Customer Contact Center. Upon successful authentication, the bot will reduce the total call handle time for the agents and allow for customers who would have failed out of the existing IVR authentication to continue to self-service. The intent of this project is for the bot to validate who the user is (authorize) and find out the caller's intent for calling into the Customer Contact Center which is routed through the IVR.									
Portfolio	Customer Services > Customer Interaction Channels > Contact Center > Customer Contact Center > * > *									
Org	CX&T	Bus Unit	INFORMATION TECHNOLOGY	Dept	Unspecified					
WORK OBJECTIVES										
Problem Statement	Total handle time and total call minutes in Customer Contact Center exceeds current staffing bandwidth. Because of this, Call Center Representatives scheduled work time becomes unpredictable and customers are experiencing longer wait times at certain parts of the day.									
Objectives	This project creates value for the Company and customers by: (1) reducing customer average call wait time through authentication and intent through an automated bot, (2) avoiding calls into the call center that previously would have failed out of the IVR by allowing the customer to authenticate via the new bot to continue their self-service, (3) allowing the call representative to focus with the customer on the actual issue and handle more calls because user identification and intent will be passed to them.									
Scope	The project scope includes: partnering with McKinsey for the build work of the virtual assistant bot including (1) routing calls from Genesys application to Azure Cloud environment for processing, (2) authenticating the user through the virtual agent aligning with current standards, (3) determining caller intent to streamline the call if transferred to the customer service representative, and (4) transferring the call from Azure cloud environment back to Genesys to be handled by the Customer Service Representative.									
Alternatives	Alternatives considered included: (1) Not making any changes to Interactive Voice Response (IVR) system. This alternative was not selected because call wait times and average handle times are higher than desired currently, (2) considering an expanded scope/timeline to bring in more functionality into the IVR. This alternative was not selected because it is more beneficial to see immediate results upon a more focused implementation, (3) hire additional Customer Service Representatives. This alternative was not selected because we have tried this solution before and we didn't see the results anticipated, and (4) implement a virtual agent bot, run with generative artificial intelligence to support the Customer Contact Center. This alternative was selected because it provides the best balance between achieving average handle time objectives, controlling costs, and optimizing value to customers through less wait time.									
DATES (phase end)										
Initiation	Project Plan & Scope Definition			Final Engineering, Planning & Design			Execution			
3/1/2025	3/15/2025 In-Service/Go-Live 6/27/2025			3/29/2025 Closeout 7/11/2025			6/20/2025			
FUNDING SUMMARY										
	2024	2025	2026	2027	2028	2029	2030	2031 +	Total	
Cap+COR	-	\$6,036	-	-	-	-	-	-	\$6,036	
O&M	-	\$1,383	\$0,460	\$0,460	\$0,460	\$0,460	\$0,460	-	\$3,686	
Total Cost of Ownership	-	\$7,420	\$0,460	\$0,460	\$0,460	\$0,460	\$0,460	-	\$9,722	
	2024	2025	2026	2027	2028	2029	2030	2031 +	Total	
Labor	-	\$0,240	-	-	-	-	-	-	\$0,240	
Outside Services	-	\$6,100	-	-	-	-	-	-	\$6,100	
Business Expense/Overheads	-	\$0,850	-	-	-	-	-	-	\$0,850	
Employee Benefits	-	-	-	-	-	-	-	-	-	
Materials	-	-	-	-	-	-	-	-	-	
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-	
Other	-	-	-	-	-	-	-	-	-	
Total Project Cost	-	\$7,190	-	-	-	-	-	-	\$7,190	
VALUE & IMPACTS SUMMARY										
FINANCIAL IMPACTS										
	2024	2025	2026	2027	2028	2029	2030	2031 +	Total	
O&M	Reduction	-	-	-	-	-	-	-	-	
	Initial	-	\$1,383	\$0,460	\$0,460	\$0,460	\$0,460	\$0,460	\$3,686	
	Incremental	-	-	-	-	-	-	-	-	
	Net	-	\$1,383	\$0,460	\$0,460	\$0,460	\$0,460	\$0,460	\$3,686	
Cap+COR	Reduction	-	-	-	-	-	-	-	-	
	Initial	-	\$6,036	-	-	-	-	-	\$6,036	
	Incremental	-	-	-	-	-	-	-	-	
	Net	-	\$6,036	-	-	-	-	-	\$6,036	
Revenue	Reduction	-	-	-	-	-	-	-	-	
	Initial	-	-	-	-	-	-	-	-	
	Incremental	-	-	-	-	-	-	-	-	
	Net	-	-	-	-	-	-	-	-	
B/C Ratio (Overall)			-1.000							
Risk Tolerance										
Corporate Risk	Impact	Likelihood	Description							
OTHER VALUE										
Type	Description									
Avoided Costs	The bot will handle the contact center authentication. This assumes a blended rate of \$0.0184595 cost per second of handle time based on historical averages. CSR handled calls = 2,864,382 net calls which could be completed in IVR (227,076) = 2,637,306 calls. This also assumes a 55 second Average Handle Time (AHT) for authentication minus a 15 second AHT for a CSR to get up speed with authentication from a bot transferred call. That will be multiplied by an 80% success rate. Final calculation: ((35-15)*AP*0.0184595 * 2,637,306) = \$1,357,986 avoided cost per year for customer authentication.									
Avoided Costs	The bot will handle the contact center intent. This assumes a blended rate of \$0.0184595 cost per second of handle time based on historical averages. Conservative 9% IVR non-authentication match * conservative 46.473% IVR containment rate * blended cost \$0.0184595 * total seconds handled (1,073,903,132) = \$626,140 avoided costs.									

U21585-AG-CE-0523
Page 1 of 1

Question:

198. Refer to Exhibit A-72 (MJF-2) on Corporate Services. Please:

- a. For each item on lines 2-7, provide detailed functions and components of what makes up that line item in Excel for each year 2019 to 2023, and the projected test year expense for each of those functions and components with the Other Adjustments assigned to each of those functions or components. Explain any variances of 10% or greater year over year.
- b. Provide the number of employees in each function for each year 2019 to 2023 and forecasted for 2024, 2025, and 2026 at year-end in Excel. Explain any changes in headcount in each function of 3 or more employees.
- c. For insurance costs, provide the actual expense for each year 2019 to 2023, and the amount forecasted for 2024, 2025, 2026, and the projected test year in Excel. Show and explain how you determined the forecasted amounts for each year in Excel.
- d. Provide any premium refunds or rebates received from insurance companies during each year 2019 to 2023 and forecasted for 2024 to 2026 along with a copy of any communication received from the insurance carrier. Explain whether those refunds or rebates are included in the expense provided in subpart (c). If no, explain why not.

Response:

- a. The detailed functions and components for each organization are described on Pages 3 – 5 of Matthew J. Foster’s direct testimony. Please see U21585-AG-CE-0523_Foster_ATT_1 for the actual costs for 2019-23 and the forecasted amounts for 2024-26. Please see U21585-AG-CE-0523_Foster_ATT_2 for the variance explanations.
- b. Please see U21585-AG-CE-0523_Foster_ATT_3 for the number of employees for 2019-23 and the forecasted amounts for 2004-26. Please see U21585-AG-CE-0523_Foster_ATT_4 for the variance explanations. Please note that some of the employee numbers represent best estimates because of reorganizations that occurred in previous years.
- c. Please see U21585-AG-CE-0523_Foster_ATT_5, line 6 for the actual costs for 2019 – 23 and the forecasted amounts for 2024 – 26. Property premiums are based on estimated values and rate increases. Other future premiums are calculated using a year over year percent increase.
- d. Please see U21585-AG-CE-0523_Foster_ATT_5, line no. 5 for the actual distributions for 2019 – 23 and the forecasted amounts for 2024 – 26.

Witness: Matthew J. Foster
Date: September 3, 2024

CECo Response to AG-CE-0523

U21585-AG-CE-0523 Foster_ATT 5										
Line No.		2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 FC	2025 FC	2026 FC	12 Mos. Ending 2/28/2026
1	Property Insurance	\$ 8,811,478	\$ 7,184,455	\$ 7,973,962	\$ 8,603,397	\$ 8,836,652	\$ 7,995,896	\$ 9,754,336	\$ 10,997,583	\$ 9,961,544
2	Liability Insurance	\$ 7,455,225	\$ 8,028,213	\$ 8,311,978	\$ 8,636,802	\$ 9,206,282	\$ 11,157,291	\$ 11,160,307	\$ 12,238,684	\$ 11,340,037
3	Other	\$ 7,740	\$ 8,128	\$ 8,022	\$ 8,626	\$ 9,923	\$ 10,164	\$ 11,368	\$ 11,557	\$ 11,400
4	Total Premiums	\$ 16,274,443	\$ 15,220,796	\$ 16,293,962	\$ 17,248,825	\$ 18,052,857	\$ 19,163,351	\$ 20,926,011	\$ 23,247,824	\$ 21,312,980
5	Distributions	\$ (7,117,179)	\$ (13,861,119)	\$ (8,609,556)	\$ (12,469,851)	\$ (3,519,597)	\$ (6,141,051)	\$ (4,719,877)	\$ (4,719,877)	\$ (4,719,877)
6	Net Insurance O&M	\$ 9,157,264	\$ 1,359,677	\$ 7,684,406	\$ 4,778,974	\$ 14,533,260	\$ 13,022,300	\$ 16,206,134	\$ 18,527,947	\$ 16,593,103

AG Adjustment to Insurance Expense

Line No.		2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 FC	2025 FC	2026 FC	12 Mos. Ending 2/28/2026	Percent Annual Increase 2019-2023	AG Forecast with Annual Increase *
1	Property Insurance	\$ 8,811,478	\$ 7,184,455	\$ 7,973,962	\$ 8,603,397	\$ 8,836,652	\$ 7,995,896	\$ 9,754,336	\$ 10,997,583	\$ 9,961,544	0.10%	\$ 8,854,906
2	Liability Insurance	\$ 7,455,225	\$ 8,028,213	\$ 8,311,978	\$ 8,636,802	\$ 9,206,282	\$ 11,157,291	\$ 11,160,307	\$ 12,238,684	\$ 11,340,037	7.29%	\$ 10,724,045
3	Other	\$ 7,740	\$ 8,128	\$ 8,022	\$ 8,626	\$ 9,923	\$ 10,164	\$ 11,368	\$ 11,557	\$ 11,400	8.63%	\$ 11,877
4	Total Premiums	\$ 16,274,443	\$ 15,220,796	\$ 16,293,962	\$ 17,248,825	\$ 18,052,857	\$ 19,163,351	\$ 20,926,011	\$ 23,247,824	\$ 21,312,980		\$ 19,590,828
5	Distributions	\$ (7,117,179)	\$ (13,861,119)	\$ (8,609,556)	\$ (12,469,851)	\$ (3,519,597)	\$ (6,141,051)	\$ (4,719,877)	\$ (4,719,877)	\$ (4,719,877)		\$ (9,115,460)
6	Net Insurance O&M	\$ 9,157,264	\$ 1,359,677	\$ 7,684,406	\$ 4,778,974	\$ 14,533,260	\$ 13,022,300	\$ 16,206,134	\$ 18,527,947	\$ 16,593,103		\$ 10,475,367
7	Five-Year Average					\$ (9,115,460)						
8	CECo Forecasted Amount											\$ 16,593,103
9	Adjustment											\$ (6,117,736)

Source: U21585-AG-CE-0523_Foster_ATT_5

* Annual increase over 26 months

U21585-AG-CE-0460

Page 1 of 1

Question:

145. Regarding the \$2.6 million to be paid out as shown on Exhibit A-70 (AMC-3), page 1, provide what the payout would be if all the metrics are achieved at the "Threshold level" and specify how much of the total would be for non-financial metrics.

Response:

The projected test year amount shown on Exhibit A-70 (AMC-3), page 1 of \$2.6 million (ie 100% target) would be \$1.3 million if all the metrics are achieved at the threshold level.

Witness: Amy M. Conrad

Date: August 26, 2024

Computation of Revenue Deficiency for Projected Test Year Ending February 2026
 (\$000)

Line	Description (a)	Jurisdictional Company Filed Amount (b)	AG Recommended Adjustments (c)	Revised Amount (d)
1	Rate Base ⁽¹⁾	\$ 15,571,480	\$ (950,237)	\$ 14,621,243
2	Rate of Return	6.21%	-0.27%	5.94%
3	Income Required	\$ 966,300	\$ (97,798)	\$ 868,502
4	Adjusted Net Operating Income ⁽²⁾	735,242	66,369	801,611
5	Income Deficiency (Sufficiency)	\$ 231,058	\$ (164,167)	\$ 66,891
6	Revenue Multiplier	1.3381	1.3381	1.3381
7	Revenue Deficiency (Sufficiency)	\$ 309,174	\$ (219,668)	\$ 89,506
8	Campbell revenue requirement adjustment	(6,596)	-	(6,596)
9	Adjusted revenue deficiency (sufficiency)	\$ 302,578	\$ 219,668	\$ 82,910

⁽¹⁾ Rate Base Adjustments Exhibit AG-1.16.

⁽²⁾ AG adjustments to Operating Income		Source
Revenue	\$ -	
Lower Forecast of O&M Expenses	48,000	Exhibit AG-1.31
Property Taxes	3,368	Exhibit AG-1.15
Depreciation Expense	43,077	Exhibit AG-1.15
Total	\$ 94,445	
Effective Tax Rate (1-1/1.3381)	25.27%	
Taxes	23,863	
Interest Synchronization for Cap. Ex. adjustments	(4,214)	AG-1.45 WP1
Adjusted Net Operating Income	\$ 66,369	

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
CONSUMERS ENERGY COMPANY)
for authority to increase its rates for)
the generation and distribution of)
electricity and for other relief.)
_____)

Case No. U-21585

QUALIFICATIONS AND DIRECT TESTIMONY
OF
MICHAEL W. DEUPREE

September 27, 2024

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MICHIGAN DEPARTMENT OF THE ATTORNEY GENERAL

QUALIFICATIONS AND DIRECT TESTIMONY OF MICHAEL W. DEUPREE

Line
No.

1 **I. INTRODUCTION**

2 **Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?**

3 A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place
4 Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

5 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

6 A. I am testifying in this proceeding on behalf of the Michigan Department of the
7 Attorney General (“AG”).

8 **Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE
9 OF EMPLOYMENT?**

10 A. I am a Research Consultant with the Acadian Consulting Group (“ACG”), a
11 research and consulting firm that specializes in the analysis of regulatory, economic,
12 financial, accounting, statistical, and public policy issues associated with regulated and
13 energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is
14 located in Baton Rouge, Louisiana.

15 **Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.**

16 A. I hold a Bachelor of Arts degree in Business Economics from Buena Vista
17 University in Storm Lake, Iowa, and a Master of Arts degree in Economics from the
18 University of Kansas in Lawrence, Kansas. I began my professional career with the Staff
19 of the Kansas Corporation Commission in 2008 while in graduate school conducting
20 analyses of topics related to energy and economy as a Research Assistant, eventually

1 being promoted to a Research Analyst and later Senior Research Economist after
2 graduation. I left the Kansas Corporation Commission to take a position with ACG in late
3 2011, where I have been promoted to positions of increasing responsibility since,
4 including my current position which I started in mid-2021. At ACG I managed research
5 teams supporting expert testimony and have overseen dozens of litigated preceding,
6 including multiple proceedings on behalf of the AG. Appendix A provides my professional
7 resume, which includes a listing of my publications, presentations, pre-filed expert witness
8 testimony, expert reports, and expert legislative testimony.

9 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

10 A. No.

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

12 A. I have been retained by the AG to provide an expert opinion to the Commission on
13 issues related to the Company's proposed test year ("TY") capital expenditures related to
14 generation plant and operations support. My testimony and accompanying exhibits have
15 been prepared by me or those under my direction and control.

16 **Q. HAVE YOU SPONSORING ANY EXHIBITS?**

17 A. Yes. The following exhibits have been prepared in support of my testimony:

- 18 • Exhibit AG-2.1: Total Capital Expenditure Adjustments
- 19 • Exhibit AG-2.2: Discovery Response U-21585-AG-CE-0560
- 20 • Exhibit AG-2.3: Discovery Response U-21585-ST-CE-0019
- 21 • Exhibit AG-2.4: Discovery Response U-21585-AG-CE-0561
- 22 • Exhibit AG-2.5: Discovery Response U-21585-AG-CE-0563
- 23 • Exhibit AG-2.6: MPSC Case No. U-21389, Exhibit A-96
- 24 • Exhibit AG-2.7: Discovery Response U-21585-AG-CE-0564

25 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

1 A. My testimony is organized into the following sections:

- 2 • Section II: Summary of Recommendations
- 3 • Section III: Overview of Company's Proposal
- 4 • Section IV: Methods and Standard of Review
- 5 • Section V: Proposed Capital Expenditure Adjustments
- 6 • Section VI: Conclusions and Recommendations

7 **II. SUMMARY OF RECOMMENDATIONS**

8 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

9 A. A summary of my proposed recommendations is provided in Exhibit AG-2.1. In
10 sum, I recommend \$525.5 million in projected capital expenditures associated with solar
11 projects be removed from the Company's proposed revenue requirement calculations. I
12 also recommend the following additional amounts of capital expenditures be removed
13 from the Company's revenue requirement calculation: \$134.6 million in capital
14 expenditures associated with Hydro projects; \$118.6 million in capital expenditures
15 associated with Battery Storage projects; \$17.5 million in capital expenditures associated
16 with new operational support construction; and \$24.7 million in capital expenditures
17 associated with operational support renovations. Specifically, I recommend the following
18 proposed adjustments and actions be taken by the Commission in this proceeding:

- 19 • Removal of \$24.2 million in projected capital expenditures associated with the
20 Washtenaw Solar project. The amount and timing of the capital expenditures are
21 not fully known and measurable.
- 22 • Removal of \$270.3 million in projected capital expenditures associated with the
23 Muskegon Solar project. The amount and timing of the capital expenditures are
24 not fully known and measurable.
- 25 • Removal of \$231.0 million in projected capital expenditures associated with the
26 Spring Creek Solar project. The amount and timing of the capital expenditures are
27 not fully known and measurable.

- 1 • Removal of the \$134.6 million projected capital expenditures associated with
2 proposed hydroelectric projects. The amount and timing of the capital
3 expenditures are not fully known and measurable.
- 4 • Removal of the \$118.6 million projected capital expenditures associated with an
5 unnamed Battery Storage project. The amount and timing of the capital
6 expenditures are not fully known and measurable.
- 7 • Removal of the \$17.4 million projected capital expenditures associated with the
8 Lansing Service Center project. The amount and timing of the capital expenditures
9 are not known and measurable.
- 10 • Removal of the \$0.1 million projected capital expenditures associated with the
11 Hastings Service Center project. The amount and timing of the capital
12 expenditures are not known and measurable.
- 13 • Removal of the \$14.2 million projected capital expenditures associated with the
14 Kalamazoo Service Center project. The amount and timing of the capital
15 expenditures are not known and measurable.
- 16 • Removal of the \$10.5 million projected capital expenditures associated with
17 renovations to the Company's Control/Dispatch Center. The amount and timing of
18 the capital expenditures are not known and measurable.

19 **III. OVERVIEW OF COMPANY'S PROPOSAL**

20 **Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S PROPOSED RATE**
21 **INCREASE.**

22 A. The Company requests a \$325 million rate increase consisting of a \$303 million
23 base rate increase (equal to an overall base rate increase of 6.5 percent)¹ to recover what
24 it claims are insufficient revenues to fairly compensate the Company for costs and
25 expenses incurred since its last rate increase became effective January 20, 2024, as well
26 as projected costs the Company estimates it will incur through February 28, 2026; and a
27 12-month distribution deferral surcharge of \$22 million (the requested rate increase is 7.0
28 percent inclusive of the proposed distribution deferral surcharge). In addition, the
29 Company is proposing a Service Restoration Cost Sharing Mechanism;² an all-

¹ Direct Testimony of Heidi Myers at 5:12-13 and 18:4-6.

² *Id.*, at 11:17-21.

1 encompassing demand response surcharge;³ and continuation of the PowerMIDrive
2 Program and the creation of permanent electric vehicle programs.⁴

3 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED TEST YEAR.**

4 A. The Company seeks to establish rates based on a future TY, representing the 12
5 months ending February 28, 2026. A bridge period ("BP"), representing the 14 months
6 ending February 29, 2025, and a historical year ("HY"), representing the 12 months
7 ending December 31, 2023, precede the TY.

8 **IV. METHODS AND STANDARD OF REVIEW**

9 **Q. DOES THE USE OF A FUTURE TEST YEAR CREATE ANY UNIQUE**
10 **REGULATORY REVIEW CHALLENGES?**

11 A. Yes. Michigan law provides that "[a] utility may use projected costs and revenues
12 for a future consecutive 12-month period in developing its requested rates and charges."⁵
13 The use of forward TYs is associated with three particular downsides. The first downside
14 is that the future is unknown and it is only by happenstance that a projected TY will reflect
15 actual after-the-fact outcomes.⁶ The second downside is that there is a considerable
16 degree of asymmetric information in the regulatory process that makes it difficult for
17 regulators, and other stakeholders to evaluate projected TY information.⁷ The third
18 downside is that forward TYs can also lead to potential capital and expense inefficiencies
19 since there are little to no downside from a utility spending up to an overstated capital
20 and/or expense forecast.⁸ These drawbacks have been noted in a publication by the

³ *Id.*, at 13:21-23.

⁴ *Id.*, at 14:9-14.

⁵ MCL Section 460.6a(1).

⁶ Ken Costello, "Future Test Years: Challenges Posed for State Utility Commissions," Briefing Paper No. 13-08, NRRI, July 2013, p. iv,

⁷ *Id.*

⁸ *Id.* at p. v.

1 National Regulatory Research Institute (“NRRRI”), the research arm for the National
2 Association of Regulatory Utility Commissioners (“NARUC”), which observed

3 [F]orecasts are susceptible to error and some costs and sales
4 elements are inherently difficult to predict. Another factor, as
5 this paper stresses, is that utilities [] have incentives to
6 present biased forecasts that are not always easy for
7 commission staff and interveners to uncover.⁹

8 ...

9 [I]f a utility makes poor forecasts, if a cost or sales element is
10 susceptible to a potentially large forecasting error, or if the
11 utility biases its forecasts that go undetected, [a future test
12 year] could easily take money away from utility customers and
13 give it to the utility and its shareholders.¹⁰

14 **Q. WHAT BURDEN MUST A UTILITY SATISFY BEFORE THE COMMISSION WILL**
15 **APPROVE PROJECTED YEAR CAPITAL EXPENDITURES?**

16 A. The Commission has clearly noted that “[t]he burden is on the utility to prove the
17 accuracy of each and every test year projection.”¹¹ Indeed, the Commission has
18 reiterated its position on the need for detail and certainty to support projected test year
19 expenses in multiple prior cases.¹²

20 For future guidance, the Commission’s expectation is that the
21 parties will fully document the basis of their test year
22 projections by offering into evidence detailed supporting
23 explanations and underlying assumptions rooted in expected
24 business, financial, and economic circumstances. Rate
25 applications may not rely on undocumented estimates of
26 future ratemaking expenses and revenue criteria. When
27 necessary, parties should provide competing projections, with
28 a similar basis of support. The record thus created should
29 lend itself to a comparative review of the reasonableness and
30 prudence of the projections. Historical data may play a role,
31 but ordinarily will not be a controlling factor except in
32 circumstances that clearly demonstrate that it is a more fair

⁹ Ken Costello, “Future Test Years: Challenges Posed for State Utility Commissions,” Briefing Paper No. 13-08, NRRRI, July 2013, p. iv.

¹⁰ *Id.* at p. v.

¹¹ Order, MPSC Case No. U-20561, May 8, 2020, p. 12.

¹² *Id.* at 13; *citing* Order, MPSC Case No. U-15645, November 2, 2009, p. 9.

1 and reasonable reflection of the utility's cost of service,
2 relative to projected data.¹³

3 The Commission has also determined that a utility's presentation of substantial evidence
4 on a particular proposal "does not make the reasonableness and prudence of that
5 proposal a foregone conclusion..."¹⁴ Thus, in sum, it is not enough that a utility's projected
6 capital expenditures be associated with a prudent capital project; instead, the projected
7 capital expenditures must also be adequately supported.

8 **Q. HOW DID THE COMMISSION'S PREVIOUS STATEMENTS INFORM YOUR**
9 **REVIEW OF THE COMPANY'S PROJECTED CAPITAL EXPENDITURES?**

10 A. My review of the Company's projected capital expenditures focused on examining
11 the Company's underlying support and documentation to assess the degree to which the
12 projected investments are grounded on reasonable known and measurable information
13 and that projected investment are reasonably expected to be used and useful during the
14 projected TY.

15 **Q. HOW DO YOU DEFINE REASONABLY KNOWN AND MEASURABLE**
16 **INVESTMENT AND EXPENSE ADJUSTMENTS?**

17 A. I have generally used the following criteria:

- 18 • Adjustments identified and recognized standards applied in general rate cases.
19 This would include, for example, changes that result from contractual
20 obligations, government action, Board of Director actions, and so forth.
- 21 • Adjustments that have been identified in prior utility filings and/or received
22 explicit Commission approval.
- 23 • Adjustments that include clear documentation that identifies construction or
24 development start dates, current development progress, and clear anticipated
25 commercial operation dates.

¹³ Order, MPSC Case No. U-15645, November 2, 2009, p. 9.

¹⁴ Order, MPSC Case No. U-18014, January 31, 2017, pp. 5-8.

- 1 • Adjustments that have clearly shown or documented construction expenditures
2 to date, remaining expenditures to complete, and current budget variances.

3 **Q. CAN REASONABLY UNCERTAIN COSTS BE CONSIDERED KNOWN AND**
4 **MEASURABLE?**

5 A. No. Known and measurable costs may not be speculative. Instead, there must
6 be an ironclad commitment to the project associated with the capital expenditures and
7 there must be certainty as to the timing and amount of the capital expenditures.

8 **Q. WILL THE COMPANY BE PREJUDICED IF ANY INVESTMENT OR EXPENSE**
9 **ITEM IS REMOVED FROM THE PROJECTED TEST YEAR REVENUE REQUIREMENT**
10 **BY THE COMMISSION IN THIS PROCEEDING?**

11 A. No. Any properly recoverable investment or expense that is not reasonably known
12 and measurable at the current time will be eligible for rate recovery in the future if that
13 expense or investment can be shown to have actually materialized and was prudently-
14 incurred. Further, holding the Company to a firm line on its burden of proof regarding its
15 projected TY investments and expenses will create strong incentives for the Company to
16 provide more complete and convincing documentation in the future filing. In addition,
17 academic research indicates that utilities are generally more cost efficient when cost
18 recovery is delayed (i.e., regulatory lag is present).¹⁵

19 **Q. HAS THE COMMISSION RECENTLY APPLIED THE USED AND USEFUL**
20 **STANDARD TO DISALLOW COMPANY PROJECTED CAPITAL EXPNDITURES?**

¹⁵ Utility regulation researchers have noted that regulatory lag prevents utility regulation from devolving into a “cost-plus” approach that simply passes through costs on a dollar-for-dollar basis to ratepayers and can lead to cost and investment inefficiencies. The cost-plus regulatory approach also shifts a considerable amount of performance-related risk away from utilities and onto ratepayers and leads to inefficient outcomes, which was recognized in the 1960s, has come to be known as the “Averch-Johnson” or “A-J effect.” See, for example, Elizabeth E. Bailey and Roger D. Coleman.(1971). “The Effect of Lagged Regulation in an Averch-Johnson Model.” *Bell Journal of Economics and Management Sciences*. 2 (Spring): 278-292.

1 A. Yes. In Case No. U-20963, the Company argued, while attempting to support
2 projected environmental costs for a project that would not be completed within the
3 projected TY, that “the Commission is not bound to apply only the used and useful
4 standard and is not bound to any particular method in setting just and reasonable rates.”¹⁶
5 Intervenor Association of Businesses Advocating Tariff Equity (“ABATE”) disagreed,
6 arguing that, in the past, the Commission has agreed to a comprehensive examination of
7 the used and useful doctrine and noted that the Commission has articulated its
8 expectation for projected spending to be used and useful in the TY. The Commission
9 agreed with ABATE, finding that it is premature to include initial capital expenditures
10 associated with capital projects that are not expected to be used and useful during the
11 test year:

12 While the ALJ is correct that the Commission has previously
13 allowed environmental costs to be recovered in rates prior to
14 being used and useful, the Commission finds persuasive
15 ABATE’s arguments that this project will not take place until
16 2023 [i.e., after the 2022 TY], and thus inclusion of capital
17 expenditures related to the project is premature.¹⁷

18 **Q. HAS THE USED AND USEFUL DOCTRINE BEEN APPLIED ELSEWHERE IN**
19 **THE FIELD OF UTILITY REGULATION?**

20 A. Yes. The used and useful doctrine is a longstanding and fundamental principles
21 of utility regulation. The doctrine dates to *Smyth v. Ames*, a U.S. Supreme Court decision
22 in 1898, and is intended to promote distributional equity between utility investors and
23 captive ratepayers.¹⁸ Used and useful simply requires that assets not be included in rate
24 base for rate recovery unless or until these assets can be demonstrated to be providing

¹⁶ Order, MPSC case No. U-20963, December 22, 2022, p. 103.

¹⁷ *Id.*

¹⁸ Fundamentals of Energy Regulation, at 133-134, discussing *Smyth v. Ames*, 169 U.S. 466 (1898).

1 services that are useful to ratepayers.¹⁹ The used and useful doctrine along with the
2 earlier referenced known and measurable doctrine are designed to encourage utilities to
3 make disciplined economic operating and investment decisions.

4 **V. PROPOSED CAPITAL EXPENDITURE ADJUSTMENTS**

5 **A. Company-Owned Solar Projects**

6 **Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENTS REGARDING THE**
7 **COMPANY'S SOLAR PROJECTS?**

8 A. I recommend the Commission remove projected capital expenditures associated
9 with the Washtenaw, Muskegon and Spring Creek projects when establishing the
10 Company's revenue requirement. The Washtenaw project in particular has seen
11 significant delays and currently does not have an anticipated commercial operation date
12 ("COD").²⁰ The Muskegon project is under construction and is expected to be finished at
13 the end of 2025 which is a one-year delay from the original COD of December 31, 2024,
14 and problematically near the conclusion of the projected TY for a project that has already
15 seen significant delays. The Spring Creek project is a new project for which the Company
16 is still seeking some permits for, with an anticipated COD of June 1, 2026, or several
17 months after the end of the Company's projected TY.²¹

18 **Q. PLEASE DISCUSS THE WASHTENAW PROJECT.**

19 A. The Washtenaw Project was selected pursuant to the Company's 2020 IRP
20 competitive solicitation process.²² The Company forecasts spending \$24.2 million in the

¹⁹ *Id.* at 49.

²⁰ Exhibit AG-2.2 - Discovery Response U21585-AG-CE-0560.

²¹ *Id.*

²² Direct Testimony of Thomas P. Clark at 32:12-18.

1 projected TY on the Washtenaw Project.²³ The Company has explained that due to a
2 lack of securing a sufficient amount of land rights this project has been delayed. The
3 project currently depends on the implementation of the state certification process. MPSC
4 is in the process of developing requirements for the state certification process, but the
5 law does not go into effect until November 29, 2024, which sets the approval of the state
6 certification for this project in 2025.²⁴ The earliest the Washtenaw Solar Project would be
7 in operation is late 2027.²⁵

8 **Q. IS THERE UNCERTAINTY ASSOCIATED WITH THE WASHTENAW**
9 **PROJECT?**

10 A. Yes. After the Company executed a Build Transfer Agreement (“BTA”) with a third
11 party constructing the Washtenaw project on the Company’s behalf in late 2021, the local
12 township changed its zoning ordinances, requiring the Company to acquire additional
13 land rights in order to be sited locally.²⁶ The Company states that it has secured only a
14 portion of the necessary land rights, “but to date has not acquired sufficient land rights to
15 meet the setbacks adopted in the [recently enacted] local ordinance.”²⁷ As the Company
16 has seen with the Mustang Mile project, even obtaining land rights is not necessarily
17 sufficient to greenlight a project as there is potential for protracted litigation from
18 opposition groups of unknown duration.²⁸ Further, the Company has noted that no
19 permits have been submitted due to changes in local ordinances requiring significant
20 additional land acquisitions.²⁹

²³ *Id.*, at 34 Table 6.

²⁴ *Id.*, at 33:11-20.

²⁵ *Id.*, at 33:20.

²⁶ *Id.*, at 32:19 to 33:3.

²⁷ *Id.*, at 33:5-6.

²⁸ *Id.*, at 30:7-13.

²⁹ Exhibit AG-2.2 - Discovery Response U21585-AG-CE-0560.

1 **Q WHAT ARE YOUR RECOMMENDATIONS REGARDING COST RECOVERY OF**
2 **THE WASHTENAW PROJECT?**

3 A I recommend the Commission exclude all \$24.2 million in total projected capital
4 expenditures. There exists continuing uncertainty regarding the timing and amount of the
5 projected expenditures due to delays. Indeed, the Company currently does not forecast
6 an anticipated COD date associated with the Washtenaw project due to an uncertain
7 timeframe associated with local and/or state siting processes.³⁰ The proposed
8 investment in the Washtenaw Project is therefore not sufficiently known and measurable.

9 **Q. IS YOUR PROPOSED RECOMMENDATION REGARDING COST RECOVERY**
10 **OF THE WASHTENAW PROJECT CONSISTENT WITH THE TREATMENT OF OTHER**
11 **SPECULATIVE CAPITAL EXPENDITURES FORECASTED BY THE COMPANY?**

12 A. Yes. The Company's Mustang Mile solar project has been mired in legal
13 challenges for years.³¹ While the Company is optimistic that opposition groups will fail in
14 their current legal challenges, the Company has acknowledged that the unpredictable
15 nature of these proceedings and timelines have made it so that it cannot give an accurate
16 COD for the Mustang Solar Project and therefore decided to remove all capital costs
17 associated with the project from this case.³² Importantly, the Company reserves the right
18 to move forward on the Mustang solar project should these legal woes conclude, with
19 cost recovery being handled in a future case.³³

20 **Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO INCLUDE THE**
21 **MUSKEGON PROJECT IN ITS PROPOSED BASE RATES.**

³⁰ *Id.*

³¹ See, Direct Testimony of Thomas P. Clark at 30:7 to 31:23.

³² *Id.*, at 31:20-23.

³³ *Id.*, at 32:4-8.

1 A. The Muskegon Project, which was selected via the Company's 2021 IRP
2 competitive solicitation, had an originally anticipated COD of December 31, 2024;
3 however, the project has been delayed by material, equipment, and labor constraints.³⁴
4 The Company now estimates that the Muskegon Project's COD will be delayed by nearly
5 a year to November 12, 2025, with interim transfer to the Company not expected to take
6 place until December 29, 2025.³⁵ The Company forecasts spending \$141.4 million in the
7 BP and \$128.9 million in the projected TY on the Muskegon Project, for a total of \$270.3
8 million.³⁶

9 **Q. HAS THE COMPANY OBTAINED THE NECESSARY PERMITS TO COMPLETE**
10 **THE MUSKEGON PROJECT?**

11 A. Yes. In response to discovery the Company states that all but one construction
12 permits have been obtained for the Muskegon project.³⁷ The remaining permit the
13 Company must obtain pertains to generation tie line construction.

14 **Q WHAT ARE YOUR RECOMMENDATIONS REGARDING COST RECOVERY OF**
15 **THE MUSKEGON PROJECT?**

16 A I recommend the Commission exclude all \$270.3 million in total projected capital
17 expenditures. The anticipated COD for the Mukegon project is November 12, 2025, with
18 interim transfer to the Company not expected to take place until December 29, 2025.³⁸
19 This represents a nearly one year delay from the original date of December 31, 2024, set
20 in the initial contract, and fall only two months prior to the end of the projected TY.

³⁴ *Id.*, at 35:20-22.

³⁵ *Id.*, Exhibit A-184 (TPC-2).

³⁶ *Id.*, at 36, Table 7.

³⁷ Exhibit AG-2.3 - Discovery Response U21585-ST-CE-0019.

³⁸ Direct Testimony of Thomas P. Clark, Exhibit A-184 (TPC-2).

1 However, it should be recognized that the initial turnover date does not necessarily
2 represent full commercial operations of the project. Indeed, the Company does not
3 anticipate completion of required tests and commissioning of the Muskegon project until
4 April 2026.³⁹ Based on historic delays there is reason to believe that there is an elevated
5 likelihood that the Muskegon project will not be used and useful during the projected TY.
6 The Commission should thus require the Company to provide additional evidence
7 verifying that the Muskegon project will be used and useful within the projected TY before
8 including estimated capital expenditures in projected TY rate base.

9 **Q. PLEASE DISCUSS THE SPRING CREEK SOLAR PROJECT.**

10 A. The Spring Creek Solar project was selected pursuant to the Company's 2022 IRP
11 competitive solicitation process. The Company forecasts spending \$108.2 million in the
12 BP and \$122.8 in the projected TY.⁴⁰ Currently, the Company has secured all land rights
13 associated with the Spring Creek project,⁴¹ and anticipates construction commencing
14 sometime in the second quarter of 2025.⁴² Anticipated COD for the Spring Creek project
15 is slated for June 1, 2026.⁴³

16 **Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING COST RECOVERY**
17 **OF THE SPRING CREEK SOLAR PROJECT?**

18 A. I recommend the commission exclude all of the \$231 million in total projected
19 capital expenditures. The Company anticipates the COD date for this project to be June
20 1, 2026,⁴⁴ which is four months beyond the end of the projected TY and therefore not

³⁹ *Id.*

⁴⁰ Direct Testimony of Thomas P. Clark at 39, Table 8.

⁴¹ *Id.*, at 38:17.

⁴² *Id.*, Exhibit A-192 (TPC-10).

⁴³ *Id.*, at 38:22.

⁴⁴ *Id.*, at 38:21-22.

1 used and useful within the projected TY. Furthermore, like the Company's other solar
2 projects, this COD and indeed the timing of all forecasted capital expenditures is
3 preliminary and subject to potential future delays. Due to the uncertainty surrounding the
4 timing and amount of the capital expenditures the projected costs are not known and
5 measurable.

6 **B. Hydro Facilities**

7 **Q. WHAT AMOUNT OF PROJECTED CAPITAL EXPENDITURES RELATED TO**
8 **HYDRO FACILITIES IS THE COMPANY SEEKING TO RECOVER?**

9 A. The Company currently owns and operates fourteen hydroelectric facilities: the
10 Ludington Pumped Storage Plant and thirteen River Hydro units.⁴⁵ These facilities are
11 licensed by Federal Energy Regulatory Commission ("FERC").⁴⁶ The Company projects
12 spending \$42.4 million in the BP and \$92.3 million in the TY⁴⁷ in order to implement safety,
13 regulatory compliance, reliability, and infrastructure projects for River Hydro units.⁴⁸ The
14 investments include 13 projects that are each expected to cost more than \$1 million and
15 14 projects that cost between \$200,000 and \$1 million.⁴⁹

16 **Q. DOES THE COMPANY EXERCISE JUDGEMENT WHEN PRIORITIZING ITS**
17 **HYDRO SAFETY INVESTMENTS?**

18 A. Yes. The Company notes that FERC's Part 12D regulations require the Company
19 to employ independent dam safety consultants to conduct regular safety reviews of the
20 dams and make recommendations for any necessary safety improvements.⁵⁰ Upon

⁴⁵ Direct Testimony of Adam Monroe at 4:3-4.

⁴⁶ *Id.*, at 4:3-4.

⁴⁷ *Id.*, at 36:13-14.

⁴⁸ *Id.*, at 36:11-47:38.

⁴⁹ *Id.*, at 36:11-48:38.

⁵⁰ *Id.*, at 21:22-22:5

1 receiving a recommendation, the Company then “typically works with FERC to prioritize
2 these Part 12D recommendations in terms of timing, design, and implementation.”⁵¹ In
3 other words, when establishing the priority of its safety investments, the Company usually
4 (but not always) works with FERC. In other words, the priority of the safety investments
5 are usually based on the Company’s judgement, rather than a FERC directive, as
6 evidenced by the following conclusion by the Company regarding the need for the Hardy
7 auxiliary spillway: “In my opinion, failure to make this investment in a timely fashion would
8 cause FERC to order the Company to cease operation of the facility well before its project
9 license expires.”⁵²

10 **Q. IS THE COMPANY CURRENTLY EVALUATING THE FUTURE OF ITS HYDRO**
11 **FACILITIES?**

12 A. Yes. The Company is currently evaluating its long-term strategy for its River Hydro
13 facilities, and will present the Commission a retirement and decommissioning study by
14 the end of 2024, as required by the settlement agreement in Case No. U-20849.⁵³
15 However, despite its ongoing study and the long-term uncertainty surrounding the River
16 Hydro facilities, the Company is proposing to spend \$42.4 million in the BP and \$92.3
17 million in the TY on River Hydro investments.⁵⁴ The Company notes that, during its study,
18 it is considering the following four options for each of its 13 dams: (a) relicensing and
19 continuing to generate electricity, (b) selling the dam to a third party, (c) removing the

⁵¹ *Id.*, at 22:7-8. (*Emphasis added*)

⁵² *Id.*, at 22:13-15 (*Emphasis added*)

⁵³ Direct Testimony of Heidi Myers at 15:4-6.

⁵⁴ Direct Testimony of Adam Monroe, Exhibit A-190 (TPC-8).

1 dam, and (e) replacing the dam with an alternative structure that maintains some level of
2 reservoir.⁵⁵

3 **Q. DID THE FINAL ORDER IN CASE NO. U-21389 ADDRESS THE COMPANY'S**
4 **PROPOSED HYDRO INVESTMENTS?**

5 A. Yes. In the final order in case U-21389 the Company agreed with staff to disallow
6 \$1.96 million to the Hardy Dam project for the test year.⁵⁶ The Commission also warned
7 that the "total estimated costs are significant and this is an asset that may not be providing
8 generation in the not-so-distant future."⁵⁷ The Commission directed Consumers to
9 provide a full evaluation of alternative options for the Hardy Dam given the uncertainty of
10 possible decommissioning.⁵⁸ Regarding the Alcona and Rogers dam projects the
11 Commission agreed with ABATE and the AG to disallow the costs for these projects. This
12 includes a total of \$8.63 million for the Rogers dam and \$3.3 million for the Alcona dam.⁵⁹
13 The Commission noted that Consumers "did not show that these two projects are far
14 enough along to warrant rate base treatment".⁶⁰

15 **Q. PLEASE DISCUSS YOUR PROPOSED ADJUSTMENTS FOR THE HYDRO**
16 **FACILITY CAPITAL EXPENDITURES.**

17 A. The fact that the Company is currently studying the future of its River Hydro
18 investments clearly indicates that there is some uncertainty regarding the need for these
19 investments.⁶¹ Because of the uncertainty surrounding the future of the River Hydro
20 facilities I recommend that the Commission remove from the Company's revenue

⁵⁵ *Id.*, at 12:10-14.

⁵⁶ Order, MPSC Case No. U-21389, March 1, 2024.

⁵⁷ Order, MPSC Case No. U-21389, March 1, 2024, pg. 66.

⁵⁸ Order, MPSC Case No. U-21389, March 1, 2024, pg. 67.

⁵⁹ Order, MPSC Case No. U-21389, March 1, 2024, pg. 70.

⁶⁰ *Id.*

⁶¹ *See*, Direct Testimony of Adam Monroe at 14:8-13.

1 requirement all \$134.6 million in projected capital expenditures associated with the River
2 Hydro investments.

3 **C. Battery Energy Storage Systems**

4 **Q. PLEASE BRIEFLY DESCRIBE THE ARMSTRONG BESS PROJECT.**

5 A. The Armstrong BESS project is a 2.5 MW battery located in Calhoun County.⁶²
6 The Company has secured a 30-year easement for the property on which the BESS will
7 be placed. Given the delay in of certain studies being conducted, the battery procurement
8 has been delayed until 2024.⁶³ The Armstrong BESS project is expected to be finished in
9 2026. In case U-21389 the final commissioning was scheduled to be late 2025.⁶⁴

10 **Q. HAS THE ARMSTRONG BESS PROJECT EXPERIENCED DELAYS?**

11 A. Yes. The Armstrong BESS, besides functioning as a generation resource, is
12 designed to provide insights into the potential to use localized battery systems to restore
13 power quickly during outage events while upstream faults are cleared, and thus is
14 designed with a protection system capable of operating under normal and reduced fault
15 current scenarios.⁶⁵ The Company had anticipated that a protection study (i.e. study
16 concerning the ability of Armstrong BESS to operate under reduced fault currents)
17 conducted by Schweitzer Engineering Laboratories (“SEL”) would be completed by
18 October 2023;⁶⁶ however, the study did not officially conclude until the end of March
19 2024.⁶⁷ This delay also delayed battery procurement activities according to the
20 Company.⁶⁸ The Company had originally projected to spend \$1.53 million for the bridge

⁶² Direct Testimony of Thomas P. Clark at 51:12-13.

⁶³ *Id.*, at 51:21-52:2.

⁶⁴ MPSC Case No. U-21389, Direct Testimony of Thomas P. Clark at 49:6-7.

⁶⁵ Direct Testimony of Thomas P. Clark at 51:14-19.

⁶⁶ *Id.*, at 54:7-10.

⁶⁷ *Id.*, at 52:5.

⁶⁸ *Id.*, at 52:7-10.

1 period January 1, 2023 to February 28, 2024 but in fact only spent \$258,304 due to delays
2 in the protection study.⁶⁹ The Company now projects a total of \$3.9 million for the current
3 BP and \$4.9 million in the TY.⁷⁰

4 **Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING COST RECOVERY OF**
5 **THE ARMSTRONG BESS PROJECT?**

6 A. Given the significant delays already associated with this project I recommend the
7 commission exclude all of the \$8.8 million associated with the Armstrong BESS Project
8 since it is now not anticipated to be used and useful by the end of the projected TY. Based
9 on information provided by the Company, the Armstrong BESS Project is currently still in
10 the development phase with an expected commercial operation date of June 2026, or
11 four months after the conclusion of the projected TY.⁷¹

12 **Q. PLEASE BRIEFLY DESCRIBE THE IOSCO BESS PROJECT.**

13 A. The losco BESS project is a 30 MW lithium-ion battery storage system. It is being
14 developed as part of the 2021 IRP settlement. The Company is projected to spend \$15.6
15 million in the BP and \$29.9 million in the TY.⁷²

16 **Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING COST RECOVERY OF**
17 **THE IOSCO BESS PROJECT?**

18 A. I recommend that the Commission exclude the \$15.6 million in the BP and \$29.9
19 million in the TY. Based on information provided by the Company, the losco BESS Project

⁶⁹ *Id.*, at 54:6-12.

⁷⁰ *Id.*, at 54, Table 11.

⁷¹ Exhibit AG-2.4 - Discovery Response AG-CE-0561.

⁷² Direct Testimony of Thomas P. Clark at 48:8-10.

1 is currently still in the development phase with an expected commercial operation date of
2 June 2026, or four months after the conclusion of the projected TY.⁷³

3 **Q. PLEASE BRIEFLY DESCRIBE THE WEADOCK BESS PROJECT.**

4 A. The Weadock BESS project is a 45 MW lithium-ion battery storage project located
5 in Bay County. It is being developed as part of the 2021 IRP settlement. This system is
6 being set up to be interconnected at the Weadock substation which is a high voltage
7 distribution system.⁷⁴ The Company states this project will provide localized grid support
8 as well as provide data regarding reliability and resiliency.⁷⁵ The Company is projected
9 to spend \$19.8 million in the BP and \$44.2 million in the TY.⁷⁶

10 **Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING COST RECOVERY OF**
11 **THE WEADOCK BESS PROJECT?**

12 A. I recommend that the Commission exclude the \$19.8 million in the BP and \$44.2
13 million in the TY. Based on information provided by the Company, the Weadock BESS
14 Project is currently still in the development phase with an expected commercial operation
15 date of June 2026, or four months after the conclusion of the projected TY.⁷⁷

16 **D. New Service Center Construction and Building Renovations**

17 **Q. PLEASE BRIEFLY DESCRIBE THE LANSING SERVICE CENTER**
18 **CONSTRUCTION PROJECT AND ITS PROGRESS.**

19 A. The Lansing Service Center (“LSC”) project, which received support from the
20 Commission in Case No. U-20963, involves construction of a new service center in a new

⁷³ Exhibit AG-2.4 - Discovery Response AG-CE-0561.

⁷⁴ Direct Testimony of Thomas P. Clark at 45:13-14.

⁷⁵ *Id.*, at 45:15-17.

⁷⁶ *Id.*, at 46, Table 10.

⁷⁷ Exhibit AG-2.4 - Discovery Response AG-CE-0561.

1 location to replace the existing service center, which was built in 1958.⁷⁸ The LSC project
2 has been delayed due to supply chain and labor issues resulting from the COVID-19
3 pandemic.⁷⁹ During the delay, the Company reconfigured the project, recognizing that
4 savings could be secured by using hybrid work arrangements. This reconfiguration has
5 resulted in a changed spend plan since the Commission's order in Case No, U-20963.
6 The Company now estimates the total project cost to be \$47.3 million (versus the previous
7 estimate of \$54.8 million)⁸⁰ and projecting to spend \$3.4 million in the BP and \$14.0
8 million in the projected TY.⁸¹

9 **Q. WILL THE PROPOSED LSC PROJECT BE COMPLETED BY THE END OF THE**
10 **PROJECTED TY?**

11 A. No. The projected completion of this project is currently set for fourth quarter
12 2026.⁸² As mentioned above the original total cost for this project was \$54.8 million with
13 a completion date of 2023.⁸³ Indeed, it appears that the Company only anticipates that it
14 will have spent approximately \$17.4 million of the total anticipated \$47.3 million, or
15 approximately 37 percent, by the end of the projected TY.⁸⁴

16 **Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE CAPITAL**
17 **EXPENDITURES ASSOCIATED WITH THE LSC PROJECT?**

18 A. Yes. Due to the uncertainty surrounding the timing and amount of the capital
19 expenditures forecasted for a project that has already experienced significant delays and

⁷⁸ MPSC Case No. U-21389, Direct Testimony of Quentin Guinn at 21:9-12.

⁷⁹ MPSC Case No. U-21389, Direct Testimony of Quentin Guinn at 27:13-14.

⁸⁰ Note that the Company allocates 54 percent of the project's costs to the Company's electric business and 46 percent to the Company's gas business. See, Direct Testimony of Quentin Guinn at 26:18-21.

⁸¹ Direct Testimony of Quentin Guinn at 22:13-14.

⁸² Exhibit AG-2.5 - Discovery Response U21585-AG-CE-0563.

⁸³ Direct Testimony of Quentin A. Guinn, Exhibit A-82 (QAC-3).

⁸⁴ *Id.*

1 is still in its design phase, the projected costs are not known and measurable. Because
2 the projected costs are not known and measurable and because the project will not be
3 used and useful within the projected TY, I recommend the Commission remove \$17.4
4 million in projected capital expenditures associated with the LSC project from the
5 Company's revenue requirement.

6 **Q. WAS A PORTION OF THE LSC PROJECT INCLUDED IN PRIOR COMPANY**
7 **RATE CASES?**

8 A. Yes. As mentioned previously, the LSC Project was originally outlined in a prior
9 Company's rate case, Case No. U-20963. In that case the Company proposed to spend
10 \$2.2 million a 2021 bridge year and \$13.6 million in a 2022 projected test year.⁸⁵
11 However, since Case No. U-20963 the Company has reevaluated its plans for the LSC
12 project and experienced delays due to supply chain and labor issues stemming from the
13 Covid-19 pandemic.⁸⁶ In actuality, the Company only incurred \$311,000 in capital
14 investments associated with the LSC project in 2022.⁸⁷ Concurrently, in Case No. U-
15 21389 the company projected to spend \$3.7 million in the BP (14 months ending Feb.
16 2024) and \$6.4 million in the TY (12-months ending Feb. 2025).⁸⁸ The Company only
17 spent \$1.7 million in the 2023 historic year.

18 **Q. PLEASE BRIEFLY DESCRIBE THE HASTINGS SERVICE CENTER**
19 **CONSTRUCTION PROJECT AND ITS PROGRESS.**

20 A. The Company is planning on constructing a new Hasting Service Center ("HSC")
21 at the existing service center location to include an adjacent property the Company is

⁸⁵ MPSC Case No. U-21389, Direct Testimony of Quentin A. Guinn at 26:18-21.

⁸⁶ *Id.*, at 27:13-17.

⁸⁷ Exhibit AG-2.6 - MPSC Case No. U-21389, Direct Testimony of Quentin A. Guinn, Exhibit A-96 (QAG-3).

⁸⁸ MPSC Case No. U-21389, Direct Testimony of Quentin Guinn at 26:5-6.

1 negotiating to purchase from the landowner.⁸⁹ However, an agreement for a property
2 transfer with the adjacent landowner was not initially reached, so the Company entered
3 into negotiations with another landowner, the Barry County Road Commission, to
4 purchase a different adjacent property to the existing service center.⁹⁰ The Company
5 recently received approval from the Barry County Road Commission for the conceptual
6 plan for development of the HSC, and now expects commercial operations to begin in the
7 fourth quarter of 2026.⁹¹

8 **Q. WILL THE PROPOSED HSC PROJECT BE COMPLETED BY THE END OF THE**
9 **PROJECTED TY?**

10 A. No. As mentioned above, the HSC project has been delayed due to issues in
11 negotiating property transfers from an existing landowner. While this appears to now be
12 resolved, these delays have pushed the expected commercial operations of the new HSC
13 into the fourth quarter of 2026.⁹²

14 **Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE CAPITAL**
15 **EXPENDITURES ASSOCIATED WITH THE HSC PROJECT?**

16 A. Yes. Due to the uncertainty surrounding the timing and amount of the capital
17 expenditures forecasted for a project that has already experienced delays, the projected
18 costs are not known and measurable. Because the projected costs are not known and
19 measurable and because the project will not be used and useful within the projected TY,
20 I recommend the Commission remove the full \$136,000 in projected capital expenditures

⁸⁹ Direct Testimony of Quentin Guinn at 23:15-17.

⁹⁰ *Id.*, at 25:4-14.

⁹¹ Exhibit AG-2.5 - Discovery Response AG-CE-0563.

⁹² *Id.*

1 associated with initial investments in the HSC project from the Company's revenue
2 requirement for the current filing.⁹³

3 **Q. PLEASE BRIEFLY DESCRIBE THE KALAMAZOO SERVICE CENTER**
4 **RENOVATION PROJECT AND ITS PROGRESS.**

5 A. The Kalamazoo Service Center ("KSC") project involves the renovation of the
6 existing KSC in order to replace aging building systems, conduct environmental
7 remediation, and reconfigure workspaces.⁹⁴ Since receiving support from the
8 Commission in Case No. U-20963, the project's spend plan has changed, with the
9 Company now estimating a total project cost of \$35 million (versus \$52 million initially)
10 and projected spending of \$4.8 million in the BP and \$9.4 million in the projected TY.⁹⁵

11 **Q. WILL THE PROPOSED KSC PROJECT BE COMPLETED BY THE END OF THE**
12 **PROJECTED TY?**

13 A. No. The revamped KSC project is still in its design phase.⁹⁶ Therefore, there
14 remains significant uncertainty regarding the timing and amount of capital expenditures
15 associated with the KSC project. Indeed, the Company anticipates only approximately
16 \$14.2 million of the total anticipated \$35 million will be encumbered by the end of the
17 projected TY.⁹⁷

18 **Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE CAPITAL**
19 **EXPENDITURES ASSOCIATED WITH THE KSC PROJECT?**

⁹³ Direct Testimony of Quentin Guinn at 26:20-21.

⁹⁴ *Id.*, at 42:12-18.

⁹⁵ *Id.*, at 43:20-21 and 43:7-10.

⁹⁶ *Id.*, at 31:2-5.

⁹⁷ Direct Testimony of Quentin Guinn, Exhibit A-82 (QAG-3).

1 A. Yes. Due to the uncertainty surrounding the timing and amount of capital
2 expenditures that will be incurred for a project that has already experienced delays and
3 is still in its design phase, I recommend the Commission remove all \$14.2 million in
4 projected capital expenditures associated with the KSC project from the Company's
5 revenue requirement, as these costs are not known and measurable.

6 **Q. PLEASE BRIEFLY DESCRIBE THE PROPOSED CONTROL/DISPATCH**
7 **CENTER CONSOLIDATION PROJECT.**

8 A. A new consolidated Control/Dispatch Center was approved by the Commission in
9 the Company's last rate case, Case No. U-21389.⁹⁸ The Company's plans for a
10 consolidated Control/Dispatch Center is designed to improve organizational effectiveness
11 and efficiency, communications, outage response and restoration costs by consolidating
12 the current electric Dispatch, Distribution Control, and System Control Centers into a
13 single primary operating center with a remote backup center.⁹⁹ As part of this overall
14 consolidation, the Company proposes to renovate the Company's existing facilities for a
15 total cost of \$14.8 million.¹⁰⁰

16 **Q. WILL THE PROPOSED CONTROL/DISPATCH CENTER CONSOLIDATION**
17 **PROJECT BE COMPLETED BY THE END OF THE PROJECTED TY?**

18 A. No. The proposed Control/Dispatch Center renovation project has only recently
19 completed conceptual designs, with the Company still preparing to bid design/engineering

⁹⁸ Order, MPSC Case No. U-21389, March 1, 2024, pg. 176.

⁹⁹ MPSC Case No. U-21389, Direct Testimony of Brenda L. Houtz at 25:21-25.

¹⁰⁰ Direct Testimony of Andrew R. Snider at 24:8-10.

1 services for the project.¹⁰¹ Because of this, the Company does not anticipate the
2 renovations to be complete until the third quarter of 2026.¹⁰²

3 **Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE CAPITAL**
4 **EXPENDITURES ASSOCIATED WITH THE PROPOSED CONTROL/DISPATCH**
5 **CENTER CONSOLIDATION PROJECT?**

6 A. Yes. Due to the uncertainty surrounding the timing and amount of the capital
7 expenditures forecasted for a project that is still in the design phase, the projected costs
8 are not known and measurable. Because the projected costs are not known and
9 measurable and because the project will not be used and useful within the projected TY,
10 I recommend the Commission remove \$10.5 million in projected capital expenditures
11 associated with the proposed Control/Dispatch Center Consolidation project from the
12 Company's revenue requirement.

13 **VI. CONCLUSIONS AND RECOMMENDATIONS**

14 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

15 A. A summary of my proposed recommendations is provided in Exhibit AG-2.1. In
16 sum, I recommend \$525.5 million in projected capital expenditures associated with solar
17 projects be removed from the Company's proposed revenue requirement calculations. I
18 also recommend the following additional amounts of capital expenditures be removed
19 from the Company's revenue requirement calculation: \$134.6 million in capital
20 expenditures associated with Hydro projects; \$118.6 million in capital expenditures
21 associated with Battery Storage projects; \$17.5 million in capital expenditures associated
22 with new operational support construction; and \$24.7 million in capital expenditures

¹⁰¹ Exhibit AG-2.7 - Discovery Response U-21585-AG-CE-0564.

¹⁰² *Id.*

1 associated with operational support renovations. Specifically, I recommend the following
2 proposed adjustments and actions be taken by the Commission in this proceeding:

3 • Removal of \$24.2 million in projected capital expenditures associated with the
4 Washtenaw Solar project. The amount and timing of the capital expenditures are
5 not fully known and measurable.

6 • Removal of \$270.3 million in projected capital expenditures associated with the
7 Muskegon Solar project. The amount and timing of the capital expenditures are
8 not fully known and measurable.

9 • Removal of \$231.0 million in projected capital expenditures associated with the
10 Spring Creek Solar project. The amount and timing of the capital expenditures are
11 not fully known and measurable.

12 • Removal of the \$134.6 million projected capital expenditures associated with
13 proposed hydroelectric projects. The amount and timing of the capital
14 expenditures are not fully known and measurable.

15 • Removal of the \$118.6 million projected capital expenditures associated with an
16 unnamed Battery Storage project. The amount and timing of the capital
17 expenditures are not fully known and measurable.

18 • Removal of the \$17.4 million projected capital expenditures associated with the
19 Lansing Service Center project. The amount and timing of the capital expenditures
20 are not known and measurable.

21 • Removal of the \$0.1 million projected capital expenditures associated with the
22 Hastings Service Center project. The amount and timing of the capital
23 expenditures are not known and measurable.

24 • Removal of the \$14.2 million projected capital expenditures associated with the
25 Kalamazoo Service Center project. The amount and timing of the capital
26 expenditures are not known and measurable.

27 • Removal of the \$10.5 million projected capital expenditures associated with
28 renovations to the Company's Control/Dispatch Center. The amount and timing of
29 the capital expenditures are not known and measurable.

30 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

31 A. Yes.

Michael William Deupree
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Acadian Consulting Group
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Baton Rouge, LA 70808

EDUCATION

M.A. in Economics, Kansas University, 2009

B.A. in Business Economics, Buena Vista University, 2007

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

Summer 2021 – Present	Research Consultant
Summer 2016 – Summer 2021	Research Associate
Winter 2011 – Summer 2016	Senior Research Analyst

Utilities Division - Kansas Corporation Commission, Topeka, Kansas

Summer 2011 – Winter 2011	Senior Research Economist
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Research Division – Kansas Corporation Commission, Topeka, Kansas

Spring 2009 – Summer 2011	Research Analyst
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Kansas Energy Council – Kansas Corporation Commission

Summer 2008 – Spring 2009	Research Assistant
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PUBLICATIONS AND REPORTS

1. The challenges of the regulatory review of diversification mergers. With Dr. David E. Dismukes. *The Electricity Journal* 29 (2016) 8-14. (May 2016)

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Report. *Review of LPSC Rules Regarding Distributed Generation: Report on Phase II of Rule-Making*. Docket No. R-33929. (2019). *In Re: Review of Policies Related to Customer-owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules*. On behalf of Louisiana Public Service Commission.
2. Expert Report. (2011). *2011 Kansas Generation Planning Survey*. On behalf of the Kansas Corporation Commission Staff.
3. Expert Testimony. Docket No. 11-KCPE-581-PRE. (2011). Before the Kansas Corporation Commission. *In the Matter of the Petition of Kansas City Power &*

- Light Company ("KCP&L") for Determination of the Ratemaking Principles and Treatment That Will Apply to the Recovery in Rates of the Costs to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239. On Behalf of the Kansas Corporation Commission Staff. Issues: System Planning, Predetermination.*
4. Expert Testimony. Docket No. 10-KCPE-795-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas City Power & Light Company for Approval to Implement a Portfolio of Demand Side Management Programs Including Affordability, Energy Efficiency, Demand Response and Educational Programs, and to Implement a Rider for Recovery of Program Costs and Incentives Associated with this Portfolio.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.
 5. Expert Testimony. Docket No. 10-WSEE-775-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for an Order Authorizing them to participate in Efficiency Kansas, Approve the SimpleSavings Program Rider, and related cost recovery.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.
 6. Expert Testimony. Docket No. 10-BHCG-639-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Black Hills/Kansas Gas Utility Company, LLC, d/b/a Black Hills Energy for Approval to Implement Black Hills Energy's Five-Year Energy Efficiency Plan Consisting of Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate About Efficient Energy Usage, to Provide for Program Cost Recovery Through a Rider Mechanism, Permit the Implementation of a Revenue Normalization Mechanism to Replace the Weather Normalization Adjustment, a Performance Incentive Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.
 7. Expert Testimony. Docket No. 10-EPDE-497-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of the Empire District Electric Company for Approval to Implement its Portfolio of Energy Efficiency and Demand Response Programs for its Kansas Customers, to Provide for Program Cost Recovery and Lost Revenue Through a Rider Mechanism, to Obtain any Necessary Waivers for the Commission, and for Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.
 8. Expert Testimony. Docket No. 10-KGSG-421-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas Gas Service,*

a Division of ONEOK, Inc., for Approval to Implement the Efficiency Kansas Energy Efficiency Program, to Implement Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate about Efficient Energy Usage, To Provide for Program Cost Recovery Through a Rider Mechanism, to Establish Administrative Charges and a Program Initiation Fee, Permit the Implementation of a Revenue Decoupling Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing. On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

Table of Exhibits

Witness Deupree
Case No. U-21585

Title	Exhibits
Total Capital Expenditure Adjustments	Exhibit AG-2.1
Discovery Response U-21585-AG-CE-0560	Exhibit AG-2.2
Discovery Response U-21585-ST-CE-0019	Exhibit AG-2.3
Discovery Response U-21585-AG-CE-0561	Exhibit AG-2.4
Discovery Response U-21585-AG-CE-0563	Exhibit AG-2.5
MPSC Case No. U-21389, Exhibit A-96 (QAG-3)	Exhibit AG-2.6
Discovery Response U-21585-AG-CE-0564	Exhibit AG-2.7

Total Capital Expenditure Adjustments

Witness Deupree
Case No. U-21585
Exhibit AG-2.1

	Bridge Period Adjustments			Test Year Adjustments	Total Adjustments	Source
	12 months ending 12/31/2024	2 months ending 2/28/2025	14 months ending 2/28/2025	Incremental 12 months ending 2/28/2026	12 months ending 2/28/2026	
Capital Adjustments	----- (\$ Thousands) -----					
Generation (Solar, Hydro, Battery Storage)						
Washtenaw Solar Project	-	-	-	24,233	24,233	A-190 (TPC-8)
Muskegon Solar Project	-	-	141,387	128,907	270,294	A-190 (TPC-8)
Spring Creek Solar Project	-	-	108,185	122,819	231,004	A-190 (TPC-8)
Hydro Facilities	38,052	4,324	42,376	92,258	134,634	A-12 (RTB-3)
Battery Storage	39,672	-	39,672	78,921	118,593	A-12 (RTB-3)
Total Generation (Solar, Hydro, Battery Storage)	\$ 77,724	\$ 4,324	\$ 331,620	\$ 447,138	\$ 778,758	
Operational Support						
<u>New Construction</u>						A-82 (QAG-3)
Lansing Service Center	2,151	1,254	3,405	13,967	17,372	A-82 (QAG-3)
Hastings Service Center	136	-	136	-	136	A-82 (QAG-3)
<u>Renovations</u>						A-82 (QAG-3)
Kalamazoo Service Center	3,973	842	4,815	9,424	14,239	A-82 (QAG-3)
Control/Dispatch Center	4,400	503	4,903	5,570	10,473	A-82 (QAG-3)
Total Operational Support	\$ 10,660	\$ 2,599	\$ 13,259	\$ 28,961	\$ 42,220	
Total	\$ 88,384	\$ 6,923	\$ 344,879	\$ 476,099	\$ 820,978	

U21585-AG-CE-0560
Page 1 of 3

Question:

224. Please refer to the Direct Testimony of Thomas P. Clark at 14:2-7, where Witness Clark discusses delays to Company-owned solar projects due to local permitting issues, interconnection timelines, or supply chain constraints.

- a. Please provide an update on the current status of the Company's Mustang Mile Solar Project, including the status of permits/litigation, agreements with third party contractors, and interconnection issues, and the currently expected commercial operations date.
- b. Please provide an update on the current status of the Company's Washtenaw Solar Project, including the status of permits/litigation, agreements with third party contractors, and interconnection issues, and the currently expected commercial operations date.
- c. Please provide an update on the current status of the Company's Muskegon Solar Energy Center Project, including the status of permits/litigation, agreements with third party contractors, and interconnection issues, and the currently expected commercial operations date.
- d. Please provide an update on the current status of the Company's Spring Creek Solar Project, including the status of permits/litigation, agreements with third party contractors, and interconnection issues, and the currently expected commercial operations date.

Response:

- a. **Mustang Mile Current Status:** As discussed on pages 29-30 of my direct testimony, this project is presently in the development phase, contingent upon the outcomes of ongoing litigation.

Permits/Litigation: As discussed on pages 30-31 of my direct testimony, Mustang Mile is currently delayed due to several legal challenges. The building permit dispute is currently awaiting the Court of Appeals' decision on the application for leave to appeal. The SLUP appeal is also before the Court of Appeals, with a decision expected from a three-judge panel. Additionally, the Civil Case is pending the scheduling of a hearing date by the Court of Appeals.

Agreements with third party contractors: This Project is being delivered by Invenergy via a Milestone Build Transfer Agreement. The MBTA is fully executed.

Interconnection Issues: Fully executed Generator Interconnect Agreement.

Expected Commercial Operation Date: TBD pending conclusion of litigation.

- b. **Washtenaw Solar Current Status:** As discussed on pages 32-33 of my direct testimony, this project is presently in the development phase.

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Page 2 of 3

Permits/Ligation: No permits have been submitted due to the changes in the local ordinance which require significant additional land acquisition. Land acquisition activities are still ongoing. No litigation is currently underway.

Agreements with third party contractors: This Project is being delivered by Invenergy via a Milestone Build Transfer Agreement. The MBTA is fully executed.

Interconnection Issues: Fully executed Generator Interconnect Agreement.

Expected Commercial Operation Date: TBD pending land acquisition and/or State Siting process.

- c. **Muskegon Solar Current Status:** As discussed on pages 34-35 of my direct testimony, this project is currently in the execution phase.

Permits/Ligation: All necessary permits required to begin construction have been approved and are in effect.

Agreements with third party contractors: As discussed on page 36 of my direct testimony, all major contracts have been fully executed and are provided as Exhibits A-185 (TPC-3), Exhibit A-187 (TPC-5) and Exhibit A-189 (TPC-7)

Interconnection Issues: The Generator Interconnection Agreement is fully executed, however, the MISO DPP-2020 Study Cycle took 367 days longer than indicated by MISO at study kickoff. This resulted in a one-year delay in interconnection of the Muskegon Solar project. As a result, Muskegon Solar's COD was delayed from 12/31/2024 to 12/31/2025. The MISO DPP-2020 Study Cycle took a total of 926 days to complete. At the time of the DPP-2020 Study Kickoff, MISO estimated a total of 559 days to complete.

Expected Commercial Operation Date: 12/31/2025

- d. **Spring Creek Current Status:** As discussed on page 38 of my direct testimony This project is presently in the execution phase.

Permits/Ligation: Most permits have been received or are expected soon. A Special Land Use Permit application has been submitted to Barry County with approval expected in September. A Conditional Use Permit application is planned to be filed with Bedford Charter Township later this fall.

Agreements with third party contractors: As discussed on page 39 of my direct testimony, all major contracts have been fully executed and are provided as Exhibits A-193 (TPC-11), Exhibit A-195 (TPC-13) and Exhibit A-197 (TPC-15).

Interconnection Issues: Spring Creek Solar is assigned J2815 in the MISO DPP-2022 Study Cycle. The MISO DPP-2022 Study Cycle is in Phase 1. Delays in the study cycle are expected to delay the execution

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Page 3 of 3

of a Generator Interconnection Agreement, however, the Company has executed an Engineering and Procurement agreement with Internation Transmission Company to allow for interconnection facilities to be designed and major equipment to be procured to enable interconnection in a timely manner.

Expected Commercial Operation Date: 6/1/2026

Witness: THOMAS P CLARK
Date: September 10, 2024

U21585-ST-CE-0019

Page 1 of 1

Question:

7. What is the current state of the Muskegon solar project? Has the Company completed all engineering design and long-lead material procurement? Is there any additional permitting necessary for construction or operation? Has construction begun?

Response:

The Muskegon Solar project is currently in active construction. The Company has completed approximately 75% of engineering with a targeted completion of all engineering by the end of October 2024. All long lead materials have been procured. The Company and their agent, Burns and McDonnell, have obtained all known permits for construction besides one permit from generation tie line construction. Construction of the Muskegon Solar facility has commenced.

Witness: THOMAS P CLARK

Date: July 16, 2024

U21585-AG-CE-0561
Page 1 of 2

Question:

225. Please refer to the Direct Testimony of Thomas P. Clark at 45:6-11, where Witness Clark discusses Company-owned Battery Energy Storage System (“BESS”) projects.

- a. Please provide an update on the current status of the Company’s Weadock BESS, including the status of permits/litigation, agreements with third party contractors, and interconnection issues, and the currently expected commercial operations date.
- b. Please provide an update on the current status of the Company’s Iosco BESS, including the status of permits/litigation, agreements with third party contractors, and interconnection issues, and the currently expected commercial operations date.
- c. Please provide an update on the current status of the Company’s Armstrong BESS, including the status of permits/litigation, agreements with third party contractors, and interconnection issues, and the currently expected commercial operations date.

Response:

- a. **Weadock BESS Current Status:** This project is presently in the development phase.

Permits/Litigation: No permits have been started and there is no pending litigation.

Agreements with third party contractors: Consumers Energy has executed three major contracts. A Battery Supply Purchase Agreement with Our Next Energy, an Engineering, Procurement, and Construction Agreement with Rauhorn Electric, both of which were provided in response to discovery question U-21585-AG-CE-0189

The Generator Step Up Main Power Transformer purchase agreement with Virginia Transformer Company is discussed on page 46 of my direct testimony, and provided as Exhibit A-200 (TPC-18).

Interconnection Issues: The Interconnection Facilities Study has been completed (INT-15007) and an Interconnect Agreement is being finalized.

Expected Commercial Operation Date: 6/2026

- b. **Iosco BESS Current Status:** This project is presently in the development phase.

Permits/Litigation: No permits have been started and there is no pending litigation.

Agreements with third party contractors: Consumers Energy has executed three major contracts. A Battery Supply Purchase Agreement with Our Next Energy, an Engineering, Procurement, and Construction Agreement with Rauhorn Electric, both of which were provided in response to discovery

U21585-AG-CE-0561
Page 2 of 2

question U-21585-AG-CE-189. The Generator Step Up Main Power Transformer purchase agreement with Virginia Transformer Company is discussed on page 48 of my direct testimony, and provided as Exhibit A-203 (TPC-21).

Interconnection Issues: The Interconnection Facilities Study has been completed (INT-15004) and an Interconnect Agreement is being finalized.

Expected Commercial Operation Date: 6/2026

c. **Armstrong BESS Current Status:** This project is presently in the development phase.

Permits/Ligation: No permits have been started and there is no pending litigation.

Agreements with third party contractors: Consumers Energy is negotiating contracts for this project.

Interconnection Issues: The Interconnection System Impact Study has commenced, and the Interconnection Facilities Study will begin shortly after it is completed.

Expected Commercial Operation Date: 6/2026

Witness: THOMAS P CLARK
Date: September 10, 2024

U21585-AG-CE-0563

Page 1 of 1

Question:

227. Please refer to the Direct Testimony of Quentin A. Guinn at 15:17-20, where Witness Guinn identifies new construction projects at the Company's Lansing and Hasting Service Centers.

- a. Please provide an update on the current status of the Company's Lansing Service Center, including the status of permits/litigation, agreements with third party contractors, and the currently expected commercial operations date.
- b. Please provide an update on the current status of the Company's Hasting Service Center, including the status of permits/litigation, agreements with third parties, and the currently expected commercial operations date.

Response:

- a. Commercial operations for the Lansing Service Center Project are expected to begin in the fourth quarter of 2026. The Company has executed third party contracts and begun work with a general construction contractor and architect / engineering firm. The Company is preparing to order pre-engineered building materials for construction of the Lansing Service Center Project. Site plan approvals for the Lansing Service Center Project are in process and the Company is preparing to submit for appropriate building permits.
- b. The Company has received approval from the Barry County Road Commission for the Company's conceptual plan for development of the parcel on which the Hastings Service Center Project will be constructed. The Company is currently completing acquisition of this parcel from the Barry Road Commission. An expected commercial operations date for the Hastings Service Center Project will be established once the Company engages an architect / engineering firm for design of the project.

Witness: Quentin A. Guinn

Date: September 9, 2024

MPSC Case No. U-21389, Exhibit A-96 (QAG-3)

Witness Deupree
Case No. U-21585
Exhibit AG-2.6

Michigan Public Service Commission
Consumers Energy Company
Detailed List of Projected Electric Capital Expenditures
Operations Support
(000's)

Case No: U-21389
Exhibit No: A-96 (QAG-3)
Page: 1 of 3
Witness: QAGuinn
Date: May 2023

Line No	Historical Year	Projected Bridge Period			Projected Test Year	
		12 Mos Ended 12/31/2022	12 Mos Ended 12/31/2023	2 Mos Ending 2/29/2024		14 Mos Ending 2/29/2024
	Electric	Electric	Electric	Electric	Electric	
1	<u>Other Equipment</u>	<u>862</u>	<u>671</u>	<u>-</u>	<u>671</u>	<u>690</u>
2	Wellness Equip	98	51	-	51	52
3	Computer Equipment	18	17	-	17	17
4	Print Equipment	-	43	-	43	44
5	Real Estate Tools & Equipment	18	10	-	10	10
6	Supply Chain Tools & Equipment	727	507	-	507	522
7	Facilities Tools	-	43	-	43	43
8	<u>Emergent Repairs</u>	<u>1,523</u>	<u>1,932</u>	<u>152</u>	<u>2,084</u>	<u>1,856</u>
9	Asset Preservation - Unplanned Repair	1,523	1,932	152	2,084	1,856
10	<u>Asset Replacement</u>	<u>16,020</u>	<u>9,949</u>	<u>958</u>	<u>10,906</u>	<u>10,998</u>
11	Statewide Paving	3,755	1,998	107	2,105	1,327
12	Statewide Roofing	6,533	1,576	295	1,872	3,366
13	Statewide Mechanical/Electrical	3,846	5,107	342	5,449	3,975
14	Statewide Elevators	1,318	1,091	30	1,121	365
15	Marshall Roadway Paving	26	40	171	211	1,829
16	Furniture	541	136	12	147	136
17	<u>New Construction</u>	<u>3,054</u>	<u>3,760</u>	<u>684</u>	<u>4,443</u>	<u>8,539</u>
18	Lansing Service Center	311	3,146	523	3,669	6,402
19	Hastings Service Center	3	543	37	580	815
20	Greenville Cold Storage Building	-	-	27	27	289
21	Ludington Cold Storage Bldg	-	50	96	146	1,032
23	Hardy Headquarter Building	2,740	21	-	21	-
24	<u>Renovations</u>	<u>5,017</u>	<u>5,980</u>	<u>1,603</u>	<u>7,583</u>	<u>13,690</u>
25	Kalamazoo Service Center	182	848	452	1,300	5,513
26	Pamall Renovations (P1-3)	2,715	214	-	214	-
27	Jackson Dispatch	292	543	-	543	-
29	Midland Building	85	-	-	-	-
30	Grand Rapids LVD-UG	1,545	1,386	-	1,386	-
31	Control/Dispatch Center	81	1,551	903	2,454	5,500
32	South Monroe Interior Renovation	5	200	248	448	2,677
33	EV Infrastructure	113	1,238	-	1,238	-
34	Miscellaneous	<u>1,705</u>	-	-	-	-
35	Total Capital	28,181	22,292	3,397	25,688	35,773

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Question:

228. Please refer to the Direct Testimony of Quentin A. Guinn at 28:1-8, where Witness Guinn identifies renovation projects to Company service and dispatch centers.

- a. Please provide an update on the current status of the Company's Kalamazoo Service Center renovations, including the status of permits/litigation, agreements with third party contractors, and the currently expected commercial operations date.
- b. Please provide an update on the current status of the Company's Jackson Dispatch center renovations, including the status of permits/litigation, agreements with third parties, and the currently expected commercial operations date.
- c. Please provide an update on the current status of the Company's consolidation of control and dispatch, including the status of permits/litigation, agreements with third parties, and the currently expected commercial operations date.
- d. Please provide an update on the current status of the Company's South Monroe renovations, including the status of permits/litigation, agreements with third party contractors, and the currently expected commercial operations date.

Response:

- a. Commercial operations for the Kalamazoo Service Center Project are expected to begin in the third quarter of 2026. The Company has executed third party contracts and begun work with a general construction contractor and architect / engineering firm. Construction and abatement work on the project are underway.
- b. The Jackson Dispatch Center renovations are complete and in commercial operation.
- c. Conceptual design and cost estimates for the Control/Dispatch Center Project are complete. The Company is preparing to bid design / engineering services for the project. Commercial operations for the Control/Dispatch Center Project are currently expected to begin in the third quarter of 2026.
- d. Commercial operations for the South Monroe Renovation Project are expected to begin in the second quarter of 2025. The Company has executed third party contracts for design work with an architect/engineering firm. The Company has also issued a Request for Proposal for construction services, has received bids for construction services, and is currently evaluating and selecting a construction firm from this bid process.

Witness: Quentin A. Guinn

Date: September 9, 2024

PROOF OF SERVICE - U-21585

The undersigned certifies that copies of the *Attorney General's Testimonies and Exhibits of Sebastian Coppola and Michael Deupree* were served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 27th day of September 2024.

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