

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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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.

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MPSC Case No. U-21224

**The Attorney General's Initial Brief**

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## I. Introduction and Overview

The Michigan Department of Attorney General, Special Litigation Division, by and through Celeste R. Gill, Assistant Attorney General, files this Initial Brief on behalf of the Attorney General of Michigan before the Michigan Public Service Commission (“Commission”) to respond to Consumers Energy Company’s (“Consumers Energy,” “Consumers,” “CECo,” or “the Company”) application seeking another rate increase for its electric utility less just months after the Commission granted it a \$34 million rate increase in Case No. U-20963 and less than a year and a half after receiving a \$90 million rate increase in Case No. U-20697.

Consumers Energy’s application seeking an additional \$287.2 million Michigan jurisdictional rate increase for the 12-month period ending December 31, 2023 (“projected test year” or “test year”) was filed on April 28, 2022. As part of its case, Consumers Energy is requesting a return on equity (“ROE”) of 10.25%, an overall rate of return on total rate base of 5.84%<sup>1</sup> and equity ratio of 51.50%.

The Company’s initial proposed rate increase represented an overall increase in base rates of 6.5% and an increase of nearly 6.8%% to residential base rates. The

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<sup>1</sup> Application, p 6 – the Company initially request a \$272 million rate increase (\$266 million jurisdictional), however in rebuttal, the Company increased its revenue deficiency to \$287 million. (Aponte rebuttal).

revised amount increases the rate impact. However, the percentages only tell part of the story. The Company's cost projections in recent rate cases have resulted in excess earnings and returns on equity capital well above authorized levels.

On August 24, 2022, the Attorney General filed the direct testimony of her expert witnesses – Sebastian Coppola and Dr. David Dismukes. The Direct Testimony of Sebastian Coppola, included 170 pages of questions and answers, attached to it was an appendix A with his experience and qualification, and exhibits AG-1.1 through AG-1.39.<sup>2</sup> The exhibits included:

1. Exhibit AG-1.1 DR Response – Inflation factors & U.S. Treasury Rates
2. Exhibit AG-1.2 DR Response – New Services YTD 2022
3. Exhibit AG-1.3 DR Response – Major LVD Projects
4. Exhibit AG-1.4 DR Response – MDOT Project Kalamazoo
5. Exhibit AG-1.5 DR Response – Major HVD Projects
6. Exhibit AG-1.6 DR Response – Zeeland Projects 2023
7. Exhibit AG-1.7 DR Response – Solar Projects
8. Exhibit AG-1.8 DR Response – Avoidable Capital Expenditures
9. Exhibit AG-1.9 DR Response – New Service Centers
10. Exhibit AG-1.10 DR Response – Metro City Project & New Marshal Training Bld.
11. Exhibit AG-1.11 DR Response – IT Projects with No Business Requirements
12. Exhibit AG-1.12 DR Response – IT Server and Storage Equipment

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<sup>2</sup> Coppola, 4 TR 3220 – 3408.

13. Exhibit AG-1.13 Summary Cap Ex, Rate Base and Depreciation Expense
14. Exhibit AG-1.14 Overall Cost of Capital
15. Exhibit AG-1.15 Cost of Common Equity
16. Exhibit AG-1.16 Cost of Common Equity-DCF
17. Exhibit AG-1.17 Cost of Common Equity-CAPM
18. Exhibit AG-1.18 Cost of Common Equity-Risk Premium
19. Exhibit AG-1.19 ROE Decisions by Regulatory Commissions
20. Exhibit AG-1.20 Peer Group Selection Screening
21. Exhibit AG-1.21 Market to Book Ratios
22. Exhibit AG-1.22 Pro-Forma Cash Flow Coverage Ratios
23. Exhibit AG-1.23 DR Response - Moody's May 24, 2022 Report on CEC
24. Exhibit AG-1.24 DR Response – S&P March 30, 2022 Report on CEC
25. Exhibit AG-1.25 DR Response – Moody's May 24, 2021 Report on CEC
26. Exhibit AG-1.26 Values Line Report on Market Volatility vs. Risk
27. Exhibit AG-1.27 O&M Adjustments Summary
28. Exhibit AG-1.28 O&M Adjustments - Distribution Operations
29. Exhibit AG-1.29 O&M Adjustments – Pension and OPEB Expense
30. Exhibit AG-1.30 O&M Adjustments – Health Care Expense
31. Exhibit AG-1.31 DR Response – Distribution Training Expense
32. Exhibit AG-1.32 DR Response – ECAP Expense
33. Exhibit AG-1.33 DR Response – Avoid O&M Expense
34. Exhibit AG-1.34 DR Response – Environmental Management Expense
35. Exhibit AG-1.35 CONF DR Response – Pension and OPEB Discount Rates, etc.
36. Exhibit AG-1.36 DR Response – Historical Health Care Costs
37. Exhibit AG-1.37 DR Response – Incentive Compensation for all officers
38. Exhibit AG-1.38 AG Revenue Deficiency Calculation

39. Exhibit AG-1.39 DR Response – Reliability Goals SAIDI, SAIFI, and CAIDI

Dr. Dismukes' direct testimony was 45 pages long, filed with it was an appendix A containing his qualification, and exhibits AG-2.1 to AG-2.14. Dr. Dismukes exhibits included:

1. Exhibit AG-2.1 Analysis of Historic Company Rates
2. Exhibit AG-2.2 Consumers' Annual System Load Factor, 2021
3. Exhibit AG-2.3 Consumers' Annual System Load Factor, 2016-2021
4. Exhibit AG-2.4 Updated 2013 Staff Analysis of Consumers' Generation Units
5. Exhibit AG-2.5 Alternative Analysis of Consumers' Electric Generation Units – 2021 Capacity Factors
6. Exhibit AG-2.6 Alternative Analysis of Consumers' Electric Generation Units – Levelized Costs
7. Exhibit AG-2.7 Analysis of Load Diversity on Consumers' Circuits – Primary-Voltage Circuits
8. Exhibit AG-2.8 Analysis of Load Diversity on Consumers' Circuits – Secondary-Voltage Circuits
9. Exhibit AG-2.9 Results of Alternative Class Cost of Service Study
10. Exhibit AG-2.10 Results of Company Class Cost of Service Study
11. Exhibit AG-2.11 Comparison of Company and Alternative Revenue Allocations
12. Exhibit AG-2.12 Comparison of Company and Alternative Proposed Rates
13. Exhibit AG-2.13 Consumers' 2021 Year-End Electric Rate Benchmarking
14. Exhibit AG-2.14 Case No. U-20963 Response to AG-CE-825

The Attorney General also had Exhibits AG-1.40 – AG-1.55 and Exhibit AG-2.15 admitted in lieu of cross examination of certain witnesses.

After reviewing the testimony, exhibits and discovery conducted in this case, the Attorney General concludes that the Company's revenue deficiency for the projected test year is excessive and instead it should be no more than \$134.1 million based on the following adjustments:<sup>3</sup>

1. Capital expenditures should be reduced resulting in a reduction of the Company's revenue deficiency by \$7.2 million.<sup>4</sup>
2. The Commission should adopt a cost of capital rate of 5.45%, a capital structure with 50% equity capital and a return on common equity of 9.50%. These recommendations reduce the Company's revenue deficiency by \$72.6 million.
3. Operations and Maintenance expenses should be reduced by \$47.3 million which results in a reduction to the Company's revenue deficiency of \$47.3 million.
4. Depreciation expense should be reduced by \$6.4 million because of the lower capital expenditures and additions to plant discussed in 1

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<sup>3</sup>As revised after rebuttal from the Attorney General's original filed position of a revenue deficiency of \$123.8 million (Coppola, 4 TR 3328).

<sup>4</sup>This is an adjustment from the Attorney General's position in prefiled testimony recommending a reduction of \$17.5 million (Coppola, 4 TR 3329).

above. This adjustment reduces revenue deficiency by approximately \$6.4 million.

5. The Commission should reject the Company's proposed Service Restoration Cost Deferral and Recovery mechanism.
6. The Commission should establish the revenue deferral mechanism proposed by Attorney General witness Coppola to hold the Company accountable for achieving Service Reliability goals.
7. The Commission should reject the Company's proposed CCOSS and Multi-Voltage Peak allocation method and instead adopt the Attorney General's proposed 55-0-45 production cost allocation.

The Attorney General requests that the Commission issue an order reflecting a revenue deficiency consistent with the recommendations in this brief. Further, the Commission should not authorize a ROE of more than 9.5%.

This Initial Brief has been prepared based on available resources and therefore it focuses on the significant issues of concerns summarized above. The Attorney General's silence on other issues should not be construed as approval of the Company's position. Further, the Attorney General reserves the right to address other issues raised by other parties in their Initial Briefs in a Reply Brief.

While examining the Attorney General's substantive objections, the Commission should consider that Consumers Energy bears the burden of proof to

demonstrate that its proposals are just and reasonable. The obligation of proving any fact lies upon the party who substantially asserts the affirmative of the issue. *White v Campbell*, 25 Mich 463, 475 (1872). A plaintiff always has the burden of proving its cause of action. *Caruso v Weber*, 257 Mich 333; 241 NW2d 198 (1931). As applied to administrative cases, a party seeking relief must prove his, her, or its claim by a preponderance of evidence. *Dillon v Lapeer State Home & Training School*, 364 Mich 1, 8; 110 NW2d 588 (1961); *BCBSM v Governor*, 422 Mich 1, 88-89; 367 NW2d 1 (1985). Likewise, in cases before the Commission, the utility bears the burden of proof by a preponderance of evidence. *In re Michigan Gas Utilities Co*, MPSC Case No. U-7484, Opinion & Order dated August 30, 1983; *In re Detroit Edison Co*, MPSC Case No. U-8030-R, Opinion & Order dated July 9, 1987, pp 16-17. Given the nature of the burden of proof, the Commission may reject even uncontradicted evidence. *Woodin v Durfee*, 46 Mich 424, 427; 9 NW 457 (1881); *Accord, Yonkus v McKay*, 186 Mich 203, 211; 152 NW 1031 (1915); *Cuttle v Concordia Mut Fire Ins Co*, 295 Mich 514, 519; 295 NW 246 (1940). When the burden of proving a fact falls on one party, then the other party does not have the burden of proving the opposite fact. *S.C. Gary, Inc v Ford Motor Co*, 92 Mich App 789, 803-804; 286 NW2d 34 (1979).

## ARGUMENTS

### II. Rate Base.

#### A. Net Utility Plant

In this rate case, Consumers Energy continues to seek greater capital expenditures and a never-ending expansion of rate base. A significant part of the Company's \$287 million rate increase (\$120 million) is for higher rate base related to new capital spending. This increase in rate base is also driving force behind the \$97 million increase in operations and maintenance (O&M) expense and cost of capital in this case.<sup>5</sup> The Company has proposed capital expenditures of \$1.1 billion for 2021, \$987 million for 2022, and an additional \$2.1 billion for 2022.<sup>6</sup> These proposals follow capital expenditures of \$2.6 billion over the previous three years – 2018 and 2020<sup>7</sup> These expenditures place tremendous upward pressure on rates and have a disproportionately negative impact on lower income ratepayers. As a result, the reasonableness and prudence of these costs must be closely examined and any expenditures that are not supported by the evidence eliminated.

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<sup>5</sup> Torrey, 4 TR 2553. See also, Coppola 4 TR 3230.

<sup>6</sup> In case No. U-20963, the Company projected lower amounts for 2021 and 2022 than it projects in this case.

<sup>7</sup> See, Exhibit A-12, Schedule B-5 in Case No. U-20963, U-20697 and U-20134. See also Coppola, 4 TR 3231.

In analyzing the Company's forecasted capital expenditures, Mr. Coppola often considered recent historical costs incurred by the Company, where appropriate, to determine the reasonableness of the Company's forecasted costs. In fact, the Company provided both historical and forecasted capital expenditures by major program and sub-program along with related units of work or unit costs for most programs which he relied upon along with other information in his analysis.<sup>8</sup> He did not use that methodology for all capital expenditures, however when he did, he also he applied a 6.75% inflation escalator for 2022 and 2.75% for 2023 using the same forecasting service used by the Company to account for potential increases in cost.<sup>9</sup>

The evidence supports a \$360.9 million reduction in the amount of the capital expenditures requested by the Company. The recommended changes in capital expenditures and rate base are explained below.

It appears that the Company has finally acknowledged the Commission's longstanding prohibition against including contingency costs in rate base.<sup>10</sup>

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<sup>8</sup> Coppola, 4 TR 3233 – 3234.

<sup>9</sup> *Id.* at 3332.

<sup>10</sup> See, February 28, 2017 Order in Case No. U-17990; Case Nos. U-18124, U-18322 and U-20322 and U-20697 and DTE cases U-18255, U-28014, U-17999, U-17767 and U-20162.

Although the Company included contingency costs for various capital projects in 2022 and 2023 in its filing, it did not include those costs in the calculation of rate base, therefore, the Attorney General’s adjustments do not include the “informational” contingency amounts. Despite this treatment, the Attorney General does not waive and instead maintains her objection to any future attempts to include contingency amounts in rate base for the reasons provided in the referenced Commission orders.

**1. Distribution Capital Expenditures.<sup>11</sup>**

**a. Company’s request.**

The Company identifies multiple projects related to the Company’s electric distribution system that it asserts require capital expenditures. The Company indicates that it spent \$765.6 million for electric distribution in 2021 and forecasts spending \$645.5 million in 2022. It also forecasts spending \$746.5 million for 2023.<sup>12</sup> Included in these amounts are capital expenditures for New Business,

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<sup>11</sup> Blumenstock, 4 TR 1127 – 1419; Lynd 4 TR 719 – 986; Ortiz, 4 TR 1848 – 1933; Fox, 4 TR 1934 – 1953; Coppola, 4 TR 3232 – 3258; Wang (MPSC Staff), 4 TR 3867 - 3909; Becker (MPSC Staff), 4 TR 3949 - 3961; York (ABATE) 4 TR 2896 - 2905; Ozar (MNSC), 4 TR 3758 - 3789; Jester (MNSC) 4 TR 3690 - 3698; Kentworthy (CEO) 4 TR 3531 - 3575.

<sup>12</sup> See, Exhibit A-12 (RTB-1), Schedule B-5.1. In Case No. U-20963, the Company forecasted spending \$696.1 million for 2021 and \$766.3 million for 2022. See, the same exhibit in that case.

Reliability programs, Capacity expansions, Demand Failures upgrades, Asset Relocation projects and Other Electric Operations.

The Company's electric distribution system consists of High Voltage Distribution ("HVD") and Low Voltage Distribution ("LVD") facilities, and the Company presented its capital expenditures by these categories, therefore, this section of the brief is presented in a similar fashion.

The Attorney General has determined that the Company fails to support some of its proposed distribution capital expenditures as described subsections b, c, and d below.

**b. High Voltage Distribution**

**i. HVD Line New Business Strategic Customers**

The Company forecasted capital expenditures of \$8,977,000 for the year 2022, and \$9,689,000 for 2023 to connect new large commercial and industrial customers after spending \$20,268,000 for 2021.<sup>13</sup> According to the Company, it may take months or years after it receives an inquiry for electric service before a contract is signed to allow the Company to proceed with construction. Mr. Blumenstock states

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<sup>13</sup> Exhibit A-59 (RTB-24), line 8. The Company projected spending \$10 million in 2022 in its last electric rate case.

that its 2022 and 2023 capital expenditure forecast for this sub-program reflects some known projects and expectations of projects that may arise during the year.<sup>14</sup> The Company only identified several projects that may be completed in 2022 and 2023 and its projections include large placeholder amounts for unknown projects for both years. For 2022, almost \$3 million of the nearly \$9 million estimate is for unknown projects and for 2023, \$7.7 million of the projected \$9.7 million is for unknown projects.<sup>15</sup> The Commission has previously ruled that placeholder amounts are not appropriate for inclusion in rate base.

To accommodate the emergent nature of this subprogram, the Attorney General proposes using the average cost per project for the most recent historical three years as a reasonable approach to forecast capital spending. The Company spent \$6,463,000 on 20 projects at a cost per project of \$323,000 in 2019, \$4,038,000 on 12 projects for cost per project of \$337,000 in 2020, and \$20,268,000 on seven projects in 2021. However, in 2021, two of the projects were large and unusual for a total amount of \$11.5 million.<sup>16</sup> After subtracting this amount from the \$20,268,00, the remaining amount of \$8,768,000 for the five projects results in a cost of

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<sup>14</sup> Blumenstock, 4 TR 1180 - 1181.

<sup>15</sup> See, Exhibit A-52 (RTB-17) page 1 and Exhibit A-53 (RTB-18) page 1, respectively. Coppola, 4 TR 3238.

<sup>16</sup> See, Exhibit A-59, line 8.

\$1,754,000 per project. Over the three-year period, the Company spent on average \$6,423,000 on 12 projects for an average cost per project of \$535,000 and adjusting this amount for inflation, it comes to \$571,000 per project. Using that amount, Mr. Coppola forecasted the cost for the eight projects that the Company has projected for 2022 is \$4,565,000, which is \$4,412,000 lower than the \$8,977,000 forecasted by the Company.<sup>17</sup> For 2023, the \$571,000 cost per project is further adjusted for inflation to \$587,000. This per project cost when applied to the ten projects that the Company anticipates working on in 2023, results in a forecasted cost of \$5,867,000,<sup>18</sup> which is \$3,822,000 lower than the Company's forecast of \$9,689,000.<sup>19</sup>

Therefore, Attorney General recommends that the Commission deduct \$4,412,000 and \$3,822,000 from the Company projected capital expenditures for 2022 and 2023, respectively for a total reduction of \$8,234,000. If the Commission does not accept this recommendation, the Attorney General recommends in the alternative that it remove the placeholder amounts of \$2,970,000 from 2022 and \$7,689,000 from 2023 for a total reduction of \$10,659,000.

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<sup>17</sup>  $\$535,000 \times 1.0665 \times 8 = \$4,565,000$ . See, Coppola, pp. 19 – 20.

<sup>18</sup>  $\$571,000 \times 1.0275 \times 10 = \$5,867,000$ .

<sup>19</sup> Coppola, 4 TR 3239.

ii. **HVD Lines and Substations Capacity**

The Company provided several HVD Project Concept Approval documents describing major projects that it plans to undertake in future years, including the scope, alleged reasons for the projects and forecasted cost.<sup>20</sup> The Attorney General sought information regarding major projects (i.e., those exceeding \$3 million).<sup>21</sup> Seven projects ranging in cost from \$3 million to \$8.8 million were identified by the Company and evaluated by the Attorney General. Most of the projects have progressed and are currently at the engineering phase or in pre-construction, however two of the projects have not progressed beyond the planning phase.<sup>22</sup>

The two projects that are still in the planning phase are the Crandall Substation Project and the Mobile Substation 26 Project with combined forecasted capital expenditures of \$500,000 for 2022 and \$11,800,000 for 2023. Because the two projects are still in the early stages of development, it is premature to include them in rate base in this rate case. The Company has not demonstrated that some or all of the capital spending for these projects will occur in 2022 and 2023 given

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<sup>20</sup> See, Exhibit A-44 (DAL-5).

<sup>21</sup> Exhibit AG-1.5 include discovery response AG-CE-0572.

<sup>22</sup> Id. page 2.

that the projects are still in the planning phase. It is unreasonable to have customers pay for the return on investment dollars that would be included in rate base and the depreciation expense related to the two projects when it is unlikely that those project costs will be incurred in 2022 and 2023.

Therefore, the Attorney General recommends that the Commission remove the amount of \$500,000 from the Company's proposed capital expenditures for 2022 and \$11,800,000 from 2023.

**c. Low Voltage Distribution**

**i. LVD Lines New Business**

The Company spent \$111.9 million in 2021 in capital expenditures to build new LVD lines for residential and small commercial customers.<sup>23</sup> In this case it is projecting approximately \$117.5 million in 2022 and \$124.7 million in 2023.<sup>24</sup> The Company has also forecasted that it will install 10,972 new service lines in 2022 and it is projecting 11,301 new lines in 2023. The number services connected each year appear to relate to the number of housing permits issued.

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<sup>23</sup> Exhibit A-59 (RTB-24), line 2.

<sup>24</sup> In Case No. U-20963, the Company only forecasted \$98.5 million for 2022.

While there was an increase in new connections in 2021, as Mr. Coppola noted, this is likely a bounce back from COVID-19 related restrictions in 2020 which resulted in connections being deferred until 2021.<sup>25</sup> This level of new connections is unlikely to continue into 2022 and 2023. New meter service installations for 2022 support this conclusion. Requests for the first five months of 2022 lag behind requests made in the same period in 2021.<sup>26</sup> New housing tends to be sensitive to mortgage interest rates. Inflationary pressure, including increases in mortgage rates will likely exert downward pressure on new housing construction and therefore new electric service connections.<sup>27</sup> Company year-to-date data supports this conclusion. As of June 23, 2022, the Company had received much lower requests for new service lines than in 2021 – 870 to 1084 (prorated) for commercial and 273 versus 2643 (prorated – 1<sup>st</sup> five months of 2021) for residential.<sup>28</sup> The total new service connections for 2021 were 2602 for commercial and 6342 for residential.

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<sup>25</sup> Coppola, 4 TR 3235.

<sup>26</sup> Coppola, 4 TR 3236.

<sup>27</sup> *Id.* at 3235.

<sup>28</sup> See, Exhibit AG-1.2.

Given the significant lag in requests year-over-year, it is unlikely that the Company's proposed increase of 320 units in 2022 and therefore increase of 323 units in 2023 will occur. It would take a significant increase in new connections for the remainder of 2022 to meet or exceed the projections for 2022. Likewise, for 2023, unless the forces impacting the residential housing market change. The Company has not demonstrated that will occur. Mr. Coppola recommends that the Commission adopt the 2021 capital expenditures adjusted for inflation for 2022 and 2023.<sup>29</sup> After adjusting for inflation, the Company's capital expenditures forecast for 2022 appear to be reasonable. However, for 2023, the capital expenditures for this sub-program should be \$122,647,000, a reduction of \$2,144,000 from the Company's forecast of \$124,791,000.<sup>30</sup>

Therefore, the Attorney General recommends that the Commission remove \$2,144,000 from the Company's forecasted capital expenditures for 2023.

ii. **LVD Asset Relocations**

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<sup>29</sup> Coppola, 4 TR 3237.

<sup>30</sup> 2021: \$111,921,506 x 1.0665 x 1.0275 = \$122,647,000. 2023: \$122,647,000 – 124,791,000 = \$(2,144,000).

The Company forecasted capital expenditures of \$30,739,000 for the year 2022,<sup>31</sup> and \$31,923,000 for 2023 to relocate LVD electric lines.<sup>32</sup> According to Mr. Lynd, most asset relocation work is unplanned and reactive to requests from third parties outside of the Company.<sup>33</sup> In 2021, the Company incurred approximately \$27 million for customer requested lines and other relocations.<sup>34</sup>

The fact that the work in this program is unplanned and generally unknown at the time the forecasts were developed calls in the question the Company's projections. According to Mr. Lynd to arrive at the forecasted 2022 capital expenditures the Company assumed a 10% increase in spending over 2021. For 2023, the Company assumed a 1% increase over the capital expenditures for 2022.

Given the emergent nature of the requests for electric line relocations received from customers, there is a high degree of uncertainty as to how many requests will be received in year. Although in the most recent three years from 2019 to 2021 the Company has experienced a steady increase in capital

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<sup>31</sup> In Case No. U-20963, the Company project \$52,506,000 for this category of expenditures in 2022.

<sup>32</sup> Exhibit A-59 (RTB-24), line 18.

<sup>33</sup> Lynd, 4 TR 781 – 791.

<sup>34</sup> Coppola, 4 TR 3251.

expenditures for this sub-program, in 2018 the Company experience a decline in spending following an increase in the prior year. The significant increase in interest rates beginning in the spring of 2022 is likely to temper economic activity and reduce the number of construction projects that typically require relocation of electric lines.

Due to the lack of specific projects in which to base a forecast and taking into consideration the up and down nature of relocation projects in any given year, Mr. Coppola determined that the best approach is to base the forecast for this sub-program on the most recent five-year historical average adjusted for inflation for 2022 and 2023. This is consistent with the approach used by the Commission for other expenditures that vary from year to year.<sup>35</sup> Accordingly, the five-year average amount of \$21,604,000 for lines relocations multiplied by the inflation factor results in forecasted capital expenditures of \$23,041,000 for 2022 and \$23,675,000 for 2023.<sup>36</sup> These amounts are lower than the Company's forecasted amount of \$30,739,000 for 2022 and \$31,923,000 for 2023 by \$7,698,000 and \$8,248,000, respectively. Therefore, the Attorney General recommends that the Commission

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<sup>35</sup> Coppola, 4 TR 3252 – 3353.

<sup>36</sup> 2022: \$21,604,000 x 1.0665 = \$23,041,000. 2023: \$23,041,000 x 1.0275 = \$23,675,000.

remove the amount of \$7,698,000 and \$8,248,000 from the Company's forecasted capital expenditures for 2022 and 2023.

### iii. **LVD Lines Reliability**

The LVD Lines Reliability program consists of four sub-programs providing for upgrades to the LVD system, including replacing or improving electric circuits, replacing electric poles, and acquiring land easements or land right of way rights.<sup>37</sup>

The Attorney General's recommendations address the Targeted Circuit Improvements subprogram. The Company forecasted capital expenditures of \$20,593,000 for 2022 and \$22,601,000 for 2023 for this subprogram. According to the Company it incurred capital expenditures of \$23.4 million for 2021.<sup>38</sup>

Beginning in 2018, the Company added a third person to line crews which was reflected, along with increased contractor costs in 2019 individual project costs.<sup>39</sup> The Company's unit costs for the Targeted Circuit Improvements subprogram for 2022 and 2023 are significantly higher than in prior years. The 2022 unit costs of \$294,186 is more than twice the amount than for 2021 and the unit costs for 2023 at \$167,415 is also much higher than the unit costs for 2021.

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<sup>37</sup> Exhibit A-59, lines 20 – 24.

<sup>38</sup> Exhibit A-59, line 21.

<sup>39</sup> Lynd, 4 TR 817.

Further, there are not enough large projects to skew the average unit costs higher to support the Company's projections.<sup>40</sup> Mr. Coppola concludes that the unit costs and forecasted amounts for 2022 and 2023 are excessive. Using the unit costs for the most recent three years from 2019 to 2021, he calculated an average base unit cost of \$105,931. This unit cost reflects the larger crew size and the increased rates paid to contractors that went into effect in 2018 and 2019 and after adjusting for inflation, he applied the adjusted unit cost to the 70 projects that the Company forecasted for 2022 to arrive at forecasted capital expenditures of \$7,908,000 for 2022.<sup>41</sup> This amount is \$12,685,000 lower than the Company's forecast of \$20,593,000.

For 2023, he applied the inflation factor to the 2022 unit cost and multiplied that amount by the 135 projects forecasted by the Company to arrive at forecasted capital expenditures of \$15,671,000. This amount is \$6,930,000 lower than the Company's forecast of \$22,601,000.<sup>42</sup>

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<sup>40</sup> Coppola, 4 TR 3241.

<sup>41</sup> 2022:  $\$105,931 \times 1.0665 \times 70 = \$7,908,000$ . 2023:  $105,931 \times 1.0665 \times 1.0275 \times 135 = \$15,671,000$ .

<sup>42</sup> Coppola, 4 TR 3241 – 3242.

The Attorney General recommends that the Commission remove the \$12,685,000 and \$6,930,000 from the Company's forecasted capital expenditures for Targeted Circuit Improvements for 2022 and 2023, respectively.

iv. **LVD – Reliability/Resiliency**

The Company identified future major projects that it plans to undertake including those costing \$3 million or more.<sup>43</sup> Five of the projects are part of the Resiliency sub-program under the Reliability program for which the Company forecasted approximately \$30 million.<sup>44</sup> The other two major projects are the Coopersville line rebuild project that is under the HVD Lines and Substation Capacity sub-program (Exhibit A-53, page 7, line 41) and the Cooley Metro Substation Relocation project.

The Company expects to incur the forecasted capital expenditures for the seven projects beginning in 2023.<sup>45</sup> While some of the major projects have progressed and are currently at the engineering phase, five of the projects are

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<sup>43</sup> See, Exhibit A-141 (DAL-5) and Exhibit AG-1.3.

<sup>44</sup> See, Exhibit A-39, line 16. See also, Exhibit A-139 (DAL-3) provides more details and shows the individual major projects under the Resiliency sub-program that make up the total amount of \$30 million.

<sup>45</sup> Exhibit AG-1.3, page 1.

presently in the planning phase.<sup>46</sup> These projects and the related capital expenditures are listed below.

<b>Project Name</b>	<b>(000)</b>	<b>2023 Cap Ex</b>
Backus		\$ 6,425
Coopersville		4,565
Whittemore		4,494
Eagle		3,931
Mobile #27		3,660
<b>Total</b>		<b>\$ 23,075</b>

Because these five projects are still in the early stages of development, they are too premature for inclusion in rate base in this rate case. It is likely that some or possibly all capital spending for these projects will not occur in 2023. It is unreasonable to make Customers pay for the return-on-investment dollars that would be included in rate base and the depreciation expense related to the five projects when the evidence indicates that those project cost will not be incurred in 2023.<sup>47</sup> In the event that the Company incurs any costs in 2023 for these projects, it can seek recovery in a future rate case.

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<sup>46</sup> Id. page 2.

<sup>47</sup> Coppola, 4 TR 3245 – 3247.

Therefore, the Attorney General recommends that the Commission remove \$23,075,000 from the Company's proposed capital expenditures for 2023.

**v. LVD Lines Rehabilitation**

The purpose of this program is to replace or improve LVD electrical lines and substation equipment where failure has not yet occurred, but according to the Company are imminent. The Company provided actual and forecasted capital expenditures for three sub-programs under the LVD Lines Rehabilitation category of expenditures.<sup>48</sup> The Attorney General will be recommending disallowances for the Security Assessment Repairs Projects subprogram.

On line 98 of Exhibit A-59, According to the Company, it spent \$23,684,410 of actual capital spending in 2021, and projects spending \$19,488,000 for 2022 and \$19,655,000 for 2023 for Security Assessment Repairs Projects. While overall spending levels appear to be generally consistent with recent years, the unit cost in 2022 is significantly out of line with historical unit costs and with the unit cost for 2023. The unit cost for 2022 is \$162,400 per project compared to the unit cost in the

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<sup>48</sup> Exhibit A-59 lines 97 to 100.

prior three years 2019 to 2021 which ranged from \$51,897 to \$88,706 and averaged \$68,721. In 2023, the unit cost is within the historical range at \$61,040.

Company witness Lynd is unconcerned with unit costs, stating that unit costs are not a good measure to predict spending due to a wide range of project costs.<sup>49</sup> The Company's reaction misses the point since a review of the projects listed by the Company on pages 13 to 24 of Exhibit A-138 do not show significantly large projects in this sub-program for 2022 that would skew the average cost for the year higher and no explanation was provided by the Company to justify the disparity in the unit cost in comparison to prior years and 2023. There is no reason for average costs for 2022 to vary dramatically from the other years. It is indicative of an excessive forecast.

The Company has failed to provide sufficient evidence to justify proposed capital expenditures, and the emergent or contingent nature of the work to be performed in this sub-program means that the expenditures may not be incurred. The unit cost for the projects forecasted by the Company for 2022 is not reasonable and leads to excessive capital expenditures. Instead, the Commission should use the actual average unit cost for the most recent three years adjusted for inflation to

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<sup>49</sup> Lynd, 4 TR 865 - 869.

determine an appropriate level of expenditures for this subprogram. Based on the average unit cost of \$68,721, adjusting it for inflation, and multiplying it by the 120 projects forecasted by the Company, the forecasted capital expenditures for 2022 should be \$8,795,000.<sup>50</sup> This amount is \$10,693,000 lower than the \$19,488,000 forecasted by the Company.<sup>51</sup>

The Attorney General recommends that the Commission remove the \$10,693,000 from the Company's forecasted capital expenditures for 2022.

#### vi. **LVD Line Capacity**

The Company is forecasting \$6,483,000 for 2023 for Lines Capacity Projects Associated with Substation work. This compares to \$2,988,409 of actual capital spending in 2021, and \$4,911,000 forecasted for 2022.<sup>52</sup> Although the forecasted unit cost of \$545,667 per project for 2022 falls within the historical range of \$172,878 to \$581,976 found in the prior three years (2019-2021), the 2023 unit cost is significantly higher. For 2023, the Company shows a unit cost of \$1,296,600 per

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<sup>50</sup>  $\$68,721 \times 1.0665 \times 120 = \$8,795,000$ .

<sup>51</sup> Coppola, 4 TR 3247 – 3248.

<sup>52</sup> See, Exhibit A-59, line 117.

project. The Company has five projects planned for 2023. The number of projects is not significantly different from the eight to nine projects in 2020, 2021 and 2022.

Mr. Lynd discusses this sub-program in his direct testimony but does not explain why the five projects in 2023 would be significantly different from projects in prior years to warrant a much higher cost per project.<sup>53</sup> The Company did not provide any additional information in response to discovery other than to point back to Mr. Lynd's direct testimony and stating that unit costs are not a good measure for spending in this subprogram due to project cost variability.

The unit cost for the projects forecasted by the Company for 2023 is not reasonable and leads to excessive capital expenditures. Mr. Coppola proposes to use the actual average unit cost for the most recent three years adjusted for inflation to estimate the cost. Based on the average unit cost of \$376,135, adjusted for inflation, and multiplying by the 5 projects forecasted by the Company, the forecasted capital expenditures for 2023 should be \$2,006,000.<sup>54</sup> This amount is \$4,477,000 lower than the \$6,483,000 forecasted by the Company.

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<sup>53</sup> Lynd, 4 TR 894 – 902.

<sup>54</sup>  $\$376,135 \times 1.0665 \times 5 = \$2,006,000$ . See also, Coppola 4 TR 3249 – 3250.

The Attorney General recommends that the Commission remove the \$4,477,000 from the Company's forecasted capital expenditures for 2023.

vii. **Conservation Voltage Reduction (CVR) Projects**

The Company is forecasting \$3,964,000 for 99 Conservation Voltage Reduction projects in 2023. This compares to \$7,191,371 of actual capital spending in 2021 for 204 projects, and \$4,154,000 forecasted for 2022 for 165 projects.<sup>55</sup> During the past three years from 2019 to 2021 the average cost per project ranged between \$13,624 and \$35,252 with an average cost of \$24,786. The unit cost for 2022 is within the historical three-year period. However, the unit cost for 2023 at \$40,040 is significantly higher.<sup>56</sup>

Mr. Lynd discusses the CVR projects to be completed in 2022 and 2023 with the related forecasted capital expenditures in his direct testimony but there is no discussion why the cost per project is increasing significantly over prior years.<sup>57</sup> The unit cost for the projects forecasted by the Company for 2023 is not reasonable and leads to excessive capital expenditures. Mr. Coppola proposes to use the actual

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<sup>55</sup> Exhibit A-59, line 140.

<sup>56</sup> Coppola 4 TR 3250.

<sup>57</sup> Lynd, 4 TR 919 – 921.

average unit cost for the most recent three years adjusted for inflation. Based on the average unit cost of \$24,786, adjusting it for inflation, and multiplying by the 99 projects forecasted by the Company, the forecasted capital expenditures for 2023 should be \$2,617,000.<sup>58</sup> This amount is \$1,347,000 lower than the \$3,964,000 forecasted by the Company.

The Attorney General recommends that the Commission remove the \$1,347,000 from the Company's forecasted capital expenditures for 2023.

**d. Grid Modernization**

**i. Automation - System Control Projects?**

The Company forecasted capital expenditures of \$2,521,000 for the year 2022, and \$3,114,000 for 2023, however Company witness Blumenstock discusses the reclassification of costs from this sub-program to HVD Lines and Substation Capacity in June 2021.<sup>59</sup> Historically, expenditures in the subcategory relate to management of the distribution system by improving the operation of the control centers, streamlining operations, and improving remote control capabilities. There is some inconsistency between Mr. Blumenstock's testimony and exhibit A-59 which

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<sup>58</sup>  $\$24,786 \times 1.0665 \times 99 = \$2,617,000$ . *See also*, 4 TR 3251.

<sup>59</sup> Exhibit A-59, line 205. *See also*, Blumenstock, 4 TR 1307. In case No. U-20963, the Company projected spending \$4,944,000 for 2022.

may be a result of the reclassification of certain costs.<sup>60</sup> Based on the information provided in Mr. Blumenstock's testimony, the Company averaged \$1,223,000 of capital spending on this program during the five-year period from 2017 to 2022.<sup>61</sup> However, Mr. Blumenstock's testimony does not provide any clear or compelling reasons why the forecasted capital expenditures for 2022 of \$2.5 million for this program should more than double from the average amount spent in the past five years and from the amount spent in 2021 after some of the costs were reclassified and moved to other programs. Similarly, there is no justification why the 2023 forecasted capital expenditures of \$3.1 million should nearly triple from the \$1.2 million spent in 2021. The annual capital expenditures from 2017 to 2021 have varied significantly from year to year.

Given the lack of evidence and justification to escalate the program spending to the levels projected by the Company and the variability in spending over the past five years, the reasonable approach to forecast capital expenditures for 2022 and 2023 is to use the five-year average amount and escalate it by the inflation factor for each year.<sup>62</sup> Based on this approach, the forecasted capital expenditures for

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<sup>60</sup> Coppola, 4 TR 3256.

<sup>61</sup> Blumenstock, 4 TR 1307.

<sup>62</sup> Coppola, 4 TR 3257.

2022 are \$1,304,000 for 2022 and \$1,340,000 for 2023.<sup>63</sup> These amounts are \$1,217,000 and \$1,774,000 lower than the Company's forecasted amount for 2022 and 2023, respectively. The excess amounts should not be included in rate base.

The Attorney General recommends that the Commission remove the excess amount of \$1,217,000 for 2022 and \$1,774,000 for 2023 from the Company's forecasted capital expenditures.

ii. **Grid Capabilities – Advanced Technologies**

The Company forecasted capital expenditures for ten sub-programs under this category of expenditures. Expenditures for three of the sub-programs or projects – distributed energy resources management (DERMS), Electric Distribution Asset Management, and Grid Modernization Incubator are unsupported or excessive.<sup>64</sup>

DERMS

DERMS is intended to manage power flows from various distributed energy resources (DER).<sup>65</sup> The Company spent \$60,000 in 2020 and \$1,168,000 in 2021 on

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<sup>63</sup> 2022: \$1,223,000 x 1.0665 = \$1,304,000. 2023: \$1,304,000 x 1.0275 = \$1,340,000.

<sup>64</sup> Coppola, 4 TR 3242 - 3245.

<sup>65</sup> Ortiz, 4 TR 1896 – 1909.

this program. It forecasted no capital spending in 2022 and \$1,200,000 in 2023.<sup>66</sup>

Mr. Ortiz states that the \$1,200,000 forecasted for 2023 could be spent for up to five DERMS controllers at various locations, however, he did identify the five locations. It is evident that the Company has not yet determined where the controllers will be located and if any or all of them will be needed. Given this uncertainty, the forecasted capital expenditures by the Company has not been supported on the record and it is premature to include them in rate base.

Therefore, the Attorney General recommend that the \$1.2 million be removed from the Company's proposed capital expenditures for 2023.

#### Distribution Asset Management System.

According to the Company's Concept Approval document for this project (Exhibit A-155), the total forecasted cost of this project is \$12 million from inception to completion. In this rate case, the Company is forecasting \$2,020,000 for 2022 and \$5,045,000 for 2023 for the System.<sup>67</sup> Based on the description of this project by Company witness, Ortiz, the need for this system has not been established.<sup>68</sup>

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<sup>66</sup> See, Exhibit A-59 line 73.

<sup>67</sup> Exhibit A-59 On line 75.

<sup>68</sup> Ortiz,4 TR 1926 – 1927; 1928 - 1933.

The description of the system provided by Mr. Ortiz is similar to the Advanced Distribution Management System (ADMS,) which the Company installed over a three-year period and just completed in 2021 at a cost of approximately \$58 million.<sup>69</sup> In fact, last year in Case No. U-20963, the Company sought money to upgrade the ADMS system in 2022. The Commission approved capital expenditures for the ADMS in previous rate cases.<sup>70</sup>

Although Mr. Ortiz identifies millions of dollars of potential cost savings, the Company has not presented a cost/benefit analysis that shows it would be economically justifiable to undertake this additional distribution management project. According, to Mr. Coppola, the lack of a robust economic analysis of this proposed project and the similarities and potential overlapping of functions with the ADMS project should doom any expenditures for this project and he recommended that the proposed capital spending of \$2,020,000 and \$5,045,000 be removed from the Company's forecasted capital expenditures for 2022 and 2023, respectively.<sup>71</sup>

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<sup>69</sup> *See*, Exhibit A-59, line 71.

<sup>70</sup> Coppola, 4 TR 3243.

<sup>71</sup> *Id.* at 3243 – 3244.

Therefore, the Attorney General recommends that the Commission disallow the proposed capital expenditures for the 2022 and 2023 for the Distribution Asset Management System project.

Grid Modernization Incubator Project.

According to the Company the purpose of the Grid Modernization Incubator project is to develop the capability to perform testing and training of employees and contractors within a controlled environment instead of out in field conditions.<sup>72</sup> The project involves a testing and training facility which would be used to try new technologies and experiment with new electrical equipment. It sounds very similar to the Circuit 501 project that the Company proposed in Case No. U-20697 and the Commission rejected.<sup>73</sup> The Company spent \$390,000 spent in 2021 on this project. It has forecasted zero for 2022 and \$1.3 million for 2023 for the project.<sup>74</sup> According to the Concept Approval document prepared by the Company for this project, the total forecasted cost of this project is \$11 million from inception to completion.<sup>75</sup>

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<sup>72</sup> Ortiz, 4 TR 1926.

<sup>73</sup> MPSC Case U-20697, order dated 12/17/2020 at page 101.

<sup>74</sup> Exhibit A-59 line 76.

<sup>75</sup> See, Exhibit A-155.

Although Mr. Ortiz identifies potential cost savings from having an incubator facility and capability, the Company has not presented a cost/benefit analysis that shows it would be economically beneficial to ratepayers to undertake this project. The project is also related to the construction of the Marshall Training Center, which the Commission previously rejected.<sup>76</sup>

The lack of an economic analysis for this proposed project and the uncertainty whether the Commission will approve recovery of costs for the Marshall Training Center, leads the Attorney General to recommend that the Commission reject the proposed capital spending on this project and remove the \$1.3 million from the Company's forecasted capital expenditures for 2023.

The Attorney General recommends that the Commission disallow \$2,220,000 and \$6,345,000 from the Company's forecasted capital expenditures for 2022 and 2023, respectively for the three Grid Capabilities and Advanced Technologies projects discussed above.

e. **Distribution Capital Expenditures Adjustments – Summary.**

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<sup>76</sup> Coppola, 4 TR 3244 – 3245.

For the Distribution programs discussed above, the Attorney General recommends a total disallowance of forecasted capital expenditures of \$51,118,000 for 2022 and \$74,382,000 for 2023.

## **2. Power Generation Capital Expenditures<sup>77</sup>**

### **a. Overview**

The Company incurred capital expenditures of \$166.8 million for Power Generation plant in 2021, and forecasted \$210.9 million for 2022, and \$1.258 billion for 2023.<sup>78</sup> Included in these amounts are capital expenditures for Steam (Fossil Fuel) Power Generation, Hydro Power Plants, Pumped Storage Generation (Ludington), and Other Production Plant. The Attorney General proposes adjustments to several of these programs and component projects.

### **b. Solar Generation.**

The Company forecasts capital expenditures for solar generation projects of \$291.9 million for 2023. It also shows expenditures of \$5.2 million for 2021, and

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<sup>77</sup> Clark (Consumers), 4 TR 1625 – 1668; Hugo, (Consumers) 4 TR 2177 – 2345; Coppola, 4 TR 3258 – 3266; Champion (MPSC Staff) 4 TR 3850 - 3859; York (ABATE), 4 TR 2905 – 2911.

<sup>78</sup> Exhibit A-12 (SAH-3), Schedule B-5.7, page 1.

\$104.5 million for 2022.<sup>79</sup> Exhibit A-84 (TPC-4) provides additional details and identifies the two projects, the Mustang Mile Solar Project and the Washtenaw Solar Project, that make up the total amount of capital expenditures incurred in 2021 and forecasted for 2022 and 2023.

**i. Mustang Mile Solar Project**

According to the Company, the projects are currently in the development stage.<sup>80</sup> Mr. Clark states that the Company has experienced many challenges to solar projects achieving their planned commercial operation date due to the current state of the solar development market and that it is seeing delays associated with projects whether being developed for Company ownership or third-party ownership. The projects are seeing longer lead times and higher costs for the key components (i.e., solar modules, racking, transformers, etc.) used in the construction of a solar project. These challenges are leading to significant delays in project schedules and higher costs than originally estimated and agreed upon. The second challenge is local resistance to large solar projects and is specific to Michigan projects. The result of this challenge is significant delays in project schedules.<sup>81</sup>

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<sup>79</sup> Exhibit A-12 (SAH-3), Schedule B-5.7, page 2, line 50.

<sup>80</sup> See. Exhibit AG-1.7 ( AG-CE-582).

<sup>81</sup> Thomas Clark, 4 TR 1648.

The Company the Company is currently involved in litigation with a community group related to Mustang Mile Solar Project. As a result, the project is currently in a holding pattern.<sup>82</sup>

Although the Company has signed a contract with the developer, there is some uncertainty in the project schedule agreed in the contract due to the litigation. In fact, the Mustang Mile Project schedule has been delayed, which has resulted in a change to the spend plan. Furthermore, until the project moves from the development phase to the execution phase of the project life cycle, there will continue to be some uncertainty in both schedule and spend. The Build Transfer Agreement (BTA) is designed to protect customers and the Company from investing significant dollars before a project is ready to move beyond the development phase by containing a provision referred to as Notice to Proceed.<sup>83</sup>

The capital expenditures forecasted by the Company for this project for 2022 of \$63,593,000 and \$140,670,000 for 2023 supposedly reflect the delayed schedule. However, the timing and resolution of the litigation could further delay the project and spending plans. According to Mr. Clark's testimony, a revised Progress

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<sup>82</sup> *Id.* at 1652.

<sup>83</sup> *Id.* at 1651.

Payment Schedule that reflects the revised commercial operation date has not yet been agreed to with the developer at the time of filing of the rate case.<sup>84</sup>

ii. **Washtenaw Solar Project**

In Exhibit A-84, the Company shows actual capital expenditures of \$2,477,000 for 2021 and forecasted capital expenditures of \$40,909,000 for 2022, and \$151,220,000 for 2023 for the Washtenaw Solar Project. Mr. Clark discusses the project and states that the planned commercial operation date has been delayed from May 2023 to May 2024 for reasons like those discussed above pertaining to the Mustang Mile project. According to Mr. Clark, the Company signed the BTA with the developer on October 4, 2021 but has not yet received full land use permits from the Saline township where the project will be located.<sup>85</sup> In this proceeding, the Company is requesting cost recovery for amounts consistent with the Washtenaw Solar BTA and the updated May 2024 date of commercial operation.<sup>86</sup>

Mr. Clark makes additional statements regarding the project, notably “Given that this project will not be completed within the test year of this case and given that it is an AFUDC eligible project, the Company is not requesting rate recovery of

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<sup>84</sup> Id. at 1654.

<sup>85</sup> Id. at 1655 – 1656.

<sup>86</sup> Id. at 1657.

this project in this case but is supporting capital spending for the entire project.”<sup>87</sup>

This statement seems contrary to the amounts shown in Exhibit A-12 (SAH-3) which include capital expenditures for the Washtenaw project for 2021 through 2023 totaling to \$194.6 million. In rebuttal, Mr. Clark explained that the Company was not seeking costs in the revenue requirement sought in this case because they are totally offset through an Allowance for Funds Used During Construction (AFUDC).<sup>88</sup>

### iii. **Conclusion**

Based on Mr. Clark’s direct and rebuttal testimony, it is apparent that the two solar projects have already been delayed and are likely to suffer additional delays due to litigation and obtaining necessary approvals in addition to the supply chain problems experienced across the entire solar industry with new construction of solar projects. While the Attorney General acknowledges that the Company had partially offset the cost of adding those projects to rate base by the AFUDC credit. The total amount of the AFUDC credit that the Company reflected in the revenue requirement for those two projects is \$15,059,000 based on the calculations shown in WP-JCA-63. To match the 50% capital expenditures disallowance, the AG

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<sup>87</sup> Clark, 4 TR 1660.

<sup>88</sup> Clark, 4 TR 1667.

revenue deficiency will be adjusted by half this amount grossed up for taxes or  $\$7,529,500 \times 1.3391 = \$10.1$  million. However, she still recommends removing 50% of the forecasted amounts.

**c. Other Production Plants**

**i. Zeeland Power Plant.**

Mr. Coppola identified certain adjustments to capital expenditures proposed by the Company for its Zeeland Power Plant. Specifically, there are six projects still in the early stage of development and thus premature for inclusion in rate base in this rate case. It is likely that some or all of the capital spending for these projects will not occur in 2023 given that the projects are still in the planning phase. It is not appropriate for customers to pay for the return on investment dollars that would be included in rate base and the depreciation expense related to the six projects when it is unlikely that the capital expenditures for those projects will be incurred in 2023.

The six projects include:

<b>Project Name</b>	<b>(000)</b>	<b>2023 Cap Ex</b>
9216 ZGS - Phase 2 599 699 345kV Breaker Replacement		\$ 1,297
9217 ZGS - 299 345kV Breaker Replacement		650
9694 ZGS - HRSG Casing Replacement		2,900
9730 ZGS Phase 2 Steam Turbine Building Roof Replacement		600
9943 ZGS - LTSA - Extras not included in contract		2,700
Zee Spare GSU		1,873
<b>Total</b>		<b>\$ 10,020</b>

Therefore, the Attorney General recommends that the Commission remove the amount of \$10,020,000 from the Company's proposed capital expenditures for 2023.<sup>89</sup>

**ii. Karn and Jackson Plant Projects**

The Company included some incremental and avoidable capital expenditures for 2022 and 2023 for the Campbell Power Plant Units 1 to 3 and Karn Plants Units 3 and 4 subject to the outcome in the Company's 2021 Integrated Resource Plan (IRP) case, U-21090.<sup>90</sup> A settlement agreement was subsequently approved by the Commission by a June 23, 2022 order. The order approved the retirement date for

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<sup>89</sup> Coppola, 4 TR 3258 – 3260.

<sup>90</sup> Hugo, 4 TR 2285 – 103 – 115.

Campbell Units 1-3 by May 31, 2025 and the retirement date for Karn Unit 3 and 4 by May 31, 2031.

As a result of the Commission order, the Company will need to incur certain capital expenditures that had been identified as avoidable and not included in the capital expenditures and rate base in this rate case filing for Karn Units 3 and 4. In response to discovery request ST-CE-517, the Company identified \$6,702,000 of capital expenditures for 2022 pertaining to Karn 3 and 4, and \$6,330,000 for 2023. Both amounts exclude contingency costs.<sup>91</sup> The Company has also identified capital expenditures of \$3,722,000 for two projects at the Jackson power plant that it no longer expects to incur in 2023.<sup>92</sup>

Therefore, taking into consideration the adjustments above for the Karn and Jackson plant projects, the Attorney General recommends that the Commission increase capital expenditures for the net amounts of \$6,702,000 for 2022 and by \$2,608,000 for 2023.

### **3. Facilities Capital Expenditures<sup>93</sup>**

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<sup>91</sup> Exhibit AG-1.8 includes discovery response ST-CE-517.

<sup>92</sup> Id. includes discovery response ST-CE-518.

<sup>93</sup> Guinn, (Consumers) 4 TR 1955 – 2012; Coppola (Attorney General), 4 TR 3266 – 3277.

The Company spent \$33.5 million in capital expenditures for Asset Preservation in 2021, and has forecasted capital expenditures of \$27.1 million for 2022, and \$24.5 million for 2023.<sup>94</sup> The 2022 and 2023 forecasted capital expenditures includes amounts for three new service centers, building renovations to office space for employees returning to work locations post-Covid-19, the Marshall Metro City project and Marshall Training Center building, and a new Unified Control Center (UCC).<sup>95</sup> The Attorney General recommends disallowances for these expenditures as described below.

**a. New Service Centers**

The Company has forecasted capital expenditures for the Lansing, Hastings and Kalamazoo Service Centers. The Attorney General is recommending disallowances related to service centers because they are still in the early design phase and the timing of the expenditures is questionable.

The Company forecasts capital expenditures for the Lansing, Hastings, and Kalamazoo Service Centers for 2022 of \$1,591,000 and for the year 2023 of

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<sup>94</sup> Exhibit A-12 (QAG-1), Schedule B-5.5, line 1. In its last electric rate case the Company projected spending \$83.4 million for 2022 (See Exhibit A-12-SJB-1, Schedule B-5.5, line 1 in Case No. U-20963).

<sup>95</sup> Exhibit A-107 (QAG-3) shows the specific expenditures.

\$5,013,000.<sup>96</sup> In Case No. U-20963, the Company had forecasted capital expenditures for 2022 of \$34,775,000 but now only plans to spend a small fraction of that amount at \$1,591,000.<sup>97</sup> In Case U-20963, the Commission approved the \$34,775,000.

It appears that the Company has run into difficulties in procuring land to locate some of the service center, has experienced delays in getting certain approvals, and it has also decided to re-evaluate the design and functions of some the service centers supposedly due to Covid-19 protocols. The result has been a lack of progress which leaves the projects still at the conceptual phase.

The Company has provided the following update regarding the Service Centers:<sup>98</sup>

Lansing Service Center – The Company is working with the City of Lansing to engineer a water main extension to the project site and is also working to complete an alternative analysis to determine how the service center should be designed. Engineering work for the center is

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<sup>96</sup> Exhibit A-107 (QAG-3), lines 14, 15 and 16. See also, Guinn, 4 TR 1968 – 1985.

<sup>97</sup> Coppola, 4 TR 3267.

<sup>98</sup> Exhibit AG-1.9 included discovery responses AG-CE-589, 590 and 591.

expected to be completed sometime in 2023 with no certain date. Construction is expected to begin in the spring of 2024, approximately two years from now.

Hastings Service Center – The Company is still searching for a suitable parcel of land. Engineering work is expected to be completed in the fourth quarter of 2023 with construction to begin thereafter.

Kalamazoo Service Center – The Company is working to complete an alternative analysis to determine how the service center should be designed. Engineering work for the center is expected to be completed in fourth quarter of 2023. Construction is expected to begin in April 2024,

Based on information provided by the Company, it is apparent that the projects are still in the very early stage of development and design. Furthermore, the timing of when the forecasted expenditures are likely to occur in 2022 and 2023 is suspect. It is premature to include preliminary and uncertain capital expenditures in rate base for the Company to earn a return and recover depreciation expense before plans for construction of the facilities have been finalized and are certain to occur. Although the Commission approved larger amounts of capital expenditures for 2022 in Case No. U-20963, the Commission should not approve any capital expenditures in this rate case for the three service centers.

Therefore, the Attorney General recommends that the Commission remove the forecasted capital expenditures for the three service centers of \$1,591,000 for 2022 and \$5,013,000 for 2023.<sup>99</sup>

**b. Building Renovation Projects**

The Company included forecasted capital expenditures for 2022 and 2023 of \$2,719,000 and \$6,453,000, respectively, for potential workspace modifications to address work arrangements post- COVID-19.<sup>100</sup> Most of the renovations appear to be related to the objective of modifying office space in reaction to the Covid-19 pandemic. However, it also appears that the Company may be normalizing the expenditures as routine building modifications.<sup>101</sup>

Mr. Guinn discusses seven projects under this category of expenditures.<sup>102</sup> The Attorney General will address the projects below.<sup>103</sup>

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<sup>99</sup> Exhibit A-107, lines 14-16. See also, Coppola, 4 TR 3267 – 3270.

<sup>100</sup> Exhibit A-107 (QAG-3), line 17.

<sup>101</sup> Coppola, 4 TR 3273.

<sup>102</sup> Guinn, 4 TR 1985 – 1991.

<sup>103</sup> The cost for each project has been provided in Exhibit A-110 (QAG-6) page 2. The electric portion of the total renovations is 54%.

Parnall Floor Renovations – The Company has identified six floors that it wants to renovate because private offices are not conducive to a collaborative work environment. The cost for these renovations is: \$4,272,526 (\$2,307,164 electric share) for 2022 and \$6,800,000 (\$3,672,000 electric share) for 2023. Additional costs are forecasted for 2024 through 2027 for a total amount from inception to completion of \$31.4 million.

One Energy Plaza – Mr. Quinn states that 33% of the Company's workforce has adopted a hybrid work arrangement, meaning that these employees do not work from an office or Company location on a regular basis. The Company believes that individual workstations should be changed to collaborative space as a result of the hybrid work arrangement. The cost for these modifications is \$3,187,500 in 2023 (\$1,721,250 electric share).

Grand Rapids Service Center Conference Area – According to the Company, individual workstations are no longer conducive to the hybrid work arrangement and it wants to convert those stations and space to a collaborative work area. The cost for these renovations is \$616,250 in 2023 (\$332,775 electric share).

Jackson Service Center & Dispatch – The Company wants to separate the electric and gas dispatch functions and renovate the HVAC system. The cost for this project is \$637,500 in 2023 (\$344,250 electric share).

One Energy Plaza Incubator Lab – The Company wants to remove individual workstations and build collaborative workspace to accommodate a team of people working on corporate process improvements. The cost of this project was \$247,000, which was spent in 2021 (\$133,380 electric share).

Lansing Service Center Incubator Lab – The Company wants to remove individual workstations from the second floor of the existing Lansing Service Center and build collaborative workspace to accommodate a team of people working on company-wide process improvements. The cost of this project is \$68,000 in 2022 (\$36,720 electric share) with about \$13,000 spent in 2021.

Statewide Collaborative Workspace – The Company believes that following the Covid-19 pandemic and in light of the hybrid work arrangement adopted by one-third of its workforce that individual workstations are no longer appropriate. Therefore, it wants to replace them with collaborative workspace in several other office locations around its service area in the state of Michigan. The cost of this project is \$680,000 for each year in 2022 and 2023 (\$367,200 electric

share) with about \$152,00 spent in 2021 and an additional \$680,000 to be spent in 2024 for a total project cost of \$2.2 million from inception to completion.

Most of the renovations involve replacing current office workstations with collaborative workspace.<sup>104</sup> It is not clear what makes a workspace collaborative and why the current workstation arrangement cannot accommodate those employees who come to the office to work. With one-third of the employees working remotely entirely or part-time, there should be more than enough office space to accommodate the other employees and allow for any needed collaboration.

The Company has also not explained collaborative workspaces are needed post-Covid-19 when were able to work effectively previously in workstation arrangements. No evidence has been presented that collaborative workspace will generate sufficient work efficiencies to offset the tens of millions of dollars required by the proposed renovations. Capital expenditures for office renovations would be better directed at replacing deteriorating electric infrastructure to avoid customer power outages.

Except for the Jackson Service Center Dispatch building project, the Company has not justified the other proposed building renovations. Therefore, the

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<sup>104</sup> Coppola, 4 TR 3275 – 3276.

Attorney General recommends that the Commission remove \$2,375,000 of capital expenditures for 2022 and \$6,453,000 for 2023 from the Company's forecasted capital expenditures.<sup>105</sup>

**c. Marshall Metro City**

According to Company witness Quinn, the Marshall Metro City Project, entails construction of underground vaults, tunnels, and manholes with underground electricity cables.<sup>106</sup> The Company also plans to develop training manuals and videos at the facility. The Company has forecasted \$1,060,000 for 2023 for the new Marshall Metro City Project.<sup>107</sup>

It appears that the Marshall City Metro Project (which will be discussed below) will be built adjacent to the new Marshall Training Center. Mr. Quinn describes the objectives of what the Company seeks to achieve with this new training building/center and generally what it entails. The project will require constructing a new building in the city of Marshall where the Company already has

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<sup>105</sup> 2022: \$2,719,000 - \$344,250 for Jackson Service Station Dispatch = \$2,375,000 rounded.

<sup>106</sup> Guinn, 4 TR 1991 – 1997.

<sup>107</sup> Exhibit A-107 (QAG-3), lines 18 and 19.

an existing training center.<sup>108</sup> The city of Marshall is approximately 30 miles west of the Company's headquarters in Jackson, Michigan, and a 35-minute car ride.

According to Mr. Quinn's testimony, the Company seeks to replicate what it calls best training practices by building a new training center with the ability to conduct hands-on training that replicate real-life situations in underground vaults and above ground electric distribution grid work. The Company's refers to it as a holistic approach. Although hands on training simulating real-life conditions can certainly be effective and productive in instilling appropriate skills, the question is why two separate projects and a new building are needed to accomplish this goal. The question also arises as to how the Company has been able to impart the appropriate training up to now without the Marshall Metro City facilities and the new Training Center.<sup>109</sup>

Underground vaults with electric cables and switches are not new. Even assuming that building underground vaults, tunnels, manholes and electric cabling for training is now necessary, the question still remains why these facilities cannot be built within or near existing buildings and training centers owned by the

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<sup>108</sup> Exhibit AG-1.10 includes discovery response ST-CE-184.

<sup>109</sup> Coppola, 4 TR 3270 – 3271.

Company, thus avoiding the construction of a new building at a cost in excess of \$19.0 million. In fact, the Company has not explained or justified the need to construct a new building to house a new training center for the limited purposes that it would serve. According to Mr. Quinn, the Company also wants to add a vehicle repair facility as part of the new building to maintain and repair vehicles and equipment used in the training center. This is not a cost-effective approach despite the small amount of cost savings (\$22,000 annually) identified by Mr. Quinn.<sup>110</sup> The use of a nearby Company vehicle maintenance and repair facility that works on other vehicles and equipment would be more cost-effective.

According to the Company, design work is not yet completed on the Marshall Metro City Project and the Training Center Building but that it would be completed sometime in 2023 although it offered no specific completion date. The Company also stated that construction of the Metro City project would begin in 2023 and construction of the Training Center Building would begin sometime in 2024.<sup>111</sup> The information shows that the Company has not yet performed sufficient programming

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<sup>110</sup> Guinn 4 TR 1999.

<sup>111</sup> Exhibit AG-1.10 includes discovery response AG-CE-184.

and design of the facility to justify the proposed projects and any related capital expenditures.

The Company has not made a compelling case and has not adequately justified the need for the proposed Metro City Project and the new training center building. It is evident that the projects have not yet been fully defined and it is premature to include any capital expenditures in rate base in this rate case.

Therefore, the Attorney General recommends that the Commission remove the capital expenditures of \$1,060,000 for the Metro City project that has been included by the Company for 2023 in this rate case.

**d. Marshall Training Center**

The Company is requesting \$1,000,000 of capital expenditures for 2023 for the new Marshall Training Center.<sup>112</sup> As discussed above with regard to the Metro City project, a new building will be constructed at a location not yet disclosed to house a new training center with the ability to conduct hands-on training that replicate real-life situations. The project will also entail construction of

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<sup>112</sup> Guinn, 4 TR 1197 – 2000.

underground vaults, tunnels, and manholes with underground electricity cables. The Company also plans to develop training manuals and videos at the facility.

For the reasons already discussed above with regard to the Metro City Project, the Attorney General recommends that the Commission remove the capital expenditures of \$1,000,000 included by the Company for 2023 for this project from this rate case.

e. **Unified Control Center.**

The Company is once again seeking funding for a new control center – the Unified Control Center (“UCC”). Previously it indicated that the center would combine two separate service centers into one. However, the Company has not justified the need for a new combined control center or explained what, if any, real cost benefits and other material benefits it will provide.

In this case, Company witness Guinn testifies regarding the UCC and acknowledges that in Case No. U-20963 the Commission rejected cost recovery for the UCC as not adequately justified.<sup>113</sup> On lines 13 of Exhibit A-107 (QAG-3), the Company shows forecasted capital expenditures for the new UCC for 2022 and 2023 of \$100,000 and \$900,000, respectively. In this case, the Company is requesting

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<sup>113</sup> Guinn, 4 TR 2002.

recovery of \$1.0 million in capital expenditures to prepare a project scope, develop project details, to adequately justify the need to build this center with a master plan.<sup>114</sup>

The request for \$1.0 million in capital spending to present sufficient justification to undertake this project is unwarranted. The Company should be able to assemble the needed analysis and documents to justify recovery of the full cost of the project without having to first design a significant portion of the building. The Commission should not allow recovery of any portion of the cost of this project until it has been adequately justified and the Commission determines that any forecasted costs will be reasonably and prudently incurred.

Therefore, the Attorney General recommends that the Commission remove the \$100,000 of capital expenditures from 2022 and \$900,000 for 2023.

#### **4. Information Technology Capital Expenditures<sup>115</sup>**

##### **a. IT Overview and Expenditures**

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<sup>114</sup> *Id.*

<sup>115</sup> Wallingford (Consumers), 4 TR 2586 – 2715; Coppola (Attorney General), 4 TR 3277 – 3282; Tou (MPSC Staff), 4 TR 4017 – 4027.

In Exhibit A-12 (JMW-5), Schedule B-5.10, the Company shows total capital expenditures for Information Technology (IT) infrastructure and various projects. For 2022, the Company forecasted capital expenditures of \$40.4 million and for 2023 it forecasted \$42.9 million. Capital expenditures for 2021 were \$60.6 million. Included in the capital expenditures for 2022 and 2023 are several projects for which recovery in rates should be disallowed. For the most part, these projects are in the initial planning phase or early stage of development and have not been sufficiently vetted or justified with commensurate benefits to meet the basic threshold for inclusion in rate base in this rate case.

This first category of expenditures demonstrates the pitfalls of including (or trying to include) conceptual or very preliminary projects in rate base.

i. **Enhancements – CX&O**

In response to discovery request AG-CE-604 (Exhibit AG-1.11), the Company identified capital spending from enhancements to customer service systems (Enhancements-CX&O Capital). The amount forecasted for 2022 is \$2,912,000 and \$2,528,000 for 2023. The discovery response references pages 91, 94 and 95 of Ms.

Jennifer Wallingford's direct testimony and the Concept Approval document in Exhibit A-172 for further information and justification for the expenditures.<sup>116</sup>

After reviewing Ms. Wallingford's testimony, there is no identification and description of what specific enhancements will be completed for the forecasted capital expenditures. The information provided in the referenced pages of the testimony is very generic and explains processes and methods. The testimony on page 91 also reveals that the Company forecasted the 2022 and 2023 capital spending based on historical spending in the past three-years with no specific needs for system enhancements identified.<sup>117</sup> The Concept Approval document on page 33 of Exhibit A-172 basically repeats the same generic information on page 94 and 95 of Ms. Wallingford's testimony.<sup>118</sup>

The limited information provided by the Company does not adequately justify the \$5.4 million of capital expenditures forecasted by the Company for 2022 and 2023. Furthermore, the benefit/cost ratio calculated by the Company for this project is a negative 0.741, which means that the project costs exceed any financial cost

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<sup>116</sup> Wallingford, 4 TR 2678 – 2681.

<sup>117</sup> *Id.* at 2677.

<sup>118</sup> *Id.* at 2680 – 2681.

savings or benefits. If enhancements are being made to an existing system, it would be expected that those enhancements provide a net positive benefit/cost result.<sup>119</sup>

The forecasted capital expenditures for this project have not been sufficiently justified. Therefore, I recommend that the Commission removed \$2,912,000 of capital expenditures from 2022 and \$2,528,000 from 2023.

ii. **Bill Design and Delivery Transformation Project**

The next project is the Bill Design and Delivery Transformation project with forecasted capital expenditures of \$4.970 million for 2023. At this time, the project is still in the investment planning phase and the requirements phase has not yet been completed and according to the Company will not be completed until 2023.<sup>120</sup> Clearly, the project has not yet been fully scoped and defined and is too premature for inclusion in rate base where the Company could recover a return and depreciation expense although the actual expenditure may not occur. Further, the Company's cost-benefit analysis shows that benefits, far outweigh any potential

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<sup>119</sup> Coppola, 3279 – 3280.

<sup>120</sup> Coppola, 4 TR 3277. See also, Exhibit AG-1.11 (DR AG-CE-604).

benefits.<sup>121</sup> Therefore, the Attorney General recommends that the Commission remove the \$4.970 million of capital expenditures for the 2023 projected test year.

iii. **Facilities Work Management Project**

The Company is projecting \$1.109 million in capital expenditures for this project in 2023. However, the Company has not yet completed the requirements phase which identifies the need for specific solutions that the Company seeks to achieve with the targeted application. This analysis is not expected to be completed until the second quarter of 2024. This is a fundamental phase of the project to establish whether the planned system will meet the business requirements at a granular level. The fact that the Company has not yet completed this critical phase of the projects shows the very preliminary stage of the project. The Company should not be allowed to recover a return and depreciation expense for this project because the investment may not materialize. The Commission should reject the inclusion of costs in rate base that are uncertain to occur. In addition, the cost-benefit analysis provided by the Company shows that the project has a negative

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<sup>121</sup> Coppola, 4 TR 3278 – 3279.

ratio, meaning that on a present value basis the project costs exceed the financial benefits.<sup>122</sup>

From this economic analysis, it is apparent that this project is not a reasonable or prudent investment, and any cost recovery should be rejected by the Commission. Therefore, the Attorney General recommends that the Commission remove \$1.109 million projected by the Company for 2023 for this project.

#### iv. **Service Suite Upgrade**

The Company is projecting \$1.221 million in capital expenditures for this project in 2023. However, the Company has not yet completed the requirements phase which identifies the need for specific solutions that the Company seeks to achieve with the targeted application, which is not expected to be completed until 2023. This is a fundamental phase of the project to establish whether the planned system will meet the business requirements at a granular level. The fact that the Company has not yet completed this critical phase of the projects shows the very preliminary stage of the project. The Company should not be allowed to recover a return and depreciation expense for this project because the investment may not materialize. The Commission should reject the inclusion of costs in rate base that

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<sup>122</sup> Coppola, 4 TR 3278 – 3279. *See also*, Exhibit AG-11.

are uncertain to occur. In addition, the cost-benefit analysis provided by the Company shows that the project has a negative ratio, meaning that on a present value basis the project costs exceed the financial benefits.<sup>123</sup>

From this economic analysis, it is apparent that this project is not a reasonable or prudent investment, and any cost recovery should be rejected by the Commission. Therefore, the Attorney General recommends that the Commission remove \$1.1221 million projected by the Company for 2023 for this project.

v. **Website Redesign**

The Company has projected \$7.829 million in capital expenditures for 2023 for this project. However, the Company has not yet completed the requirements phase which identifies the need for specific solutions that the Company seeks to achieve with the targeted application which will not even be completed until 2023 according to the Company. This is a fundamental phase of the project to establish whether the planned system will meet the business requirements at a granular level. The fact that the Company has not yet completed this critical phase of the projects shows the very preliminary stage of the project. The Company should not be allowed to recover a return and depreciation expense for this project because the

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<sup>123</sup> *Id.*

investment may not materialize. The Commission should reject the inclusion of costs in rate base that are uncertain to occur. In addition, the cost-benefit analysis provided by the Company shows that the project has a negative ratio, meaning that on a present value basis the project costs exceed the financial benefits.<sup>124</sup>

It is apparent from the Company's economic analysis, that this project is not a reasonable or prudent investment, and any cost recovery should be rejected by the Commission. Therefore, the Attorney General recommends that the Commission remove \$7.829 million projected by the Company for 2023 for this project.

vi. **Core Applications Always On for Business.**

The Company has projected \$3.289 million in capital expenditures for 2022 for this project. However, the Company has not yet completed the requirements phase which identifies the need for specific solutions that the Company seeks to achieve with the targeted application. This analysis is not expected to be completed until early 2024. This is a fundamental phase of the project to establish whether the planned system will meet the business requirements at a granular level. The fact that the Company has not yet completed this critical phase of the projects shows the very preliminary stage of the project. The Company should not be

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<sup>124</sup> Coppola, 4 TR 3277 - 3279. See also, Exhibit AG-11.

allowed to recover a return and depreciation expense for this project because the investment may not materialize. The Commission should reject the inclusion of costs in rate base that are uncertain to occur. In addition, the cost-benefit analysis provided by the Company shows that the project has a negative ratio, meaning that on a present value basis the project costs exceed the financial benefits.<sup>125</sup>

It is apparent from the Company's economic analysis, that this project is not a reasonable or prudent investment, and any cost recovery should be rejected by the Commission. Therefore, the Attorney General recommends that the Commission remove \$3.289 million projected by the Company for 2022 for this project.

vii. **Digital Hybrid Cloud and Data Center Migration**

The Company has projected \$2.528 million in capital expenditures for 2023 for this project. However, the Company has not yet completed the requirements phase which identifies the need for specific solutions that the Company seeks to achieve with the targeted application and is not expected to do so until the beginning of 2023. This is a fundamental phase of the project to establish whether the planned system will meet the business requirements at a granular level. The

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<sup>125</sup> Coppola, 4 TR 3277 - 3279. *See also*, Exhibit AG-11.

fact that the Company has not yet completed this critical phase of the projects shows the very preliminary stage of the project. The Company should not be allowed to recover a return and depreciation expense for this project because the investment may not materialize. The Commission should reject the inclusion of costs in rate base that are uncertain to occur.

Therefore, the Attorney General recommends that the Commission remove \$2.528 million projected by the Company for 2023 for this project.

**viii. Generation Operations and Compressor  
Digital Work Management**

The Company has projected \$1.252 million in capital expenditures for 2023 for this project. However, the Company has not yet completed the requirements phase which identifies the need for specific solutions that the Company seeks to achieve with the targeted application. The Company project completing this analysis by the beginning of 2023. This is a fundamental phase of the project to establish whether the planned system will meet the business requirements at a granular level. The fact that the Company has not yet completed this critical phase of the projects shows the very preliminary stage of the project. The Company should not be allowed to recover a return and depreciation expense for this project because the investment may not materialize. The Commission should reject the

inclusion of costs in rate base that are uncertain to occur. In addition, the cost-benefit analysis provided by the Company shows that the project has a negative ratio, meaning that on a present value basis the project costs exceed the financial benefits.<sup>126</sup>

It is apparent from the Company's economic analysis, that this project is not a reasonable or prudent investment, and any cost recovery should be rejected by the Commission. Therefore, the Attorney General recommends that the Commission remove \$1.252 million projected by the Company for 2023 for this project.

**ix. ARP – Server and Storage**

This category of expenditures relates to IT server and storage equipment replacements. The Company follows a five-to-seven year replacement cycle for replacement purportedly to prevent failures and meet organic growth.<sup>127</sup> It is projecting capital expenditures of \$3,299,000 for 2022 and \$5,957,000 for 2023 for this program although it only spend approximately \$2.72 million in 2021 for the same.<sup>128</sup> Other than the generic explanation noted above, the Company provided no

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<sup>126</sup> *Id.*

<sup>127</sup> Wallingford 2638 – 2639.

<sup>128</sup> Exhibit A-173 (JMW-8), page 7.

specific justification such as performance problems experienced with the targeted equipment that required replacement to resolve.<sup>129</sup>

The Company claims that the increase in 2022 over the 2021 expenditure amount is due to additional labor and overhead costs for performing testing and validation of certain hardware. It provides the same reason plus the addition of hardware for the increase in 2023.<sup>130</sup> However, the Company does not explain why the additional testing, validation, and hardware are needed in 2022 and 2023, but not in 2021. If the Company was following a consistent schedule for replacement of outdated equipment every five or seven years, there should not be large fluctuations in spending year-to-year. Nonetheless, the Company is proposing increasing expenditures from approximately the \$2.7 million it incurred in 2021 to more than twice that amount in 2023.<sup>131</sup>

The Company has not justified spending \$3,299,000 in 2022 and \$5,957,000 in 2023 for this program. Given the lack of justification, a reasonable approach to estimate capital expenditures for 2022 and 2023 is to use the most recent amount

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<sup>129</sup> Coppola, 4 TR 3281 – 3282.

<sup>130</sup> See, Exhibit A-1.12 (AG-CE-605).

<sup>131</sup> Coppola, 3281 – 3282.

spent in 2021 and adjust this amount for projected inflation.<sup>132</sup> Using this approach, the capital expenditure for 2022 be set at \$2,901,000 and for 2023 at \$2,981,000.<sup>133</sup> These amounts are lower than the Company's forecasted amounts of \$3,299,000 for 2022 and \$5,957,000 for 2023. The difference is \$398,000 for 2022 and \$2,976,000 for 2023. Therefore, the Attorney General recommends that the Commission remove \$3,374,000 from the Company's forecasted capital expenditures for this program.

#### **B. Capital Expenditures Adjustments Summary**

The chart below summarizes the Attorney General's proposed reductions in capital expenditures in those areas where the level of capital expenditures presented by the Company is excessive and unnecessary. As noted above with regard to the Mustang Mile and Washtenaw solar projects, the Attorney General is making an adjustment with regard to the recommended revenue requirement.

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<sup>132</sup> Coppola, 4 TR 3282.

<sup>133</sup> 2022:  $\$2,720,070 \times 1.0665 = \$2,901,000$ . 2023:  $\$2,901,000 \times 1.0275 = \$2,981,000$ .

<b>Summary of AG Disallowed Capital Expenditures</b>	
	<b>Amount (millions)</b>
Distribution Plant	\$ 125.5
Power Generation	198.9
Information Technology	31.0
Operations Support	18.5
<b>Total</b>	<b>\$ 373.9</b>

The Commission should reduce the Company’s proposed capital expenditures by \$369.9 million and reduce average rate base by \$237.5 million, as shown in Exhibit AG-1.13. The Attorney General’s capital expenditure adjustments result in a lower rate base and consequently a reduction in the Company’s proposed revenue deficiency of \$7.6 million.

### **III. Capital Structure and Rate of Return<sup>134</sup>**

#### **A. Introduction of Company’s proposal.**

Consumers Energy proposes a capital structure with 51.50% equity, with a ROE of 10.25%. Company witness Bleckman provided direct and rebuttal

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<sup>134</sup> Bleckman 2 TR 269 – 392; Wehner 2 TR 103 – 263; other witnesses providing testimony on these topics include – Coppola (Attorney General), 4 TR 3284 – 3332; Megginson (MPSC Staff) 4 TR 3977 – 4015; Walters (ABATE) 4 TR 2916 - 2988; Perry (Walmart), 4 TR 3101 - 3112; Cira-Reyes (UCC) 4 TR 3031 - 3046.

testimony on behalf of the Company regarding the capital structure and witness Wehner was the Company's rate of return expert.

## **B. Test Year Capital Structure**

### **1. Common Equity Balance.**

The Company has proposed a permanent capital structure with a common equity component of 51.50%. While the Company's proposed common equity ratio of 51.50% is less than the 2021 historical test year percent of 52.74% it is more than the 51.02% equity ratio approved by the Commission in Case No. U-20963.<sup>135</sup> The Attorney General believes there are several factors that need to be considered in determining whether the Company's proposal is reasonable and prudent, including: (1) the Commission's directive in the Company's Case No. U-17990, which was reaffirmed in Case No. U-20963, that the Company move to a totally balanced capital structure unless it can demonstrate otherwise; (2) the Company's practice of funding a significant part of its equity contributions with long term debt issued at the parent company level; (3) the Company's unsupported position that a higher equity cushion is needed to maintain its credit ratings on long-term debt; and (4)

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<sup>135</sup> Exhibit A-14 (MRB-1), Schedule D1. See also, Coppola, 4 TR 3284 – 3285.

the fact that the common equity ratio of the peer group, used to assess the cost of common equity in this case, is approximately 46%.<sup>136</sup>

The Attorney General is recommending that the Commission approve a capital structure with a debt/equity ratio of 50% debt and 50% equity. Exhibit AG-1.14 shows the Attorney General's recommendation for the projected long-term debt, preferred equity and common equity permanent capital of the Company for the test period ending December 2023. It rebalances the Company's proposed capital structure. The long-term debt component in Exhibit AG-1.14 has been increased by \$298 million and the common equity component has been reduced by the same amount.<sup>137</sup>

In response to the Company's continuing requests for ever increasing equity ratios in recent years, the Commission in its February 17, 2017 order of in Case No. U-17990 stated:

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

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<sup>136</sup> See, Exhibit AG-1.17. See also, Coppola, 4 TR 3285.

<sup>137</sup> Coppola, 6 TR 2944.

In Case No. U-18424, the Company presented a plan to gradually decrease its common equity ratio to 52.5% in 2018, 52.0% in 2019 and by a half of a percentage point in each year until the 50% ratio is achieved in 2023. In its gas rate case, U-20322, the Company asserted that it needed to maintain its equity ratio at 52.50% for the foreseeable future. However, in its September 26, 2019 order in the that case, the Commission decided to set the common equity ratio at 52.05%, as recommended by the Commission Staff. The Commission noted on page 54 of the order that the Staff's recommendation was based in part on "...the Commission's desire to see the Company move toward a 50/50 capital structure." And, as noted above, the Commission in its December 17, 2020 order in Case No. U-20697, approved a common equity ratio of 51.11% stating that "the Staff's recommendation keeps Consumers on track to rebalance its capital structure as the Commission previously ordered while allowing Consumers to maintain its wide access to capital markets to be reasonable." In the Company's most recent electric rate case to go to a Commission order, U-20963, the Commission approved an equity ratio of 51.02%, but reaffirmed its previous requirement that the Company reach a balanced equity ratio. For the reasons provided below, the Commission should require the Company to complete its rebalancing of its equity ratio.

- a. **The Company's proffered reasons for a 51.50% common equity ratio should be rejected.**

The Company claims in this case that an equity ratio of 51.50% is mandatory for the foreseeable future for several reasons – the Tax Cut and Job Act (TCJA), the need to finance infrastructure upgrades and maintaining certain case flow ratios in support of the Company’s credit metrics, and the effects of PPA (power purchase agreements).<sup>138</sup> The Company’s plan to put the move to a 50% equity ratio on hold indefinitely is not supported by the record. The reasons offered by the Company do not require this result.

First, the focus on the TCJA is misleading as a reason to maintain an imbalanced debt-equity ratio. The Company has raised this issue in previous cases, but in the several years since its enactment have failed to show how the TCJA would impact the Company’s equity ratio.<sup>139</sup> In fact, the Company has communicated to investors and securities analysts that because of the pass-through to customers of lower taxes from the TCJA, it has “headroom” to increase capital expenditures at an even higher level.<sup>140</sup> This information clearly contradicts the view that it needs a higher equity ratio as a result of the TCJA.

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<sup>138</sup> Coppola, 4 TR 3287.

<sup>139</sup> Id. *See also*, Bleckman Cross, 2 TR 377 – 381.

<sup>140</sup> Coppola, 4 TR 3287.

In rebuttal the Company attempts to clarify this information by stating it means that due to lower cost, more money will be available for capital expenditures without raising rates, thus saving ratepayers money.<sup>141</sup> This explanation seems to be inconsistent with the actual statement. The reality is that the Company is raising rates in large part due to increasing capital expenditures and the Company has not provided any evidence that this headroom has been used to the benefit of ratepayers. Moreover, the additional debt to fund additional capital expenditures, which the Company has stated are now opportunistically possible due to the TCJA, is likely to be the real issue for rating agencies when assessing the Company's credit ratios.<sup>142</sup>

Despite the Company's claims otherwise, the rating agencies have expressed concerns with the Company's high level of capital expenditures and resulting increased debt load.<sup>143</sup> A better option to increasing the equity ratio would be for the Company to decrease capital expenditures, use internally generated cash to

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<sup>141</sup> Bleckman, 2 TR 349 – 350.

<sup>142</sup> Coppola, 4 TR 3288.

<sup>143</sup> *See*, Fitch Investor Service October 11, 2021 Report: “Concerns regarding the large capex plan are mitigated by the MPSC’s constructive ratemaking policies, including use of a forward test year which allows for timely recovery of Capex.” S&P March 30, 2022 Update: “We think this potentially signals regulatory risk that the Company must effectively manage, given its elevated capital spending program, and a regulatory strategy that assumes consistent rate case filings.”

fund capital expenditures, and issue less debt if it is concerned with its cash flow to debt coverage ratios. Otherwise, the Company's continuing escalation in capital spending and the resulting incremental debt will weaken the same cash flow ratios with which the Company is concerned.<sup>144</sup>

Second, the Commission should disregard the Company's claims that PPAs justify a higher equity ratio.<sup>145</sup> Consumers Energy is not unique in using PPAs to buy power. Most, if not all, of the Company's peer utilities buy power under PPAs. Thus, there is no basis for the argument that Consumers Energy should carry higher common equity capital to support these contracts. Moreover, the Company's largest remaining PPA will expire in 2025. Additionally, in Case No. U-20165 (the 2018 filed Integrated Resources Plan) the Commission approved a Financial Compensation Mechanism (FCM) that allows the Company to earn an additional return on equity on new PPAs. The Company proposed the FCM because of its concern that credit rating agencies were imputing a certain amount of debt against the Company's capital structure negatively impacting its debt coverage ratios. The Commission's order in the Company's 2021 IRP case, Case No. U-21090, approved the extension of the FCM. Therefore, Mr. Bleckman's argument that the credit

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<sup>144</sup> Coppola 4 TR 3288.

<sup>145</sup> *See*, Bleckman 2 TR 290.

impact of PPAs should be reflected in the capital structure has no merit and would be duplicative of the benefit that the Company obtains through the FCM.<sup>146</sup>

Third, the Company has not proven that it needs a common equity ratio of 51.50% to maintain certain cash flow ratios in support of its credit metrics. In Exhibit AG-1.22, Mr. Coppola calculated the Company's key cash flow to debt ratio for 2021 adjusted for the ROE and Common Equity ratio levels he advocates in this case for Moody's and S&P. The result of his analysis for Moody's is shown on line 4 with a cash flow to debt ratio of 20.9%. This ratio is well above the 18% downgrade threshold noted by Moody's in its most recent report. On page 2 of Exhibit AG-1.22, the results for S&P show a pro-forma coverage ratio for 2021 is 20.1%, which is well above the S&P downgrade threshold of 15%. Mr. Coppola's testimony provides a complete analysis of the ratio.<sup>147</sup>

While Moody's did downgrade the Company's debt from Aa3 to A1 in May of this 2021, that alone does not mean that the Company is less credit worthy. As Mr. Coppola noted, the Company's prior Moody's rating (double A) was out of line with ratings from S&P and Fitch's (single A's). The ratings by those companies reflected

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<sup>146</sup> Coppola, 4 TR 3288 – 3289.

<sup>147</sup>Coppola,4 TR 3293 – 3294.

the middle and top end of the A ratings category. While, the Aa3 rating by Moody's was at the lower end of the stronger Aa category and likely reflected Moody's level of comfort with the Company's risk profile and also provided the Company with added cushion against a downgrade below the middle "A" rating. The New A1 is now equivalent to or a notch above the credit ratings of S&P and Fitches.<sup>148</sup>

Other considerations appear to have impacted Moody's downgrade decision including CMS Energy's heavy debt load, and lower ROE and common equity ratio.<sup>149</sup> Moody's also pointed out the Company continued escalation of its projected capital expenditures outlook for the following five years from \$12.2 billion in the 2020 to 2024 period to \$13 billion for the 2021 to 2025 period, which is an increase of approximately 7%.<sup>150</sup>

These factors, as well as certain rate case outcomes, were undoubtedly important in the Moody's decision. Following the assignment of the new rating, in its May 2021 report<sup>151</sup> on page 2 under the caption "Factors that could lead to a

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<sup>148</sup> Coppola, 4 TR 3290.

<sup>149</sup> See, Coppola, 4 TR 3291 and Exhibit A-34.

<sup>150</sup> See the July 7, 2020 and May 10, 2021 Moody's reports under the sections "Capital Spending Remains Elevated" on pages 4 and 5 of these reports respectively. Exhibit AG-1.23 includes discovery response AG-CE-0196.

<sup>151</sup> Exhibit A-34 (MRB-12) includes the full report.

downgrade,” Moody’s cited key factors they would consider in the future. These are (1) a material deterioration in the credit supportiveness of the Michigan regulatory environment, or (2) the cash flow to debt ratio of CFO pre-W/C to debt falling below 18% on a sustained basis. Page 2 of the most recent May 2022 Moody’s report on the Company cited the same language.<sup>152</sup> Page 2 of the May 2022 Moody’s report shows that the Company’s CFO pre-W/C to debt ratio was at 21.8% for 2020 and 22.6% for 2021, both of which are above the 18% level. Among the credit challenges noted on page 2 of this report are higher leverage at the Parent company, CMS Energy, and what Moody’s refers to as a “robust capital investment plan”. It is also important to note that neither S&P or Fitch’s lowered their ratings for the Company’s debt.

There is no factual basis for the Company’s claim that it needs its equity ratio raised from 51.02% to 51.50% to maintain its credit worthiness. As demonstrated above, there is ample space in Consumers’ FFO-to-debt ratio to support a 50% equity ratio and a ROE of 9.5% and still avoid a downgrade. If the Company is truly concerned about future downgrades, there are actions it can take to alleviate

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<sup>152</sup> Exhibit AG-1.23 includes discovery response AG-CE-196 with the applicable Moody’s credit report.

those concerns, including reducing debt with a more moderate capital expenditure program.<sup>153</sup>

In rebuttal, the Company asserted that there was no concern with the level of its capital expenditures.<sup>154</sup> As discussed above, that is not true. Both S&P and Moody's discuss the Company's capital expenditure plans and hint at what it can do to help its FFO-to-debt ratio.

The Company's witness also tries a little slight-of-hand in asserting that the Company's proposed 51.50% equity ratio is the equivalent of a 49.5% equity ratio on an adjusted basis after considering leases, short-term debt and securitization debt. Leases, Short-term debt, and securitization debt is not part of the permanent capital structure. The Company made this argument in Case No. U-20963 and it was rejected by the Commission which ordered a 51.02% equity ratio when the Company claimed a 52.00% equity balance was required. In addition, the Commission was clear on its requirement for the Company to move to a 50 – 50 debt/equity ratio with only temporary short-term deviations with the burden on the

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<sup>153</sup> Coppola, 4 TR 3292.

<sup>154</sup> Bleckman, 2 TR 351 – 352.

Company to show that such deviations are reasonable and prudent.<sup>155</sup> The Company's position has no merit and should be rejected by the Commission because there is no basis for any further "deviations."

Fourth, the Company has not demonstrated that there has been any deterioration to the fundamentals underlying its financial condition. The Company's earnings have not suffered. The reality is that the greatest threats to the economic condition and creditworthiness of the Company are still factors within its control. This is a point noted in the agency reports.

Company witness Wehner's claim that the current common equity ratio of 51.50% and 10.25% ROE may not be sufficient to maintain the Company's credit rating is baseless.<sup>156</sup> The Company does not provide any evidence from the ratings agencies that certain minimum equity ratios or ROEs are needed to maintain credit ratings. In rebuttal, Mr. Bleckman referenced some "expectations" by a ratings agency of the outcome of rate cases. However, as discussed above, the agencies

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<sup>155</sup> Commission order dated December 22, 2021 in Case No. U-20963, p. 200. *See also*, Coppola, 4 TR 3289 – 3290.

<sup>156</sup> Wehner, 2 TR 125.

have clearly indicated what could lead to a downgrade and the ratios and rates advocated by the Company were not mentioned.

**b. Consumers Energy's equity ratio should be more in line with the ratios of its peer group.**

The average common equity ratio of the peer company group for 2021 was 45.5%.<sup>157</sup> Because the cost of equity for those companies in the peer group is highly dependent on the financial risk reflected in their capital structure, it is critical to synchronize the capital structure of the Company to the peer group average as closely as possible in order to have consistency with the cost of equity capital derived from those peer group companies.<sup>158</sup> The Company's proposed common equity capital ratio of nearly 51.50% creates a disconnect and is also more costly to customers. Further, the lower peer group equity ratios also demonstrate that similarly situated companies are operating and thriving with a lower equity ratio.<sup>159</sup>

**c. Impact of CMS Energy's level of long-term debt.**

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<sup>157</sup> See, Exhibit AG-1.17.

<sup>158</sup> Coppola, 4 TR 3301.

<sup>159</sup> *Id.* at 3301 – 3302.

As noted above, the relationship between Consumers Energy and its parent company, CMS Energy (“CMS”), impacts the Company’s proposed capital structure.<sup>160</sup> First, CMS controls when and how capital is injected into the Company. Therefore, it can make the Company’s common equity ratio whatever it wants in its discretion.<sup>161</sup> Over the last five years 2017 to 2021, Consumers Energy’s has experienced a net increase in common equity of \$3.3 billion from (\$5.9 billion to \$9.2 billion).<sup>162</sup>

Second, CMS Energy is a frequent issuer of long-term debt in the capital markets. CMS issued approximately \$1.3 billion in new debt over the last five years.<sup>163</sup> Nearly 100% of CMS’ assets and earnings come from Consumers Energy. Therefore, from a practical operating standpoint, CMS and Consumers Energy are one and the same. It should also not be over-looked that the Company’s practice of funding a significant part of its equity contributions with funds from long term debt issued at the parent company level is problematic.

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<sup>160</sup> See, Coppola, 3296 – 3300.

<sup>161</sup> Coppola, 4 TR 3296.

<sup>162</sup> *Id.* at 3297 (Table 1).

<sup>163</sup> Coppola, 4 TR 3298.

The excessive debt and low common equity ratio (approximately 33% in 2021) at CMS is a continuing concern for the rating agencies when assessing the debt rating of Consumers Energy. Moody's has indicated that "An increase in parent level debt leading to a decline in the credit quality of CMS" as a potential factor that could lead to a downgrade of the Company.<sup>164</sup> It is not clear how much the debt-laden capital structure of CMS has contributed to a lower debt rating than the Company could have achieved if CMS was capitalized with more equity capital. However, the statements in Moody's credit reports and similar concerns expressed by other rating agencies, indicate that the debt-laden capital structure of CMS has contributed to a lower debt rating than the Company could have achieved if CMS was capitalized with more equity capital. The result has been higher interest costs for customers. Partially to compensate for this significant leverage at CMS, the Company now wants a higher equity ratio in the capital structure that will further increase costs to customers.

See Mr. Coppola's testimony for a complete analysis of the impact of CMS's financial condition on Consumers.<sup>165</sup>

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<sup>164</sup> Exhibit AG-1.25, Moody's Report of May 2021, page 2.

<sup>165</sup> Coppola, 4 TR 3299 - 3300.

d. **Equity ratio impact.**

The revenue requirement savings related to a lower common equity ratio of 50% when compared to the Company's proposed equity ratio of 51.50% is approximately \$17.2 million annually.<sup>166</sup> This reflects (a) the difference between the pre-tax cost of common equity of approximately 14.1% versus the cost of long-term debt of 3.69%; (b) the Company's proposed rate base of approximately \$13.7 billion; and (c) the percentage of total capital being shifted from common equity to long term debt.<sup>167</sup> Therefore, the Attorney General recommends that the Commission approve a 50-50 balanced debt to equity ratio. More importantly, the Commission should not be swayed from its stated objective of requiring the Company to obtain a balanced permanent capital structure of 50% common equity and 50% debt and preferred stock capital.

2. **Long term debt balance.**

The Attorney General is utilizing the long-term capital balance sponsored by Company witness Bleckman in Exhibit A-14 (MRB-1), Schedule D1.

3. **Short-term debt balance.**

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<sup>166</sup> Coppola, 4 TR 3302.

<sup>167</sup> *Id.*

The Attorney General is utilizing the long-term capital balance sponsored by Company witness Bleckman in Exhibit A-14 (MRB-1), Schedule D1.

**C. Cost Rates - The Commission should adopt the Attorney General's adjustment to the cost of capital and ROE.**

**a. The Company's requested ROE.**

According to Company witness Todd Wehner, an appropriate ROE for the Company is 10.25%.<sup>168</sup> However, as will be discussed below, Mr. Wehner used flawed assumptions and novel and untested analysis which has led to grossly overinflated estimates for the Company's proposed ROE.

**b. Applicable Principles – Standard for Determining ROE.**

A utility company is entitled to a fair return that will allow it to attract capital and be sufficient to assure investors of its financial soundness. In its opinion in *Bluefield Water Works and Improvement Company v Public Service Commission of West Virginia* (the "Bluefield Case") 262 U.S. 679 (1923), the United States Supreme Court indicated that "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that being made at the same time...on

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<sup>168</sup>Wehner, 2 TR 109.

investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties...” The principals of the *Bluefield Case* were re-affirmed by the U.S. Supreme Court in 1944 in the case *FPC v Hope Natural Gas Company*, 320 U.S. 591. The Attorney General’s witness followed these guiding principles. Based on these standards, Mr. Coppola recommends a ROE that will enable the Company to maintain its financial integrity. Mr. Coppola considered these principles in his calculation of the appropriate ROE.<sup>169</sup>

Mr. Coppola also noted that because determining the cost of common equity for an enterprise or an industry group is inexact since investors can only estimate what the future cash flows from any enterprise may be over time. As a result, most financial experts will not rely solely on any one particular method. He utilized three approaches to assessing the cost of common equity – the Discounted Cash

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<sup>169</sup> Coppola, 4 TR 3305.

Flow (DCF) Method, the Capital Asset Pricing Model (CAPM) and the Utility Risk Premium approach.<sup>170</sup> Applying these three methodologies, Mr. Coppola calculated an average ROE of 9.06%.<sup>171</sup> However, he recommended an allowed rate of return on common equity of 9.50% for reasons provided below. He also considered the cost of common equity of a proxy group of peer companies in connection with the methods listed above in determining the cost of common equity.<sup>172</sup>

c. **Qualitative Market and Risk Considerations**

Before addressing the calculation of the ROE, it should be noted that one of the most important factors in determining the required return on equity of a utility is risk. And utilities face a smaller degree of risks compared to most of other businesses due to the regulatory scheme which provides for rate increases if reasonable and prudent and authorized rates of return. Therefore, a utility's return should be lower than other riskier businesses. Second, utilities should earn comparable returns to other businesses with similar degree of risk in order to maintain its financial soundness including maintain its credit standing, attract capital for investment and so on.

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<sup>170</sup> Coppola, 4 TR 3305.

<sup>171</sup> Coppola, 4 TR 3306. See also, Exhibit AG-1.15.

<sup>172</sup> *Id.* at 3306.

d. **Quantitative Methodologies and Conclusions -The Attorney General ROE calculation and recommendation**

Consistent with the legal principles stated above and the proper application of recognized models, the Attorney General's expert recommends a reasonable ROE of 9.50%.

i. **Proxy Group Selection Criteria.**

Despite not being publicly traded (it is a subsidiary of CMS Energy), Consumers Energy operates in, and its financial performances are a part of the general economic and industry environment. Potential investors will still compare Consumers Energy's expected returns on investment to the market returns on other available alternatives. Consequently, a broad analytical approach including studying the underlying economic environment, Federal Reserve policy, likely investors' expectation of the future returns, and the utility industry's expected returns in the current market is appropriate.

Mr. Coppola established a peer group beginning with a fairly broad search with 37 electric utilities and narrowing it down until he a group of 12 companies shown in Exhibit AG-1.20, all of which have growing earnings and dividends. Mr. Coppola's peer group is larger than the one sponsored by Company witness Wehner

and contains only seven companies. Six of these companies were in Mr. Coppola's peer group and the seventh (Pinnacle West) was purposely eliminated by him due to a recent negative rate order which has resulted in litigation between Arizona Public Service and the Arizona Commission. Mr. Coppola also included Consolidated Edison, Allete, Alliant Energy, Avista, Black Hills and IDACORP in his peer group. The smaller size of the proxy group selected by the Company for its peer group is problematic especially when developing a DCF estimate of ROE, as discussed below. Accordingly, the peer group recommended by Mr. Wehner should be given less weight due to its size.

ii. **Application of Quantitative Models**

Consumers Energy is also subject to the same risks that other firms in its industry face, including variation in demand, limits on growth, environmental compliance costs, employee benefit costs, the cost of infrastructure improvements, regulatory decisions, capital market conditions (interest rates), and the availability to credit and access to capital markets. Therefore, Mr. Coppola utilized standard DCF and CAPM methodologies to evaluate a group of comparable companies. The CAPM model considers market risk. He also used a third method – a Utility Risk Premium approach. To avoid bias and make the cost of capital analysis more

reliable, the conventional approach is to select a proxy group of comparable companies as discussed above.

### iii. **Cost of Common Stock**

Two of the approaches used by Mr. Coppola in his analysis are market-based methods: the Discounted Cash Flow (DCF) method and the Capital Asset Pricing Model (CAPM), which are both recognized methods used in the cost of capital proceedings. The DCF method is based on the anticipation of the company's futures earnings and growth opportunities.<sup>173</sup> The CAPM model is based on the risk premium concept. The third method is a Utility Risk Premium approach. In addition, he also considered investors' understanding and expectation of the economic environment, Michigan's economy and the current industry and company specific information.

### iv. **Discounted Cash Flow Methods**

The DCF method calculates the required return for an investor as follows:

$$R = D/P + g$$

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<sup>173</sup> Coppola, 6 TR 2970.

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

Regarding the growth rate in dividends, most practitioners rely on earnings growth as a substitute for this item.

In the equation, “R” is the required rate of return on investment by investors. It is also the discount rate that is used to convert the future cash flows from the investment into the present value. “D” is the amount of dividend paid to equity holders. “P” is the market price of the common stock, representing the current valuation of the company by the market. So “D/P” is the current dividend yield on the company’s common stock. And “g” is the expected growth rate of the dividend or earnings.

The DCF method provides the minimal return for a company to attract and maintain investment in the company’s common equity. It represents the investor’s expectation based on available current market information. It is a measuring stick to compare alternative investment opportunities. Mr. Coppola further explains his inputs for the DCF model, including the stock price he uses, his calculation of the dividend yield, the growth rate he utilized and why he used it and summarized his ROE calculations under the constant growth DCF model as follows:

The results of my DCF analysis are summarized in Exhibit AG-1.16. The stock price information in column (c) of this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from May 18 to June 30, 2022. The annual dividend in column (d) is the projected average dividend level for 2022 and 2023 as projected by the Value Line Investment Survey. Column

(h) shows the average long-term earnings growth rate based on (1) the estimate of earnings growth for the five years (2021 to 2026) per Value Line; and (2) the earnings growth estimate by stock analysts over the next five years which is available from Yahoo.com.<sup>174</sup>

Using the DCF Method, Mr. Coppola calculated an average return on common equity for the proxy group of 8.73%. This result is higher than the Company's DCF calculations of 9.44%<sup>175</sup>. Timing and peer group differences contribute to the difference between the Company's and Mr. Coppola's DCF estimates.<sup>176</sup>

#### v. **The CAPM Method**

As noted above, the CAPM method is based on an analysis of risks. It considers two types of risks: risk that investors can diversify away or reduce by combining different investments into a portfolio; and market risk that an investor cannot reduce by diversification. Therefore, the CAPM method is a risk premium model, based on the calculation of the risk differential between investments on the market portfolio and the individual stock. The calculation of the required rate of return on the company's stock is as follows:

$$K = R_F + \beta (R_M - R_F)$$

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<sup>174</sup> Coppola, 4 TR 3308.

<sup>175</sup> See, Wehner, 2 TR 109 – 110. See also, Exhibit A-14 (TAW), Schedule D-5, page 6.

<sup>176</sup> Coppola, 4 TR 3309 – 3310.

Where:       $K$  = the required return.  
               $R_F$  = the risk-free rate.  
               $R_M$  = the required overall market return; and  
               $\beta$  = beta, a measure of a given security's risk relative to that  
                  of the overall market.

The purpose of using the CAPM model to calculate the required return on the individual investment is to find the equivalent return for an investor based on the relative risk of the investment as compared to the alternative investment opportunities. The CAPM model has two general components: one is the risk-free rate, and the other is the company risk premium, which is the product of the company's beta and market risk premium ( $R_M - R_F$ ). The market risk premium is the difference between the market return and the risk-free rate. Mr. Coppola provide the following detailed explanation of his calculation of the required return based on the CAPM model:

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

than the overall market. Reflective of this outcome, the average Beta of the Peer Group is 0.86.”<sup>177</sup>

The Attorney General’s CAPM calculation can be found in Exhibit AG-1.17.<sup>178</sup> The resulting ROE based on the CAPM is 10.02%. Mr. Coppola believes that the CAPM is useful in assessing the relative risk of different stocks or portfolios of stocks. However, it has limitations because it assumes that the entire risk of a stock can be measured by the “Beta” component and as such the only risk an investor faces is created by fluctuations in the overall market. However, investors take into consideration company-specific factors in assessing the risk of each particular security. Therefore, he gives the CAPM approach less weight than the DCF approach in determining the cost of common equity.<sup>179</sup>

#### vi. **Utility Risk Premium Approach**

Generally, one can estimate the cost of common equity for a peer group of utility companies by (1) projecting the cost of debt for the peer group and adding to

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<sup>177</sup> Coppola, 4 TR 3311.

<sup>178</sup> See, Mr. Coppola’s testimony at 4 TR 3311 - 3312 for a detailed explanation of the calculation.

<sup>179</sup> Coppola, 4 TR 3312.

this cost (2) the average return differential of utility common stocks over utility bonds.<sup>180</sup> This approach is called the utility risk premium approach.

Mr. Coppola calculated a return on common equity under this approach by adding the credit spread of utility bonds rate “A” and “BBB” of 5.24% with the spread utility bonds over U.S. treasury bonds of 1.44%% for electric. The resulting cost of common equity is 9.87% which is shown on line 7 of Exhibit AG-1.18.<sup>181</sup>

**vii. Criticism of the Company’s method of calculating ROE.**

As noted above, the Company is seeking a ROE of 10.25%. However, the Company uses novel and unorthodox methodology to reach that result. Mr. Wehner relied on what he termed a Projected CAPM, Projected ECAPM and Projected Risk Premium methods to calculate ROE.<sup>182</sup> Mr. Coppola provides a comparison of the Company and Attorney General’s ROEs based on the various methods:

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<sup>180</sup> Coppola 4 TR 3312 – 3313.

<sup>181</sup> See, 4 TR 3313 for a description of Mr. Coppola’s calculation of the Risk Utility Premium Approach.

<sup>182</sup> See, Exhibit A-14, pages 2, 3, 4 and 5.

	<b>Utility Risk Premium</b>	<b>Traditional CAPM</b>	<b>Total Beta CAPM</b>	<b>ECAPM</b>
<b>Attorney General ROE</b>	9.87%	10.02%	N/A	N/A
<b>Company ROE</b>	12.76%	10.37%	12.69%	10.56%
<b>Exhibit A-14 (TAW-1) Page</b>	5	2	4	3

As you can see, the Attorney General did not provide an estimated ROE using an ECAPM method for reasons discussed below. As noted by Mr. Coppola, the differences between the Company's and the Attorney General's ROE estimates, is the risk premium rates utilized in the application of the models.

Mr. Coppola's calculations use the historical risk premiums for both the CAPM analysis and the Utility Risk Premium analysis, whereas witness Wehner utilizes risk premiums based on short time periods.<sup>183</sup> Both of the Company's CAPM estimates and ECAPM estimate sponsored by witness Wehner utilize a short-term market risk premium (MRP) of 8.64%, which is 1.4% above the long-term (1926-2020) rate of 7.25% that Mr. Coppola utilized. Mr. Wehner's developed his 8.64% MRP in Exhibit A-14 (TAW-1), page 13. This MRP was based upon a

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<sup>183</sup> Coppola, 4 TR 3314-3316.

projection of expected returns of the S&P 500 Index over the three years 2022 to 2024,<sup>184</sup> (again, a short period). This approach to the development of an MRP and Total Beta CAPM has several drawbacks.

Mr. Coppola elaborates further in his testimony regarding the fallacies in Mr. Wehner's methodology, including using extremely short historical periods to determine his risk premiums, using periods of economic recovery which leads to results that are upwardly biased compared to the long-term outlook among other things.<sup>185</sup> In the case of his Projected Risk Premium method, Mr. Wehner is using two extremely short historical periods (the 1942 to 1951 period and the 2011 to 2020 period) to measure results and determine his risk premium. These two periods of time involve (a) the World War II recovery period from the "Great Depression"; and (b) the recovery years following the "Great Recession" of 2008 to 2009. As such, Mr. Wehner's results are upwardly biased and not reflective of long-term reality.

The use of a short time-period to calculate the market risk premium does not take into consideration the stock market returns during both expansion and contractions in the economy. To determine an appropriate expected market return and risk premium, multiple economic cycles over a long timeframe must be

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<sup>184</sup> See DR AG-CE-0211

<sup>185</sup> Coppola, 4 TR 3315 – 3319.

considered. Otherwise, the calculations of market risk premiums would result in very high ROEs during periods of economic expansion, as Mr. Wehner has calculated under his unconventional approach, and very low and perhaps even negative ROEs during periods of economic decline.

These concerns are also echoed by Dr. Roger Morin who favors the use of the longest possible period for calculating a market risk premium. On page 114 of his book “New Regulatory Finance” Dr. Morin states the following:

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

Clearly, Mr. Wehner’s approach to calculating projected market risk premiums is not academically or practically sound and merely an attempt to produce a result that is more favorable to the Company. The Commission should give those ROE calculations no weight.

The Commission should also give no weight to the Company’s use of the ECAPM. The basic premise for the use of the ECAPM method is that the Beta

factors published by Value Line when used in CAPM analysis do not accurately predict stock performance. However, for reasons discussed in Mr. Coppola's testimony that argument is flawed.<sup>186</sup> Notwithstanding Mr. Wehner's arguments, there is academic disagreement with the validity of the original studies that led to the use of ECAPM. First, the original study used raw betas and not the adjusted Value Line betas, which Mr. Coppola uses, and other cost of capital experts normally rely upon. Second, the original studies relied upon short-term risk-free rates. Instead, cost of capital witnesses, including Mr. Coppola, who have been involved in the Company's rate cases use long-term risk-free rates in the CAPM model.

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

Finally, Mr. Wehner relies on the "Comparable Earnings" method to calculate its ROE. As shown on page 86 of Exhibit A-14 (TAW-1), Schedule D-5, Mr. Wehner derives a 10.10% projected average ROE rate based on the forecasted earnings

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<sup>186</sup> Coppola, 4 TR 3320 – 3322.

divided by the book value of common equity for his peer group. His overall recommended ROE of 10.50% relies on this estimated return on equity rate.

Unfortunately, this is not an academically sound approach to determine the cost of common equity for any company. What Mr. Wehner is doing is simply dividing (1) the projected earnings per share (“EPS”) approximately four years from now for each peer group company (as estimated by Value Line) by (2) the projected Book Value for each such peer group company. This exercise perhaps has some use in evaluating how well each peer group company employs capital over longer periods of time but is useless as a tool to set the authorized ROE of a utility company. This method does not take into account investors’ expectations or stock market parameters.<sup>187</sup>

In summary, this approach appears to be another attempt to find a cost of capital calculation method to fit a desired level of return on equity. The Commission should give no weight or reliance to this alternative method.

viii. **The Attorney General’s ROE calculation is reasonable and fair to the Company and ratepayers.**

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<sup>187</sup> Coppola, 4 TR 3323.

The weighted average return on equity is 9.34% which Mr. Coppola believes reflects the Company's true cost of equity. However, he recommends an allowed ROE of 9.5% for reasons discussed below. The recommended ROE is fair to the Company. By allowing a higher ROE that is slightly higher than the required ROE for investment purposes, it represents a gradual return to the true and just ROE.

To confirm his analysis Mr. Coppola compared his recommended ROE of 9.5% to allowed ROEs granted by the public service commissions in the U.S. Exhibit AG-1.19 shows the ROEs granted by state regulatory commissions for U.S. electric utilities in 2020 and 2021. The average rate in the 41 ROE decision in 2020 and 34 decisions in 2021 were around 9.5% with some below 9.5%.<sup>188</sup> The higher rates shown on page 3 of Exhibit AG-1.9 are primarily from two jurisdictions.<sup>189</sup>

For most of the other electric utilities that have business and financial risks comparable to Consumers Energy's electric operations have ROE rated around 9.5% in the past two years.<sup>190</sup> This evidence supports Mr. Coppola's proposed ROE rate of 9.50%. The Company's proposed ROE rate of 10.25% is outside the realm of reasonableness and clearly unsupported. Exhibit AG-1.19 also shows several

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<sup>188</sup> Coppola 4 TR 3324.

<sup>189</sup> Exhibit AG-1.9, page 3.

<sup>190</sup> Coppola, 4 TR 3324.

electric utilities that have assessed capital markets at competitive interest rates since receiving a ROE below 9.5%.<sup>191</sup> Likewise, equity investors have not abandoned utilities that have been granted ROEs below 10%. The evidence suggests that stock investors continue to migrate to utility stocks because authorized ROEs are still above the true cost of equity. Exhibit AG-1.21 shows the market to book ratios for each of the peer group companies, and many of these companies have received rate orders during the past few years reflecting ROEs as low as 8.38%. Yet this group of companies has an average Market to Book common equity value ratio of approximately 2.0 times.<sup>192</sup> So, the need to raise capital because of large capital expenditures does not require the ROE requested by the Company.

Recent volatility in the capital markets should not be a concern in setting a fair ROE for the Company in this case. The stock market has historically been very volatile. However, in setting ROE rates for utilities, the Commission's focus should be on the long-term financial health of the utility not the short-term gyrations of the stock market.<sup>193</sup> Further, the Commission should not confuse volatility with risk

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<sup>191</sup> Coppola, 4 TR 3328.

<sup>192</sup> *Id.*

<sup>193</sup> Coppola, 4 TR 3329.

because it is not.<sup>194</sup> Finally, utility stocks are a safe haven for investors during times of uncertainty and volatility because they are not as susceptible to volatility as the general stock market. This is reflected in the average Beta value of 0.83 of the utility peer group used in the CAPM discussed earlier, in contrast with the general stock market value of 1. Therefore, the Commission should not give any weight to arguments that the Company's ROE should reflect investors' concerns with stock market volatility. In fact, the debt markets have been receptive to utility companies, including Consumers. In August 2021, Consumers issued \$300 million at an interest rate of 2.65% debt with a 31-year term reflecting a spread of just 78 basis points.<sup>195</sup>

#### ix. **ROE Conclusion**

The Attorney General recommends a ROE of no more than 9.5%. In Exhibit AG-1.15, Mr. Coppola summarized the cost of equity rates from the three methods discussed above. The range of returns for the industry peer group is from 8.73% at the low end, using the DCF approach and 10.02% at the high end using the CAPM approach. Mr. Coppola gave 50% weight to the DCF method as a more reliable approach to estimating the cost of equity and 25% for each of the other two

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<sup>194</sup> See, Exhibit AG-1.26.

<sup>195</sup> Coppola, 4 TR 3330.

methods. The result is a weighted average cost of common equity of 9.34%. To this base cost of equity capital, he added an additional premium adjustment of 16 basis points to arrive at a recommended ROE rate of 9.50% for Consumers Energy's electric business to provide a cushion to absorb the impact of higher risks from recent economic conditions; and to address higher interest rates.<sup>196</sup> The Attorney General also recommends against simply maintaining the status quo at 9.90% since that results in an additional cost for customers of approximately \$27.3 million annually compared to a 9.50% ROE.<sup>197</sup>

## 2. Long-Term Debt Costs.

For the long-term debt cost rate, Mr. Coppola used the rate of 3.55% which was developed by the Company.<sup>198</sup>

## 3. Short-term Debt Costs.

Mr. Coppola used the Short-term Debt rates recommended by Company witness Bleckman.<sup>199</sup>

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<sup>196</sup> Coppola, 4 TR 3331 – 3332.

<sup>197</sup> Coppola, 4 TR 3332.

<sup>198</sup> Coppola, 6 TR 2965.

<sup>199</sup> *Id.*

#### 4. Other Cost Rates

Mr. Coppola used a 4.5% rate for the Company's preferred stock which is consistent with the rate recommended by Company witness Bleckman. He also used the Company's Deferred Taxes cost rates. Cost rates for JDITC reflect those rates Mr. Coppola used for the permanent capital sources.<sup>200</sup>

#### D. Overall Rate of Return

The Attorney General recommends an overall return on capital of 5.42%, which includes a return on common equity of 9.50%, as shown in Exhibit AG-1.34 and discussed above. Even though the average ROE calculated under the three methods discussed above is approximately 9.06%, Mr. Coppola used a 9.50% ROE rate to calculate the overall cost of capital.<sup>201</sup> Mr. Coppola's testimony includes an explanation of his calculation.<sup>202</sup>

### IV. Adjusted Net Operating Income

#### A. Other O&M Expense

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<sup>200</sup> *Id.*

<sup>201</sup> *Id.*

<sup>202</sup> Coppola, 6 TR 2966.

The Company is projecting operations and maintenance (“O&M”) expenses of approximately \$696.4 million for the projected test year, an increase of \$96.2 million, or 16% from 2021.<sup>203</sup> For the reasons provided below, the Attorney General recommends reducing the Company’s projected O&M expenses by \$47.3 million.<sup>204</sup>

### 1. **Distribution O&M Expense**

The Company is projecting \$213.6 million in expenses for distribution operations for the 2023 test year. This compares to expenses of \$249.8 million in the historical test year.<sup>205</sup> Excluding Service Restoration Costs, which is addressed separately below, the total Distribution Expenses are projected by the Company to increase from \$90.1 million in 2021 to \$117.1 million in the 2023 projected test year which is an increase of \$27 million or approximately 30%. Company witness Blumenstock provided direct and rebuttal testimony for this category of expenses, but with very little quantifiable support for proposed increases in cost.<sup>206</sup> Mr. Coppola evaluated the Company’s proposed expenses and found unexplained and unsupported increases in certain programs. The Attorney General recommends

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<sup>203</sup> Exhibit A-13 (JCA-41), Schedule C-5 (excluding O&M expenses for Service Restoration costs and pension and OPEB).

<sup>204</sup> See, Exhibit AG-1.27 for a summary of proposed O&M expense adjustments.

<sup>205</sup> See, Exhibit A-47 (RTB-12), line 64.

<sup>206</sup> Coppola, 4 TR 3335.

adjustments under this category of expenses for non-forestry reliability, operations, maintenance and metering, service restoration, field operations, and electric planning.<sup>207</sup>

a. **Electric Operations**

i. **Non-forestry Reliability**

The Company is forecasting \$9,926,000 for its non-forestry reliability program for 2023 test year which is a significant increase over the Company's previous experience and projections in this area.<sup>208</sup> Consumers incurred \$5,410,000 of expense for this program in the 2021 historical test year, \$3,975,000 for the 5-year average, and \$4,286,000 for 2022.<sup>209</sup> Mr. Blumenstock provides testimony regarding this program however he does not provide sufficient information to justify the significant increase proposed by the Company.<sup>210</sup>

First, the Company failed to support its projection with specific information such as additional work units or work activities, justifying the forecasted increase in expense for 2023. Second, Mr. Coppola pointed out inconsistency in the

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<sup>207</sup> See, Coppola, 4 TR 3334 – 3357 for a complete analysis of the recommendations.

<sup>208</sup> *Id.* at 3335.

<sup>209</sup> Exhibit A-47, line 8.

<sup>210</sup> Blumenstock, 4 TR 1324 – 1335.

Company's expense planning – “For example, in the Company's last rate case U-20963, the Company projected \$8.0 million of Non-Forestry Reliability expenses for its 2022 test year.<sup>211</sup> Now, in this rate case, the 2022 expense level according to Mr. Blumenstock has been adjusted downward to \$4.3 million, which is a 46% reduction,”<sup>212</sup> which call into question the Company's estimates.<sup>213</sup> Third, he also notes the possibility of the Company shifting cost to the 2023 test year which would allow the Company to recover a higher amount in rates than it actually spent for the previous test year.<sup>214</sup>

Instead of relying on the Company's unreliable estimates, Mr. Coppola recommended an alternative basis for estimating this expense in 2023. He proposed using the most recent actual expense amount incurred by the Company for this category of expense. The 2021 actual expense of \$5,410,000 is the highest expense incurred in the last five years. Using the CPI-Urban Inflation factors for 2022 and 2023, he calculated \$5,923,000 as the projected expense amount for 2023.<sup>215</sup> As a result, the Attorney General recommends that the Commission remove \$4,003,000

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<sup>211</sup> Case No. U-20963 Exhibit A-44 (RTB-11), line 8.

<sup>212</sup> Exhibit A-47 (RTB-12), line 8.

<sup>213</sup> Coppola, 4 TR 3336.

<sup>214</sup> See, Coppola, 4 TR 3335 – 3337 for further discussion.

<sup>215</sup> Coppola, 4 TR 3337 – 3338.

from the Company's forecasted expense for Non-Forestry Reliability program for 2023.

ii. **Operations, Maintenance and Metering**

The Company is forecasting \$41,580,000 for the programs that make up its operations, maintenance, and metering category of expenditures for the 2023 test year. This is a significant increase over the Company's previous experience and projections in this area. The Company incurred \$37,798,000 of expense for this program in 2021, \$33,207,000 for the 5-year average, and \$34,207,000 is projected for 2022.<sup>216</sup> The large increase in expenditures in Operations, Maintenance and Metering come from three specific subprograms: Staking, Substations Demand LVD and Substations Demand HVD. Company witness Blumenstock discusses this program and its sub-programs in his testimony which lacks specific information, such as substantial reference to specific increases in work units or work activities with related dollar amounts and explanations of why those activities are increasing, to justify the large increases in expense at the sub-program level or at the overall program level in 2023.<sup>217</sup>

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<sup>216</sup> Exhibit A-47 (RTB-12), line 21. *See also*, Coppola, 4 TR 3338.

<sup>217</sup> Blumenstock, 4 TR 1336 – 1355. *See also*, Coppola, 4 TR 3338.

First, for Staking, historic expenses over the five years ending in 2021 have ranged from approximately \$3.0 million in 2019 and 2020 to \$3.5 million in 2018. The Company only provides generic information for this subprogram and assumes a 5% annual increase in staking orders.<sup>218</sup> However, support for the projected 5% annual increase in orders is lacking given the current economic slowdown<sup>219</sup> and higher interest rates affecting the housing market.<sup>220</sup> It is unlikely that construction activity and staking requests will increase in 2023 over 2021 actual levels. Moreover, a 5% increase in staking orders alone would not justify the increase in staking expenses from \$3.3 million in 2021 to \$4.4 million in 2023, which is a 36% increase.<sup>221</sup>

Second (and third), the Company claimed that it would be ramping up its 2022 expenses in the Substations Demand LVD and Substations Demand HVD subprograms in its last rate case U-20963. The following table compares those projections to the Company's 2022 spending plans in the current case:

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<sup>218</sup> Blumenstock, 4 TR 1344 – 1345.

<sup>219</sup> Gross Domestic Product fell 1.6% and 0.9% in the first two quarters of 2022 per the Bureau of Economic Analysis (U.S. Department of Commerce).

<sup>220</sup> Housing starts fell from a 1.8 million annual level to a 1.56 million annual level in April 2022 per Trading Economics.com.

<sup>221</sup> See, Coppola, 4 TR 3339.

**2022 Projection per Electric Rate Case**

<b><u>Thousands of Dollars</u></b>	<b><u>U-20963</u></b>	<b><u>Current Case U-21224</u></b>	<b><u>Difference</u></b>
Substations Demand LVD	\$4,650	\$3,358	(\$1,292)
Substations Demand HVD	<u>3,780</u>	<u>2,239</u>	<u>(1,541)</u>
<b>Total</b>	<b><u>\$8,430</u></b>	<b><u>\$5,597</u></b>	<b><u>(\$2,833)</u></b>

While the projections in this case reflect increases of \$2.6 million (an 88% increase) and \$1.5 million (a 51% increase) over 2021 actual expenses, respectively, the Company now forecasts spending \$2.8 million less in 2022. This is a repeat of the deferral of expenses into the 2023 test year and perhaps beyond discussed above with regard to the non-forestry reliability program. Likewise, the Company's projections are not reliable.<sup>222</sup>

Because the Company fails to support its projections, which are excessive, Mr. Coppola recommends using the actual expense amount incurred in 2021 adjusted for inflation as the most reasonable basis for estimating the 2023 expense. As a result, the Attorney General recommends removing \$4,446,000 from the Company's forecasted expense of \$41,480,000 projected by the Company for the Operations, Maintenance and Metering program for 2023.<sup>223</sup>

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<sup>222</sup> Coppola, 4 TR 3339 – 3340.

<sup>223</sup> See, Coppola, 4 TR 3341`.

### iii. Field Operations

On line 33 of Exhibit A-47 (RTB-12), The Company is forecasting expense of \$35,925,000 for 2023 which is compared to \$26,469,000 of expense for this program in 2021, \$22,667,000 for the 5-year average, and \$28,370,000 for 2022. The 2023 forecasted expense is an increase of \$9.5 million over the 2021 actual expense, or a and \$13.3 million higher than the 5-year average amount of \$22.7 million, or an increase of 59%. Mr. Blumenstock discusses this program and the sub-programs in his testimony but does not provide sufficient support for the proposed increases in the sub-programs, except for the Grid Management sub-program.<sup>224</sup>

It is reasonable to expect the Company to provide substantial evidence of specific increases in work units or work activities with related dollar amounts and explanations of why those activities are increasing to justify the large increases in expense at the sub-program level. Without this detailed support and justification, it is not possible to accept the Company's forecasted expenses as reasonable or support their approval. Mr. Coppola identified three areas where the Company

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<sup>224</sup> See, Blumenstock, 4 TR 1356 – 1364. See also, Coppola, 4 TR 3338.

proposes large increases that are unsupported including, Training, Supervision/Admin. Staff and HVD Construction Lines Workforce.

For the Company's Field Operations Training expenses, the projected 2023 test year expenses are \$13.4 million, which is an increase of \$2.6 million over actual 2021 expenses of \$10.8 million, or a 24% increase. The \$13.4 million expense level is also \$6.4 million higher than the five-year average of \$7.0 million for a 91% increase. In discovery, the Company was asked to provide the total training hours in each year from 2018 to 2023. The information provided shows training hours decreasing from 153,566 in 2021 to 135,440 in the 2023 projected test year, which represents a decrease of 12%.<sup>225</sup> Clearly, the decrease in training hours does not support an increase in training expense. At most, 2023 training expenses should not exceed the \$10,807,000 spent in 2021, adjusted for inflation, or \$11,843,000. This amount is considerably higher than the five-year average of \$7.0 million. The \$11,843,000 is lower than the Company's forecast by \$1,572,000.<sup>226</sup>

The Company's Field Operations Supervision/Admin. Staff expenses are also unsupported. The Company is projecting \$8.1 million for the projected test year,

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<sup>225</sup> Exhibit AG-1.31 includes discovery response AG-CE-0367.

<sup>226</sup> Coppola, 4 TR 3347.

which is an increase of \$3.1 million, over actual 2021 expenses of \$5.0 million. The \$8.1 million expense level is also \$1.6 million higher than the five-year average of \$6.4 million. Instead of pointing to specific business needs, Mr. Blumenstock states that he developed the projected increase by looking to “...Additional approved vacancies...” and “...any large known promotions...”<sup>227</sup> All large organizations have some level of turnover. However, Mr. Blumenstock’s testimony does not provide any support to justify a large increase in administrative and supervisory positions and the related forecasted cost. According to Mr. Coppola, to accommodate some level of employee turnover and vacant positions in 2021, a reasonable approach to forecasting 2023 test year expense for this program area is to use the five-year average expense amount, which is higher than the 2021 actual amount spent. The five-year average expense amount is \$6,408,000. After adjusting it for inflation, the forecasted amount for 2023 would be \$7,022,000, or \$1,033,000 lower than the amount forecasted by the Company.<sup>228</sup>

A new program appearing in 2022 under Field Operations is the HVD Lines Construction Workforce. The Company is forecasting \$593,000 for the 2023

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<sup>227</sup> Blumenstock, 4 TR 1359.

<sup>228</sup> Coppola, 4 TR 3349.

projected test year for this program.<sup>229</sup> According to Mr. Blumenstock, this expense is for staff salaries associated with the supervision of the HVD Lines construction workforce.<sup>230</sup> It appears that the Company had been outsourcing the HVD lines construction and now is evaluating bringing that function in-house. There are two problems with the proposed expense of \$593,000 for the projected test year.

First, the Company has had staff dedicated to bidding work out to contractors and exercising some level of monitoring and supervision of the work performed by contractors. As such, the Company has been incurring expenses related to the outsourcing of the HVD Lines construction that would no longer be incurred by bringing the work in-house. These cost savings have not been offset against the costs for bringing the function in-house. Second, this new program is in the early exploratory stage and no evidence has been presented that a change from outsourcing services to in-house employees is economically justified and in the best interest of customers.<sup>231</sup> The inclusion of \$593,000 of expense in the projected test year is premature and not adequately justified. Therefore, the Attorney General recommends that the Commission disallow recovery of this expense.

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<sup>229</sup> Exhibit A-47 (RTB-12), line 31.

<sup>230</sup> Blumenstock, 4 TR 1363.

<sup>231</sup> Coppola, 4 TR 3349.

The total expense adjustments for the Field Operation subcategory is \$3,198,000. Therefore, the Attorney General recommends that the Commission remove \$3,198,00 from the Company's forecasted expense of \$35.9 million for the Field Operations area for the 2023 projected test year.

#### iv. **Compliance and Controls**

The Company is forecasting \$2,768,000 for Compliance and Control expenses for 2023.<sup>232</sup> This compares to \$1,686,000 of expense for this program for 2021, \$951,000 for the 5-year average, and \$1,643,000 for 2022. The 2023 forecasted expense is an increase of \$1.1 million over the 2021 actual expense, and \$1.8 million more than 5-year average amount of \$0.9 million.

The Company's proposed ECAP program, is the principal driver of the large increase in expense in this area. The Company has indicated that it was revising its cost estimate for the ECAP program for the projected test year downward from \$1.0 million to \$0.3 million, or a reduction of \$0.7 million.<sup>233</sup>

Therefore, the Attorney General recommends that the Commission remove \$0.7 million from the Company's forecasted expense of \$2.8 million and approve the

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<sup>232</sup> Exhibit A-47 (RTB-12), line 35.

<sup>233</sup> See, Exhibit AG-1.32 (DR AG-CE-0371). See also, Coppola, 4 TR 3350 – 3351.

2023 expense amount of \$2.1 million for the Compliance & Controls program category.

**b. Electric Engineering and Support**

**i. Electric Planning**

The Company is projecting electric planning expense of \$13,848,000 for 2023. This compares to actual expense of \$9,403,000 for this program in 2021, \$9,190,000 for the 5-year average, and 11,538,000 for 2022.<sup>234</sup> The 2023 forecasted expense is an increase of \$4.4 million over the 2021 actual expense, and \$4.6 million over the 5-year average.

Mr. Blumenstock discusses this program and the sub-programs within the larger program category but does not provide sufficient specific information to support the increases in the sub-programs.<sup>235</sup> Specifically, his testimony lacks specific data, such as work units or work activities with related dollar amounts and explanations of why those activities are increasing to justify the large increases in expense at the sub-program level. Without this detailed support and justification, it

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<sup>234</sup> Exhibit A-47 (RTB-12), line 56.

<sup>235</sup> See, Blumenstock, 4 TR 1371 – 1377.

is not possible to accept the Company's forecasted expenses as reasonable nor recommend their approval.<sup>236</sup>

Mr. Coppola specifically addressed expenses for the LVD System Planning program. He testified that the forecasted expense for 2023 cannot be relied on given the large shortfall in spending from the expense amount forecasted in the prior rate case. In case U-20963, the Company forecasted an expense amount of \$6.9 million for 2021 and \$6.7 million for 2022.<sup>237</sup> It turns out that the Company actually spent \$3.8 million in 2021 and now forecasts that it will spend \$5.2 million in 2022.<sup>238</sup> These are large variations between forecasted and actual spending, which do not instill confidence in the Company's O&M expense projections for the 2023 projected test year. Furthermore, the underspending in prior years leads to higher forecasted expense in future years after the Company has received a financial windfall for underspending in those prior years.

The Company's forecasted expense for the Electric Planning program for 2023 is excessive and not adequately justified. Given the underspending in prior years and financial windfall received by the Company, Mr. Coppola proposes that

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<sup>236</sup> Coppola, 4 TR 3351 – 3352.

<sup>237</sup> From Case U-20963 Exhibit A-44 (RTB-11) line 49.

<sup>238</sup> See, Exhibit A-47 (RTB-12) lines 51 and 55.

the 2023 expense amount for the Electric Planning program category be set at the 5-year average expense amount of \$9,199,000 which is lower than 2021 actual. Adjusting this expense amount for inflation, the result is a forecasted expense of \$10,081,000 for the projected test year.<sup>239</sup>

Therefore, the Attorney General recommends that the Commission remove \$3,767,000 from the Company's forecasted expense of \$13,848,000 and approve the 2023 expense amount of \$10,081,000 for the Electric Planning program.<sup>240</sup>

ii. **O&M Expense Savings from Electric Distribution Grid Modernization and Automation.**

In his direct testimony, Company witness Mark Ortiz discusses the benefits that the Company and customers derive from capital spending on modernizing and automating the electric distribution grid. The Company will have spent in excess of \$336 million on improving the distribution grid between 2017 and 2023.<sup>241</sup> Mr.

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<sup>239</sup> Coppola, 4 TR 3352.

<sup>240</sup> *Id.* at 3353.

<sup>241</sup> See, Exhibit A-59, lines 69 and 70.

Ortiz identifies reduced or avoided costs to the Company and avoided outage costs to customers from modernizing the grid and installing advanced technologies.<sup>242</sup>

In response to a discovery request, the Company provided additional information detailing the avoided costs and other benefits by year.<sup>243</sup> In 2023, The Company expects to reduce or avoid O&M expenses and service restoration costs in the total amount of \$1,671,147 in 2023.<sup>244</sup> The Company seems to argue that these are avoided costs that would be incurred absent the distribution grid improvements, which may make sense if the Company had reduced the 2023 forecasted O&M expenses included in the rate case filing for Distribution Operations by the same amount as a result of implementing the grid improvements. However, there is no evidence that the Company has done so. Instead, the Company has increased Distribution O&M expenses for the projected test year over historical levels nearly across the board. Moreover, the Company shows Distribution Grid Management expenses increasing from \$4.1 million in 2017 to \$8.0 million in 2023.<sup>245</sup> If the \$1.7 million of expected reduced/avoided expense for 2023 are not real cost savings to be

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<sup>242</sup> Ortiz, 4 TR 1861 – 1862.

<sup>243</sup> Exhibit AG-1.33 (DR AG-CE-601 with Attachment 1).

<sup>244</sup> Id.

<sup>245</sup> See, Exhibit A-47, line 30.

achieved in the projected test year, then the \$336 million of capital spending on grid automation/modernization is not producing tangible benefits and the level of spending should be re-evaluated.

Mr. Ortiz identifies nearly \$2.1 billion of cost savings to customers from avoided power outages over the 10 years from 2022 to 2031 by modernizing and automating the distribution grid.<sup>246</sup> Although the Company applied what seems to be a logical methodology, it is difficult to assess if the forecasted benefits are reasonable and the avoided minutes of power outages will be achieved for each project implemented. The Company has not presented any evidence that it has achieved those levels of outage reduction with previous projects completed and for any sustainable period. Therefore, the customer avoided outage costs should be looked at with a healthy dose of skepticism until further actual evidence is provided by the Company in future years.

The Company was asked to quantify the amount of outage costs that customers experienced in 2021 from all the power outages that customers experienced in that year using the same methodology to calculate the future customer benefits. In response to the request, the Company reported that in 2021

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<sup>246</sup> Ortiz, 4 TR 1861 – 1862, Figures 2 and 3.

its customers experienced \$2.9 billion of costs or economic loss from power outages. The amount seems high and perhaps reflective of unrealistic assumptions. The same is true of the projected benefits to customers from avoided power outages from grid modernization and automation. If the \$2.1 billion in avoided costs shown in Figure 2 and 3 in Mr. Ortiz's testimony were realistic and were to occur, by 2031, the Company would have eliminated more than 70% of the customer power outage costs incurred in 2021.<sup>247</sup>

These calculations and projections seem unlikely and even misleading when used to justify billions of dollars of capital expenditures. The Commission should be skeptical in embracing such projections of avoided outage costs to justify billions of dollars of capital expenditures (which are real costs) over the next 10 years, versus tenuous projections of benefits in the future.

### iii. **Conclusion**

In total for the Distribution Operations, the Attorney General recommend that the Commission disallow \$22,900,000 from the Company's forecasted Distribution O&M expense of \$213,587,000 for the 2023 projected test year.

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<sup>247</sup> \$2.1 billion of \$2.9 billion in 2021 = 70%.

## 2. Service Restoration Expenses.

The Company projects expenses of \$96,478,000 for 2023 for this category of expenses. It incurred \$159,659,000 of expense for this program in 2021, its 5-year average for this expense is \$85,429,000 and expects to incur \$94,194,000 for 2022.<sup>248</sup> Company witness Houtz, provided testimony regarding this program and used the average expense amount over the five years from 2017 and 2021, and added labor and other inflation increases for 2022 and 2023 to estimate the test year expense.<sup>249</sup>

According to Ms. Houtz, service restoration costs can vary significant from years to year due to weather events. From 2017 to 2020, actual service restoration costs ranged from \$50.2 million to \$159.7 million.<sup>250</sup> Despite using a five-year average in her calculation of the service restoration expense for 2023, Ms. Houtz appears to have made errors, which makes the Company's projections inaccurate.

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<sup>248</sup> Exhibit A-47 (RTB-12), line 23.

<sup>249</sup> Houtz, 4 TR 2133 – 2137.

<sup>250</sup> See, Exhibit AG-1.49 (DR AG-CE-587).

First, Ms. Houtz shows higher Service Restoration costs in the Figure 3 table on page 7 of her testimony in comparison to the Service Restoration costs on Exhibit A-47 (RTB-12), line 22.<sup>251</sup> The comparison and differences are shown below.

<u>Year</u>	<u>Service Restoration Expense (\$ Millions)</u>	
	<u>Houtz Testimony</u>	<u>Exhibit A-47</u>
2017	\$ 62.9	\$ 50.2
2018	55.9	53.9
2019	92.1	92.1
2020	75.1	71.3
2021	<u>168.9</u>	<u>159.7</u>
5 Yr. Avg.	<u>\$ 90.9</u>	<u>\$85.4</u>
5 Yr. Avg. Plus Inflation	<u>\$ 96.5</u>	<u>\$90.6</u>

The source and higher costs used by Ms. Houtz in her direct testimony are unexplained. The historical amounts in Exhibit A-47 were used in the Company's prior electric rate case U-20963.

Second, Ms. Houtz did not take into consideration savings attributable to the enhanced tree trimming program that will be achieved in future years. The Commission's order in Case No. U-20963, dated December 22, 2021, directed the Company to provide a more detailed analysis of those cost savings in this rate

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<sup>251</sup> Coppola, 4 TR 3342 – 3343; Houtz, 4 TR 2136.

case.<sup>252</sup> According to Ms. Houtz's testimony, the Company expects nearly \$2.2 million of service restoration cost savings (i.e., avoided costs) in 2023 due to the amounts spent on the tree trimming and forestry management program.<sup>253</sup> The Attorney General recommends the savings from the ratepayer financed tree trimming program be used to offset some of the Company's service restoration expense in the 2023 projected test year.

In support of its projected restoration costs, the Company also pointed to the expanded incident command system (ICS) and higher mutual assistance costs as factors to be considered in approving its projected expense.<sup>254</sup> As noted by Mr. Coppola, the number of people involved in the ICS skyrocketed in 2019 from 600 to 900 people with the Company assigning fewer tasks to more individuals and supervisory groups. The Company has indicated that it will increase the number of people involved in pre-staging activities. While the Company touts more rapid restoration of service to customers, the costs have skyrocketed by all measures resulting in total service restoration costs of \$159.7 million in 2021.<sup>255</sup> Further, it is

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<sup>252</sup> Case No. U-20963, order dated December 22, 2021, page 259.

<sup>253</sup> Houtz, 4 TR 2144, Figure 10.

<sup>254</sup> Exhibit AG-1.50.

<sup>255</sup> See, Coppola, pp. 125 – 126.

not clear how much more value is being derived from the massive increase in people added to pre-staging activities or that staffing at that level is necessary to improve service.

a. **Five-year average.**

To address the unpredictable nature of these costs Mr. Coppola used a five-year average of actual expenses from 2017 to 2021 to estimate the 2023 costs because it smooths out the volatility in costs that can occur over a shorter time period and is a reasonable approach. In contrast, the Company's projected Service Restoration Expense of \$96.5 million is based on five years of historical data that are not supported in comparison to actual expenses shown in the Company's Exhibit A-47.

As noted above, to forecast the 2023 expense amount, Mr. Coppola proposes using the actual five-year average expense of \$85,429,000 shown on line 22, column (g) of Exhibit A-47 adjusted for inflation and deducting the \$2.2 million of expected cost savings from the enhanced tree trimming or forestry program. The resulting amount is \$91,465,000.<sup>256</sup>

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<sup>256</sup>  $\$85,429,000 \times 1.0665 \times 1.0275 - \$2,151,000 = \$91,465,000$ . See, Coppola 4 TR 3345 – 3346.

Therefore, the Attorney General recommends that the Commission remove \$5,013,000 from the Company's forecasted expense of \$96,478,000 and approve the amount of \$91,465,000 for the projected test year.

**b. Deferred Accounting Proposal**

**i. Consumers Energy's proposal.**

Company witnesses, Ms. Houtz and Mr. Foster describes the Company's proposal to defer service restoration costs above a certain threshold and recover them in a subsequent rate case.<sup>257</sup> Under the Service Restoration Deferred Accounting Mechanism, a service restoration expense amount of \$97 million would be established in the revenue requirement in this rate case and to establish an accounting deferral mechanism for any service restoration expense incurred above \$102 million and up to \$152 million. According to Ms. Houtz's testimony, the Company would defer a potential refund to customers for any differences in actual expense between \$92 million and a minimum expense level of \$42 million incurred by the Company in a future year.

**ii. The Commission should reject the Company's proposal.**

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<sup>257</sup> Houtz, 4 TR 2157 – 2165 and Foster, 4 TR 1845 – 1846.

The proposed deferral mechanism, which is similar to a proposal made by the Company in a prior rate case (and rejected by the Commission) is not necessary and likewise should be rejected by the Commission in this case. First, the \$102 million level of expense proposed by the Company to trigger a deferral is higher than any amount of expense incurred by the Company during the past 10 years, other than 2021 which was an unusual year with service restoration expense reaching \$159 million.<sup>258</sup> In comparison, service restoration costs for other prior years were below \$93 million with a five-year average of \$85.4 million.<sup>259</sup> Second, the Attorney General's recommended \$91.5 million service restoration expense amount is higher than what the Company has previously received in rate cases and diminishes the need for the proposed mechanism.<sup>260</sup> Third, a large portion of the increase in service restoration expense in 2021 was due to the addition of hundreds of people for storm preparedness, including hundreds of people to manage the Incident Command System both on an on-going basis and during significant weather emergencies. The Company reported that it utilized at least 883 employees in Storm Pre-Staging activities in 2020 and forecasted that it would exceed 2,300

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<sup>258</sup> Coppola, 4 TR 3382.

<sup>259</sup> See, Exhibit A-47, line 22.

<sup>260</sup> Coppola, 4 TR 3382.

employees in 2021 and 2022.<sup>261</sup> The Company needs to better justify this large escalation in resources and the related increase in service restoration costs. Finally, a cost deferral and recovery mechanism can incentivize the Company to increase cost instead of control them in future years because it would be able to pass through large cost increases to customers.<sup>262</sup>

The record does not establish the need for such a mechanism and the Commission should reject this proposal.

### **3. Power Generation Expense.<sup>263</sup>**

The Company is projecting \$7,186,000 in 2022 and \$7,312,000 in 2023 for Enterprise Project Management Environmental Services.<sup>264</sup> This appears to be a new expense beginning in 2022 and the Company's witness, Scott Hugo, who sponsors the O&M expense for Power Generation, did not address this new expense item in his direct testimony.<sup>265</sup>

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<sup>261</sup> Case No. U-20963 CEC's response to discovery response AG-CE-869.

<sup>262</sup> Coppola, 4 TR 3381 – 3383.

<sup>263</sup> Hugo, 4 TR 2292 – 2345; Coppola, 4 TR 3358 -3359; Shi (MPSC Staff),

<sup>264</sup> Exhibit AG-1.34 (AG-CE-0586 and Attachment).

<sup>265</sup> Coppola, 4 TR 3358.

It is not clear why this expense item is included under Power Generation Base O&M expenses since environmental operating costs are classified under a separate category on line 3 of Exhibit A-133 (SAH-5). If these costs are being reclassified, there should be a corresponding reduction in O&M expense in other areas of Power Generation Operations. It does not appear that an offsetting reduction has been made. Further, the basis for this expense was not provided.

In rebuttal Mr. Hugo, disagrees with Mr. Coppola's recommendation stating that his assumptions are incorrect because of the Company's opaque presentation of the information. "The Company does not always record actual Enterprise Management Environmental Services expense information in the same format a projected."<sup>266</sup> In a jumbled presentation that references a mystery exhibit, Mr. Hugo reveals in rebuttal that the primary reason for the increase relates to maintenance for the Covert Plant.<sup>267</sup> However, he does not explain what the maintenance consists of or provide information on the basis for the amount.

The incremental expense of \$7,312,000 for 2023 is not supported by testimony or evidence. Therefore, the Attorney General recommends that the

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<sup>266</sup> Hugo, 4 TR 2339.

<sup>267</sup> Hugo, 4 TR 2341.

Commission remove this amount from the Company's forecasted O&M expense for the projected test year.

#### 4. Facilities, Real Estate, Supply Chain O&M Expenses<sup>268</sup>

The Company forecasted \$18.3 million of O&M expense in the Operations Support area. This forecasted expense is \$1.6 million higher than the \$16.7 million historical 2021 test year O&M expense, or a 9.7% increase.<sup>269</sup> The main driver of the increase is the Real Estate sub-group where the labor component is increasing from \$1.3 million in 2021 to \$2.6 million in 2023. Company witness Guinn did not explain the basis for the \$1.2 million non-inflationary portion of the increase in his direct testimony. According to Mr. Guinn the functions in this area include dealing with easements, rights of way, encroachments, third party requests to use Company property and managing corporate facilities.<sup>270</sup>

Although the non-labor costs in these areas are consistent from 2021 to 2023, the labor cost is not. The Company indicates that the increase in expense results

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<sup>268</sup> Guinn, 4 TR 1954 – 2012; Coppola, 4 TR 3357 – 3358.

<sup>269</sup> Coppola, 4 TR 3357.

<sup>270</sup> Guinn, 4 TR 2003 – 2004.

from adding eight new employees in the Real Estate area which is a 26% increase over the 31 employees and contractors already assigned to this area. Improving response time to requests for real estate records and improving the quality of those records is the reason provided for the increase in headcount. However, the Company did not provide any evidence in its direct case to show what specific problems exist in this area and how adding an additional eight employees will resolve those problems.<sup>271</sup> Given the lack of evidence the increase in the labor expense is unjustified and inappropriate.

In rebuttal, the Company cites to new measures required under the Michigan Marketable Title Act, MCL 565.101 et seq which were enacted in 2019 for the increase in headcount, however Mr. Guinn later clarified that it is not the largest driver, just one of the reasons.<sup>272</sup> Part of the cost may go to clearing up a backlog. According to the Company identifying impacted property rights and taking other steps to comport with the new statutory requirements is labor intensive, but it could use contracted personnel rather than additional employees to perform the necessary task. It proposed increasing the Real Estate sub-group labor component in Line 2 of Exhibit A-106 (QAG-2) from \$1.28 million in 2021 to \$2.0 million in 2023 which

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<sup>271</sup> Coppola, 4 TR 3358.

<sup>272</sup> Guinn, 4 TR 2007. *See also*, Exhibit AG-1.40, page 1.

would result in a reduction in the Support O&M expense from \$18.3 million to \$17.7 million in Line 4 of Exhibit A-106 (QAG-2).<sup>273</sup> The Company revised proposal is unreasonable.

It appears that using contractors is more expensive than new employees who presumably would receive pay and benefits (a \$720,000 increase in real estate vs. a \$600,000 reductions in Operations Support). More importantly, the Company has not adequately explained and supported the proposed increase whether new employees or contractors are used.

Therefore, the Attorney General recommends that the Commission disallow \$1.2 million of expense and set the Operations Support O&M expense level at \$17.1 million for the 2023 projected test year.

#### **5. Corporate Services O&M Expense<sup>274</sup>**

The Company forecasts Corporate O&M expenses increasing from \$46.7 million in 2021 to \$53.1 million in the 2023 projected test year.<sup>275</sup> This \$6.4 million increase includes not only inflationary cost increases calculated by the Company,

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<sup>273</sup> Guinn, 4 TR 2008.

<sup>274</sup> Foster, 4 TR 1818 – 1824; Coppola, 4 TR 3368 – 3370.

<sup>275</sup> Exhibit A-101 (MJF-1), line 1.

but other items that are increasing the total expense amount. Included in the projected increase under the talent enablement project are costs related to employee development programs and training for certain employees for which the Attorney General is proposing adjustments.

a. **Employee Development**

The Company is seeking recovery of expenses for two projects under this subcategory of expense. Company witness Foster discusses two employee development plans and the related expense for 2023 to pursue those programs.<sup>276</sup> The first project is called the Career and Reward Framework for which the Company has proposed an O&M expense amount of \$162,500 to hire an industry expert to “...implement a framework to create a seamless experience from hiring process through career development.” It appears that program is intended to develop career paths for employees.<sup>277</sup>

Mr. Coppola’s testimony questioned the need to hire an outside consultant to do work that the Company’s human resources should be able to do.<sup>278</sup> The hiring of a consultant to perform a task that should be done by the Company’s HR

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<sup>276</sup> See, Foster, 4 TR 1818 – 1822.

<sup>277</sup> Coppola, 4 TR 3369.

<sup>278</sup> *Id.*

department seems costly and unnecessary. Therefore, the Attorney General recommends that the Commission disallow this proposed expense amount of \$162,500.

The Company has forecasted \$1,989,000 of expense for the Co-worker Development project which is intended to expand the current leadership training program and apparently retrain employees to support the Company's [new] Electric strategy. It is not clear what the leadership program is being expanded to accomplish and why co-workers need retraining. The purpose and definitions underlying the project are vague.

The Company has not adequately defined and justified spending \$1,989,000 in 2023 on this project. Therefore, the Attorney General recommends that the Commission remove this amount from the Company's forecasted expense for the projected test year.

## **6. Pension and Benefits O&M Expense**

There are two major concerns with the Company's forecasted expense for employee benefits for the projected test year relating to (1) the continuing decline in the expected rate of return for the pension and OPEB plans, and (2) excessive increases in forecasted expenses for active healthcare, life insurance and long-term

disability (LTD) expenses. The Attorney General recommends adjustment for each of these areas.<sup>279</sup>

a. **Long-term decline in the rate of return for pension plan and the OPEB plan.**

The Expected Return rate is a major component in the calculation of pension and OPEB expense performed by an actuary. A decrease in the forecasted rate over multiple years will increase pension and OPEB expense booked currently by the Company. Conversely, an increase in the Expected Return rate will decrease pension expense. The reason for this impact on pension expense is that if the plan is expected to realize higher returns from investments in stocks, bonds and other securities, it will partially offset future pension and OPEB costs. Since at least 2015, the Company has gradually lowered the Expected Return rate for the pension plan and the OPEB plan with each filed rate case. The result has been higher pension and OPEB expense than would have been otherwise experienced had the Expected Return rate been held constant or reduced less.

The Company included a credit or negative expense of \$29.7 million for pension expense and a credit or negative expense for OPEB expense of \$65.7 million

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<sup>279</sup> Christopher, 4 TR 1572 – 1624; Coppola, 4 TR 3359 – 3368.

for the projected test year in its original filing in this case.<sup>280</sup> Company witness Christopher discusses the Pension Plan costs and the OPEB Plan costs.<sup>281</sup> The Company indicated plans to decrease the expected return on assets rate for the pension plan from 6.75% in 2021 to 6.5% for 2022 and 2023. Ultimately, it planned to reduce the expected return to 5.75% by the year 2028.<sup>282</sup> Exhibit A-79 shows similar decreases in the expected return rate for the OPEB plan. However, the proposed steep decline in the expected return rate on plan assets is not justified by the actual returns earned by the Pension and OPEB plans over the last ten years. Although actual returns can go up and down from year to year, over the past ten years from 2012 to 2021, the Company's pension assets have earned an average return on assets of 9.8%.<sup>283</sup> The 6.75% rate used in 2021, as well as the 6.5% rate for 2022 and 2023, that the Company assumed in the actuarial analysis deviate greatly from the long-term actual return rates achieved. In addition, the actual OPEB asset returns earned over the 10-year period are also far higher than the

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<sup>280</sup> See, Exhibit A-77 (LBC-1).

<sup>281</sup> Christopher, 4 TR 1579 - 1584 and 4 TR 1590 – 1602, respectively.

<sup>282</sup> See, Exhibit A-78.

<sup>283</sup> Exhibit AG-1.29.

expected return rate used by the Company given a similar asset investment strategy.<sup>284</sup>

The declining Expected Return rates have significant implications on the amount of pension and OPEB expense forecasted each year and the amount included in rates. Although financial consultants perform certain analyses and provide recommendations, the Company ultimately decides what the Expected Return rate should be. The Company provided no credible justification for reducing the expected return rate assumption from 6.75% to 6.50%. The Company did rely on an asset investment analysis performed by NEPC, a hired consulting firm, that purportedly justified the change in the expected return rate.<sup>285</sup> NEPC based its analysis on its assumption that stock market equity returns would be in a range of 6.4% to 8.7% annually in the future. However, this assumption is at odds with the long-term historical returns of the stock market which have averaged 12.61% during nearly the 100 years from 1926 to 2020.<sup>286</sup> It is also at odds with the Company's past reliance on the same stock market return rate information in

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<sup>284</sup> *Id.* See also, Coppola, 4 TR 3360.

<sup>285</sup> Exhibit AG-OM-1.35 CONF includes discovery response AG-CE-0374 with Attachments Confidential. See also, Coppola, 4 TR 3361.

<sup>286</sup> Coppola, 4 TR 3361.

calculating its proposed ROE rate under the CAPM analysis, including previous claims that the return of the market may be 11.5% going forward.<sup>287</sup>

Mr. Coppola calculated the impact on pension and OPEB expense using a higher expected return rate. According to his calculation, a minor adjustment of keeping the expected return rate at 6.75% versus the Company's projected reduced rate of 6.5% results in a larger negative expense of \$4.8 million for the pension plan and \$2.6 million for the OPEB plan for 2023.<sup>288</sup> Therefore he recommended that the Commission adopt a total expense adjustment of \$7.4 million. Given, recent significant increases in interest rates and the likelihood they would result in significantly lower expense, Mr. Coppola strongly suggested that the Company provide updated expense amounts reflective of the higher discount rates in its rebuttal.<sup>289</sup>

In rebuttal, the Company disagreed with Mr. Coppola's use of an expected return of 6.75% and sought the implementation of a Pension/OPEB volatility mechanism and regulatory liability treatment to be amortized over ten years, if the

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<sup>287</sup> Exhibit A-14 (TAW-1) page 10 showing a long term annual average return of 12.61% for the 1926 to 2020 period for the stock market and page 13 showing a 11.48% ROE for the stock market.

<sup>288</sup> Coppola, 4 TR 3361 – 3362. See also, Exhibit AG-1.29.

<sup>289</sup> Coppola, 4 TR 3362 – 3363.

actual expense ends up being lower than projections.<sup>290</sup> Ms. Christopher then provides updated projections including discount rates from its actuary Aon through the end of June 2022. According to the Company it shows that 2023 projected pension expense should be reduced by \$1.4 million, but that the projected 2023 OPEB expense should increase by \$23.5 million, resulting in a net increase of \$22.1 million.<sup>291</sup> The Company further updated its projected pension expense in response to post-rebuttal discovery to a reduction in rate of \$4.7 million on Revised Exhibit A-213 (LBC-9) resulting in a proposed net increase of \$18.8 million.<sup>292</sup> It claims that it is reasonable to use its updated projections in this case.<sup>293</sup> The Attorney General disagrees that the updated projections should be used in this case. They represent more than just an adjustment in expected return rates and it would be prejudicial to use the adjustments to support such a large increase in revenue requirements so late in the proceeding.<sup>294</sup> Further, the Attorney General disagrees that continued use of an expected return rate of 6.75% would result in increase in OPEB expense of more than \$23 million.

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<sup>290</sup> Christopher, 4 TR 1620 – 1623.

<sup>291</sup> *Id.* at 1623.

<sup>292</sup> Exhibit AG-1.44, p. 3.

<sup>293</sup> *Id.* at 11.

<sup>294</sup> *See*, Exhibit AG-1.45 CONF.

For the reasons provided above, the Attorney General recommends that the Commission adjust the Company's pension and OPEB expense as she recommended above or at most keep the expense at the same level that the Company originally projected in this case.

b. **Excessive projected increase in active health care, life insurance and LTD.**

The Company has forecasted active health care, life insurance and LTD expenses will increase from \$25.8 million in the historical test year 2021 to \$30.7 mill in the projected test year 2023. Specifically, Exhibit A-77 (LBC-1) shows expenses of 25.8 million in 2021, \$28.8 million in 2022 and \$30.7 million in 2023. The Attorney General believes that the projection for 2023 is too high for four reasons.

First, the Company's projection is based on 2021 expenses that have been inflated by the COVID-19 pandemics impact on healthcare. Ms. Christopher uses 2021 as a starting point to apply the percentage increases obtained from outside consultants, however medical expenses in 2020 and 2021 were distorted because many medical facilities and hospital were either closed for much of 2020 or dealing primarily with Covid-19 issues resulting in a postponement of medical care until

2021 and even beyond.<sup>295</sup> The Company does not appear to take this fact into consideration in Ms. Christopher's testimony. Expense data provided by the Company in response to a discovery request bears this out. Total company Active Health Care and Life/LTD Insurance costs were \$84.5 million in 2019, \$75.7 million in 2020 (a 10% decrease), and \$93.6 million in 2021 (a 24% increase) before allocation to the electric business and capital expenditures.<sup>296</sup> This information makes it clear that using the expenses for 2021 as a starting point to project 2023 expenses, as the Company has done, is inappropriate.<sup>297</sup>

Second, the 2020 and 2021 Active Health Care costs contain the effect of Covid-19 health care expenses for treatment of employees who contracted the virus, as well as testing costs. Ms. Christopher discusses changes to the Health Care Plans for 2020 and 2021 in her testimony but she not provide COVID-19 related cost information and does not reduce her estimate of Health Care costs for 2023 to remove the non-recurring Covid-19 expenses included in 2021.<sup>298</sup>

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<sup>295</sup> The Health Care Cost Institute report released in May 2022 indicates that utilization of medical services declined in 2020 by 7.5% (<https://healthcostinstitute.org>).

<sup>296</sup> Exhibit AG-1.36 (AG-CE-376 Attachment 1).

<sup>297</sup> Coppola, 4 TR 3363 – 3364.

<sup>298</sup> *Id.* at 3364. *See also*, Christopher, 4 TR 1601 – 1602.

Third, Ms. Christopher's projected health care costs for 2023 assume that the portion of costs allocated to the electric business will increase. While she does not discuss this issue in her testimony, the information provided in response to discovery shows the allocation percentage to the electric business increasing from 55% in 2021 to 57% for 2022 and 2023, which is not explained in direct testimony.<sup>299</sup>

Fourth, Ms. Christopher's estimated Health Care inflation factor of 6.9% in direct testimony is based entirely on the Willis Towers Wyatt study and is disconnected from the Company's actual experience which reflects lower levels of Health Care inflation in recent years. Over projecting the inflation factor has been a recurring problem for the Company and its outside experts.<sup>300</sup> Further, the Company has initiated cost savings measures for its Active Health Care plans that should be taken in consideration in projecting an increase in costs.<sup>301</sup> As shown in Exhibit AG-130, During the five-year period from 2016 to 2021, the actual average annual rate of increase in health care costs for the Company has been 3.9%.

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<sup>299</sup> See, Coppola, 4 TR 3364 – 3365.

<sup>300</sup> See, Coppola, 4 TR 3367. See also, Exhibit AG-1.36 (DR AG-CE-376).

<sup>301</sup> Coppola, 4 TR 3368.

The Attorney General proposed an expense amount of \$26.3 million for 2023.<sup>302</sup> For 2020 and 2021 Mr. Coppola averaged the cost over the two-year period to account for the changes in utilization of medical services due to the COVID-19 pandemic and establish an expense base. He then applied a 3.9% escalation factor to the expense base to calculate the forecasted expense for half of 2021, all of 2022 and 2023.<sup>303</sup> Mr. Coppola's calculation result in an expense estimate that is \$4.4 million less than the Company's projection for the 2023 test-year.<sup>304</sup> In rebuttal, the Company made adjustments to its estimate including reducing the projected trend rate for Active Health Care from 6.9% to 5.8%<sup>305</sup> and reducing its projected expense amount from \$30.7 million to \$28.7 million – a \$2 million dollar reduction.<sup>306</sup> However, that adjustment still results in an excessive active health care, life insurance and LTD projected expense.

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<sup>302</sup> *See*, Exhibit AG-1.30.

<sup>303</sup> Coppola, 4 TR 3365 – 3366.

<sup>304</sup> *Id.*

<sup>305</sup> Christopher, 4 TR 1618.

<sup>306</sup> *Id.* at 1620.

Therefore, the Attorney General recommends that the Commission reduce the Company's forecasted cost to no more than \$26.3 million which is a \$4.4 million reduction from the Company's originally filed estimate of \$30.7 million for 2023.

#### **7. Incentive Compensation (EICP) Expense**

Company witnesses Amy Conrad and Michael Stuart presented testimony in support of the Company's Employee Incentive Compensation Plan (EICP). They both filed direct and rebuttal testimony.<sup>307</sup>

Consumers Energy has requested the inclusion of approximately \$2.1 million in its rates for short-term incentive compensation.<sup>308</sup> The overall structure of the short-term incentive plan has not changed from previous rate cases, however, the operating performance measures for the short-term incentive payouts have been revised for 2022. The Company expects the operating performance measures to

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<sup>307</sup> See, Conrad, 3 TR 494 – 553; and Stuart, 3 TR 464 - 492. See also, Coppola 4 TR 3370 – 3380.

<sup>308</sup> Exhibit A-94 (AMC-3)

remain the same in 2023 as they exist for 2022. The level of performance needed to qualify for incentive pay under the EICP for 2022 has changed.

The Company has two slightly different short-term Employee Incentive Compensation Plans (EICP) for non-officers and officers, both of which are still weighted toward financial measures that mostly benefit shareholders and not customers. The amount of the EICP requested for inclusion in customer rates assumes a 100% payout for both officer and non-officer EICPs will occur. For the reasons discussed below, the Commission should not allow recovery of the cost of the EICPs in rates.

a. **Consumers Energy has not met its burden of demonstrating how its short-term incentive compensation plans benefits ratepayers.**

There are several shortcomings with the Company's proposed EICPs. First, recent changes to plans, especially the operational measures make a historically weak plan even weaker.

i. **Non-Officer EIPC**

In Case No. U-20650 for the 2019, the operating performance measures included a customer experience index, a customer on-time delivery measure, and a

service on-time commitment metric. These later two performance metrics have been dropped and only the customer experience index remains. As for employee-related performance metrics, the employee safety metric continues, and the Company has added an employee empowerment metric which has now been modified slightly with a diversity component and renamed as the culture index. Also, the previous metric related to replacing vintage services has been dropped and two new metrics have been added which are (1) methane reduction from repairing/replacing leaking gas pipes, and (2) the affordability index which relates to O&M cost savings.<sup>309</sup> While some of the previous customer related performance metrics overlapped and thus some redundancy may have been eliminated, the Company has not demonstrated how the new performance metric mix will incentivize employees in a way that benefit ratepayers since employees have little impact on achieving those metrics.<sup>310</sup> The Company's claim that making employees aware of the metric so that they understand and "strive for" them is not compelling.<sup>311</sup>

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<sup>309</sup> Coppola, 4 TR 3374. 155, referencing Exhibit A-32 (AMC-1) from Case No. U-20650.

<sup>310</sup> Id. at 3374.

<sup>311</sup> Stuart, 3 TR 491. *See also*, Conrad, 3 TR 547.

The EICP for non-officer employees for 2021, included 9 performance measures related to employee safety, customer experience, electric reliability, gas flow deliverability, generation customer value, cyber-security, as well as new goals for employee empowerment, methane reduction, and clean energy. To achieve 100% payout of this grouping of “operating” measures, the Company had to achieve 6 of the 9 performance measures.<sup>312</sup>

In this case, the Company is changing the plan’s performance metrics for the 2022 EICP plan year. Only four of the existing metrics are being retained. They are related to employee safety, the customer experience metric, electric reliability, and the methane reduction metric. Four of the 2021 plan year metrics related to generation customer value, gas flow deliverability, cyber security and the clean energy metric have been eliminated. The previous employee empowerment index has been changed to include a diversity element and it has been renamed as the “culture index”. Finally, the Company established an “affordability” metric related to O&M savings, which witness Conrad states are not included as cost offsets in the Company’s cost recovery request in this case. The four existing metrics retained (as noted above) plus the addition of the culture index and the affordability metric now total to six performance measures and make up 100% of the operational metrics for

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<sup>312</sup> See, Exhibit A-92 (AMC-1), page 1.

2022.<sup>313</sup> The Company is moving away from arguably customer related goals to more internal administrative goals.

It has become easier to qualify for incentive pay. There used to be a minimum number of operating metrics requiring at least two-thirds of the metrics being met to trigger an incentive payout (e.g., 9 of 11 in 2011 or 6 of 9 in 2021 to receive 100% payout). Minimal requirements have essentially been eliminated and achievement of only one metric is now sufficient to trigger a payout. The Company claims that such minimal effort should be rewarded so that employees will not give up on achieving the goals.<sup>314</sup> Therefore, even mediocre performance will be rewarded if only a single metric is achieved. This is a very generous incentive plan that is not directly connected with achieving superior customer benefits before making threshold incentive payouts.<sup>315</sup>

Other weaknesses include the fact that the performance measures use CMS Energy financial information and combine electric and gas business measures. Although the Company is a combined gas and electric utility and makes up more than 95% of CMS Energy, appropriate cost segregation is required to avoid having

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<sup>313</sup> Coppola, 4 TR 3371 – 3372.

<sup>314</sup> Conrad, 3 TR 551.

<sup>315</sup> Coppola, 4 TR 3375.

electric customers subsidize other businesses, particularly non-utility operations. Furthermore, the Company continues to pay salary or merit increases each year of approximately 3.2% and has included such an increase in the test year O&M expenses for all employee labor costs.<sup>316</sup> So any claims that incentive pay is needed to make up competitive market pay should be dismissed.

ii. **Officer EICP**

Incentive pay under the officer EICP is based primarily on two financial measures – earnings per share and operating cash flow, with only 30% related to operational measures and 70% related to achieving financial measures.

iii. **Standard for Recovering Incentive pay not met.**

Historically, the Commission had been reluctant to grant recovery of incentive pay from ratepayers because of the utility companies' inability to demonstrate how such pay benefits their customers. The Commission established the standard for allowing the recovery of incentive compensation pay in its Opinion and Order in the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity

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<sup>316</sup> *Id.* at 3376.

and for Other Relief, Case No. U-14347, dated December 22, 2005 (December 22 Order): “[E]xecutive bonus and employee incentive plans require a showing that the **benefits to ratepayers from the bonus and incentive plans, at a minimum, will be commensurate with the programs costs.** Moreover, the utility has **the burden of establishing how the proposed programs benefit ratepayers.**” P. 34. [Emphasis added].

To recover incentive pay, Consumers has a three-part burden of showing (1) that benefits accrue to ratepayers **as a result of** the bonus and incentive plans; (2) that those benefits are at least equal to the cost; and (3) exactly how ratepayers are benefited by the incentive pay plan. For the reasons explained below, Consumers fails to meet its burden.

The EICPs, as designed by the Company, are heavily weighted toward achieving and rewarding financial measures that benefit shareholders of Consumers’ parent company, CMS Energy, or meeting the Company’s business goals.<sup>317</sup> While, the Company is not requesting recovery of any EICP dollars in this case related to the financial metrics, clearly the bulk of the benefits that employees

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<sup>317</sup> Conrad, 3 TR 549 (“We have a portfolio of goals that we share with all of our employees that are important to serving our customers and achieving our Company strategies.”)

see continue to derive from the financial performance of the Company. the officer group that sets the direction of the Company is still far too focused on financial results. The Company's witnesses did not demonstrate how the financial measures benefited ratepayers to the extent that they and not shareholders should bear the cost of the EICPs. Customers do not directly benefit from shareholders achieving a higher return on their investment. Further, the Company does not issue common stock directly to public shareholders so there is no direct proof that the financial focus even benefits ratepayers by lowering the cost of capital.

The Commission noted in its December 22 Order, while Consumers characterized its EICP as an overall part of its compensation package, it was clear that those payments were significantly related to improving the Company's bottom line. "The benefits of improved employee performance because of Consumers' incentive programs accrue to investors in the form of higher prices and dividends but benefit rate payers only tangentially." P. 34. Like the incentive pay program presented in case number U-14347, the current plan does not meet the Commissions' standard. The Attorney General is aware that the Commission has granted partial recovery of incentive pay related to the non-officer EICP's performance goals in recent Consumers Energy cases, but for reasons explained in this brief, she does not believe the standard for recovery has been met in this case.

As discussed above, the non-officer EICP and to a certain extent the officer EICP also purports to measure and reward achieving certain performance goals identified in Exhibit A-92 (AMC-1), page 2. The descriptions of these measures are general and vague. And, as discussed above, officers are guaranteed to receive almost all of their incentive compensation if the financial measures are met, even if the Company fails to meet performance objectives.

The Company's witnesses have been unable to draw a direct correlation between the performance metrics, incentive compensation, and benefits to Consumer's electric customers that are at least commensurate with the cost. The Company attempts to quantify alleged customer benefits of certain performance measures included in the EICP but fails in its efforts.

First, the Company's analysis of the benefits of the EICP does not account for the fact that other factors could influence employee performance, such as training, possible discipline, or promotion. It is also possible that spending on other parts of O&M, which ratepayers also fund, could affect achieving the EICP's goals. The methane emission reduction goal is one such metric. Under the Company's plan employees can receive incentive pay for activities that the Company is required to do by EPA requirements as part of its normal operations. Further, the Company

was unable to quantify any benefits – other than quality of life benefits which ratepayers pay through rates.<sup>318</sup>

Second, some of measures that the Company relies upon to demonstrate purported benefits to ratepayers, have had reversals in outcomes in recent years that call into question their value to customers. Mr. Stuart testifies with regard to the Employee Safety metric that the Company will reduce incidents by 6% from the 4-year historic average and that this will result in \$314,000 of savings.<sup>319</sup> The real results from Exhibit A-163 show the Company’s safety incidents climbing from an average of 104 per year (2018 to 2020) to 135 in 2021. Therefore, the savings Mr. Stuart presents are not real but “hoped for savings”.<sup>320</sup>

Mr. Stuart testified that the Company is saving \$12.5 million per year due to distribution reliability based on the Berkley Labs cost per outage minute data if the Company can reduce its SAIDI level in 2022 to 180 minutes.<sup>321</sup> However, recent

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<sup>318</sup> Stuart, 3 TR 487 – 491.

<sup>319</sup> Stuart, 3 TR 476.

<sup>320</sup> Coppola, 4 TR 3377.

<sup>321</sup> Stuart, 3 TR 477.

data shows that the SAIDI minutes have ranged from 195 to 233 from 2018 to 2021 making such goal questionable.<sup>322</sup>

Claims regarding other metrics are equally questionable.<sup>323</sup> “After analyzing the cost savings that are hoped for or possible in the future as presented by Mr. Stuart, it becomes obvious that the claimed financial benefits are doubtful or dependent upon further capital expenditures that ultimately are paid for by customers.”<sup>324</sup>

Third, the lack of any benefit is further illustrated by the fact that not all of the measures used to award incentive pay is related or exclusively related to the provision of electric service and yet the Company’s EIPCs include achievement of those measures in the calculation for awarding incentive pay in this case. For example, the reduction of methane emission is a measure related primarily to the provision of natural gas service.

Fourth, as discussed above, there is an extremely low threshold for payout based on operational goals. Employees can fail to meet all but one of the

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<sup>322</sup> See, Exhibit A-164 (RMS-3).

<sup>323</sup> See, Coppola, 4 TR 3377 – 3378.

<sup>324</sup> *Id.* at 3378.

operational goals and still qualify for at least some incentive pay as long as reach a 50 percent threshold for that goal.<sup>325</sup> The EICP rewards mediocre to average performance which diminishes any real customer benefits. Incentive compensation should be paid for exceptional performance, at least to pass the test of cost recovery in rates. Performance that is ordinary and achieves basic goals and efficient operations should be paid for in base salaries.

The Company has failed to demonstrate how the EICPs influence employee performance in a way that benefits rate payers commensurate with the cost. Because Consumers' EICP programs for both non-officers and officers do not provide a benefit to ratepayers commensurate with the cost *none* of the \$ 2.1 million should be included in customer rates.

#### **8. Summary of Adjustments to Other O&M Expenses.**

Operations and maintenance expenses represent a large part of the Company's cost structure. As discussed above, certain expenses are excessive or not needed and should be disallowed. The Attorney General recommends that the Commission reduce the amount of total O&M costs proposed by the Company by

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<sup>325</sup> Conrad, 3 TR 550 – 553.

\$47.3 million and reduce the revenue deficiency accordingly. Mr. Coppola Testimony<sup>326</sup>.

## **B. Depreciation Expense**

The Attorney General is recommending that approximately \$369.5 million in adjustments be made to the Company's proposed capital expenditures with a resulting reduction in rate base of \$237.5 million.<sup>327</sup> The reduction in capital expenditures lower the amount of depreciation expense that the Company will incur during the projected test year by \$6.4 million.<sup>328</sup> The Attorney General recommends that the Commission reduce the Company's depreciation expense by \$6.4 million for the projected test year.

## **V. Other Revenue, Accounting and Performance Issues**

### **A. Service Reliability Accountability Mechanism.**

#### **1. Background for the Attorney General's proposal.**

The Company proposes capital expenditures of nearly \$794 million for 2022 and 2023 for Reliability and Demand Failures programs in this case. During the

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<sup>326</sup> Coppola, 4 TR 3380. *See also*, Exhibit AG-1.27.

<sup>327</sup> *See*, Exhibit AG-1.13.

<sup>328</sup> *Id.*

past five years from 2017 to 2021, the Company has spent more than \$1.8 billion on those same programs in order to replace aging and failing electric infrastructure, reduce customer power outages, and improve service reliability.<sup>329</sup> However, the results, as measured by the SAIDI score excluding major event days, shows that the Company has been unsuccessful in improving service reliability. During the past three years from 2019 to 2021, the average number of minutes of outages experienced by all customers was 219 minutes (3.7 hours), which exceeded all prior years since 2012.<sup>330</sup>

In this case, the Company has set specific goals to achieve improved service reliability goals during the coming five years from a baseline level.<sup>331</sup> It expects to improve its SAIDI score by reducing the number of service outage minutes from a baseline of 194 down to 162 minutes by the end of 2026.<sup>332</sup> According to Mr. Blumenstock, both prior and planned capital investments on electrical

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<sup>329</sup> Exhibit A-37 (RTB-2) lines 27 and 45.

<sup>330</sup> See, Exhibit AG-1.39 (AG-CE-559). See also, Coppola, 4 TR 3383 – 3384.

<sup>331</sup> Blumenstock, 4 TR 1147 – 1168.

<sup>332</sup> See, Blumenstock, 4 TR 1149, Figure 2.

infrastructure replacements and upgrades should help the Company achieve those reliability goals in the next five years.<sup>333</sup>

Historically, the Company has failed to meet its goal for eight of the past 10 years. The only years when it met its SAIDI goal was in 2012 and 2014. As indicated in the table below<sup>334</sup>:

<b>Year</b>	<b>SAIDI Actual</b>	<b>SAIDI Target</b>
2012	204	210
2013	218	200
2014	168	182
2015	177	163
2016	207	138
2017	161	138
2018	201	138
2019	233	165
2020	195	180
2021	228	180

These results demonstrate that not only did the Company consistently fail to achieve reliability performance goals, but the magnitude of that failure casts doubt on its ability to achieve the goals in the future.

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<sup>333</sup> Coppola, 4 TR 3384.

<sup>334</sup> See, Exhibit AG-1.39 (AG-CE-559).

Mr. Coppola notes that “the Company is rewarded for making capital investments by earning a return on those investments added to rate base, plus recovering the principal invested through depreciation expense, and included in rates billed to customers irrespective of whether the reliability goals are achieved. This is a one-way, asymmetrical paradigm, that places the entire risk and cost of achieving reliability goals on customers and insulates the Company from any accountability for achieving those goals.”<sup>335</sup> To correct this imbalance, he proposes the adoption and implementation of a Service Reliability Accountability Mechanism (SRAM). The SRAM can also help further the Commission’s recently announced goals to investigate and increase service reliability for utility customers.

## **2. The Attorney General’s proposed Service Reliability Accountability Mechanism**

The proposed SRAM will help to rebalance the one-directional paradigm described above by deferring a portion of the Company’s revenue requirement consisting of the return on investment, depreciation expense, and property taxes for 2022, 2023, and the following three years until the has shown that it has achieved the SAIDI goal in four of the five years from 2022 to 2026. Specifically, it would defer 20% of the revenue requirement on the investments on Reliability and

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<sup>335</sup> Coppola, 4 TR 3386.

Demand Failures in those years that the Company fails to meet the SAIDI goal provided in Figure 2 Mr. Blumenstock's direct testimony.<sup>336</sup> If at the end of the five-year period (2022-2026), the Company has met the SAIDI goals in four or more years, the Company would be able to recover the deferred revenue requirement in a future rate case. By achieving the targeted goals in four of the five years, the Company would in effect achieve 80% of the annual goals ( $4 \div 5 = 80\%$ ). This is a reasonable threshold given that customers pay for 100% of the capital investments added to rate base each year. If the Company fails to achieve the SAIDI goal in at least four of the five years, it must refund the deferred revenue to customers in the next rate case as an offset to its future revenue requirement.<sup>337</sup>

**3. The mechanism is fair to the Company and customers.**

A 20% deferral of the revenue requirement related solely to the capital investments made in the year where the SAIDI goal was not met is fair to the Company and helps it focus on achieving its service reliability goals. First, the SAIDI measure combines both the SAIFI and CAIDI measures which capture the frequency and duration of power outages and therefore, it is a more comprehensive measure of reliability performance than either SAIFI or CAIDI alone. Second, it is

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<sup>336</sup> Blumenstock, 4 TR 1149.

<sup>337</sup> Coppola, 4 TR 3386 – 3387.

frequently used as a service reliability performance measure by the Company and others in the electric industry and therefore it simplifies the proposed deferral mechanism. Third, the Company's failure to achieve the stated goal in a given year is indicative of the failure to provide customers sufficient value for what they paid in rates and that loss of value can be as much as 100% of the revenue requirement paid in that year for the related cumulative investments added to rate base.<sup>338</sup>

**4. The Attorney General's Mechanism should be adopted now.**

Over the past years, there has been discussions and proposals made about establishing broader performance-based ratemaking (PBR) system but nothing has been established to date due to complexities surrounding the implementation of PBR systems. A more narrowly focused approach at holding the Company accountable for service reliability results, such as the SRAM proposed by the Attorney General can provide clear benefits to ratepayers in the while a broader PBR system is developed. It is specific to reducing power outages, which is one of the greatest benefits to customers given the amounts they pay each month for electric service. As described above, the SRAM is simple and easy to implement. It allows the Company to retain the rewards of earnings on capital investments if it

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<sup>338</sup> *Id.* at 3387.

meets a threshold level of performance over a five-year long-term period. On the other hand, the SRAM also returns to customers a portion of the cost for services paid for which they did not receive sufficient value.<sup>339</sup>

Unsurprisingly, the Company opposes the Attorney General's proposed SRAM labeling it unreasonable and premature. Neither label is accurate. Mr. Blumenstock claims that the Company's SAIDI targets as aspirational, set to drive innovation, not rate recovery.<sup>340</sup> That does not appear to be true. As discussed above, the Company uses the reduction in its SAIDI score as one of the bases for employees recovering incentive pay, which the Company seeks to recover in rates. The Company's claim also misses the point. The SRAM is designed to push the Company to improve reliability because ratepayers are being shortchanged on the reliability they pay for. The Company's reliability as represented by its SAIDI scores demonstrate that customers are not receiving the full benefit of the investment through rates.

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<sup>339</sup> *Id.* at 3388.

<sup>340</sup> Blumenstock, 4 TR 1407.

For the reasons provided above, the Attorney General recommends that the Commission implement the SRAM beginning with this rate case for the period 2022 to 2026.

## **VI. Revenue Deficiency Calculation**

The Company project a revenue deficiency on a Michigan jurisdictional basis of \$266.4 million with its rate case application. It subsequently increased its requested rate-relief to \$287 million through rebuttal testimony. As discussed above and through her witness's testimony, the Attorney General has calculated a revenue deficiency of only \$134.1 million for the Company. She recommends that the Commission issue an order granting rate relief to the Company no greater than \$134.1 million.<sup>341</sup>

## **VII. Cost of Service, Rate Design and Tariff Issues -**

### **A. COSS<sup>342</sup>**

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<sup>341</sup> See, Exhibit AG-1.38 which summarizes the adjustments to rate base and operating income from the Attorney General's prefiled testimony. The Attorney General's revenue deficiency has been adjusted in response to rebuttal and further discovery, as discussed above in this brief.

<sup>342</sup> Dismukes, 4 TR 3422 – 3448. Other parties' witnesses addressing CCOSS include: Emily Davis (Consumers) 4 TR 988 – 1084; Brian Andrews (ABATE), 4 TR 2827 – 2883; Justin Bieber (Kroger Company), 4 TR – 3065 – 3092; Mark Pung (MPSC Staff) 4 TR – 4150 – 4155; Douglas Jester (MNSC), 4 TR 3707 – 3720;

The Company provided two versions of its CCROSS model. The first version is based on past methodologies adopted by the Commission with updates to certain allocation schedules as required by the Final Order of the Company's last rate case.<sup>343</sup> The second version builds off the first, with the following changes:<sup>344</sup>

- i. Breakout and allocate battery plant and related costs;
- ii. Breakout and allocate PowerMI Drive ("PMD") and PowerMI Fleet ("PMF") regulatory asset and amortization expense;
- iii. Move the calculation of Rate EIP interruptible credits out of the COSS to enable the inclusion/centralization of the calculation in Rate Design; and
- iv. Replace Class Peak with multi-hour voltage peak ("MHVP") in the allocation of demand-related distribution plant and the Sum of Individual Maximum Demand ("SIMD") in allocating costs at the Voltage 4 level.

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Alexander Zakem (Energy Michigan), 4 TR 3132 – 3138; and Kevin Lucas (CEO), 4 TR 3605 – 3608; and Perry (Walmart) 4 TR 3112 – 3115.

<sup>343</sup> Davis, 4 TR 993.

<sup>344</sup> Davis, 4 TR 1003. *See also*, Dismukes, 4 TR 3422 – 3423.

The company is proposing to use the second version to allocate rates in this case.<sup>345</sup> The Attorney General's analysis primarily focuses on the Company's proposed allocation methodologies.

### 1. **Battery Plant Cost Treatment**

The Company is proposing to breakout costs associated with its battery plant investments and separately allocate these costs to various customer classes. Historically, the Company has recorded battery plant in FERC account 363 (Distribution Plant: Storage Battery Equipment) or FERC account 348 (Other Production Plant: Energy Storage Equipment- Production) depending on whether it is distribution or production related.<sup>346</sup> The Company believes that the breakout and reallocation of its battery plant and related costs is necessary due to the increase in its battery plant investments.<sup>347</sup> In functionalizing battery plant between production and distribution, the Company is proposing to allocate production- related battery plant using the 4CP 75-0-25 methodology.<sup>348</sup> For the distribution-related battery plant, the Company is proposing to use a MHVP

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<sup>345</sup> Davis, 4 TR 1003.

<sup>346</sup> *Id.* at 1004.

<sup>347</sup> *Id.*

<sup>348</sup> *Id.* at 1005.

allocation factor rather than the class peak allocation factor the Commission has approved for all demand-related distribution plant.<sup>349</sup> For the reasons provided below, the MHVP allocation factor should not be approved and instead a class peak allocation factor should be used.

## **2. PowerMIDrive and PowerMIFleet Regulatory Asset and Amortization**

The Company is proposing to breakout the regulatory and amortization expense for both programs and allocate PMD costs to its residential class and PMF costs to its commercial and primary rate classes.<sup>350</sup> The Company states this results in a “better reflection of how customers use and benefit from both programs”.<sup>351</sup>

## **3. EIP Interruptible Credits**

The Company is proposing a change in the method it uses for calculating interruption credits arising during critical peak events. The Company has

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<sup>349</sup> *Id.* at 996 – 998.

<sup>350</sup> *Id.* at 1006.

<sup>351</sup> *Id.*

previously calculated this within its COSS model and rate design. However, it is proposing to make calculations and adjustments within its rate design only.<sup>352</sup>

#### 4. Allocation of Demand-Related Distribution Costs

The Company uses a variety of demand allocators within its CCOSS. The Company uses what it refers to as a “4CP 75/0/25” cost allocation method to allocate production plant costs that are classified as “demand-related.”<sup>353</sup> This is a hybrid allocation factor based on a weighted average that has two separate components. The first component is based on each rate class’s contribution to the Company’s average four monthly CPs (“4CP”) and receives a 75 percent weight. The second component is comprised of each rate classes’ contribution to the Company’s annual energy requirement and has a 25 percent weight. The Company’s demand-related classification of transmission plant is based upon what it refers to as a “12CP 100” cost allocation method, which measures the Company’s average twelve monthly CP (“12CP”).<sup>354</sup> For lower-voltage distribution facilities classified as demand-related, the Company used the Class Peak Demand allocator in version 1 of its CCOSS

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<sup>352</sup> *Id.* at 1007.

<sup>353</sup> Davis, 4 TR 1002.

<sup>354</sup> *Id.*

model and uses the Voltage Peak allocator in allocating demand- related distribution costs in version 2 of its CCOSS model.<sup>355</sup>

Dr. Dismukes raises two issues with the Company's CCOSS. First, he disagrees with cost allocation method related to the classification of production plant. Second, he also disagrees with the Company's proposed Multi-Hour Voltage Peak allocation methodology.

a. **Multi-Hour Voltage Peak (MHVP)**

The Company's proposed Multi-Hour Voltage Peak allocation replaces traditional Class Peak (CP) allocation for assigning costs associated with the Company's demand-classified distribution plant facilities such as substations, lines, and distribution poles. In its MHVP allocation methodology, the Company develops separate allocators for each of four-defined voltage levels<sup>356</sup> based on CP of the system. Therefore, the Company's MHVP allocation allows for time-separated peaks for each of its four voltage levels. In rebuttal, the Company recommends that given other parties' opposition to the MHVP allocation method, the Commission

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<sup>355</sup> *Id.*

<sup>356</sup> The Company's four voltage levels are numbered sequentially 1 to 4 and correspond to (1) transmission voltage; (2) sub-transmission voltage; (3) primary distribution voltage; and (4) secondary distribution voltage.

approve its proposed Alternative Class Peak instead of approving its MHVP allocation method.<sup>357</sup> However, the Company did not withdraw its MHVP.

Traditional cost of service methods use class-specific NCP or CP measures of demand to analyze each classes contribution to the demand needs of a system. These measures are multiplied by line loss factors to account for the difference between customer-loads and load pressures that are placed on the system in question. Finally, higher voltage classes are excluded in allocations of lower voltage systems because they bypass these systems. The Attorney General continues to support the Commission reliance on Class Peak.

#### i. **Background**

Dr. Dismukes provides a comprehensive review and analysis of the evolution of cost allocation methodology in his direct testimony.<sup>358</sup> The Attorney General will just highlight a few pertinent issues.

First, the Commission noted in Case No. U-17689 that electric generating units (“EGUs”) are designed to serve both energy and demand/capacity needs of a

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<sup>357</sup> Davis, 4 TR 1025 – 1026.

<sup>358</sup> See, Dismukes 4 TR 3427 – 3435.

utility.<sup>359</sup> The exact degree of this split between energy and demand functionality depends on the individual EGU in question and its place in the utility's dispatch curve.<sup>360</sup> EGUs defined as baseload units serve more of the utility's energy needs, while EGUs defined as peaking units serve more of the utility's demand or capacity needs. It is therefore not uncommon to develop composite energy and demand allocators that represent this mixed use and classification.

According to Dr. Dismukes, the Commission's 4CP 75-0-25 cost allocation method from Case No. U-17689, closely resembles the Average and Peak ("A&P") cost allocation methodology,<sup>361</sup> or peak and average demand cost allocation methodology,<sup>362</sup> used in some other regulatory jurisdictions. An A&P cost allocation methodology is based upon a two-component weighted average. The first

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<sup>359</sup> In the Matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) *et seq.*, with regard to DTE Electric Company; Case No. U-17689, Opinion and Order at 21 and 22.

<sup>360</sup> Today in Energy (August 17, 2012), "Electric generator dispatch depends on system demand and the relative cost of operation," Energy Information Administration.

<sup>361</sup> See, Dismukes, 4 TR 3432. For example, In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service, Arkansas Public Service Commission Docket No. 13-028-U, Direct Testimony of Corey A. Pettett, 8:11-20.

<sup>362</sup> Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners at 57-59.

component represents each rate class's share of a utility's total annual energy sales, and the second component represents each rate class's share of a utility's annual system peak demand. These components are combined through a weighted average: in the case of the 4CP 75-0-25 allocation, 75 percent demand and 25 percent energy.<sup>363</sup> While the framework of the 4CP 75-0-25 allocation adheres to commonly accepted cost allocation practices, the 75 percent demand and 25 percent energy weighting for classifications does not. The weighting between demand and energy components should generally be equal (i.e. 50-50) or based on the utility's system load factor.<sup>364</sup> This latter method weights the energy component by the utility's overall system load factor while the peak demand component is weighted by the inverse of the system load factor (i.e., 1 minus the system load factor).

Second, Exhibit AG-2.3 shows the Company's system load factor for 2016 to 2021. The Company's system load factor narrowly ranged from 52.2 to 56.5 percent based on the measure of peak demand during that period. Under 4 CP, the measure of peak demand used in the current production plant allocator, results in a system load factor of 54.3 percent for the test year.<sup>365</sup>

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<sup>363</sup> Dismukes, 4 TR 3432.

<sup>364</sup> See, Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners at 57-59.

<sup>365</sup> Exhibit AG-2.2.

Third, Dr. Dismukes' analysis confirmed that 4CP is an appropriate measure of demand for the utility; however, the current 4CP 75-0-25 cost allocation methodology is too heavily weighted towards demand considerations relative to energy when compared to the Company's actual reported data.<sup>366</sup> The analysis of the Company's system load factors shows that the split between these two functional requirements is essentially equal, a finding that should be reflected in the allocation for cost-of-service purposes in the Company's CCOSS.

- ii. **The Commission should reject the Company's proposed use of a Multi-Hour Voltage Peak Allocation Method.**

The Company disagrees with the current Commission approved method for CCOSS which treats costs associated with meters and services as customer-related and costs associated with all other distribution plans as demand-related. It claims that poles, wires, and related distribution plant are designed to meet the Company peak demand requirements and provide service to customers. Therefore, the Company argues that classifying these systems as 100 percent demand is inaccurate.<sup>367</sup>

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<sup>366</sup> See, Exhibits AG-2.2 through AG-2.3.

<sup>367</sup> Davis, 4 TR 1007 – 1008.

In the past, the Company has proposed to allocate costs associated with some distribution plant facilities based on a minimum size, a zero-intercept, or a similar study. However, those approaches were rejected by the Commission. So, in its last electric rate case U-20963, the Company proposed replacing the traditional class peak allocation method and instead use a Voltage Peak allocation method to partially alleviate some of its concerns associated with the allocation of costs associated with distribution plant facilities.<sup>368</sup> Although the Commission rejected the Company's proposal in that case, it did order it to evaluate and present a CCROSS utilizing the MHVP allocator proposed by Staff in their next filing.<sup>369</sup> Therefore, the Company has presented its MHVP in this case. It suffers from the same theoretical shortcomings as the previously proposed voltage peak allocation method.<sup>370</sup>

The Company's proposed MHVP allocation methodology is premised on a claim that aggregating customers by customer class results in inappropriate allocations, and that somehow measurements at the voltage levels would result in

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<sup>368</sup> 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-20963, Direct Testimony of Emily A. Davis, at 2:22 -3:4.

<sup>369</sup> 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-20963, Order at Page 351.

<sup>370</sup> See, Dismukes, 4 TR 3439 – 3440.

more appropriate cost allocations. Dr. Dismukes notes that this approach may make sense *if* the Company's electric system consisted of four singular systems at different voltage levels, however because of the design of the Company's electric system, this approach is inappropriate and overly simplistic. The Company's system contains multiple circuits, also called feeders, connecting population centers to the transmission system, and dozens of primary and secondary voltage distribution circuits transporting electricity to customers throughout a utility service territory. Each circuit has different load requirements and timing which the Company's proposal does not recognize.<sup>371</sup>

The Company's proposed MHVP allocation would aggregate these load requirements into a singular secondary-voltage distribution peak even though the circuits experience maximum load requirements at different times.<sup>372</sup> Dr. Dismukes provides an illustration – “Consider two secondary-voltage distribution circuits. One circuit primarily serves commercial office complexes that operates a traditional 9-5 workday and thus experiences maximum load requirements during the middle of a summer day when workers are at work in air-conditioned offices. The second circuit primarily serves residential neighborhoods that typically

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<sup>371</sup> *Id.*

<sup>372</sup> *Id.* at 3440.

experience peak electric demand requirements during the early evening hours of the summer when workers return home. On the other hand, traditional class peak measurements of demand recognize the differences in individual circuit load requirements.<sup>373</sup> The Company has failed to identify how its new proposal would be superior to current cost allocation practices.

Like with the proposed voltage peak allocation method from its last rate case U-20963, the Company has not done its homework on this approach. The Company has not examined, nor is it aware of any study that examine the diversity of loads on its distribution circuits.<sup>374</sup> The Company does not even track the number of customers by rate class which are served by each feeder.<sup>375</sup> Dr. Dismukes analyzed the Company's 2,000+ primary distribution circuits and found significant diversity of customer-types taking service on individual Company circuits.<sup>376</sup> He also analyzed the Company's 500,000+ secondary distribution circuits, and while less diverse than the primary distribution circuit, he found that they served a mixture of both residential and non-residential customers.<sup>377</sup>

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<sup>373</sup> See, Dismukes, 4 TR 3440 – 3441.

<sup>374</sup> *Id.* at 3441.

<sup>375</sup> *Id.*

<sup>376</sup> *Id.* See also, Exhibit AG-2.7.

<sup>377</sup> Dismukes, 4 TR 3441 - 3442. See also, Exhibit AG-2.8.

There is no support for the Company's proposal outside of its high-level discussion of distribution system planning. The Company cannot identify any authoritative sources which discuss the use of coincident peak demand measurements at separate system voltage levels to allocate costs associated with distribution plant investments, similar to its proposal.<sup>378</sup>

For the reasons provided above, the Attorney General recommends the Commission reject the proposed MHVP allocation methodology as theoretically flawed and insufficiently supported.

**b. Sum of Individual Max Demand (SIMD)**

The Company continues to seek approval of its SIMD proposal to use the sum of individual customer's peak demand requirements to allocate costs associated with secondary-voltage distribution plant facilities.<sup>379</sup> In rebuttal it also sought approval in the alternative of a proposal to weight SIMD by 78% and Alternative Class Peak by 22% as a compromise due to some parties' objections to its original proposal.<sup>380</sup> The Commission should not approve either of the Company's proposals.

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<sup>378</sup> Id. at 3441 – 3442.

<sup>379</sup> Davis, 4 TR 1013. *See also*, Davis, 4 TR 2018 – 1031.

<sup>380</sup> Davis 4 TR 1030 - 1031.

SIMD places a higher burden on lower load factor customer classes, such as residential customers, because it assumes that facilities must be designed to serve the maximum demand of each customer simultaneously, regardless of how customer load profiles compare to each other.<sup>381</sup> While distribution system components such as substations, feeders, and transformers are typically designed in a fashion that ensures sufficient capacity is available to meet the local area loads, load diversity present on such systems must also be considered. Primary distribution-voltage circuits may serve some primary voltage commercial customers and some secondary-voltage electric circuits. Secondary-voltage electric circuits can still have load diversity if such circuits serve customers with different load profiles, such as a retail storefront operating during daylight hours and a residential housing community whose residents are typically home during evening hours.<sup>382</sup>

Generally, end use load diversity impacts cost allocation. According to Dr. Dismukes, the design motivation of distribution system components depends on the load diversity present, with more diverse systems serving broader system-wide peak demands, and less diverse systems serving more localized peak demands. Accordingly, the choice of appropriate demand allocation factor should also follow

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<sup>381</sup> Dismukes, 4 TR 3443.

<sup>382</sup> *Id.* at 3443 - 3444.

this separation, with systems designed to meet broader system-wide peak demands being allocated based on allocators derived from CP measures of demand, as opposed to systems designed to meet more localized peak demands being allocated based on allocators derived from localized system demand measures such as NCP measures. The Company's use of an allocator based on the sum of individual customers' maximum demands implies a hyper-undiversified system wherein secondary-voltage distribution systems serve customers' loads that effectively peak simultaneously.<sup>383</sup> To the contrary, Dr. Dismukes research into how other utilities have allocated costs associated with secondary-voltage distributions systems found some measure of diversification overall.<sup>384</sup>

The Commission previously rejected a proposal by the Attorney General to change the cost allocation methodology associated secondary-voltage distribution plant related costs to one based on class NCP instead of the sum of customer individual demands based on the recommendation of the ALJ in Case No. U-20561.<sup>385</sup> The ALJ found that the Attorney General's previous proposal "had merit,"

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<sup>383</sup> *Id.* at 3444.

<sup>384</sup> *Id.* at 3445.

<sup>385</sup> In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority, Case No. U-20561, Order at 224.

but that the survey of 18 general rate cases over an eight-year period used to justify the proposed change was not a robust survey.<sup>386</sup>

The Attorney General has addressed that concern in this case and is presenting a more robust survey consisting of a review of 49 rate cases filed over a 10-year period from 2010 to 2020 to support her proposed change in the cost allocation methodology associated with secondary-voltage distribution plant. This is a significantly larger review than the previous limited survey of 18 cases that the ALJ and Commission objected to in Case No. U-20561. The Attorney General recommends that the Commission allocate costs associated with demand-related secondary-voltage distribution systems based on class NCP demands. As noted above, the Company's proposed allocation places too much emphasis on individual customer peak loads failing to recognize that not all customers present on the system peak at the same time. Furthermore, allocating secondary-voltage distribution costs in a manner consistent with the allocation of primary-voltage distribution costs is consistent with how these costs are typically allocated in other jurisdictions. Allocating secondary-voltage distribution costs based on class NCP

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<sup>386</sup> *Id.*, Proposal for Decision at 399.

demands would also be consistent with the Commission's historic approach to allocating secondary-voltage distribution costs for Consumers.<sup>387</sup>

**c. Attorney General's Alternative Production Plant Allocation Method.**

**i. Attorney General's Proposal.**

Not only should the Commission reject the Company's proposed MHVP allocation method, but as discussed above, the currently used 4CP 75-0-25 allocation method deviates from commonly accepted cost allocation practices and should be reconsidered. As Dr. Dismukes notes, "[i]t is not common to find weightings between the demand and energy components that are so far apart from one another or differ from shares that are based on a utility's system load factor and one minus that load factor."<sup>388</sup> According to Dr. Dismukes, there is an alternative approach that would provide more appropriate results. Rather than using multiplication, this alternative analysis uses simple averages, which also removes the Company's inappropriate weighting of base load generation facilities discussed above which focus too much on demand considerations rather than energy compared

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<sup>387</sup> Dismukes, 4 TR 3446 – 3447.

<sup>388</sup> *Id.* at 3433.

to the Company's actual reported data.<sup>389</sup> The results of this analysis show that the energy weighting based on the consideration of simple averages ranges from 46.1 to 51.6 percent with a five-year average of 49.4 percent, which is consistent with Dr. Dismukes' recommended 55-0-45 weighting.<sup>390</sup>

Dr. Dismukes analyzed the relative classification of the Company's individual generation units to support his recommendation.<sup>391</sup> Exhibits AG-2.5 and AG-2.6 present the results of two separate analyses of the Company's EGU operations during the test year. The first analysis, presented as Exhibit AG-2.5, examines the gross plant in service of each unit, and the unit's capacity factor during the test year to characterize the role the unit serves in the Company's dispatch of electricity.<sup>392</sup> The second analysis, presented as Exhibit AG-2.6, also examines the gross plant in service of each unit but relies on an examination of the levelized cost of each unit relative to established market analyses to classify the function the unit serves.<sup>393</sup>

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<sup>389</sup> *Id.* at 3435 – 3436.

<sup>390</sup> *See*, Exhibit AG-2.4. *See also*, Dismukes, 4 TR 3438.

<sup>391</sup> *Id.* at 3436 – 3437.

<sup>392</sup> *Id.* at 3436.

<sup>393</sup> *Id.*

This second analysis can be appropriately viewed as a close facsimile to the equivalent peaker method the Commission has noted in the past.<sup>394</sup>

Dr. Dismukes' first analysis of Company EGU operations results in a 53.0 and 47.0 split between energy and capacity functions within the Company's rate base. His second analysis of Company EGU operations finds that, at most, only 52.97 percent of the Company's production plant in service could be classified as being associated with provision of demand-functions.<sup>395</sup>

Dr. Dismukes recommends that the Commission modify the weighting of the existing 4CP 75-0-25 cost allocation method to one that weights demand and energy concerns almost equally, or a 4CP 55-0-45 cost allocation methodology. The current 4CP 75-0-25 allocation method is too heavily weighted towards demand concerns and consequently over-allocates costs associated with generation plant assets to low-load factor customer classes (i.e., residential and small commercial).<sup>396</sup> The proposed 4CP 55-0-45 cost allocation method is based on his analysis of what would constitute a fair and reasonable approximation of the relative cost of service. Specifically, it would make the cost allocation of the Company's production plant

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<sup>394</sup> *Id.* at 3437.

<sup>395</sup> *See*, Dismukes, 4 TR 3437.

<sup>396</sup> *Id.* at 3438.

consistent with recent system load factors for the Company over the last five years (2016 through 2021), which have consistently ranged between 52.2 and 56.5 percent. Furthermore, his recommendation would make the cost allocation consistent with examinations of the relative classification of individual Company generation units.

The Attorney General recommends that the Commission adopt the proposed 4CP 55-0-45 cost allocation method.<sup>397</sup>

ii. **Other parties' criticisms of the Attorney General's proposal should be dismissed.**

Company witness Davis, ABATE's witness, Andrews and Kroger's witness Bieber all criticized certain aspects of the testimony of Dr. Dismukes testimony in rebuttal, especially as it relates to the Attorney Generals proposed 4CP 55-0-45 production cost allocator. The parties' rebuttal does not address the core of Dr. Dismuke's analysis that the production allocation factors used in the Company's cost of service should reflect the actual nature of service produced by the Company's generation assets and that neither the Company's proposed multi-hour voltage

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<sup>397</sup> See, Dismukes, 4 TR 3448. See also, Exhibit AG-2.9 containing an explanatory CCOSS using Dr. Dismukes recommended allocation factors; and Exhibit AG-2.10 which shows the results of the Company's CCOSS in the same format.

production allocation method nor the current 4CP 75-0-25 (which is too heavily weighted to demand and does not adequately address the energy provided by the Company's system), do so.

The Attorney General acknowledges that the Commission has previously rejected similar arguments in past cases, however that does not prohibit it from considering her updated proposal in this case. More importantly, consideration of the actual service being provided, which is addressed by the Attorney General, should be a paramount factor in determining the cost of service. The Attorney General will briefly highlight a couple of the claims made by other parties.

First, Kroger disagrees with Dr. Dismukes' testimony that it is uncommon to find weightings between demand and energy components that are so far apart or differ from shares that are based on a utility's load factor and that the NARUC Manual clearly prescribes a different demand and energy weighting method.<sup>398</sup> This is not correct. The NARUC Manual does not prescribe a particular method. However, the notes to Table 4-14 on page 57 of the NARUC Manual states, "The portion of the production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of (a) the annual system peak

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<sup>398</sup> Bieber, 4 TR 3088 – 3092.

demand, Table 4-3, column 2, plus (b) the average system demand for the test year, Table 4-10A, column 3.” According to Dr. Dismukes, this is clearly intended to represent a facsimile to system load factor typically calculated as 1 minus average system demand divided by system peak demand,<sup>399</sup> thus supporting his testimony.

ABATE’s Andrews claims among other things, that Dr. Dismukes did not show that the current 4CP 75-0-25 production facility cost allocator does not provide rates equal to the cost of service.<sup>400</sup> To the contrary, Dr. Dismukes testified to the history leading to the development of the 4CP 75-0-25 allocator and that the shortcomings of the allocator.<sup>401</sup> He discussed changes in the Company’s system since and that very little of the Company’s current generation plant in service is related solely to serving peak energy requirements. He conducted analyses of the Company’s individual generation units to better classify their function between energy and capacity functions within the Company’s rate base. The result was that the Company’s current 4 CP 75-0-25 cost allocation method is too heavily weighted towards demand.<sup>402</sup>

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<sup>399</sup> See, Exhibit KRO-1R. See also, Exhibit AG-2.15

<sup>400</sup> Andrews, 4 TR 2849, 2873, and 2877.

<sup>401</sup> Dismukes, 4 TR 3432 – 3435.

<sup>402</sup> *Id.* at 3436 – 3438.

Mr. Andrews also claimed that Dr. Dismukes has not shown that the Attorney General's proposed 4 CP 55-0-45 allocator would provide rates equal to the cost of service.<sup>403</sup> In addition to the points made in response to Mr. Bieber's rebuttal above, the Attorney General notes that the Michigan Legislature and the MPSC have utilized fixed percent weightings for production plant. A 50-50 allocation split, or a 55-45 allocation split, as proposed by Dr. Dismukes, better aligns with system average load factors than the Company's current allocation. Consumers Energy Company's most recent reported annual system load factor was 52.2 percent.<sup>404</sup> The Attorney General's proposed allocation represents a fair and reasonable approximation of the relative cost of service because it would make the cost allocation of the Company's production plant consistent with recent system load factors.<sup>405</sup>

Dr. Dismukes also provides evidence in this case of other utilities and commissions that have approved the use of a 50-50 weighting for demand and energy components using the average and excess (A&E) 4 CP demand cost allocation method which utilizes system load factor to weight the average demand

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<sup>403</sup> Andrews, 4 TR 2849, and 2874 – 2875.

<sup>404</sup> Exhibit AG-15.

<sup>405</sup> Dismukes, 4 TR 3413.

component including SouthWestern Public Service Company in its last four rate cases;<sup>406</sup> Oklahoma Corporation Commission in its regulation of Oklahoma Gas & Electric Company and the Public Service Company of Oklahoma,<sup>407</sup> and the Texas Public Utility Commission in its regulation of Southwestern Electric Power Company, Austin Energy, and Entergy Texas, Inc.<sup>408</sup>

In other words, the Attorney General has more than made the case for using the 4 CP-55-0-45 production cost allocator.

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<sup>406</sup> In the Matter of SouthWestern Public Service Company's Application for: (1) Revision of Its Retail Rates Under Advice Notice No. 282; (2) Authorization and Approval to Shorten the Service Life of an Abandon Its Tolk Generating Station Units; and (3) Other Related Relief, NM Case No. 19-00170-UT, Direct Testimony of Richard M. Luth at 29:18 to 30:5.

<sup>407</sup> See, In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing to Modify Its Rates, Charges and Tariffs for Electric Service in the State of Oklahoma, Cause No. PUD 201100087, Order No. 599558; and Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in Its Rates and Charges for Electric Service in the State of Oklahoma, Cause No. PUD 200800144, Order No. 564437.

<sup>408</sup> See, Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs, PUC Docket No. 40443, Final Order at 282-283; Petition by Homeowners' United for Rate Fairness to Review Austin Rate Ordinance No. 2012607-055, PUC Docket No. 40627, Final Order at 42; and Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs and Obtain Deferred Accounting Treatment, PUC Docket No. 39896, Final Order at 183-184. See also, Exhibit AG-15.

## **B. Revenue Distribution.**

### **1. Background**

The revenue distribution process is the initial step taken to establish rates. It allocates a utility's overall revenue deficiency across customer classes, and ultimately leads to the establishment of new retail rates. The revenue distribution process often uses the results from the CCOSS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their CCOSS-estimated class returns. The class revenue responsibilities that are finally established are then used, in conjunction with each class's billing determinants, to determine rates.<sup>409</sup>

There are several generally accepted rate-making principles used in utility regulation that include:

- Rates should be fair, just, and reasonable, and not unduly discriminatory.

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<sup>409</sup> Dismukes, 4 TR 3448 – 3449.

- To the extent possible, gradualism should be used to protect customers from rate shock.
- Rate continuity should be maintained.
- Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
- Rates should be understandable to customers.<sup>410</sup>

Act 341 requires that the Commission approve rates equal to the cost of providing service to each customer class.<sup>411</sup> This requirement is universal across all customer classes, with small exceptions for the establishment of low-income and senior citizen rates for eligible customers.<sup>412</sup> However, Act 341 also provides for the potential for the Commission to implement customer rate changes over a period of time if the Commission determines that the impact of imposing cost of service rates would have a material impact on customer rates.<sup>413</sup> “In all, the generally accepted rate-making principles are applied in Michigan the same as in other jurisdictions,

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<sup>410</sup> *Id.* at 3449.

<sup>411</sup> 2016 PA 341 § 11(1).

<sup>412</sup> 2016 PA 341 § 11(2).

<sup>413</sup> 2016 PA 341 § 11(1).

though Michigan ratemaking potentially places a greater emphasis on informing rates by costs than some other jurisdictions.”<sup>414</sup>

The Company’s proposed revenue allocations are based on its CCOSS results and would move each class’s rates to levels that equalize its individual class rate of return (“ROR”) (or 100 percent relative rate of return (“RROR”)). The Company’s revenue allocations are split between those associated with the provision of production and delivery services. Exhibit AG-2.12 presents the Company’s revenue distribution under its proposed rates.

According to Dr. Dismukes, the Company’s proposed revenue distribution places too great a burden on many customer classes. For example, the Company is requesting at least a 6.5 percent overall increase in this proceeding, proposing to increase residential customers’ share of total revenue by 6.8 percent.<sup>415</sup>

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<sup>414</sup> Dismukes, 4 TR 3450.

<sup>415</sup> In rebuttal, the Company increased its revenue requirement, thereby potentially increasing the rate impacts.

2. **Analysis shows that Company's rate increases has had disproportionate negative impact on residential ratepayer.**

The Company has seen its annual revenues increase by \$898.2 million, or by nearly two percent per year over a 12-year period with a disproportionate impact on residential and other smaller usage customer classes relative to primary-voltage and other high load factor customer classes.<sup>416</sup> The revenues collected from residential customers have increased by 59 percent since Case No. 15645. Revenues from primary-voltage customers, on the other hand, have decreased by 7.9 percent over the same period. These trends will only continue if the Company's proposals are accepted in full by the Commission in this proceeding.<sup>417</sup>

The Company's own 2021 analysis of the competitiveness of its rate compared to other utilities shows that its rates compare poorly to competing Midwestern utilities.<sup>418</sup> It also reveals that the Company's residential and commercial retail rates are particularly uncompetitive compared to its regional peers as they are

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<sup>416</sup> Dismukes, 4 TR 3416. *See also*, Exhibit AG-2.1 shows the Company's rate increase trends since Case No. 15645 in 2009.

<sup>417</sup> Dismukes, 4 TR 3416.

<sup>418</sup> *Id.* at 3417. *See also*, Exhibit AG-2.13.

higher than the Midwestern or U.S. averages and are also higher than most all other Michigan utilities.<sup>419</sup>

Likewise, the Company's rate competitiveness analysis shows that its commercial rates are higher than all Midwestern peers, U.S., and Michigan utility averages. The Company's commercial retail rates are also some of the highest in the country, exceeding the state-wide average of all states in the continental U.S. outside of New England and California.<sup>420</sup> Similarly, in its regional peer analysis, the Company found that its commercial rates were higher than all other competing Midwestern electric utilities except for one.<sup>421</sup> The Company's analysis shows that its industrial rates are higher than the average of all Midwestern, U.S., and Michigan utility averages but, are competitive with some regional peers operating in Ohio and Indiana.<sup>422</sup>

Using the Company's proposed revenue requirement, and the Attorney General's proposed alternative CCOSS recommendations discussed earlier, Dr. Dismukes prepared Exhibit AG-2.11, which presents an explanatory revenue

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<sup>419</sup> *Id.* at 3417.

<sup>420</sup> Exhibit AG-2.13, at 5.

<sup>421</sup> *Id.*, at 10.

<sup>422</sup> *Id.*, at 11.

distribution along with the Company's recommended revenue distribution. Exhibit AG-2.12 presents an explanatory comparison of the results of his proposed alternative CCOSS recommendations at the Company's proposed revenue requirement to both current and Company proposed rates. Under Dr. Dismukes' approach and using the Company's original proposed revenue requirement, residential customers would receive a 3.9% increase in rates, secondary customers receiving a 6.5 increase in rates and primary customers receiving a 11.7% increase in rates.<sup>423</sup>

The Attorney General recommends that the Commission adopt a revenue distribution that reflects Dr. Dismukes' alternative CCOSS recommendations. The ultimate revenue distribution effects of these changes will depend on the Commission's adopted revenue requirement for the Company.

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<sup>423</sup> Dismukes, 4 TR 3452.

**VIII. Conclusion and Request for relief.**

The Attorney General respectfully requests the Administrative Law Judge to issue a proposal for decision that is consistent with the positions set forth in the Attorney General's Initial Brief.

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**PROOF OF SERVICE - U-21224**

The undersigned certifies that a copy of the *Attorney General's Initial Brief* was served upon the parties listed below by emailing the same to them at their respective e-mail addresses on the 26th day of October 2022.

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