October 21, 2025

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917

Re: Case No. U-21870 – 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.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find **Consumers Energy Company's Rebuttal Testimony and Exhibits.** This is a paperless filing and is therefore being filed only in a PDF format. An updated exhibit list has been included as well as a Proof of Service showing electronic service upon the parties.

Sincerely,

Digitally signed by Gary A. Gensch, Jr.
Date: 2025.10.21 09:00:50 -04'00'

Gary A. Gensch Jr.
Phone: 517-788-0698
Email: gary.genschjr@cmsenergy.com

cc: Parties per Attachment 1 to the Proof of Service.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Stacy H. Baker, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Stacy H. Baker who provided direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony and exhibits submitted by the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") and Attorney General witness Sebastian Coppola in this case concerning the Information Technology ("IT") Department's Operations and Maintenance ("O&M") expenses and capital expenditures. Specifically, I will respond to:

- Staff witness Emma Zichi's proposed adjustments to capital expenditures to correct errors discovered through audit and discovery;
- Staff witness Zichi's proposed adjustments to IT capital expenditures and IT Investments O&M for IT/Digital Foundation and Security projects;
- Staff witness Zichi's proposed recommendations for the SAP S/4HANA Implementation project;
- Staff witness Brittney Klocke's proposed adjustments to IT capital expenditures and IT Investments O&M expenses for the Product Family Enhancements-Customer-Capital project; and
- Staff witness Jessica Duell's proposed adjustments to IT capital expenditures to correct errors discovered through discovery for the Service Restoration Artificial Intelligence project.

I will also respond to Attorney General witness Coppola's proposed adjustments to IT capital expenditures and IT Investments O&M expenses.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes.

Exhibit A-183 (SHB-12)	Asset Refresh Program ("ARP")-Field Device Asset Management ("FDAM") and ARP-Workstation Asset Management ("WAM") New Purchases Four-Year Historical Average;
Exhibit A-184 (SHB-13)	Staff Audit Responses U21870-SA-CE-024 and U21870-SA-CE-090; and
Exhibit A-185 (SHB-14)	Asset Refresh Program-Field Device Asset Management for the replacements and new purchases for 2021, 2022, 2023, and 2024 including new purchases; and
Exhibit A-186 (SHB-15)	Staff Audit Response U21870-SA-CE-080.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

MPSC STAFF

Q. What project is Staff witness Zichi proposing adjustments for in this case?

A. On page 4, line 1, through line 17, of her direct testimony, Staff witness Zichi is proposing a partial adjustment for the ARP-Collaboration project.

Q. What amount is Staff witness Zichi proposing to adjust for the ARP-Collaboration project?

A. Based on Staff witness Zichi's Exhibit S-14.0, line 5, she is proposing a partial adjustment of $250,023 in the 12-month bridge period ending 12/31/2025, $46,300 in the 4-month bridge period ending 4/30/2026 and $138,902 for the projected test year ending 4/30/2027 of capital expenditures for the ARP-Collaboration project. This adjustment corresponds to the capital expenditures in Confidential Exhibit A-20 (SHB-5), lines 143, 217 and 295 and

is within the IT/Digital Foundation business category in Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5.

Q. Do you agree with Staff witness Zichi's proposed adjustment to the ARP-Collaboration project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Audit Response No. U21870-SA-CE-006 (Exhibit S-14.1, page 2) that the original projection for auditorium refreshes planned for 2025, 2026, and 2027 were based on costs to replace historical equipment. The Company was able to refresh the historical equipment at a lower cost than what was planned for 2025. Based on the revised cost estimates for Conference Room Refreshes, capital expenditures for 2025, 2026, and 2027 should be reduced by $250,023 in the 12-month bridge period ending 12/31/2025, $46,300 in the 4-month bridge period ending 4/30/2026 and $138,902 for the projected test year ending 4/30/2027 for the ARP-Collaboration project.

Q. What adjustments is Staff witness Zichi proposing for the ARP-FDAM project in this case?

A. On page 4, line 18, through page 5, line 4, of her direct testimony, Staff witness Zichi is recommending a full disallowance of all new device purchases for 2026 and 2027 included in the ARP-FDAM project.

Q. What amount is Staff witness Zichi proposing to adjust for the ARP-FDAM project in this case?

A. Based on Staff witness Zichi's Exhibit S-14.0, line 6, she is proposing a full disallowance of $228,567 for the 4-month bridge period ending 4/30/2026 and $658,700 for the projected test year ending 4/30/2027 of capital expenditures for the ARP-FDAM project. This

adjustment corresponds to the capital expenditures in Exhibit A-22 (SHB-7), page 5, line 3, columns (e) and (f) and is within the IT/Digital Foundation business category in Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5.

Q. What is Staff witness Zichi's rationale for proposing full disallowance of the new field device purchases for the ARP-FDAM project?

A. On page 5, lines 5 through 14, of her direct testimony, Staff witness Zichi provides the rationale that due to a lack of information provided by the Company through audit regarding the methods used to calculate the total projected costs for new purchases in 2026 and 2027, the costs should be fully disallowed.

Q. Did the Company provide the information and the method for projecting the new field device purchases costs?

A. Yes. The Company provided in audit response at Exhibit S-14.1, page 5 (U21870-SA-CE-008), that the Company projected the Total Company new purchases of $1 million for each 2026 and 2027, which was based on the historical spend. In the same audit response, the Company provided the historical actuals that were used to validate the reasonableness of the projected 2026 and 2027 new purchase costs for ARP-FDAM. The Commission's September 30, 2025 Order in Case No. U-21806, pages 119-122, agrees with the Company that its evidence supports its projected costs based on historical spending and projected need for new purchases for the ARP-FDAM project. The Commission also noted in the same order that they would have liked to see more specificity in cost projections for this program, which I will address later in my testimony.

Q. Does Staff find the method used by the Company for the projected 2026 and 2027 new purchase costs for ARP-FDAM problematic?

A. Yes. On page 5, line 15, through page 6, line 7, of her direct testimony, Staff witness Zichi provides that the method used by the Company for the projected 2026 and 2027 new purchase costs for ARP-FDAM problematic because the Company did not explicitly state in its audit response that the average of all four years of historical data was used to determine the total projected costs of the new field device purchases. Additionally, the Company stated that the projected costs were validated using historical costs. Staff further explains that the method does not provide certainty as the Company did not provide the calculation or the method used to validate the projected cost for new field device purchases.

Additionally, on page 6, lines 11 through 13, Staff provides that a full analysis cannot be completed of the projected new purchase costs if the Company does not share the methods or calculations used to project these costs.

Q. Does Staff believe that the purchase of new field devices for the ARP-FDAM is unnecessary?

A. No. On page 6, lines 8 through 20, of her direct testimony, Staff witness Zichi provides that Staff understands the importance of new field device purchases for this project and does believe the Company will spend the projected 2026 and 2027 costs for the ARP-FDAM project.

Q. Does the Company agree with the Commission and Staff that using a more explicit or specific method for projecting new field device purchases for the ARP-FDAM project would provide more certainty in the projected costs?

A. Yes. The Company agrees that using a four-year historical average for new field devices purchases and providing information about any adjustments would be a more explicit or specific method to calculate the total projected costs for new field device purchases for the ARP-FDAM project. I have provided information below and in Exhibit A-183 (SHB-12) that will permit this approach for this case, and the Company commits to using this method in future cases as well.

Q. Please describe Exhibit A-183 (SHB-12).

A. Exhibit A-183 (SHB-12) is the four years of historical actuals data for the Years 2021, 2022, 2023, 2024, and total Company and electric allocation four-year historical average calculations for the costs associated with new purchases of field devices and workstations for the ARP-FDAM and ARP-WAM projects. Specifically:

- Column (a) provides each historical year used in the total Company and electric allocation four-year historical average calculations;
- Column (b) provides the actual data for each historical year and the total Company and electric allocation four-year historical average calculations; and
- Column (c) provides a reference to the exhibits from prior cases where historical actual data was provided.

Q. Based on using a four-year historical average of 2021 through 2024 for new field device purchases does the Company have any adjustments for the projected 2026 and 2027 new purchases costs for the ARP-FDAM project?

A. Yes. Based on the electric allocation four-year historical average of 2021 through 2024 of $611,611 (Exhibit A-183 (SHB-12), page 1, line 6, column (b)) for new field device purchases the 2026 and 2027, projected costs should be reduced by $24,696 for the 4-month bridge period ending 4/30/2026 and $74,089 for the projected test year ending 4/30/2027 of capital expenditures for the ARP-FDAM project.

Q. What adjustments is Staff witness Zichi proposing for the ARP-WAM project in this case?

A. On page 6, line 21, through page 7, line 8, of her direct testimony, Staff witness Zichi is recommending a full disallowance of all new device purchases for 2026 and 2027 included in the ARP-WAM project.

Q. What amount is Staff witness Zichi proposing to adjust for the ARP-WAM project in this case?

A. Based on Staff witness Zichi's Exhibit S-14.0, line 7, she is proposing a full disallowance of $228,567 for the 4-month bridge period ending 4/30/2026 and $685,700 for the projected test year ending 4/30/2027 of capital expenditures for the ARP-WAM project. This adjustment corresponds to the capital expenditures present on Exhibit A-22 (SHB-7) page 15, line 10, columns (e) and (f) and is within the IT/Digital Foundation business category in Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5.

Q. What is Staff witness Zichi's rationale for proposing full disallowance of the new workstation purchases for the ARP-WAM project?

A. On page 7, lines 9 through 19, of her direct testimony, Staff witness Zichi provides the rationale that due to a lack of information provided by the Company through audit regarding the methods used to calculate the total projected costs for new purchases in 2026 and 2027, the costs should be fully disallowed.

Q. Did the Company provide the information and the method for projecting the new workstation purchases costs?

A. Yes. The Company provided in audit response at Exhibit S-14.1, page 7 (U21870-SA-CE-010), that the Company projected the Total Company new purchases of $1 million for each 2026 and 2027, which was based on the historical spend. In the same audit response, the Company provided the historical actuals that were used to validate the reasonableness of the projected 2026 and 2027 new purchase costs for ARP-WAM. The Commission's September 30, 2025 Order in Case No. U-21806, pages 122-124, agrees with the Company that its evidence supports its projected costs based on historical spending and projected need for new purchases for the ARP-WAM project. The Commission also noted in the same order that they would have liked to see more specificity in cost projections for this program, which I will address later in my testimony.

Q. Does Staff find the method used by the Company for the projected 2026 and 2027 new purchase costs for ARP-WAM problematic?

A. Yes. On page 7, line 20, through page 8, line 3, of her direct testimony, Staff witness Zichi provides that as stated for the ARP-project, the method used by the Company for the projected 2026 and 2027 new purchase costs for ARP-WAM does not specify that the

projections are based on historical actuals; rather, the new purchase costs are just validated by the historical actuals. Staff further explains that the Company did not use a calculation to project the new purchase total Company costs of $1 million, leaving Staff to question how the Company arrived at its projection for new workstation purchases.

Q. Does Staff believe that the purchase of new workstations for the ARP-WAM is unnecessary?

A. No. On page 8, lines 8 through 20, of her direct testimony, Staff witness Zichi provides that Staff understands the importance of new field device purchases for this project and does believe the Company will spend the projected 2026 and 2027 costs for the ARP-WAM project.

Q. Does the Company agree with the Commission and Staff that using a more explicit or specific method for projecting new workstations purchases for ARP-WAM project would provide more certainty in the projected costs?

A. Yes. The Company agrees that using a four-year historical average for new workstation purchases and providing information about any adjustments would be a more explicit or specific method to calculate the total projected costs for new workstation purchases for the ARP-WAM project. I have provided information in Exhibit A-183 (SHB-12) that will permit this approach for this case, and the Company commits to using this method in future cases as well.

Q. What is the total Company and electric allocation four-year historical average for 2021 through 2024 for new workstation purchases for the ARP-WAM project?

A. The total Company and electric allocation four-year historical average for 2021 through 2024 are $1,817,867 and $1,246,512, respectively (Exhibit A-183 (SHB-12), page 2, lines 5 and 6, column (b)) for new workstation purchases for the ARP-WAM project.

Q. Did the Company make any adjustments to the four-year historical average for new workstation purchases when projecting the costs for 2026 and 2027 of $1 million each year?

A. Yes. The actual new workstation purchases of $4,583,866 in 2021 were significantly higher than the projected 2021 new workstation projections of $1,611,867 in Case No. U-20963 Exhibit No. A-110 (JDT-9), page 9, lines 9-14 and 17–22 (estimated workstation portion of additional accessories, shipping and handling, etc. to be 81% of lines 21 and 22 ($60,657) or $48,813). The actual increase was due to additional workstation and monitor purchases to adhere to the Centers for Disease Control and Prevention guidelines for in-person work due to the COVID-19 pandemic. The Company considered this unique occurrence when projecting the new workstation purchases for 2026 and 2027 of $1 million each year.

Q. Based on using a four-year historical average of 2021 through 2024 for new workstation purchases, with the adjustments just described, does the Company have any adjustments to the projected 2026 and 2027 costs for the ARP-WAM project?

A. No. The four-year historical average and the adjustments just described was the method used to project 2026 and 2027 costs for the ARP-WAM project.

Q. What adjustment is Staff witness Zichi proposing for the Digital-Infrastructure Automation project in this case?

A. On page 8, line 17, through page 9, line 5 of her direct testimony, Staff witness Zichi is proposing a full disallowance for the Digital-Infrastructure Automation project.

Q. What amount is Staff witness Zichi proposing to adjust for the Digital-Infrastructure Automation project?

A. Based on Staff witness Zichi's Exhibit S-14.0, line 8, she is proposing an adjustment of $382,043 (Rough Order of Magnitude ("ROM") Adjusted) of capital expenditures and $159,902 of Investments O&M expense for the projected test year ending 4/30/2027 for the Digital-Infrastructure Automation project. This adjustment corresponds to the capital expenditures and Investments O&M expense in Confidential Exhibit A-20 (SHB-5), line 307 and is within the IT/Digital Foundation business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5 and Exhibit A-19 (SHB-3), page 1, line 3.

Q. What is Staff witness Zichi's rationale for proposing adjustments to the Digital-Infrastructure Automation project?

A. On page 9, lines 6 through 10, of her direct testimony, Staff witness Zichi provides that Staff is recommending adjustments to the Digital-Infrastructure Automation project due to lack of information from the Company supporting the prudency of this project and failure to quantify the operational cost reduction.

Q. Does the Company have a clarification of what was intended in this instance by "reducing operational costs" on page 98, lines 38 and 39 of my direct testimony?

A. Yes. The Company's use of "reducing operational costs" in this instance on page 98, lines 38 and 39, of my direct testimony was intended to state "avoiding operational costs"

due to the operational efficiencies through reducing manual processes and defects by automating tasks and doing more with less while improving quality and productivity. The operational efficiencies and avoided operational costs were discussed in several sections of the project synopsis, specifically the Objectives, page 99, lines 8 through 19 and Alternatives, page 99, line 25, through page 100, line 2, of my direct testimony. The risk mitigation and avoided costs were also provided in my Exhibit A-21 (SHB-6), pages 56 and 57, in the Corporate Risk and Other Value sections.

Q. Do you agree with Staff witness Zichi's proposed adjustments of the Digital-Infrastructure Automation project?

A. No. The Company does not agree with Staff witness Zichi's proposal of adjustments to the Digital-Infrastructure Automation project. The Digital-Infrastructure Automation project will reduce the risk of a major application failure due to security issues that arise in the infrastructure; optimize the deployment of infrastructure by reducing manual effort by 80%; and materially reduce misconfigurations, rework, and time to deliver deployment of infrastructure from 2-4 weeks to 1-3 days.

Q. What adjustments is Staff witness Zichi proposing for the ISIS Papyrus 2026 Upgrade project in this case?

A. On page 10, lines 11 through 21, of her direct testimony, Staff witness Zichi is proposing a full disallowance for the ISIS Papyrus 2026 Upgrade project.

Q. What amount is Staff witness Zichi proposing to adjust for the ISIS Papyrus 2026 Upgrade project?

A. Based on Staff witness Zichi's Exhibit S-14.0, line 9, she is proposing $164,499 in the projected 4-month bridge period ending 4/30/2026, and $263,199 (ROM Adjusted) for the

12-month test year ending 4/30/2027. This adjustment corresponds to the capital expenditures presented on Confidential Exhibit A-20 (SHB-5), line 228 and is within the IT/Digital Foundation business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 5. Staff is also recommending a partial disallowance of $114,044 in Investments O&M expense for the 12-month test year ending 4/30/2027, which is under the Information Technology Investment O&M expense on Exhibit A-19 (SHB-3), page 1, line 3, and corresponds to the O&M expenses shown on Confidential Exhibit A-20 (SHB-5), line 228.

Q. What is Staff witness Zichi's rationale for proposing adjustments to the ISIS Papyrus 2026 Upgrade project?

A. On page 10, line 22 through page 11, line 18, of her direct testimony, Staff witness Zichi provides that Staff is recommending this adjustment due to a lack of information from the Company supporting the prudency of this project at this time.

Q. Do you agree with Staff witness Zichi's proposal of full disallowance of the ISIS Papyrus 2026 Upgrade project?

A. No. The Company does not agree that the upgrade is not required to be completed in 2026. The Company plans to implement the ISIS Papyrus upgrade in 2026 to mitigate the risk of technology obsolescence. Maintaining a current software release ensures the application receives critical security patches, vendor-issued fixes, and functional enhancements. The vendor has indicated they will continue providing cybersecurity patches. However, these patches may only apply to future releases. Cybersecurity patches of this nature cannot always be applied to older versions of the software. As a result, the Company may be required to upgrade to a more recent version to apply certain patches, depending on how

the vendor addresses specific vulnerabilities within the application code. The application has not been updated in over two years, delaying the upgrade increases the risk of technical obsolescence and exposure to security vulnerabilities, which will negatively impact the Company's ability to create electronic and paper bills, dunning notices, and customer correspondences.

Q. If Staff witness Zichi's proposed disallowance for the ISIS Papyrus 2026 Upgrade project is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?

A. Yes. The Company has identified necessary adjustments for the ISIS Papyrus 2026 Upgrade project. As stated on page 49 of my direct testimony, the Company's total capital projections include a 20% reduction for those projects with an ROM estimate. Based on the "ROM estimate type" indicated for the projects, which are shown in my Confidential Exhibit A-20 (SHB-5), column (k), the capital projections include reductions in the specified year. The projected 4-month bridge period ending 4/30/2026 capital expenditures for the ISIS Papyrus 2026 Upgrade project included in this case is the ROM-adjusted amount of $131,600 ($164,499 less 20% ROM Adjustment). Therefore, the ROM adjusted electric projected capital expenditures of $131,600 should be used for the 4-month bridge period ending 4/30/2026 rather than the $164,499 that Staff witness Zichi used for this period.

Q. Are there any other corrections the Company has identified for the ISIS Papyrus 2026 Upgrade project?

A. Yes. Based on Staff witness Zichi's Exhibit S-14.0, line 9, she is proposing disallowance of $114,044 in Investments O&M expense for the 12-month test year ending 4/30/2027.

By contrast, on page 10, lines 11 and 18, of her direct testimony, she is recommending partial disallowance of $144,044 in Investments O&M expense for the 12-month test year ending 4/30/2027. Based on the Investments O&M expense of $171,066 the Company provided on Confidential Exhibit A-20 (SHB-5), line 228, column (s), the correct Investments O&M expense amount for the 12-month test year ending 4/30/2027 is $114,044 (eight months of $171,066) as provided in Staff witness Zichi's Exhibit S-14.0, line 9.

Q. What adjustments is Staff witness Zichi proposing for the Security business category in this case?

A. On page 12, line 3, through page 14, line 8, of her direct testimony, Staff witness Zichi is proposing full disallowance of the Business Continuity – Program Management Tool project.

Q. What amount is Staff witness Zichi proposing to adjust for the Business Continuity-Program Management Tool project in this case.

A. Based on Staff witness Zichi's Exhibit S-14.0, line 11, she is proposing $50,579 in investments O&M expenses for the 12-month test year ending 4/30/2027. This adjustment corresponds to the investments O&M expenditure presented on Confidential Exhibit A-20 (SHB-5), lines 249 and 325, and is within Security business category on Exhibit A-19 (SHB-3), page 1, line 4.

Q. What is Staff witness Zichi's rationale for proposing full disallowance of the Business Continuity-Program Management Tool project?

A. On page 12, line 15, through page 13, line 11, of her direct testimony, Staff witness Zichi provides that new information was learned through audit regarding past decisions by the

Company for this project. Specifically, Staff learned that the Company adopted the Federal Emergency Management Administrative ("FEMA") and Incident Command System ("ICS") standards in 2013 and that the current system implemented in 2023 did not adhere to these standards. She concludes that the Company's current system should have adhered to these standards and further provides that the Company failed to address this inconsistency and provide supporting information as to the prudency of adopting these standards now.

Q. Do you agree with Staff witness Zichi's proposal of full disallowance of the Business Continuity – Program Management Tool project?

A. No. The Company does not agree with Staff's conclusion that the current system, implemented in 2023, should have included incident command system capabilities solely because the standards were adopted in 2013. The current tool supports Business Continuity ("BC") and Disaster Recovery ("DR") but does not include incident response capabilities aligned with FEMA and National Incident Management System ("NIMS") ICS principles. Incident management and BC/DR tools typically serve distinctly different functions. BC/DR tools focus on maintaining and restoring business functions during and after disruptions, while incident management tools address immediate response coordination and command during emergencies. The Company does not have an incident management tool in place. This was also true in 2023 at the time of procurement, although the Company had a BC/DR tool that was at risk of technology obsolescence. Thus, the chosen solution was selected to replace unsupported BC/DR software, fulfilling those immediate BC/DR requirements but not incident management needs. There is currently no single solution that comprehensively meets both BC/DR and FEMA/NIMS ICS-aligned incident management

requirements and that is cost effective, and the decision to procure the BC/DR solution was appropriate given the Company's needs and the capabilities available at the time.

Q. Did Staff provide any recommendations regarding the SAP S/4HANA Implementation project?

A. Yes. On page 14, line 16, through page 15, line 6, of her direct testimony, Staff witness Zichi proposed two recommendations regarding the SAP S/4HANA Implementation project.

First, Staff is recommending the Commission direct the Company to meet with Staff quarterly to provide progress of the SAP S/4HANA Implementation project, including any advancements and/or setbacks in project implementation, budget adherence, changes to project scope, timeline, expenses, and any problems the Company has experienced or anticipates experiencing with any operations or customer interactions.

Second, Staff is recommending the Company include in future rate case filings until implementation is complete, any over and under recovery of each projected expense for the project compared to the 80% base (ROM Adjusted Amount).

Q. Does the Company agree with Staff witness Zichi's recommendations regarding the SAP S/4HANA Implementation project?

A. Yes. The Company agrees with Staff witness Zichi's recommendations regarding the SAP S/4HANA Implementation project as described above.

Q. What projects is Staff witness Klocke proposing adjustments for in this case?

A. On page 4, lines 16 through 22, of her direct testimony, Staff witness Klocke is proposing adjustments for the Product Family Enhancement-Customer-Capital project that includes Customer Self-Service Mobile Application, Low Moderate Income ("LMI") Customer

Support, Web Chat AI, Web Dashboard Redesign, and Web Rebate for Personalization enhancements in Confidential Exhibit A-20 (SHB-5), lines 14, 112, 193, and 269. Company witness Jessica R. Byrom and I will address each proposed adjustment.

Q. What amounts is Staff witness Klocke proposing to disallow for the Product Family Enhancements-Customer-Capital project that includes Customer Self-Service Mobile Application, LMI Customer Support, Web Chat AI, Web Dashboard Redesign, and Web Rebate for Personalization enhancements?

A. Staff witness Klocke is proposing the following adjustments of the capital expenditures and IT Investments O&M expenses for the following enhancements that are a part of the Product Family Enhancements-Customer-Capital project based on Staff witness Klocke's Exhibit S-10.2, pages 1 through 2 and Staff witness Zichi's Exhibit S-14.0, line 1.

	Capital				O&M	
Enhancements	**Historical 12-Month Ended 12/31/2024**	**Bridge Period 12-Month Ending 12/31/2025**	**Bridge Period 4-Month Ended 4/30/2026**	**Test Year 12-Month Ended 4/30/2027**	**Projected Test Year**	**Exhibit S-10.2, page 1 Reference**
Customer Self-Service Mobile Application	$1,056,334	$1,305,671	$0	$0	$0	Lines 1 – 3, 5 – 11, and 14
LMI Customer Support	$0	$525,246	$0	$0	$0	Line 18
Web Chat Artificial Intelligence ("AI")	$0	$0	$157,574	$315,148	$19,896	Line 22
Web Dashboard Redesign		$525,246	$0	$0	$0	Line 17
Web Rebate Personalization	$0	$0	$87,541	$175,082	$11.053	Line 21
Total	$1,056,334	$2,356,163	$245.115	$490,230	$30,949	

Q. What adjustments is Staff witness Klocke proposing for Customer Self-Service Mobile Application enhancements that are part of the Product Family Enhancements-Customer-Capital project?

A. On page 5, lines 1 through 8, of her direct testimony, Staff witness Klocke is proposing an adjustment of $1,056,334 of capital expenditures for the historical year ended 12/31/2024 and $1,305,671 of capital expenditures for the year ending 12/31/2025 for the Customer Self-Service Mobile Application enhancements that are a part of the Product Family Enhancements-Customer-Capital project. This adjustment corresponds to the capital expenditures present on Confidential Exhibit A-20 (SHB-5), lines 14 and 112 and is within the Customer business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 2.

Q. Do you agree with Staff witness Klocke's adjustments to the Customer Self-Service Mobile Application enhancements that are a part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's adjustments of the Customer Self-Service Mobile Applications enhancements that are part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. What adjustment is Staff witness Klocke proposing for the LMI Customer Support enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. On page 7, lines 13 through 21, of her direct testimony, Staff witness Klocke is proposing a full disallowance of $525,246 in capital costs for the year ending 12/31/2025 for the LMI Customer Support enhancement that is a part of the Product Family Enhancements-

Customer-Capital project. This adjustment corresponds to the capital expenditures present on Confidential Exhibit A-20 (SHB-5), line 112 and is within the Customer business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 2.

Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the LMI enhancement that is part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the LMI enhancement that is a part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. What adjustments is Staff witness Klocke proposing for the Web Chat AI enhancement that is a part of the Product Family Enhancements-Customer-Capital in this case?

A. On page 14, lines 8 through 15, of her direct testimony, Staff witness Klocke is proposing full disallowance of $157,574 in capital expenditures for the partial bridge period ending 4/30/2026 and $315,148 in capital expenditures and $19,896 in Investments O&M for the partial test year ending 12/31/2026 for the Web Chat AI enhancement that is a part of the Product Family Enhancements-Customer-Capital project. This adjustment corresponds to the capital expenditures present on Confidential Exhibit A-20 (SHB-5), line 193 and is within the Customer business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 2.

Q. Do you agree with Staff witness Klocke's proposal of full disallowance of the Web Chat AI enhancement that is part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's proposal of full disallowance of the Web Chat AI enhancement that is part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. What adjustment is Staff witness Klocke proposing for the Web Dashboard Redesign enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. On page 16, lines 11 through 17, of her direct testimony, Staff witness Klocke is proposing disallowance of the $525,246 in capital expenditures for the bridge period ending 12/31/2025 for the Web Dashboard Redesign project that is a part of the Product Family Enhancements-Customer-Capital project. This adjustment corresponds to the capital expenditures present on Confidential Exhibit A-20 (SHB-5), lines 112 and is within the Customer business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 2.

Q. Do you agree with Staff witness Klocke's rationale for the adjustment of the Web Dashboard Redesign enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's rationale for the full disallowance of the Web Dashboard Redesign enhancement that is a part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. Do you agree with Staff witness Klocke's proposed adjustment of the Web Dashboard Redesign enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. Yes. Due to other higher priority work, the Web Dashboard Redesign enhancement will not be completed as planned. Therefore, the $525,246 in capital expenditures for the 12 months ending 12/31/2025 should be removed from this case.

Q. What adjustments is Staff witness Klocke proposing for the Web Rebate Personalization enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. On page 17, line 19, through page 18, line 3, of her direct testimony, Staff witness Klocke is proposing a full $87,541 for the partial bridge ending 4/30/2026 and $175,082 in capital expenditures and $16,580 in IT Investments O&M expense for the partial test year ending 12/31/2026 for the Web Rebate Personalization enhancement that is a part of the Product Family Enhancements-Customer-Capital project. This adjustment corresponds to the capital expenditures present on Confidential Exhibit A-20 (SHB-5), line 193 and is within the Customer business category on Exhibit A-12 (SHB-4), Schedule B-5.1, page 1, line 2.

Q. Do you agree with Staff witness Klocke's rationale for adjustment of the Web Rebate Personalization enhancement that is part of the Product Family Enhancements-Customer-Capital project?

A. No. The Company does not agree with Staff witness Klocke's rationale for full disallowance of the Web Rebate Personalization enhancement that is part of the Product Family Enhancements-Customer-Capital project. Company witness Byrom's rebuttal testimony further addresses this project's value.

Q. Are there any other corrections the Company has identified to the IT Investments O&M expense for the Web Rebate Personalization enhancement that is part of the Product Family Enhancements-Customer-Capital project?

A. Yes. On page 18, lines 2 through 3, of Staff witness Klocke's direct testimony, she is proposing a disallowance of $16,580 in IT Investments O&M expense for the partial test year ending 12/31/2026. The correct partial test year ending 12/31/2026 amount is $11,053 (8 months of $16,580).

Q. Do you agree with Staff witness Klocke's proposed adjustment of the Web Rebate Personalization enhancement that is a part of the Product Family Enhancements-Customer-Capital project?

A. Yes. Due to other higher priority work, the Web Rebate Personalization enhancement will not be completed as planned. Therefore, $87,541 for the partial bridge ending 4/30/2026 and $175,082 in capital expenditures and $11,053 in IT Investments O&M expense for the partial test year ending 12/31/2026.

Q. What is the current status of the Company's website redesign project Staff witness Klocke discusses in her direct testimony related to Web Chat AI, Customer Self-Service Mobile Application, and LMI Customer Support enhancements that are part of Product Family Enhancements-Customer-Capital project?

A. As discussed in Staff Audit Response U21870-SA-CE-080 (Exhibit A-186 (SHB-15)), the Company has put the website redesign on hold due to extended support of the current on-premises Sitecore web content management system and the Company's SAP S/4HANA planned implementation.

The previous timing for the website redesign was developed with the expectation that the Company would need to migrate to the cloud/Software-as-a-Service ("SaaS") version of the Sitecore system based on Sitecore's published product support lifecycle at that time. This would have been a major reason to initiate the website redesign. Since then, Sitecore has extended mainstream support for the on-premises version 10.4 to December 31, 2027, giving the Company more flexibility in its migration schedule.

In addition, the Company's implementation of the SAP S/4HANA system will be a major undertaking, which will significantly impact the design of integration between the Company's website and SAP. The Company plans to complete the S/4HANA implementation before starting the website redesign.

It is important to note that improvements to the Company's website design, content, navigation, accessibility, and features are not static or stopped until the website redesign project is undertaken. The Company is regularly prioritizing and executing updates to web pages, content, and flows based on customer needs and challenges. An example of this is for the LMI Customer Support Enhancement. In fact, much of the investment in this enhancement is being achieved through updates to website design, content, features, and navigation, without the full re-architecture associated with the eventual website redesign project.

Q. Do you agree that the Company's website redesign would negate the need to make investments in Customer Self-Service Mobile Application and Web Chat AI?

A. No. The Website Redesign would not negate the need to make investments in the Customer Self-Service Mobile Application, Web Chat AI, or any other channels preferred by

customers for specific needs, as discussed in Company witness Byrom's rebuttal testimony.

Q. What adjustments is Staff witness Duell proposing for the Service Restoration AI project in this case?

A. On page 21, lines 19 through 22, and page 22, lines 8 through 11, of her direct testimony, Staff witness Duell is proposing a partial adjustment for the Service Restoration Artificial Intelligence project.

Q. What amount is Staff witness Duell adjustments for the Service Restoration AI project?

A. Staff witness Duell is proposing an adjustment of $31,082 for the partial bridge period ending 4/30/2026 and $56,805 for the test year ending 4/30/2027.

Q. Do you agree with Staff witness Duell's proposal of adjustment of the Service Restoration AI project?

A. Yes. The Company agrees with the basis of the proposed adjustment as explained in its response to Staff Discovery Request No. U21870-ST-CE-0269 (Exhibit S-18, page 4) that Non-Labor Other costs for both capital and O&M in 2026 and 2027 were inadvertently miscalculated. The capital expenditures should be reduced by $31,082 in the 12-month bridge period ending 12/31/2025 and $56,805 for the projected test year ending 4/30/2027 for the Service Restoration AI project.

Q. Are there any corrections the Company has identified for the Service Restoration AI project?

A. Yes. On page 21, line 16, of Staff witness Duell's direct testimony, she indicates that the projected capital expenditures for the bridge period are $1,370,000 for the Service

Restoration AI project. Based on the Company's response to Staff Discovery Request No. U21870-ST-CE-0269 (Exhibit S-18, page 4), the correct projected capital expenditures for the bridge period are $754,716 ($603,773 ROM Adjusted). Additionally, on page 22, line 5, of Staff witness Duell's direct testimony, she indicates that the projected capital expenditures for the test year are $6,123,000. Based on Staff Discovery Request No. U21870-ST-CE-0269 (Exhibit S-18, page 4), the correct projected capital expenditures for the test year are $165,505 ($132,404 ROM Adjusted).

ATTORNEY GENERAL

Q. What amount does Attorney General witness Coppola propose removing for four IT projects that are in the investment planning phase?

A. On page 89, line 16, through page 90, line 19 of his direct testimony, Attorney General witness Coppola proposes to remove $1,448,000 of capital expenditures for the projected bridge ending in 4/30/26, $3,067,000 of capital expenditures for the projected test year ending in 4/30/2027, and $1,260,000 of O&M expense for the projected test year ending 4/30/2027 for the four IT projects in the investment planning phase. This adjustment corresponds to the following capital expenditures and Investments O&M expense in capital and O&M in Confidential Exhibit A-20 (SHB-5) and Exhibit A-12 (SHB-4), Schedule B-5.1, page 1.

Project	Business Category	Confidential Exhibit A-20 (SHB-5) Reference	Exhibit A-12 (SHB-4), Schedule B-5.1, page 1 Reference
Electric Geographic Information System ("GIS") Design Platform Modernization	Electric	Lines 23, 123, 200, and 276	Line 3
Electric GIS Utility Network Transformation	Electric	Line 277	Line 3
Integrated Energy Management Platform Optimization	Electric	Line 279	Line 3
Service Restoration Artificial Intelligence	Electric	Lines 204 and 282	Line 3

Q. What is the rationale Attorney General witness Coppola describes for adjustments to these four IT projects?

A. On page 90, lines 5 through 13, of his direct testimony, Attorney General witness Coppola is basing his proposal on the Company's responses to Discovery Request No. U21870-AG-CE-0592 (Exhibit AG-27, pages 1 through 6) on whether a project is in the Investment Planning phase or the detailed requirements phase (*i.e.,* whether detailed requirements[1] have yet to be completed).

Q. Does the Company agree with Attorney General witness Coppola's proposal to remove these four IT projects in the investment planning phase?

A. No. Attorney General witness Coppola's proposal is a broad brush to reduce costs for IT projects without considering the value created by these projects, nor recognizing the

[1] Detailed requirements typically include detailed business objectives and requirements, performance and security requirements, stakeholder requirements, function and non-functional solution requirements, refined cost estimates, refined project plan, conducting a Request for Proposal and contract management.

requirement work completed to develop each business case, as described in my direct testimony on page 36, line 20 through page 37, line 3.

Q. Does the Company agree that significant requirements are not complete, and that IT projects in the Investment Planning phase should be disallowed?

A. No. These four IT projects should not be disallowed on the basis that they are in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is incomplete or lacking information. An IT business case was completed and approved for this project prior to consideration for inclusion in the Company's rate case, following the Company's business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and these five IT projects should be included and approved as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

Q. Has the Company provided the value of these IT projects?

A. Yes. The Company has detailed the description, scope and value of each project in my direct testimony, exhibits and workpapers, audit and discovery responses, and provided exact references for each IT project.

Q. Can you please summarize the value for each of these IT projects?

A. Yes. The project name and the Company witness that has summarized the value for the four IT projects is below, including other supporting information provided in my Exhibit A-21 (SHB-6). The intangible value such as avoided costs, safety, and quality of these

projects must be considered along with the hard savings to provide a true picture of the opportunity missed if these projects are not approved.

Project	Witness	Exhibit A-21 (SHB-6) References
Electric GIS Design Platform Modernization	M. Kelly	Pages 58 and 59
Electric GIS Utility Network Transformation	M. Kelly	Pages 62 and 63
Integrated Energy Management Platform Optimization	M. Metz	Pages 101 and 102
Service Restoration Artificial Intelligence	A. Snider	Page 144

Q. Has the Company taken measures to address the concerns of over recovery of IT projects?

A. Yes. In addition to the detailed efforts the Company takes to investigate, provide quality reviews and approvals for each business case, the Company has proactively taken a 20% ROM reduction in this case to address Commission concerns from Case No. U-20963 of over recovery for projects that have a ROM estimate. This is discussed further in my direct testimony on page 49, line 1, through page 50, line 7.

Q. What amount does Attorney General witness Coppola propose removing for an additional five IT projects that are in the investment planning phase?

A. On page 91, line 1, through page 92, line 7 of his direct testimony, Attorney General witness Coppola proposes to remove $6,283,000 for the projected bridge ending in 4/30/26 and $11,428,000 for the projected test year ending in 4/30/2027 of capital expenditures, and 1,876,000 for the projected test year ending 4/30/2027 of Investments O&M expense for an additional five IT projects in the Investment Planning phase. This adjustment corresponds to the following capital expenditures and Investments O&M expense in Confidential Exhibit A-20 (SHB-5) and Exhibit A-12 (SHB-4), Schedule B-5.1, page 1.

Project	Business Category	Confidential Exhibit A-20 (SHB-5) References	Exhibit A-12 (SHB-4), Schedule B-5.1, page 1 References
Critical Substation Upgrade	Security	Lines 242 and 320	Line 6
Data & Analytics Platform Rationalization	IT/Digital Foundation	Lines 154 and 226	Line 5
Operational Technology (OT) Datacenter Migration	IT/Digital Foundation	Lines 222 and 302	Line 5
Forward Web Proxy Services	Security	Lines 252 and 328	Line 6
Physical Access Management and Alarm Response	Security	Lines 253 and 329	Line 6

Q. What is the rationale Attorney General witness Coppola describes for adjustments to these additional five IT projects?

A. On page 91, lines 9 through 17, of his direct testimony, Attorney General witness Coppola is basing his proposal on the Company's responses to Discovery Request Nos. U21870-AG-CE-0594, U21870-AG-CE-0595, U21870-AG-CE-0596, U21870-AG-CE-0601, and U21870-AG-CE-0602 (Exhibit AG-29, pages 1 through 12) on whether a project is in the Investment Planning phase and detailed requirements have yet to be completed.

Q. Does the Company agree with Attorney General witness Coppola's proposal to remove these additional five IT projects in the investment planning phase?

A. No. Attorney General witness Coppola's proposal is a broad brush to reduce costs for IT projects without considering the value created by these projects, nor recognizing the requirement work completed to develop each business case.

Q. Does the Company agree that significant requirements are not complete, and that IT projects in the Investment Planning phase should be disallowed?

A. No. These additional five IT projects should not be disallowed on the basis that they are in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is incomplete or lacking information. An IT business case was completed and approved for this project prior to consideration for inclusion in the Company's rate case, following the Company's business case process. Even though the business case is complete and approved, projects remain in this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and these five IT projects should be included and approved as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

Q. Has the Company provided the value of these IT projects?

A. Yes, the Company has detailed the description, scope and value of each project in my direct testimony, exhibits and workpapers, audit and discovery responses, and provided exact references for each IT project.

Q. Can you please summarize the value for each of these IT projects?

A. Yes. The project name and summarized value for each IT project is below, including the direct testimony cross reference and other supporting information provided in my Exhibit A-21 (SHB-6). The intangible value such as avoided costs, safety, and quality of these projects must be considered along with the hard savings to provide a true picture of the opportunity missed if these projects are not approved.

- Critical Substation Upgrade will provide enhanced perimeter and electronic security at designated substations to detect, deter, and respond to threats in real-time, thereby reducing the risk of large-scale outages, preserving electric delivery reliability, strengthening operational resilience, and protecting public safety and critical infrastructure. (Company witness Baker direct testimony page 79, line 13 through page 80, line 33 and Exhibit A-21 (SHB-6), pages 47 and 48.)

- Data & Analytics Platform Rationalization will consolidate outdated, inefficient legacy data and analytics systems into Data Lake 2.0, migrate reports to modern visualization tools, and retire duplicative legacy platforms to reduce total cost of ownership, eliminate redundant support and licensing burdens, improve data accessibility and governance, and enable scalable, cloud-aligned analytics capabilities. (Company witness Baker direct testimony page 97, line 4 through page 98, line 32 and Exhibit A-21 (SHB-6), page 51.)

- Operational Technology ("OT") Datacenter Migration will relocate critical OT infrastructure from the Parnall facility to a co-located vendor datacenter to eliminate site and environmental risks, ensure redundant power and climate controls, strengthen physical security and operational resilience, revalidate production and disaster-recovery procedures, and decommission an at-risk facility. (Company witness Baker direct testimony page 100, lines 3 through 40 and Exhibit A-21 (SHB-6), pages 114 and 115.)

- Forward Web Proxy Services will replace the current web proxy platform with a mature, scalable service to restore consistent access to internet and cloud resources, enforce advanced threat protections such as browser isolation and sandboxing, and implement continuous Zero Trust verification to preserve business continuity and reduce cyber risk. (Company witness Baker direct testimony page 114, line 30 through page 115, line 37 and Exhibit A-21 (SHB-6), pages 88 and 89.)

- Physical Access Management and Alarm Response will centralize physical access control to eliminate system instability, reduce manual intervention and rework, mitigate unauthorized access risk, enable mobile digital IDs, and improve alarm orchestration and compliance. (Company witness Baker direct testimony page115, line 38 through page117, line 24 and Exhibit A-21 (SHB-6), pages 116 and 117.)

This is a snapshot reminder of the benefits of these five IT projects that need to be considered when evaluating each project. The value of these projects should not be dismissed in a simple review of whether a project is in the Investment Planning phase.

Q. Has the Company taken measures to address the concerns of over recovery of IT projects?

A. Yes. In addition to the detailed efforts the Company takes to investigate, provide quality reviews and approvals for each business case, the Company has proactively taken a 20% ROM reduction in this case to address Commission concerns from Case No. U-20963 of over recovery for projects that have a ROM estimate. This is discussed further in my direct testimony on page 49, line 1, through page 50, line 7.

Q. Are there additional points that the Company would like to address for the additional five projects?

A. Yes. The Company would like to address additional points for the Critical Substation Upgrade, Data & Analytics Platform Rationalization, and OT Datacenter Migration projects.

Q. Are there any corrections the Company has identified for the Critical Substation Upgrade project?

A. Yes. Based projected test year capital of $3,498,167 for the Critical Substation Upgrade project provided in my direct testimony, on page 79, line 13, the correct projected ROM Adjusted Capital for the test year should be $2,798,533 ($3,498,167 less 20% ROM Adjustment) instead of the $3,135,966 amount I included in in my direct testimony, on page 79, line 14.

Q. If Attorney General witness Coppola's proposed disallowance for the Critical Substation Upgrade project is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?

A. Yes. The Company has identified necessary adjustments for the Critical Substation Upgrade project. Based on the corrected projected ROM Adjusted Capital previously provided in my rebuttal testimony for the test year of $2,798,533, the projected test year amount in Exhibit AG-28, line 6, for the Critical Substation Upgrade project should be updated to $2,798,533. Therefore, Attorney General witness Coppola's proposal to remove $11,428,000 in capital expenditures for the projected test year ending in 4/30/2027 should be updated to $11,091,000.

Q. Have any of the projects advanced beyond the Investment Planning phase?

A. Yes, the Data & Analytics Platform Rationalization project has completed the Planning phase and is now in Execute, with plans for the first release to go live in December 2025.

Q. What was the Commission's decision on page 130 of its September 30, 2025 Order in Case No. U-21806 related to the OT Datacenter Migration project?

A. The Commission found the Company provided insufficient justification on why relocating the datacenter to an entirely new facility is a cost-effective and reasonable option in comparison to fixing the problems in the existing building for the OT Datacenter Migration project. The Commission adopted the ALJ's recommendation, on pages 168-169 of the PFD in Case No. U-21806. Additionally, both the Commission and PFD indicated that this

project could be shown to be reasonable and prudent, should the Company provide more robust support for cost recovery.

Q. Has the Company estimated the costs of addressing the aging climate control equipment and continuing water filtration issues of the location of the datacenter in the basement of the Parnall building?

A. Yes. The Company has estimated the costs of addressing the aging climate control equipment and continuing water filtration issues of the current location to be $5,082,728. The projected costs to replace the aging climate control equipment including labor is $4,965,728. To remediate the water infiltration issue it would require removal of architectural concrete and replacing the waterproof membrane, which is estimated to be $117,000. This does not address the risk of the datacenter location being in the basement of the Parnall building near the main water pipe for the building. By moving the data center to a new co-located facility, this cost would be avoided and mitigate the risk of the location of the datacenter being near the main water pipe for the building.

Q. Why does the presence of a railway in the vicinity of the Parnall building make it an inappropriate site for a data center?

A. The presence of a railway near a data center increases physical risk such as vibration and environmental hazards such as trains carrying hazardous material or fuels. A more recent Industry standard, ANSI/BICSI 002-2024, recommends maintaining a safe distance – typically 1.6 km (1 mi) or more – to ensure long-term stability and minimize risk. The current distance from the railway to the building, where the data center is located, is approximately 170 meters.

Q. If the OT Datacenter Migration project were approved, would the Company be able to avoid costs in the ARP-OT Support Common and ARP-OT Support Electric projects in future years?

A. Yes. If the OT Datacenter Migration project were approved, the Company would be able to avoid ARP-OT Support Common and ARP-OT Support Electric project costs in future years.

Project	Total Company		Electric Allocation	
	Capital	O&M	Capital	O&M
ARP-OT Support Common	$809,200	$83,440	$554,868	$51,717
ARP-OT Support Electric	$828,600	$87,120	$828,600	$87,120

Q. In the Commission's September 30, 2025 Order in Case No. U-21806, pages 106-107, did the Commission advise the Company to refrain from submitting information confidentially that will directly affect the calculation of the revenue deficiency?

A. Yes. The Commission did advise the Company to refrain from submitting information confidentially that will directly affect the calculation of the revenue deficiency or, if the Company believes it is necessary to do so, to at least provide a detailed explanation of the reason for confidential treatment on the record.

Q. Why did the Company classify the capital expenditures and O&M expense amounts related to the SAP S/4HANA Implementation project as confidential?

A. The Company classified the capital expenditures and O&M expense amount related to the SAP S/4HANA Implementation project as confidential due to the impact of publicly disclosing the total projected costs of the project. Publicly disclosing the total projected project costs would impact the Company's ability to competitively bid contractor and software costs, impacting the cost-effectiveness of the project for customers.

Q. Does the Company intend to maintain the confidentiality of its test year capital expenditures and O&M expense and cloud implementation costs?

A. No. Given the Commissions advisement, the Company has decided to declassify the following items it previously classified as confidential:

- Company witness Baker Direct Testimony, page 102, amounts on lines 23 through 24;
- Company witness Daly Direct Testimony, page 33, amounts on lines 3, 4 and 9;
- Exhibit A-26 (SHB-11), line 1, column O; and
- Exhibit A-86 (PDD-62).

The Company is maintaining the confidential classification for the following items:

- Company witness Baker Direct Testimony, page 103, content on line 21;
- Confidential Exhibit A-20 (SHB-5), lines 162, 234, and 313, columns (e), (i), (j), (l) through (y); and
- Exhibit A-21 (SHB-6), page 137
- Exhibit A-26 (SHB-11), line 1, columns b through n.

For the declassified material, the Company plans to move to bind it into the record or admit it into evidence in the public record.

Q. What projected capital expenditures adjustments is Attorney General witness Coppola proposing for the SAP S/4HANA Implementation project identified on page 90 of his direct testimony?

A. Attorney General witness Coppola is proposing on page 95, lines 15 through 17, of his direct testimony to remove $20,392,000 for the 16 months ending April 2026 and

$34,793,000 for the projected test year of the Company's capital expenditures for the SAP S/4HANA Implementation project.

Q. What is Attorney General witness Coppola proposing for SAP S/4HANA Implementation project O&M costs identified on page 95 of his direct testimony?

A. Attorney General witness Coppola is proposing on page 95, line 17, through page 96, line 2, of his direct testimony to remove $15,178,000 O&M expense for the projected test year for the SAP S/4HANA Implementation project. Additionally, Attorney General witness Coppola proposes that the Commission reject the Company's proposal to defer $15,178,000 O&M costs into a regulatory asset.

Q. What is the argument Attorney General witness Coppola describes for capital expenditures adjustments and rejecting the proposal for deferral of O&M costs to a regulatory asset for the SAP S/4HANA Implementation project?

A. The first argument Attorney General witness Coppola describes on page 95, lines 7 through 10, of his direct testimony for removing capital amounts and rejecting deferral of O&M costs for the SAP S/4HANA Implementation project is his claim that the current Enterprise Resource Planning ("ERP") system still functions well and meets the Company's operating needs, and that it appears that the option exists for the Company to continue to operate the system into 2030 and potentially past the date with system support by SAP.

Q. Does the Company agree that the option exists to continue to operate the current system into 2030 and potentially past the date with system support by SAP?

A. No. The project will take approximately three years to complete and extended support for the Company's current SAP version is only available until 2030, as discussed in my direct testimony, on page 106, lines 12 through 19. There is also an increased risk of cyberattacks

if the SAP S/4HANA project is not executed because SAP has stated that after maintenance ends, standard patches will no longer be available, as discussed on page 106, line 20, through page 107, line 3, of my direct testimony.

Q. What is the second argument Attorney General witness Coppola describes for capital expenditure adjustments and rejecting the proposal for deferral of O&M costs to a regulatory asset for the SAP S/4HANA Implementation project?

A. The second argument Attorney General witness Coppola describes on page 95, lines 12 through 14, of his direct testimony for removing capital amounts and rejecting deferral of O&M costs for the SAP S/4HANA Implementation project is his contention that the project is premature.

Q. Does the Company agree the SAP S/4HANA Implementation project capital expenditures should be disallowed and proposal for deferral of O&M costs be rejected because it is premature and in the Investment Planning phase?

A. No. This project's capital expenditures should not be disallowed and proposal for deferral of O&M costs rejected on the basis that it is in the Investment Planning phase. Investment Planning is the phase a project remains in while it is waiting for funding and does not indicate that it is premature or incomplete or lacking information. Although the Company issued a request for proposal in May 2025 for implementation partners, the Company leveraged a third party that specializes in preparing for S/4HANA upgrades to develop the cost estimates for the business case, as stated in my direct testimony on page 107, lines 14 through 16. The IT business case was completed and approved for this project prior to consideration for inclusion in the Company's rate case, following the same strict business case process. Even though the business case is complete and approved, projects remain in

this Investment Planning Phase and are not released for further planning and implementation activities until funding is approved through rate case and budget disposition. Therefore, significant requirements are complete, and the project should be included and approved as the Company fully plans to spend the projected expenditures based on the project timeline in this case.

Q. What is the argument Attorney General witness Coppola describes for removing the O&M amounts for the SAP S/4HANA Implementation project?

A. Similar to the capital expenditures, the argument Attorney General witness Coppola describes on page 95, lines 7 through 14, of his direct testimony for removing amounts for the SAP S/4HANA Implementation project is his contention that the project is premature.

Q. What was the Commission's decision on page 106 of its September 30, 2025 Order in Case No. U-21806 related to the SAP S/4HANA Implementation project?

A. The Commission found the Company's evidence to be satisfactory and adopted the ALJ's recommendation, on page 134 of the PFD in Case No. U-21806, to approve the SAP S/4HANA Implementation project and the associated requests for deferral of O&M expenses and amortization of the associated cloud computing costs and declined to disallow the project as recommended by the Attorney General.

Q. What adjustments is Attorney General witness Coppola proposing for the ARP-FDAM project in this case?

A. On page 97, lines 6 through 11, of his direct testimony, Attorney General witness Coppola is recommending a partial disallowance of $1,039,000 for the project bridge period ending 4/30/2026 and $2,513,000 for the project test year in capital expenditures for the ARP-FDAM project.

Q. Do you agree with Attorney General witness Coppola's proposal, at page 97, of his direct testimony, to reduce capital expenditures for the 16 months ending April 2026 by $1,039,000, and for the projected test year to $2,513,000 for the ARP-FDAM project?

A. No. Attorney General witness Coppola is basing the projections on a three-year historical average plus an adjustment for forecasted inflation. This does not consider that the cost projected for each year for the ARP-FDAM project is for specific hardware that requires replacement based on timing of when it was installed and risk if it were not replaced in the four-year refresh cycle.

Q. What other evidence should Attorney General witness Coppola consider when evaluating the prudency and reasonableness of the projected test year capital expenditures for the ARP-FDAM in addition to the actual capital expenditures provided in Discovery Response No. U21870-AG-CE-0603 (Exhibit AG-31)?

A. Attorney General witness Coppola should consider the following other evidence: (1) the new field device purchases that were purchased as a part of the ARP-WAM project in 2021, 2022, and 2023; and (2) the 425 new field device that were purchased in 2022 for training and the Compression Digital Mobility project, as discussed in my direct testimony, page 67, lines 6 through 9.

In Staff Audit Response U21870-SA-CE-008 (Exhibit S-14.1), the Company provided the new field device purchases that were purchased under the ARP-WAM project in 2021, 2022, and 2023. Additionally, the Company provided further information on the 425 new field devices purchased in 2022 discussed in my direct testimony on page 67, lines 6 through 9, in Staff Audit Responses U21870-SA-CE-024 and U21870-SA-CE-090

(Exhibit A-184 (SHB-13). These field devices are now planned to be refreshed as a part of the ARP-FDAM project in 2026.

Q. Please describe Exhibit A-185 (SHB-14).

A. Exhibit A-185 (SHB-14) is the number of replacements and new purchases for 2021, 2022, 2023, and 2024 for the ARP-FDAM project, aggregating the data provided in Staff Audit Response U21870-SA-CE-008 (Exhibit S-14.1), Discovery Response U21870-AG-CE-0603 (Exhibit AG-31), and Staff Audit Responses U21870-SA-CE-024 and U21870-SA-CE-090 (Exhibit A-184 (SHB-13). Specifically:

- Column (a) provides the unit description;
- Column (b) provides the average unit cost;
- Column (c) provides the total number of units for the specified year;
- Column (d) provides total actual capital expenditures for the specified year;
- Column (g) provides the total actual electric allocation of capital expenditures for the specified year; and
- Column (h) provides a reference for the actual data.

Q. What is the impact of co-workers not having a field device to perform work in service of customers?

A. The absence of field devices for co-workers can significantly impact their ability to perform work effectively. Without field devices, co-workers face productivity losses due to the need to access information through less efficient means, such as using paper-based resources. This can lead to delays in work initiation and completion. The lack of access to electronic safety manuals and resources can increase safety risks. Workers may not have the most up-to-date safety information readily available, which is crucial for maintaining a safe working environment. Field devices facilitate better communication, especially

during emergencies or unexpected events. Without them, there is a risk of losing business continuity and effective communication, which can hinder timely responses to customer needs. Field devices provide access to online training and Company resources, which are essential for continuous learning and skill development. Without these devices, workers may miss out on training, leading to a gap in knowledge and skills. Sharing devices among employees can pose cybersecurity risks. Field devices help mitigate these risks by providing individual access to necessary resources, reducing the need for device sharing. Overall, the lack of field devices can lead to decreased efficiency, increased safety risks, and hindered communication, all of which negatively impact the service provided to customers.

Q. If Attorney General witness Coppola's proposed disallowance for the ARP-FDAM project is nonetheless adopted, has the Company identified any necessary adjustments to the disallowance?

A. Yes. The Company has identified necessary adjustments for the ARP-FDAM project. Referring to page 97, lines 1 through 6, of Attorney General witness Coppola's direct testimony, the calculation of the forecasted capital expenditures of $2,957.000 is not correct. Based on the most recent three historical years from 2022 to 2024 of $2,218,000, then prorated to 16 months and applying the inflation factor of 2.9%, the forecasted capital expenditures would be $3,043,000 ($2,218,00 X 16/12 X 1.029). Therefore, the adjustment would be $953,000 rather than $1,039,000.

Q. If Attorney General witness Coppola's proposed disallowance for the ARP-FDAM project is nonetheless adopted, is there overlap with Staff witness Zichi's proposed disallowance for the same project?

A. Yes. If Attorney General witness Coppola's proposal that ARP-FDAM should be projected based on a three-year average plus inflation, which it should not, the resulting disallowance should be offset by the amounts reduced by the Company, as discussed in response to Staff witness Zichi above, related to new field device purchases of $24,696 for the 4-month bridge period ending 4/30/2026 and $74,089 for the projected test year ending 4/30/2027 of capital expenditures, Additionally, Attorney General witness Coppola's proposal should be offset if Staff witness Zichi's proposal for a full disallowance of $228,567 for the 4-month bridge period ending 4/30/2026 and $658,700 for the projected test year ending 4/30/2027 of capital expenditures for new field devices is adopted.

Q. Does this conclude your rebuttal testimony

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Program-Field Device Asset Management
New Purchases Historical Acutal 2021 - 2024

Case No.: U-21870
Exhibit No.: A-183 (SHB-12)
Page: 1 of 2
Witness: SHBaker
Date: October 2025

Line No.	(a) Year	(b) Total Company New Purchases	(c) Reference*
1	2021	$ 1,207,651	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns f and h, line 48 and 49 plus 21% of lines 56 - 57 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
2	2022	$ 778,339	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, lines 64 and 66 plus 35% of lines 72 - 73 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
3	2023	$ 880,134	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, lines 52-54 plus 73% of lines 59 - 60 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
4	2024	$ 701,684	U-21870, Exhibit No. A-22 (SHB-7), page 5, columns e and g, lines 12, 14, 16, and 18.
5	Total Company Four-year Historical Average	$ 891,952	
6	Electric Allocation Four-year Historical Average	$ 611,611	

*Note: In 2021, 2022, and 2023 Field Device new purchases were a part of ARP-Workstation Asset Management and not ARP-FDAM.
See U21870-SA-CE-010 Worksheet for how Accessories and Shipping, etc. costs were allocated for new purchases for ARP-FDAM and ARP-WAM

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Program-Workstation Asset Management
New Purchases Historical Acutal 2021 - 2024

Case No.: U-21870
Exhibit No.: A-183 (SHB-12)
Page: 2 of 2
Witness: SHBaker
Date: October 2025

Line No.	(a)	(b)	(c)
	Year	**Total Company New Purchases**	**Reference***
1	2021	$ 4,583,866	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns e and g, line 40 - 42, 44, 47, 50 - 51, and 53 - 57 plus 79% of lines 56 - 57 for ARP-WAM new purchases portion of accessories, shipping and handling, and other fees.
2	2022	$ 1,414,635	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, lines 48, 50, 52, 54, 56, 59, 62, 68, 70, 72, and 73 plus 65% of lines 72 - 73 for ARP-WAM new purchases portion of accessories, shipping and handling, and other fees.
3	2023	$ 318,694	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, lines 38, 39, 41, 43, 45, 47, 49, 55, 57, 59, and 60 plus 27% of lines 59 - 60 for ARP-WAM new purchases portion of accessories, shipping and handling, and other fees.
4	2024	$ 954,274	U-21870, Exhibit No. A-22 (SHB-7), page 15, columns e and g, lines 28 -34, and 36.
5	Four-year Historical Average	$ 1,817,867	
6	Electric Allocation Four-year Historical Average	$ 1,246,512	

*Note: In 2021, 2022, and 2023 Field Device new purchases were a part of ARP-Workstation Asset Management and not ARP-FDAM.

U21870-SA-CE-024
Requested By: Emma Zichi (EZ-1 - 19)
Respondent: Stacy H. Baker
Date of Response: 6/25/2025
Page **1** of **1**

Question:

19. Regarding the "ARP-FDAM" project:
a. In testimony on page 66, lines 12-13, it states the reason for a decrease in material costs related to new purchases. The reason being "current allocation factors that are updated annually" please explain what this means and how it decreased the spend on new purchases for this project.
b. When were the costs for the initial purchase of the devices, mentioned on lines 6-7 and 8-9 on page 67 of testimony, included in a rate case and subsequently approved?
c. Please explain the increased costs associated with labor and non-Labor other mentioned on line 13-14 on page 67 of testimony.

Response:

a. The Company updates the allocation factors for electric and gas annually. The cost of each common hardware asset is allocated between electric and gas based on the end users, such as employees and customers. Then the Company divides the sum of the electric allocation amounts by the total of all common hardware assets to calculate the electric allocation. In the previous Case No. U-21585, the 2025 electric allocation factor was 69.65% and, in this case, the 2025 allocation factor is 68.57%. This change resulted in $0.01 million decrease in the new purchases electric allocation.

b. The costs for the initial purchase of the devices discussed in my direct testimony on page 67, lines 6-7, were included in Case No. U-21224 as a part of the Corporate Capital and the case was settled on December 22, 2022 and approved on January 19, 2023. The first case the costs for the initial purchase of the devices in my direct testimony on page 67, lines 8-9, were included in was Case No. U21308, as a part of the Compression Digital Mobility project, and the case was settled on July 21, 2023 and approved on August 30, 2023.

c. The labor and non-labor other costs are associated with the increase in the number of field devices that are planned to be refreshed in 2026.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset refresh Program-Field Device Asset Management
For the replacements and new purchases for 2021, 2022, 2023, and 2024

Case No.: U-21870
Exhibit No.: A-185 (SHB-14)
Page: 1 of 1
Witness: SHBaker
Date: October 2025

ARP-Field Device Asset Mgmt

Line No.	(a) Units	(b) Avg. Unit Cost	(c) Total 2021 Units	(d) Total 2021 Dollars	(e) 2021 Electric Allocation Dollars	(f) Reference
	Replacements					
1	Field Devices CF33 w/acce	$4,201	235	$987,155	$690,910	U-21224, A-173 (JMW-8), page 2, line 6
2	Field Devices CF33 w/acce	$3,831	57	$218,348	$152,821	U-21224, A-173 (JMW-8), page 2, line 7
3	CF33 accessories			$111,888	$78,311	U-21224, A-173 (JMW-8), page 2, line 8
4	Software, labor, contractor and overhead and other costs			$8,057	$5,639	U-21224, A-173 (JMW-8), page 2, line 9
	New Purchases					
5	Rugged Devices(Semi Rugged devices - Toughbooks)	$2,857	45	$128,569	$89,985	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns f and h, line 48
6	Rugged Devices - Toughpads	$3,168	313	$991,513	$693,960	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns f and h, line 49
7	Add'l Accessories			$83,376	$58,355	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns f and h, 21% of line 56 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
8	Shipping and Handling, other fees			$4,193	$2,935	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns f and h, 21% of line 57 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
9	**Total Electric Allocation**			**$2,533,099**	**$1,772,916**	

Line No.	(a) Units	(b) Avg. Unit Cost	(c) Total 2022 Units	(d) Total 2022 Dollars	(e) 2022 Electric Allocation Dollars	(f) Reference
	Replacements					
10	Field Devices CF33 w/acce	$4,236	432	$1,829,952	$1,280,783	U-21389, A-182 (HNW-8), page 2, line 4
11	Accessories			$572,589	$400,755	U-21389, A-182 (HNW-8), page 2, line 6
12	Software, labor, contractor and overhead and other costs			($5,175)	($3,622)	U-21389, A-182 (HNW-8), page 2, line 7
	New Purchases					
13	Rugged Devices	$4,424.00	127	$561,848	$393,237	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, lines 64
14	Semi Rugged devices (Toughpads)	$3,312.00	33	$109,296	$76,496	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, lines 66
15	Accessories			$106,686	$74,670	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, 35% of lines 72 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
16	Shipping and Handling, other fees			$509	$356	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, 35% of lines 73 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
17	Field Devices CF33 w/acce	$4,424.00	88	$389,312	$272,479	Field devices purchased for training as a part of Corporate Capital
18	Field Devices CF33 w/acce	$4,424.00	337	$1,490,888	$1,043,473	Field devices purchased as a part of Compression Digital Mobility project.
19	**Total Electric Allocation**			**$5,055,905**	**$3,538,628**	

Line No.	(a) Units	(b) Avg. Unit Cost	(c) Total 2023 Units	(d) Total 2023 Dollars	(e) 2023 Electric Allocation Dollars	(f) Reference
	Replacements					
20	CF33 accessories	$10,655	1	$10,655	$7,237	U-21585, A-90 (SK-8), Page 2, line 8
21	Field Devices CF33 w/acce	$4,474	524	$2,344,418	$1,592,329	U-21585, A-90 (SK-8), Page 2, line 10
22	Field Devices Getac A140	$4,718	191	$901,149	$612,061	U-21585, A-90 (SK-8), Page 2, line 13
23	New Purchases					
24	Rugged Devices	$4,718	45	$212,313	$144,203	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, lines 52
25	Rugged Devices	$4,152	113	$469,140	$318,640	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, lines 53
26	Semi-Rugged Devices	$4,003	14	$56,046	$38,066	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, lines 54
27	Accessories			$133,135	$90,425	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, 73% of line 59 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
28	Shipping and Handling/other fees			$9,501	$6,453	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, line 60 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
29	Software, labor, contractor and overhead and other costs			$17,618	$11,966	U-21585, A-90 (SK-8), Page 2, line 19
30	**Total Electric Allocation**			**$4,153,974**	**$2,821,379**	U-21585, A-90 (SK-8), Page 2, line 20

Line No.	(a) Units	(b) Avg. Unit Cost	(c) Total 2024 Units	(d) Total 2024 Dollars	(e) 2024 Electric Allocation Dollars	(f)
	Replacements					
31	Field Devices CF33 w/accessories	$4,909	552	$2,709,520	$1,887,180	
32	Field Devices CF55 w/accessories	$3,652	80	$292,161	$203,490	
33	Field Devices Getac A140	$4,621	30	$138,616	$96,546	
	New Purchases					
34	Field Devices CF33	$4,909	109	$535,032	$372,650	
35	Field Devices FZ55	$3,652	20	$73,040	$50,872	
36	Field Devices Getac A140	$4,621	20	$92,411	$64,364	
37	Accessories			$1,201	$836	
38	Software, labor, contractor and overhead and other costs			$111,010	$77,319	
39	**Total Electric Allocation**			**$3,952,991**	**$2,753,258**	

U21870-SA-CE-080
Requested By: Brittney M. Klocke (BMK-3 - 1)
Respondent: Jessica R. Byrom
Date of Response: 7/17/2025
Page **1** of **2**

Question:

1. The following questions pertain to the Company's website:
a. What is the current status of the Company's website redesign?
b. If no progress has yet been made on redesigning the Company's website, when is the redesign projected to begin?
c. What areas of the Company's website are slated to be redesigned and why?

Response:

a. The Company has put the website redesign on hold due to extended support of the current on-premises Sitecore web content management system and the Company's SAP S/4HANA planned implementation.

b. The previous timing for the website redesign was developed with the expectation that the Company would need to migrate to the cloud/Software-as-a-Service (SaaS) version of the Sitecore system based on Sitecore's published product support lifecycle at that time. This would have been a major reason to initiate the website redesign. Since then, Sitecore has extended mainstream support for the on-premises version 10.4 to December 31, 2027, giving the Company more flexibility in its migration schedule. In addition, the Company's implementation of the SAP S/4HANA system will be a major undertaking, which will significantly impact the design of integration between the Company's website and SAP. The Company plans to complete the S/4HANA implementation before starting the website redesign.

c. The Company's full website is in scope for the redesign. The purpose of this initiative is to update the back-end architecture to more current methods and technology. This will provide:

   i. Flexibility: Enhances flexibility for future development initiatives.

   ii. Scalability: Allows for more efficient resource management and better performance under varying loads.

   iii. Performance and Security: Provides faster page load times and improves security measures.

   iv. Omnichannel Delivery: Delivers content seamlessly across multiple platforms.

   v. A full front-end redesign will also occur, resulting in:

   vi. Modern Visual Design: Creates a fresh, contemporary look and feel.

   vii. User-Friendly Navigation: Simplifies and makes navigation intuitive.

   viii. Enhanced Accessibility: Ensures the site is accessible to all users.

   ix. Interactive Features: Adds new interactive elements to engage users.

U21870-SA-CE-080
Requested By: Brittney M. Klocke (BMK-3 - 1)
Respondent: Jessica R. Byrom
Date of Response: 7/17/2025
Page **2** of **2**

x. Advanced Analytics: Enhances analytics capabilities to better monitor site performance.

xi. Content updates will be handled as follows:

1. Content Assessment: Pages will be assessed and all updated as needed.

2. Customer Flows: Customer flows will be evaluated and all redesigned as necessary.

xii. These improvements will significantly enhance the user experience and provide high-quality public services.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Marc R. Bleckman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Marc R. Bleckman who previously filed direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to (i) provide rebuttal to Staff and certain intervenors as it relates to the Company's Low Voltage Distribution ("LVD") Forestry Ramp Up proposal; and (ii) provide rebuttal to certain aspects of the direct testimonies of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Kirk D. Megginson, Attorney General Dana Nessel ("AG") witness Sebastian Coppola, Association of Businesses Advocating Tariff Equity ("ABATE") witness Christopher C. Walters, and Citizens Utility Board of Michigan ("CUB") witness Matthew Bandyk.

Q. How is your rebuttal testimony organized?

A. In Section I, I will provide rebuttal to portions of the direct testimony of Staff and certain intervenors as it relates to the Company's LVD Forestry Ramp Up proposal. In Section II, I will provide rebuttal to portions of the direct testimony of Staff witness Megginson. In Section III, I will provide rebuttal to portions of the direct testimony of AG witness Coppola. In Section IV, I will provide rebuttal to portions of the direct testimony of

ABATE witness Walters. In Section V, I will provide rebuttal to portions of the direct testimony of CUB witness Bandyk.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-187 (MRB-22)	Company Revision to Staff's Exhibit S-4, Schedule D-1 Alternative;
Exhibit A-188 (MRB-23)	Company Revision to Staff's Exhibit S-4, Schedule D-2 Alternative;
Exhibit A-189 (MRB-24)	MPSC Staff's Answer to Consumers Energy's Fourth Discovery Request; and
Exhibit A-190 (MRB-25)	Attorney General's Answer to Consumers Energy's Third Discovery Request.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

I. LOW VOLTAGE DISTRIBUTION FORESTRY RAMP UP

Q. Please describe the Company's proposal with respect to its LVD Line Clearing Program expenditures in this case.

A. As detailed in Company witness Patrick D. Daly's direct testimony, the Company is proposing to increase its LVD Line Clearing Program operating and maintenance ("O&M") expenditures significantly above historical levels toward attaining a five-year clearing cycle and more aggressive line clearing on targeted three phase primary lines. The Company is seeking approval in this case to defer the ramp up related expenses as a regulatory asset once the ramp up begins and through its completion (i.e. beginning in 2026 and through the 2030-2031 test period).

Q. What rate of return should the Commission authorize on the deferred expenses during the ramp up deferral period?

A. As explained on page 52 of my direct testimony, the prevailing pre-tax weighted average cost of capital ("WACC") is the appropriate rate to be applied on the balance of the regulatory asset until the costs are securitized. Due to the long-term nature of the deferred expenses, the Company intends to fund the ramp up with a mix of long-term debt and equity, aligned with the Company's approved capital structure. Consequently, the appropriate interest rate to be applied to the regulatory asset to support this customer investment should be based on the Company's prevailing pre-tax WACC during the ramp up period and until securitization occurs.

Q. In direct testimony, what rate of return did Staff and intervenors propose on the deferred forestry ramp up regulatory asset?

A. On page 8 of Staff witness Duell's direct testimony, Staff recommends that a 4.92% rate be applied to the deferred ramp up expenses, based on the short-term rate proposed in this case. On page 186 of AG witness Coppola's direct testimony, he also recommends the use of a short-term debt rate on the ramp up regulatory asset.

Q. Why is the Company's short-term debt rate not an appropriate financing rate for the deferred ramp up regulatory asset?

A. Refer to pages 52 to 54 of my direct testimony, which provides a detailed explanation of why a short-term interest rate is not the proper rate to apply for this regulatory asset. Since the regulatory asset will not be short term (i.e. less than one year), the Company cannot finance the regulatory asset with debt. Doing so would add additional strain to the Company's credit metrics which is illustrated on pages 53 to 54 of my direct testimony.

Due to the harmful credit metric impacts, the short-term debt rate is not an acceptable financing assumption for the deferred ramp up regulatory asset. The Company's total WACC matches the ramp up related spending and is the appropriate rate to be applied to the regulatory asset.

Q. On page 8 of her direct testimony, Staff witness Duell attempts to justify the application of a short-term interest rate on ramp up spending by referencing the short-term interest rate that the Commission approved for DTE Electric's tree trimming surge program. Is this an appropriate comparison for the Company in this case?

A. No. The interest rate on ramp up spending should be based on the facts and circumstances of this instant case which differ from DTE Electric's request. Refer to pages 16 to 17 of my direct testimony. A high degree of volatility and economic uncertainty has emerged in recent months (and since DTE Electric's order) with respect to financial markets, interest rates, and geopolitical tensions. These developments represent a material change in the Company's risk environment that should be considered in determining the appropriate interest rate to apply to ramp up spending in the instant case. In addition, the Company has numerous cost deferral mechanisms either existing or included for approval in this case.

While the Company is in full support of these expense deferral mechanisms, the cash flow and credit metric impact must also be considered as the Company continues to fund more customer investment ahead of customer collections. During the deferral period, the Company would be absorbing the cash and expense burden to fund the programs while not collecting any of those costs from customers. This deferral has the effect of increasing long-term financing needs for the Company without creating cash flow the way traditional

capital does via non-cash depreciation expense in rates. This makes the application of a pre-tax WACC on this particular regulatory asset balance all the more important. The credit metric degradation associated with using a short-term debt rate for ramp up expenditures described on pages 53 to 54 of my direct testimony would result in a credit metric strain in addition to these expense deferral mechanisms. Due to the harmful credit metric impacts, the short-term debt rate is not an acceptable financing assumption for the deferred ramp up regulatory asset.

Q. Does Staff witness Duell provide any other justifications for proposing a lower rate?

A. Yes. On pages 8 to 9 of her testimony, Staff witness Duell says the Company should receive a lower rate because "the Company has not invested in line clearing like they should have…."

Q. Is this a reasonable justification for proposing a lower rate than the Company can be expected to achieve?

A. No. This appears to simply be a punitive approach based on the witness's opinion that the Company has not prioritized line clearing enough. In taking this approach, Staff witness Duell does not show any concern for the detrimental customer impact of credit downgrades that can come from funding a significant amount of customer investment, such as this ramp up, entirely with debt. Company witness Daly provides further rebuttal on this subject, displaying the consistent annual increases in forestry work which the Company has requested and received authorization from the Commission to spend.

Q. Did Staff propose a higher amount of forestry spending compared to Company position in any of the cases that Staff witness Duell cites?

A. No.

Q. Staff witness Duell proposes a fixed rate of 4.92% be applied throughout the life of the regulatory asset rather than a rate that adjusts with prevailing interest rate environment. Do you agree with that position?

A. No. This is another position that demonstrates Staff's lack of comprehension of capital structure. As described in my testimony on pages 24 through 30, the rate that the Company is subject to with its short-term funding facilities are largely variable in nature based on the prevailing interest rate environment. Therefore, it is an unsound approach to "lock in" the rate applied to this balance, as proposed by Staff. The Company's position of applying the prevailing pre-tax WACC is a sound approach that will adjust for prevailing economic conditions.

Q. Are there any other positions with respect to the Company's forestry ramp up proposal that would have negative credit metric implications?

A. Yes. As explained in Company witness Daly's rebuttal testimony, AG witness Coppola and CUB witness Bunch propose a lower "baseline" O&M expense that represents the amount of funding that is included in rates for the test year. In addition to Company witness Daly's rebuttal testimony explaining why this lower baseline is inappropriate, it should be noted that lower funding and higher deferred costs places undue additional pressure on the Company's credit metrics as a result of lower cash and higher financing that would be necessary as described above. The Company's approach to calculating the baseline expense for the test year is reasonable, well supported by the evidence in this case, and aligned with long-term resiliency objectives. The baseline methodology proposed by Mr. Coppola and Mr. Bunch are without merit and should be rejected by the Commission.

II. REBUTTAL OF STAFF WITNESS MEGGINSON

A. Overview of Areas of Disagreement Addressed

Q. What aspects of Staff's recommendations are you rebutting?

A. I am rebutting Staff's projected common equity balance and the resulting common equity ratio. I am also rebutting Staff's projected cost of long-term debt. Finally, I am responding to Staff's recommendations regarding the Company's short-term credit facilities.

Q. Are there any other aspects of Staff's recommended capital structure that the Company disagrees with?

A. Yes. Consumers Energy does not agree with Staff's recommended Return on Equity ("ROE") of 9.75%. This issue, however, is addressed in the rebuttal testimony of Company witness Ann E. Bulkley, the Company's ROE witness in this case.

B. Rebuttal to Staff's Recommendation Regarding the Common Equity Ratio

Q. Do you agree with Staff's projected common equity ratio of 50.00%?

A. No. Staff's recommended common equity ratio for the test year in this case is understated. My rebuttal testimony to Staff's recommended equity ratio is organized as follows:

i. Staff Incorrectly Interprets the Company's Credit Ratings and Regulatory Environment

ii. Staff Fails to Consider New Circumstances That Justify a Deviation from an Evenly Balanced Capital Structure

iii. Staff Ignores the Potential Negative Financial Impacts of a Lower Equity Ratio

iv. Staff Fails to Consider the Average Equity Ratios of Peer Group Companies

v. Summary

i. Staff Incorrectly Interprets the Company's Credit Ratings and Regulatory Environment

Q. On page 6 of his direct testimony, Mr. Megginson minimizes the importance of Moody's downgrade of the Company's credit rating by stating that the downgrade "put the Company's credit rating more in line with the other two agencies ratings." Mr. Megginson also concludes that "the prior Moody's rating appeared to be an outlier." Do you agree with these statements?

A. No. Each of the credit rating agencies maintains its own ratings methodology and credit rating scale. It is not a universal measure in which the specific credit rating assigned by Moody's, for example, can be directly compared to the credit rating assigned by Standard and Poor's ("S&P") or Fitch. If Mr. Megginson's assertion were true, there would not be a need for more than one rating agency, as all credit rating methodologies and credit rating scales would be the same. Also, Mr. Megginson's attempt to downplay the Company's credit rating downgrade by implying that it was an inconsequential action should be rejected by the Commission. The Company's debt offerings are rated by the three main rating agencies – Moody's, S&P, and Fitch. A lower credit rating indicates higher risk which, in turn, necessitates a higher interest rate to compensate for that risk. Regardless of the presumed comparative credit ratings between the different credit rating agencies, the fact that the Company's credit rating was downgraded by Moody's was a negative event that had negative financial consequences for the Company and for customers who bear the cost of capital.

Q. Starting on page 6 of his direct testimony, Mr. Megginson describes the impact of the Company's regulatory environment on its credit rating. Mr. Megginson also references credit reports in which the Company's regulatory environment has been described as positive. Does this give support to Mr. Megginson's recommendation of a 50.00% equity ratio for the test year in this case?

A. No. I believe that Mr. Megginson's assessment of the Company's regulatory environment is incomplete. In his direct testimony, Mr. Megginson references aspects of Michigan's regulatory framework that have been established for several years under the 2008 and 2016 energy legislation, including items such as a forward-looking test year and the 10-month rate case process. Mr. Megginson's assessment fails to capture the results from the Company's most recent rate cases which demonstrate a sharp decline in authorized weighted rate of return (ROE times equity ratio) following a long period of stability. This recent shift is illustrated in the table on page 15 of my direct testimony. In addition, while rating agencies have described the Company's regulatory environment in a positive light, this rating is continuously evaluated. The persistent decline in the Company's authorized weighted rate of return since 2020 could be seen as a material deterioration in the credit supportiveness of the Michigan regulatory environment. Mr. Megginson fails to acknowledge that the Company's positive regulatory environment in past years has been fueled in large part by authorized ROE and equity ratios that were significantly higher than currently proposed by Staff for the Company in this case. In fact, the trend in rate orders with regard to authorized ROE and equity ratio was a cause for concern for Moody's in its downgrade of the Company's credit rating. An equity ratio of 50.75% and an ROE of

10.25% is better aligned with rate of return levels prior to the Company's credit rating downgrade and is therefore supportive of adequate credit quality at this time.

Q. Is there evidence that analysts have started to recognize a decline in the state of the Company's regulatory environment?

A. Yes. Refer to Exhibit A-33 (MRB-14), S&P's State Regulatory Evaluations – Energy. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average." In downgrading its state regulatory rating, S&P referenced recent rate case decisions in Michigan including authorized ROEs which "compare less favorably" to prevailing industry averages and a "tightening in the regulatory climate." Also refer to Exhibit A-34 (MRB-15). In updating its regulatory rankings for U.S. utilities in May 2023, UBS moved Michigan down a level from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." It is apparent that rating agencies and analysts have taken note of the recent trend in the Company's regulatory outcomes with regard to capital structure. A continuation or, even worse, a further degradation of the authorized weighted rate of return puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating. Michigan's regulatory standing needs to be protected and bolstered rather than drawn upon to push the Company toward over-leveraging. Broadly speaking, an above average regulatory standing translates into increased potential investment which continues to support affordable utility infrastructure financing for the state of Michigan.

Q. On page 7 of his direct testimony, Mr. Megginson references S&P's Regulatory Research Associates ("RRA") report on state regulatory evaluations. Mr. Megginson states that "the Michigan commission is rated Average/1, which is in the upper tier of the national average, in terms of utility credit supportive regulation. Only eight other commissions share Michigan's supportive rating." Do you agree with Mr. Megginson's interpretation of the RRA report?

A. No. Refer to page 9 of the RRA report on Exhibit A-33 (MRB-14). While Michigan is in the higher end of the "Average" tiers, the state is no longer in the "Above Average" category. In addition, 10 other state jurisdictions share Michigan's Average/1 rating and 8 other states are rated higher than the state of Michigan. With 18 other state jurisdictions rated at or above Michigan's, it is misleading to characterize the state as "in the upper tier." As Mr. Megginson notes in his direct testimony, Michigan's regulatory environment was considered above average for a number of years but the outcomes of recent rate case proceedings have led to a reduction of the state's regulatory ranking.

Q. Has S&P provided additional insight with regard to the future credit quality of regulated utilities including Consumers Energy?

A. Yes. Refer to Exhibit A-35 (MRB-16). In a February 2024 report "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens," S&P updated their outlook of the regulated utility industry to negative, citing "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. Also refer to Exhibit A-40 (MRB-21). In a January 2025 report on North American regulated utilities, S&P highlighted lower ratings headroom as "a high percentage of companies are operating with only minimal financial cushion from our downgrade

threshold." S&P also notes that, in 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year. With regards to the industry credit outlook for 2025, S&P identifies the following risks to utilities' credit quality:

- The portion of equity in the industry has been weak and consistently below expectations and thus pressuring the industry's financial measures. S&P states that "without significantly more common equity issuance, we expect the industry's financial measures will continue to weaken, albeit gradually, supporting our negative outlook";
- Tax legislation could weaken financial measures if the new Republican administration…reduces tax credits; and
- Robust capital spending and challenging regulatory constructs will persist for 2025, further pressuring the industry's credit quality.

S&P also cites Michigan as one of the regulatory jurisdictions that they "continue to carefully monitor." It is apparent from these rating agency reports that an ROE and equity ratio combination higher than the current authorized level, and certainly higher than the continued degradation proposed by Staff, is critical to protect the Company from receiving a credit downgrade in light of the credit risks as described above.

Q. On page 8 of his direct testimony, Mr. Megginson includes a chart showing Consumers Energy's net income from 2010 to 2024 noting that the Company's net income has risen over the years which has "enabled Consumers to access credit markets to the tune of billions in short and long-term financing at very competitive rates." Do you agree with Mr. Megginson's interpretation of this data?

A. No. Mr. Megginson reviews the Company's annual change in net income in complete isolation, without considering the changes in investment over time or the changes in rate base. To the extent that the Company has invested in the system over the period from 2010 through 2024, its net income <u>should</u> increase. However, the analysis does nothing to

demonstrate that the increases in net income are sufficient to satisfy the investor-required return on that investment, nor does it conclude anything meaningful about the Company's financial integrity. The Company's access to capital markets and its ability to raise capital at competitive rates is not based on net income, but rather is largely based on the Company's credit quality as determined by credit rating agencies. Since net income can be skewed by non-cash transactions, rating agencies instead look to the Company's cash flow metrics, including its Funds From Operation ("FFO")-to-Debt ratio. Rating agencies also look at the strength of the Company's balance sheet, including its equity ratio. These financial measures are a better indicator of the Company's credit quality and credit rating. It should be noted that the Company's "billions in short and long-term financing" over the years was executed during a period in which the Company's authorized equity ratio was significantly higher than currently proposed by Staff for the Company in this case. As the Company will continue to rely heavily on capital markets to fund capital investment, the Company's proposed equity ratio of 50.75% will help to maintain strong credit ratings and obtain financing at lower interest rates.

Q. On page 8 of his direct testimony, Mr. Megginson points to the Company's debt issuance in 2024 and projected debt issuances in this case as evidence that the Company has not been negatively impacted by Moody's credit rating downgrade. Do you agree with this conclusion?

A. No. Neither the Company's ability to issue debt in 2024 nor the projection of continued debt issuances in this case is evidence that there have been no negative impacts from Moody's credit rating downgrade. As explained earlier in my rebuttal testimony, a lower credit rating results in negative financial impacts associated with a higher cost of capital.

In addition, the Company's debt issuance in 2024 does not prove that the Company will undoubtedly have access to capital markets at reasonable rates in the future, especially with a lower weighted rate of return as proposed by Mr. Megginson.

Q. On page 9 of his direct testimony, Mr. Megginson lists several of the Company's existing and proposed recovery mechanisms, including the Power Supply Cost Recovery ("PSCR") mechanism, Energy Waste Reduction ("EWR") plan, Renewable Energy ("RE") plan, and Integrated Resource Plan ("IRP"). Mr. Megginson suggests that these mechanisms act to insulate the Company from financial risk and thereby justify a lower authorized ROE and equity ratio. Do you agree with this conclusion?

A. No. First, Staff identifies the Company's PSCR which is simply a method for the Company to recover its power costs and is a standard recovery mechanism for electric utilities. Also, Mr. Megginson again references regulatory mechanisms that have been established for several years under state energy legislation. Finally, refer to pages 44 to 45 of Company witness Bulkley's direct testimony which explains that these mechanisms are common for utilities and do not sufficiently reduce risk to justify a lower ROE. Mr. Megginson's claim that these programs support a lower authorized ROE or equity ratio is without merit and should therefore be rejected by the Commission.

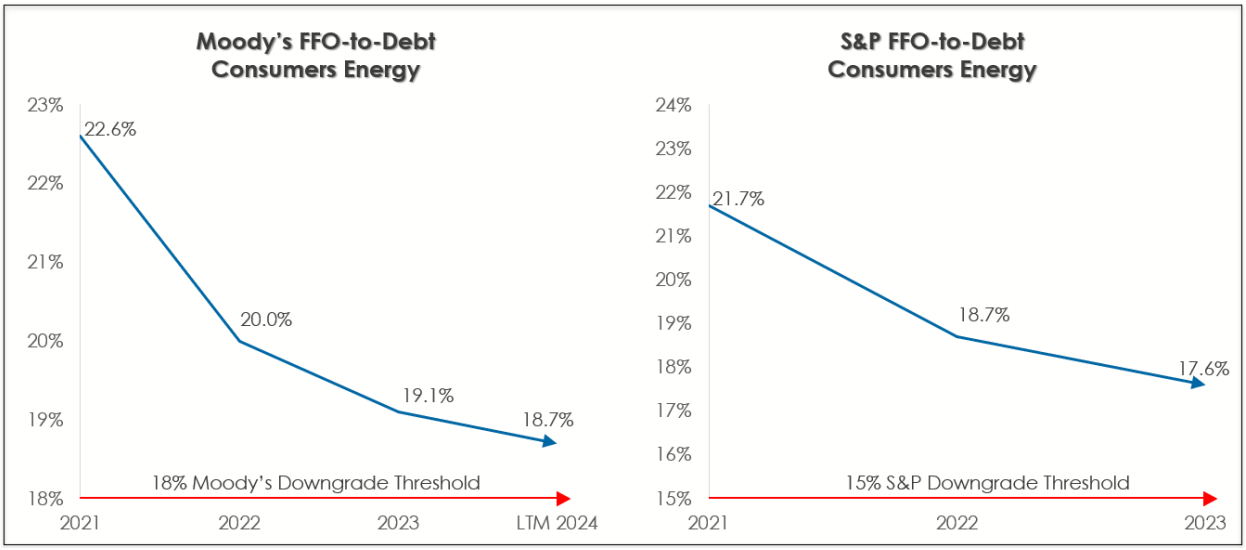
Q. On pages 10 to 11 of his direct testimony, Mr. Megginson references recent credit opinions from S&P, Moody's, and Fitch which describe the rating agencies' expectations with respect to the Company's FFO-to-Debt ratio in future years. Because the rating agencies' expectations are above the credit downgrade thresholds, Mr. Megginson concludes that "the agencies don't foresee any major deterioration or long-lasting decline in the FFO-to-Debt ratio for Consumers Energy in the foreseeable future." Do you agree with Mr. Megginson's conclusion?

A. No. In assessing credit quality, rating agencies must make certain assumptions with respect to the Company's outlook, including future financial results and regulatory outcomes. However, the assumption of credit metrics holding above the downgrade threshold should not be interpreted as assurance that these assumptions will ultimately materialize, with no risk of a credit rating downgrade. For example, in June 2019, Moody's issued a credit opinion for the Company stating that "Consumers' stable outlook reflects our expectation that the Michigan legislative and regulatory environments will remain constructive." Moody's also stated that they expected the Company's FFO-to-Debt ratio to "range between 20% and 24% over the next few years." In May 2021, Moody's downgraded Consumers Energy's credit rating "due to its weakened credit metrics." Moody's also referenced the outcome of recent rate cases which put pressure on the Company's credit metrics. While rating agencies may assume that the Company will continue to operate in a constructive regulatory environment with credit metrics above the downgrade threshold, the Company's credit rating is continuously evaluated. A reduction in the Company's rate of return lowers cash flow, increases debt, and thereby weakens the Company's FFO-to-Debt ratio. These negative credit metric impacts place the Company's credit quality and

credit ratings at risk. The authorized ROE and equity ratio in this case will be a key component of future rating agency evaluations.

Q. In his assessment of the Company's credit ratings and credit quality, did Mr. Megginson take into account the trend in the Company's FFO-to-Debt ratio in recent years?

A. No. As explained on pages 15 to 16 of my direct testimony, the Company's FFO-to-Debt ratio has been trending down in recent years, with a decrease of 350 basis points for Moody's and a decrease of 410 basis points for S&P. These credit metric results are shown in the following chart:



As the Company's FFO-to-Debt ratio deteriorates, moving closer to the rating agencies' credit downgrade thresholds, the credit metric cushion decreases and the Company becomes more at risk for a downgrade. The ROE and equity ratio combination proposed by the Company in this case is critical in protecting the Company from a credit downgrade in light of the credit metric degradation shown above.

ii. Staff Fails to Consider New Circumstances That Justify a Deviation from an Evenly Balanced Capital Structure

Q. On pages 12 to 13 of his direct testimony, Mr. Megginson references the Commission's orders in prior rate cases which reflected the desire for the Company to have a balanced equity ratio. Is this evidence that the Company's equity ratio in this instant case should necessarily be 50% as Mr. Megginson proposes?

A. No. The appropriate equity ratio for the Company should be based on the facts and circumstances presented in this instant case and not predetermined based on prior Commission orders. While the Commission voiced its desire for the Company to move toward a balanced capital structure in the cases referenced by Mr. Megginson, the Commission has also made clear that there should be flexibility in its assessment, allowing for a deviation from an evenly balanced capital structure when circumstances warrant it. This approach is illustrated in the following Commission Orders:

> **Case No. U-17990** – "A more complete analysis should be included to explain why such a result is reasonable and prudent" (when referring to a capital structure that is not evenly balanced). MPSC Case No. U-17990, February 28, 2017 Order, page 64.
>
> **Case No. U-20963** - "The Commission maintains its goal of a capital structure evenly balanced between debt and equity, while continuing to allow a utility to present arguments why a deviation from this ratio is appropriate. As it has done in previous rate cases, the Commission will continue to consider all evidence and circumstances in each rate case to determine the appropriate capital structure." MPSC Case No. U-20963, December 22, 2021 Order, page 200.
>
> **Case No. U-21585** - "The Commission, like the ALJ, acknowledges that there is some degree of flexibility and 'that the aspirational goals expressed in previous Commission orders are not permanently binding and that any target for the Company's capital structure should change if evolving circumstances indicate that the target is no longer a sound policy.'" MPSC Case No. U-21585, March 21, 2025 Order, page 232.

It is clear from previous orders that the Commission does not consider an evenly balanced capital structure a mandate to be followed blindly, but rather as a basis from which a deviation may be justified upon consideration of the evidence and circumstances of each rate case.

Q. Has the Company presented evidence in this case that an equity ratio of 50.75%, slightly above an evenly balanced capital structure, is warranted?

A. Yes. Refer to pages 10 through 22 of my direct testimony in which I outline reasons why an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case are well-measured for both the Company and its customers, while still mindful of the Commission's previous orders. This capital structure results in a modest effect on customer rates while bringing the Company more in-line with the authorized weighted rate of return experienced toward the beginning of the COVID-19 pandemic and prior to the most recent credit rating downgrade. The weighted rate of return as proposed in this case strengthens the Company's balance sheet and credit quality, which will be critical in delivering the Reliability Roadmap investments while doing so in the midst of an elevated interest rate environment.

Q. Are there any new circumstances that give weight to the Company's contention that a deviation from an evenly balanced capital structure to 50.75% equity is justified at this time?

A. Yes. Refer to pages 16 to 17 of my direct testimony. A high degree of volatility and economic uncertainty has emerged in recent months with respect to financial markets, interest rates, and geopolitical tensions. Following the Trump administration's move toward higher tariffs in the spring of 2025, fears of a trade war led to significant market

volatility. The stock market experienced a severe drop in early April, the largest decline since 2020, before recovering. Uncertainty remains over the final scope of trade policy and future tariffs. More recently, as of October 2025, a federal government shutdown is creating market uncertainty and is expected to trigger elevated market volatility. In addition, ongoing conflicts, such as those in the Middle East and between Russia and Ukraine, along with broader geopolitical uncertainty, continue to elevate risk and volatility to U.S. markets. These developments represent a material change in the Company's risk environment since the previous Commission orders that will most likely continue through the test year of this case. During this period of heightened risk and volatility, it will be critical for the Company to have an authorized ROE and equity ratio that is supportive of its good credit quality. This will be instrumental in the Company's ability to maintain uninterrupted access to needed liquidity and better withstand potential impacts from fuel price spikes, inflationary pressures, and tightening capital markets. An equity ratio of 50.75% is warranted given the facts and circumstances present in this instant case.

iii. Staff Ignores the Potential Negative Financial Impacts of a Lower Equity Ratio

Q. Starting on page 14 of his direct testimony, Mr. Megginson references the relatively higher cost of equity compared to debt as justification for a lower equity ratio. Does Staff also discuss the potential negative financial impacts of a lower equity ratio?

A. No. Staff merely states that it is important to "establish a proper equity to debt ratio to maintain reasonable costs to ratepayers." Staff makes this conclusion without analyzing or quantifying the increased costs to the Company and customers that would certainly result from further credit downgrades. Additionally, Mr. Megginson does not provide quantifiable justification as to why his chosen equity ratio of 50.00% is appropriate. This

outcome-based conclusion, which is void of an evidentiary analysis of the resulting financial impacts to the Company and its customers, should not be accepted by the Commission.

Q. Mr. Megginson argues that because equity is more expensive than debt, it necessitates a lower equity ratio. Does this rationale have merit?

A. No. Taken to extreme, this rationale would lead to Staff simply recommending that because customers would benefit most from 0% equity, the Commission should authorize a completely debt financed capital structure for the Company. Such a result would clearly ruin the financial soundness of the Company and a recommendation based on such a rationale should be given no merit. Staff's argument points out the obvious fact that the cost of equity is greater than the cost of debt – but no business can or should fund itself with an excessive level of debt. This simplistic argument adds nothing of value for the Commission to consider.

Q. Although Mr. Megginson chooses to ignore the possibility of another credit downgrade and presents no analysis or discussion of the impacts of a credit downgrade on the Company, what would be the effect of a credit downgrade?

A. Lowering the equity ratio and authorized ROE reduces the Company's overall cost of capital and rate of return. This, in turn, lowers the Company's cash flow and FFO-to-Debt ratio. The negative impacts could cause the Company's FFO-to-Debt ratio to drop below the established rating agency thresholds, placing both the Company's credit quality and credit ratings at risk. While it may seem attractive for the benefit of customers in the near-term to minimize the equity layer of the Company, such a move, and the potential resulting credit rating downgrade, could lead to the Company's customers paying higher

financing costs over the long term, and it could put at risk the Company's ability to execute on its critical investment plan on behalf of customers. Thus, it is of great importance for the regulatory response to be balanced and thoughtful, as the financial health of the Company is a critical element of its ability to implement the capital plan needed to deliver safe, reliable, and clean energy to its customers.

Q. What are the customer benefits of the Company maintaining the needed financial cushion to avoid a credit rating downgrade?

A. A higher credit rating ensures that the Company is able to obtain financing at lower interest rates, resulting in long-term customer rate stability. As shown in Exhibit A-32 (MRB-13), the Company has saved customers $152 million annually as a result of improved credit ratings and lowered interest costs. But the customer benefits extend far beyond this long-term rate stability. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments to maintain and improve utility infrastructure to improve reliability and resiliency to the benefit of customers. During this time, the Company must rely heavily on the capital markets to fund these investments. Therefore, it will be especially important for the Company to maintain strong credit ratings to ensure beneficial access to capital markets for funding to deliver these critical customer investments and enable the Company to do so at the lowest possible financing cost on their behalf. It is also important to note that maintaining credit cushion enables the Company to complete important and emergent customer work ahead of customer costs being reflected in rates when necessary, such as the regulatory deferrals as discussed earlier in my rebuttal testimony. A 50.75% equity

ratio will help ensure that the Company can complete this important customer investment without risking a credit downgrade.

iv. Staff Fails to Consider the Average Equity Ratios of Peer Group Companies

Q. How does Mr. Megginson's recommended 50.00% equity ratio compare to equity ratios authorized by other commissions?

A. Mr. Megginson's recommended 50.00% equity ratio is significantly lower than equity ratios authorized by other commissions. I researched all rate case decisions from 2020 through mid-April 2025 of peer companies and determined the authorized or approved equity ratio for each. This is reflected in Exhibit A-29 (MRB-10). The average authorized equity ratio for the peer group was 51.85%, 185 basis points higher than the 50.00% proposed by Mr. Megginson for Consumers Energy in this case. Despite this higher peer average, I am proposing a ratio of 50.75%, which balances the higher peer average with capital investment plans, credit metrics, customer rate impacts, and the guidance of this Commission, and which continues to support affordable utility infrastructure financing for the state of Michigan.

Q. Are the equity ratios reflected on Exhibit A-29 (MRB-10) based on historical financial data or commission-authorized equity ratios?

A. The equity ratios were taken directly from commission orders and public filings and represent actual regulatory equity ratios authorized or approved by the various commissions across the country, as specifically requested by the Commission on page 218 of its Order in Case No. U-20963. It is clear from this analysis that, on average, regulatory commissions of the Company's peer group are granting equity ratios that are much higher

than the 50.75% requested by the Company in this instant case, and higher still than the 50.00% equity ratio chosen by Mr. Megginson.

Q. Did Mr. Megginson also perform an analysis of average peer company authorized equity ratios?

A. Yes. On page 2 of his Exhibit S-4, Schedule D-5, Mr. Megginson calculated an average authorized equity ratio of 51.07%. This is 107 basis points higher than Mr. Megginson's recommended 50.00% equity ratio in this case and 32 basis points higher than the Company's recommended equity ratio in this case of 50.75%.

Q. On page 22 of his direct testimony, Mr. Megginson refers to his calculated peer equity ratio average of 51.07% and concludes that "the 51.0% average equity layer of Staff's proxy group is primarily due to one outlier equity layer, OGE Energy, with an equity layer well over 53.0%. Removing that firm, the proxy group's average equity layer would be roughly 50.0%, which is in line with Staff's recommendation." Do you agree with Mr. Megginson's interpretation of his average equity ratio analysis?

A. No. Mr. Megginson gives no explanation or evidence as to why the equity ratio for OGE Energy is an "outlier" and should therefore be removed from his analysis. Without such explanation, it appears that Mr. Megginson eliminates this data point solely to lower his average equity ratio calculation to be closer to his recommended equity ratio for the Company. In addition, even if removing OGE's equity ratio from his analysis were appropriate, the revised peer average would be 50.6%, which is "roughly" 51% and is more in line with the Company's recommendation of 50.75% than Staff's 50.00%. Therefore, Mr. Megginson's conclusion regarding his peer equity ratio average is without merit and should be rejected by the Commission.

Q. Is Mr. Megginson's peer equity ratio analysis a valid basis for purposes of authorizing a permanent equity ratio?

A. No. According to Mr. Megginson's exhibit, the source of the equity ratio data is S&P Global Market Intelligence. S&P Global Market Intelligence tracks the authorized equity ratio as a percentage of total capitalization. Total capitalization can be higher (thereby under-reporting an equally comparable equity ratio) because, in addition to permanent capital components, items such as short-term debt, deferred taxes, and customer deposits can be included. For example, as reflected on Exhibit A-14 (MRB-1), Schedule D-1, the Company's 50.75% permanent equity ratio in this instant case translates to only 42.94% on a total capitalization basis that would be reported in Staff's referenced database, which is a difference of 781 basis points. The Company's equity ratio, which is based on a percentage of permanent capital, should only be compared to equity ratios of peer utilities based on percentage of permanent capital in order for the comparison to be at all meaningful. The actual commission-authorized equity ratios provide the required data for a comparable analysis and were relied upon in my analysis shown in Exhibit A-29 (MRB-10) which shows the average equity ratio for the peer group utilizing this method to be 51.85%.

Q. Did Mr. Megginson perform an analysis of the national average peer company authorized ROEs consistent with previous rate cases?

A. Yes. Staff considered average electric utility authorized ROE decisions across the U.S. to support its ROE recommendation for the Company in this case.

Q. If it is appropriate to consider peer average authorized ROE's in determining the recommended ROE for the Company, is it therefore also reasonable to consider peer average authorized equity ratios in determining the recommended equity ratio for the Company?

A. Yes. In its Order in Case No. U-20963, the Commission cited Staff's average ROE analysis as one of the factors considered in determining the Company's approved ROE. In addition, in Case No. U-21585, the Administrative Law Judge ("ALJ") also considered average authorized ROEs in determining the appropriate ROE for the Company. In its Order, the Commission found that the ALJ appropriately considered the record evidence, weighing the vast testimony, methodologies, and proposed ROEs on the record. It is apparent that the Commission considers peer averages an important piece of evidence to inform the ratemaking process. To be consistent with that philosophy, it is appropriate to consider peer company equity ratio averages and trends in determining the equity ratio for the Company in this case.

v. <u>Summary</u>

Q. Please summarize your rebuttal testimony to Staff witness Megginson's recommendation of an equity ratio of 50.00% for the test year in this case.

A. In my rebuttal testimony, I have shown that Mr. Megginson's position on equity ratio is largely not evidence based and that the evidence which he does provide is unsound and should not be relied upon. Further, I have shown that, based on the recent dramatic increase in risk and volatility, a deviation from a balanced capital structure is justified at this time. I have also shown that Staff's recommended equity ratio for the test year in this case is below what is considered supportive of the Company's credit quality and also significantly

lower than the average equity ratio of peer group companies. For these reasons, Staff's recommended equity ratio of 50.00% for the test year in this case should be rejected.

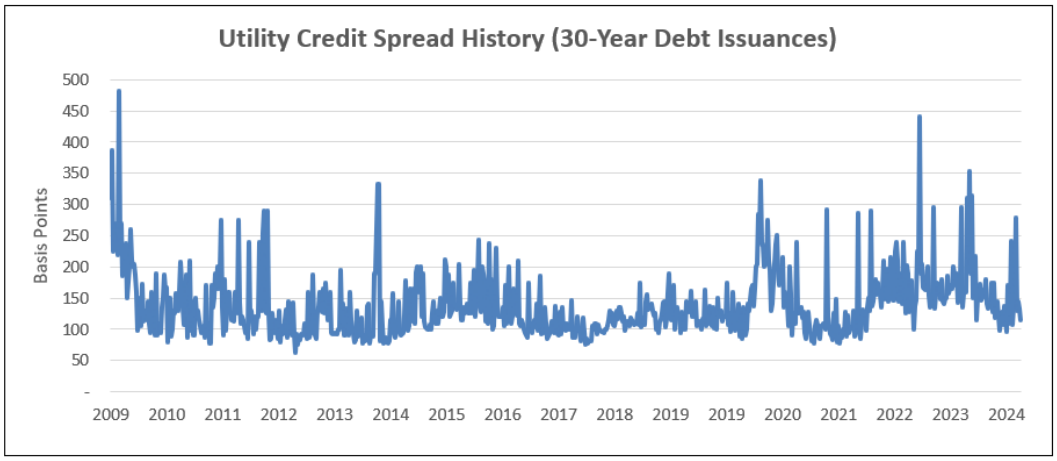
C. Rebuttal of Staff's Recommendation Regarding the Cost of Long-Term Debt

Q. On page 16 of his direct testimony, Mr. Megginson states his intention for Staff to include an updated cost of long-term debt into its revenue deficiency calculation when briefs are filed in this case. This updated cost of long-term debt calculation is reflected in Staff's Exhibit S-4, Schedule D-2 – Alternative. Do you agree with Staff's cost of long-term debt recommendation of 4.37% as reflected on this "alternative" Exhibit?

A. No. While the Company accepts Staff's inclusion of the Company's two long-term debt issuances in May 2025, Mr. Megginson's assumed interest rates on the Company's projected debt issuances in May 2026 and August 2026 are understated. First, current projections for the 30-year U.S. Treasury rate, which serve as the basis for the Company's forecasted debt issuances in 2026, are higher than Mr. Megginson used in developing his cost of long-term debt projections. On his Exhibit S-4, Schedule D-2 Alternative, Mr. Megginson projected a 30-year bond yield of 4.58% in 2026. According to Bloomberg, the projected 30-year bond yield is 4.88% for 2026. In addition, Mr. Megginson's assumed credit spread (added to the U.S. Treasury rate to calculate the total projected interest rate on the new debt issuances) is also unreasonably low.

Q. Mr. Megginson uses the credit spreads on the Company's recent long-term debt issuances as a basis for projecting a 100 basis point credit spread on the Company's forecasted debt issuances through the test year in this case. Is this a reasonable approach?

A. No. As explained on page 32 of my direct testimony, credit spreads for long-term debt issuances are very difficult to predict and can be quite volatile in short periods of time. This is because credit spreads are based on a number of factors, most notably the Company's credit rating and the market conditions at the time of the debt issuance, including both same-day and short-term supply/demand dynamics. The volatility of credit spreads is illustrated on the following chart:



Mr. Megginson's 100 basis point credit spread is also quite obviously at the very low end of the historical spreads for 30-year debt issuances, as evidenced in the chart above. In addition, as shown in Staff's discovery response included as Exhibit A-189 (MRB-24), Mr. Megginson includes credit spreads on the Company's two long-term debt issuances in May 2025 which are not 30-year maturities as a basis for projecting the credit spreads on forecasted debt issuances that are assumed to be 30-year maturities. Credit spreads on debt issuances vary based on the tenure or maturity of the debt issuance (for example, a 10-year

bond versus a 30-year bond). For these reasons, Mr. Megginson's methodology for estimating the credit spread on the Company's projected long-term debt issuances is faulty and should be rejected by the Commission. Alternatively, the Company has provided a very sound approach to projecting credit spreads. Given the lack of a reliable source for projected credit spreads, I applied the calculated average credit spread on a 30-year debt issuance for investment grade utilities from the last 16 years which was 138 basis points. Since credit spreads can be volatile in the short-term, a longer-term historical average is a rational approach with regard to credit spreads.

Q. What is the impact to Staff's projected cost of long-term debt adjusted for these items identified in your rebuttal testimony?

A. Refer to Exhibit A-188 (MRB-23) which shows Staff's cost of long-term debt calculation adjusted for current U.S. Treasury rate projections for the Company's 2026 projected issuances, and the projected credit spread on the Company's 2026 long-term debt issuances of 138 basis points. The result is an increase to Staff's projected cost of long-term debt from 4.37% to 4.43%.

Q. What is the impact on the overall cost of capital compared to Staff's position for the capital structure adjustments you recommend in your rebuttal testimony?

A. The effect of the Company's adjustments to the Staff calculation of overall cost of capital is an increase in the overall cost of capital from 6.03%, as shown on Staff's Exhibit S-4, Schedule D-1 Alternative, to 6.30%. This calculation is shown on Exhibit A-187 (MRB-22) which is the revision to Staff's Exhibit S-4, Schedule D-1 Alternative.

D. Rebuttal of Staff's Recommendation Regarding the Company's Short-Term Credit Facilities

Q. On pages 17 to 18 of his direct testimony, Mr. Megginson expresses his concerns regarding the Company's short-term credit facilities which he considers "excessive" and an "unreasonable cost to ratepayers." Mr. Megginson requests that the Commission disallow the costs associated with the Company's ScotiaBank revolver in future rate cases. Has the Company presented evidence in this case that refutes Mr. Megginson's claims?

A. Yes. In its Order in Case No. U-21585 (the Company's previous electric rate case), the Commission instructed the Company in its next electric rate case to "explain and justify the size and expense associated with its short-term borrowing facilities if only a very small portion is being or has been utilized. The purpose of such an analysis should be to determine if the size of such borrowing facilities is reasonable and to ensure that the potential benefits of maintaining these facilities is commensurate with their expense." The Company responded to this directive in this instant case. Refer to pages 43 to 49 of my direct testimony as well as Exhibit A-39 (MRB-20). My direct testimony shows that the Company's short-term borrowing facilities are:

- Appropriately sized and are in line with peer utilities on average;
- Required to support the Company's robust capital investment plan and to meet growing short-term liquidity needs;
- A key component of the Company's credit quality and credit ratings; and
- Reasonable, prudent, and beneficial to customers by effectively minimizing liquidity risk.

Mr. Megginson's characterization of the Company's short-term credit facilities and recommendation to disallow costs related to the ScotiaBank revolver are misguided, short-sighted, and should be rejected by the Commission.

Q. On page 17 of his direct testimony, in support of his recommendation to disallow future costs associated with the Company's $250 million ScotiaBank revolver, Mr. Megginson claims that the ScotiaBank revolver is "way down the pecking order of short-term funds to be used if required." Do you agree with this statement?

A. No. Refer to page 26 of my direct testimony in which I detail the prioritized order (from least expensive to more expensive) in which the Company utilizes its short-term financing facilities. The $250 million ScotiaBank revolver is second on that list.

Q. On page 17 of his direct testimony, Mr. Megginson states that the Company's ScotiaBank revolver "has never been used since its inception in 2018." Do you agree with this statement?

A. No. The Company's ScotiaBank revolver has been used and is currently being used with multiple letters of credit issued against the facility. These letters of credit are related to the Midcontinent Independent System Operator, Inc. ("MISO") which, as I explain later in my rebuttal testimony, are critical financial instruments in conducting the Company's ongoing business operations. It should be noted that Mr. Megginson includes these letters of credit in his calculation of the total cost of the ScotiaBank revolver.

Q. On page 17 of his direct testimony, Mr. Megginson states that the Company's $58 million in letters of credit associated with the ScotiaBank revolver can simply be "redirected" to the Company's JPMorgan revolver. Do you agree with this statement?

A. No. The JPMorgan revolver has a limit of $100 million for letters of credit issued against the facility. Of that capacity, the Company is currently only able to issue a maximum of $50 million in letters of credit to MISO. Since all $58 million of the ScotiaBank revolver's letters of credit pertain to MISO, the Company would not be able to move them from the ScotiaBank revolver to the JPMorgan revolver as Mr. Megginson suggests. In lieu of issuing letters of credit, the Company could have borrowed against the revolver to satisfy its financial obligations with MISO. However, this would not have been prudent, as it would have resulted in a higher cost to the Company and customers. It should also be noted that, as of September 2025, the letters of credit issued under the ScotiaBank revolver (all with MISO as the beneficiary) total $112 million.

Q. On page 17 of his direct testimony, Mr. Megginson states that "the Company provided scant information on the purpose of the letters of credit and noted that the Letter of Credit was used to cover items such as fuel purchases or margin support for certain services." Do you have anything to add regarding the purpose of the letters of credit?

A. Yes. The use of letters of credit is normal and customary for utilities in conducting ongoing business operations. As explained earlier in my rebuttal testimony, several of the letters of credit issued against the Company's ScotiaBank revolver are with MISO. The letters of credit for MISO are a critical financial instrument for an electric utility participating in MISO's energy and transmission markets. It serves as a form of financial assurance,

guaranteeing that the utility can meet its payment obligations for market transactions, transmission services, and capacity procurements. This is especially important given the volatility of energy markets and the potential for large, unexpected financial exposures. By maintaining these letters of credit, the Company demonstrates creditworthiness and compliance with MISO's tariff-based credit requirements, which helps preserve market integrity and operational continuity.

Q. On page 18 of his direct testimony, Mr. Megginson states that "The Company will tap its Commercial Paper Facility, and then use internal loans from its parent, then likely its JP Morgan Revolver, before the Scotiabank Revolver is even considered." Do you agree with this statement?

A. No. Refer to page 25 of my direct testimony. The intercompany borrowing facility is not a dedicated financing option that is always available for the Company to use, but only when CMS Energy has surplus cash and effective borrowing rates must be lower than rates available to the Company under the Commercial Paper Program. The intercompany borrowing facility, therefore, is not considered part of the total liquidity capacity available to the Company. In addition, refer again to the prioritized order of short-term facility utilization on page 26 of my direct testimony. Contrary to Mr. Megginson's statement, the Company would <u>not</u> draw on the JPMorgan revolver before utilizing the ScotiaBank revolver since the JPMorgan revolver is more expensive.

Q. In his direct testimony, Mr. Megginson considers the Company's short-term credit capacity as excessive. How does the Company (including the Company's Treasury department) evaluate the appropriateness of the size of its total short-term credit capacity?

A. In determining the appropriate size of its short-term credit capacity, the Company aims to minimize financial risk while servicing its short-term liquidity needs at the lowest cost to the Company and customers. To achieve this, the Treasury department conducts assessments of the Company's cash flow requirements, seasonal fluctuations in working capital, and potential events such as significant storm restoration costs or power supply cost volatility. The Company also evaluates its forward-looking capital plan, which includes significant investments to maintain and improve utility infrastructure and to improve reliability and resiliency to the benefit of customers. These investments often require flexible access to liquidity to ensure timely execution and to avoid disruptions or project delays. In addition, the Company evaluates the timing and scale of its upcoming long-term debt maturities, which may require interim financing solutions while permanent refinancing is secured, or may warrant accelerating or postponing debt issuance to optimize cost efficiency. Finally, the Company benchmarks its credit facilities against peer utilities and industry standards to ensure its approach remains prudent and cost-effective (Refer to Exhibit A-39 (MRB-20)). This disciplined and evidence-based evaluation process helps safeguard the Company's credit ratings and ensures that the Company and customers are not exposed to unnecessary financial risk or cost.

Q. Do the rating agencies consider the Company's liquidity including short-term credit capacity to be excessive?

A. No. Refer to Exhibit A-36 (MRB-17). In August 2024, S&P assessed the Company's liquidity, including its short-term credit capacity, as "Adequate," noting that their rating reflected the Company's "prudent risk management." Also refer to Moody's May 2024 credit rating reflected on Exhibit A-37 (MRB-18). In its credit evaluation, Moody's stated "we expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months." Finally, refer to Exhibit A-38 (MRB-19), Fitch's April 2024 credit opinion. In its assessment, Fitch identified the Company's revolving credit facilities as supporting short-term liquidity needs and rated the Company's liquidity as "adequate." It is clear from these reports that the consensus among rating agencies is that the Company's short-term credit capacity is not considered excessive, but is rather "adequate" considering the Company's liquidity needs and provides a suitable cushion to protect against times of economic stress and financial market disruption. A greater reliance on the Company's short-term credit facilities would result in a reduction in that credit capacity, leading to a weakening of the Company's liquidity profile and credit quality.

Q. In his direct testimony, does Mr. Megginson address or attempt to challenge the extensive testimony set forth by the Company in its direct filing with regard to its short-term credit facilities?

A. No. Mr. Megginson does not dispute the Company's direct testimony and exhibit which satisfies the Commission's directive and fully supports the Company's short-term credit capacity. Refer to the Company's analysis on Exhibit A-39 (MRB-20) which shows that the size of the Company's short-term credit facilities are in line (slightly below) that of

peer utility companies. Instead of presenting evidence that would attempt to contradict this analysis, Mr. Megginson merely concludes that the $250 million ScotiaBank revolver is expensive and excessive and should therefore be excluded from the Company's cost of short-term debt. In doing so, Mr. Megginson provides no evidence or analysis that would justify his exclusion or demonstrate why $250 million is not the appropriate amount. Mr. Megginson's recommendation is short-sighted, lacks proper evidence, and should therefore be rejected by the Commission.

III. REBUTTAL OF AG WITNESS COPPOLA

A. Overview of Areas of Disagreement Addressed

Q. What aspects of AG witness Coppola's recommendations are you rebutting?

A. I am rebutting Mr. Coppola's recommendation regarding the common equity ratio. I am also rebutting Mr. Coppola's recommendation regarding the Company's cost of long-term debt. Finally, I am rebutting Mr. Coppola's recommendation regarding the Company's working capital cash balance.

Q. Are there any other aspects of Mr. Coppola's recommended capital structure that the Company disagrees with?

A. Yes. Consumers Energy does not agree with Mr. Coppola's recommended ROE of 9.80%. This issue, however, is addressed in the rebuttal testimony of Company witness Bulkley.

B. Rebuttal to Mr. Coppola's Recommendation Regarding the Common Equity Ratio

Q. On page 107 of his direct testimony, Mr. Coppola references the Commission's Orders in Case No. U-21585 and Case No. U-21389, in which both orders authorized an evenly balanced equity ratio. Mr. Coppola then concludes that the Company's capital structure in this instant case should "similarly mirror" the common equity ratio last approved by the Commission. Do you agree with this conclusion?

A. No. The appropriate equity ratio for the Company should be based on the facts and circumstances presented in this instant case and not predetermined based on prior Commission orders. Refer to my earlier rebuttal testimony to Staff witness Megginson (II.B.ii. Staff Fails to Consider New Circumstances That Justify a Deviation from an Evenly Balanced Capital Structure). While the Commission authorized an evenly balanced capital structure in the cases referenced by Mr. Coppola, the Commission has also made clear that there should be flexibility in its assessment, allowing for a deviation from an evenly balanced capital structure when circumstances warrant it. It is clear from these orders that the Commission does not consider an evenly balanced capital structure a mandate to be followed blindly, but rather as a basis from which a deviation may be justified upon consideration of the evidence and circumstances of each rate case.

Q. Has the Company presented evidence in this case that an equity ratio of 50.75%, slightly above an evenly balanced capital structure, is warranted?

A. Yes. Refer to pages 10 through 22 of my direct testimony in which I outline reasons why an equity ratio of 50.75% and an ROE of 10.25% as proposed by the Company in this case are well-measured for both the Company and its customers, while still mindful of the Commission's previous orders. Also refer to my earlier rebuttal testimony to Staff witness

Megginson. There have been new circumstances that give credence to the Company's contention that a deviation from an evenly balanced capital structure is justified at this time including a high degree of volatility and economic uncertainty in recent months with respect to financial markets, interest rates, and geopolitical tensions. As provided for in previous Commission orders, an equity ratio of 50.75% (slightly above an evenly balanced capital structure) is warranted given the facts and circumstances present in this instant case.

Q. Starting on page 110 of his direct testimony, Mr. Coppola references recent credit opinions from Moody's and S&P, noting that the Company's FFO-to-Debt ratio in recent years for both rating agencies was higher than the threshold that could lead to a further downgrade if the Company fell below. For S&P, Mr. Coppola concludes that "these coverage ratios are not indicative of any concerns about a possible debt rating downgrade." Is the Company's FFO-to-Debt ratio in recent years evidence that the Company is not at risk for further credit rating downgrade?

A. No. First, as explained on pages 15 to 16 of my direct testimony and earlier in my rebuttal testimony to Staff witness Megginson, the Company's FFO-to-Debt ratio as calculated by rating agencies has been trending down in recent years – a decrease of 410 basis points for S&P and a decrease of 350 basis points for Moody's. This sizable amount of credit ratio deterioration, which is brushed off by Mr. Coppola, should be troubling to the Commission. Second, while the Company's FFO-to-Debt ratios in previous years were higher than the downgrade threshold, the results cover a time when the Company's equity ratio was significantly higher than Mr. Coppola recommends for the Company in this case - 52.7% in 2021 and 53.2% in 2022. Therefore, Mr. Coppola's statement that there is no concern of downgrade should be discounted by the Commission.

Q. On page 111 of his direct testimony, Mr. Coppola references the increase in the Company's net income in 2024. Mr. Coppola concludes that this will have a positive impact on the Company's credit metrics. Do you agree with this conclusion?

A. No. Refer to my earlier rebuttal testimony to Staff witness Megginson on this issue. Higher net income is not necessarily indicative of higher credit metrics or credit quality. Since net income can be skewed by non-cash transactions, rating agencies instead look to the Company's cash flow metrics, including its FFO-to-Debt ratio. As explained earlier in my rebuttal testimony, this ratio has been trending down in recent years. Rating agencies also look at the strength of the Company's balance sheet, including its equity ratio. Finally, rating agencies evaluate the supportiveness of the Company's regulatory environment, including the authorized ROE and equity ratio. These measures are a better indicator of the Company's credit quality and credit rating. Based on rating agencies' criteria, the weighted rate of return authorized in this case, and not net income, will be a significant factor in determining the Company's credit quality.

Q. On page 112 of his direct testimony, Mr. Coppola refers to the Company's direct testimony which showed that the Company's FFO-to-Debt ratio as calculated by S&P and Moody's has been trending down in recent years. Mr. Coppola dismisses these sharp declines as "temporary" and the result of "unusual and short-term issues." Do you agree with this assessment?

A. No. Mr. Coppola describes events such as unfavorable weather, storm activities, and higher gas prices as the main cause for the Company's decline in credit metrics in recent years. First of all, Mr. Coppola omits that, as explained on pages 15 to 16 of my direct testimony, the decline in the Company's FFO-to-Debt ratio has coincided with recent rate

cases which have resulted in a sharp decline in rate of return (ROE multiplied by equity ratio) having a directly negative result on credit metrics, both historic and future. Secondly, there is no guarantee that these issues that Mr. Coppola describes as "temporary" such as storms, will not persist in future years. For example, from the end of March 2025 through the beginning of April 2025, the Company's service territory was hit with the worst ice storm in northern Michigan in over 100 years, as confirmed by the National Weather Service. At the same time, the lower peninsula of Michigan was hit by thunderstorm systems strong enough to produce 13 confirmed tornados. The restoration costs of this catastrophic storm will have a detrimental impact on the Company's credit metrics into 2027, as they will not be considered for recovery from customers until the Company's next electric rate case filing. In fact, Mr. Coppola's testimony highlighting the negative impact of these events demonstrates the importance of maintaining strong credit metrics in preparation for such events and not managing the Company toward the lower margins.

Q. On pages 113 to 114 of his direct testimony and his Exhibit AG-44, Mr. Coppola references his calculation of the Moody's FFO-to-Debt ratio for the Company for the year ended March 2025 assuming a 9.80% ROE and a 50.0% equity ratio. According to Mr. Coppola's calculations, the Company's FFO-to-Debt ratio would have been 20.0%, or 60 basis points <u>higher</u> for the year ended March 2025 with these assumptions. Do you agree with Mr. Coppola's calculations?

A. No. In his calculations, Mr. Coppola applies a targeted <u>regulatory</u> equity ratio (50.0%) to the Company's actual <u>financial</u> equity ratio (48.4%) calculated from the Company's Securities and Exchange Commission reported balance sheet which is prepared under Generally Accepted Accounting Principles ("GAAP"). Mr. Coppola increases the

pro-forma FFO and decreases the pro-forma debt resulting in a 100 basis point improvement in the pro-forma Moody's FFO-to-Debt ratio. However, there are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. In fact, the Company's equity ratio on a ratemaking basis as of March 2025 was 50.43%. Therefore, to appropriately assess the pro-forma impact of a 50.00% equity ratio, Mr. Coppola should have increased the pro-forma debt and reduced the pro-forma FFO. Mr. Coppola's adjustments to increase common equity from 48.4% to 50% is faulty and results in a pro-forma FFO-to-Debt ratio that is significantly overstated. For these reasons, this calculation should be rejected by the Commission.

Q. On pages 114 to 115 of his direct testimony, Mr. Coppola references recent credit opinions from rating agencies which indicate a stable outlook for the Company. Is this evidence that the Company is not at risk for further credit rating downgrade?

A. No. In assessing credit quality, rating agencies must make certain assumptions with respect to the Company's outlook, including future financial results and regulatory outcomes. However, the assumption of a stable outlook should not be interpreted as assurance that these assumptions will ultimately materialize, with no risk of a credit rating downgrade. For example, Mr. Coppola highlights the rating agencies' assumption that the Company will continue to operate in a constructive regulatory environment. However, the Company's credit rating is continuously evaluated, and the authorized ROE and equity ratio in this case will be a key component of future evaluations. As shown on page 15 of my direct testimony, the results from the Company's most recent rate cases demonstrate a sharp decline in authorized weighted rate of return (ROE times equity ratio) following a long period of stability. The persistent decline in the Company's authorized weighted rate

of return since 2020 could be seen as a material deterioration in the credit supportiveness of the Michigan regulatory environment. In addition, refer to my earlier rebuttal testimony to Staff witness Megginson. In August 2024, S&P lowered its ranking of Michigan's regulatory environment from "Above Average" to "Average" referencing less favorable authorized ROEs and a "tightening in the regulatory climate." In updating its regulatory rankings for U.S. utilities in May 2023, UBS also moved Michigan down a level from Tier 1 to Tier 2. In describing the negative change, UBS specifically mentioned authorized ROEs as well as a lowering of their "subjective factor" for the Michigan regulatory jurisdiction, which is based on UBS's "knowledge of current commission actions." It is apparent that rating agencies and analysts have taken note of the recent trend in the Company's regulatory outcomes with regard to capital structure. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating.

Q. On page 116 of his direct testimony, Mr. Coppola attempts to discredit the Company's inclusion of the May 2023 UBS report of regulatory rankings for U.S. utilities which downgraded Michigan from Tier 1 to Tier 2. Mr. Coppola claims that the Company "mischaracterizes" the report because UBS is not a credit rating agency. Mr. Coppola also considers the report "old information." Do you agree with this assessment?

A. No. While the UBS report was presented under the subsection "Rating Agencies' Assessment of the Regulatory Environment," the Company did not characterize the report as coming from a rating agency. As stated on page 20 of my direct testimony, the question

posed was "Is there evidence that analysts have also started to recognize a decline in the state of the Company's regulatory environment." The UBS report included as Exhibit A-34 (MRB-15) is evidence of this. While UBS is not a rating agency, it is a well-known investment bank that utilizes expert research analysts to examine and report on companies, sectors, and topics in order to guide investment decisions. The UBS regulatory rankings for U.S. utilities is therefore relevant to the Company's assessment of Michigan's regulatory environment in this case. With regard to the fact that the report was published in May 2023, the Company is presenting this report as evidence that entities other than rating agencies have recognized a degradation in Michigan's regulatory environment. The report was published after a sharp decline in rate of return (ROE multiplied by equity ratio) as explained on page 15 of my direct testimony and is therefore still relevant to the Company's testimony in this case.

Q. On pages 116 to 118 of his direct testimony, Mr. Coppola references the Company's Exhibit A-35 (MRB-16), a report by S&P "Rising Risks: Outlook for North American Investor-Owned Regulated Utilities Weakens." Mr. Coppola argues that this report should be dismissed because it is "generic" and is "inapplicable to the Company's regulatory and financial position." Do you agree with Mr. Coppola's assessment of this report?

A. No. While certain aspects of this report are not applicable to Consumers Energy, there are also key portions that are directly relevant to the appropriate equity ratio for the Company in this case. For example, in the report S&P cites "headwinds to credit quality" including increased cash flow deficits that are funded to a higher extent with debt versus equity. This concern is relevant in this instant case given that the Company's authorized equity ratio

has decreased 205 basis points from 2019 to present, weakening credit quality and putting the Company's credit rating at risk. S&P also notes utilities as having "strained financial cushion," defined as an FFO-to-Debt ratio less than 100 basis points above a company's downgrade threshold. This is also relevant to the Company in this case given that, as explained in my direct testimony and earlier in my rebuttal testimony, the Company's FFO-to-Debt ratio as calculated by S&P and Moody's has been trending down in recent years, moving closer to the downgrade thresholds for the Company. Finally, the report cites multiple additional credit headwinds that all utilities (including Consumers Energy) are facing including higher interest rates, a narrowing spread between U.S. Treasuries and authorized ROE's, and elevated inflation rates. Therefore, Mr. Coppola's assertion that the Commission should dismiss this relevant industry report should be rejected. It should also be noted that, on page 117 of his direct testimony, Mr. Coppola acknowledges that the Company has minimized financial risk by not maintaining a significant amount of short-term debt and instead borrowing on a "seasonal" basis.

Q. On page 118 of his direct testimony, Mr. Coppola references the Company's Exhibit A-40 (MRB-21), a January 2025 report from S&P on North American regulated utilities. Mr. Coppola attempts to downplay the risks to utilities' credit quality identified in the report as not being applicable to Consumers Energy. Do you agree with Mr. Coppola's assessment of this report?

A. No. Refer to page 21 of my direct testimony. One of the risks identified by S&P in the report is the weakening of utilities' equity layer. Specifically, S&P states "The portion of equity in the industry has been weak and consistently below expectations and thus pressuring the industry's financial measures." S&P also states that "without significantly

more common equity issuance, we expect the industry's financial measures will continue to weaken, albeit gradually, supporting our negative outlook." The Company's equity ratio has decreased significantly in recent years. Therefore, despite Mr. Coppola's assessment, this report is relevant and directly applicable to determining the appropriate equity ratio for the Company in this case.

Q. Beginning on page 119 of his direct testimony, Mr. Coppola states that "common equity capital infusions into Consumers Energy by the parent company are being funded to some extent by long term debt." He cites "financial transactions" between Consumers Energy and CMS Energy. Do you agree with these statements?

A. No. Mr. Coppola's assertion that equity investments into the Company from Consumers Energy's parent company, CMS Energy, are the result of CMS Energy borrowing debt and investing the proceeds into the Company is inaccurate and unsupported. The timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy. Equity infusions are determined after considering the capital spending and financing needs of Consumers Energy. The goals of the parent company include maintaining a strong and healthy utility, capable of serving the needs of its customers. This commitment is reflected in the equity infusions from the parent company to Consumers Energy over the last several years and the resulting actual equity ratio.

Q. On page 121 of his direct testimony, Mr. Coppola provides an analysis of the capital structure of CMS Energy and Consumers Energy from 2010 to 2024, attempting to link changes in long-term debt and equity between the two companies. Does this analysis have any merit in this instant case?

A. No. As explained above, the timing and amounts of long-term debt and equity issued by CMS Energy have no bearing on the timing and amount of equity infusions made into Consumers Energy. Also, in Case No. U-18124 the AG made this same argument that Consumers Energy's equity balance is, at least in part, funded by long-term debt from its parent company. In its July 31, 2017 Order in Case No. U-18124, the Commission adopted the findings and recommendations of the ALJ, who determined this argument from the AG "has been considered and rejected by the Commission." Mr. Coppola's analysis has been found to have no merit in the past and should again be rejected.

Q. On page 123 of his direct testimony, Mr. Coppola's argument for setting a 50.00% equity ratio in this case is that the common equity ratio of his peer group was 42.2% in 2024, as shown on his Exhibit AG-38. Is this an appropriate comparison to the projected common equity ratio in this case?

A. No. The average equity ratio calculation for the proxy group on Mr. Coppola's Exhibit AG-38 uses the equity ratio at the parent holding company level and is, thus, a misleading and inappropriate comparison. As the Company has repeatedly explained in response to this exact same argument by the AG over the years, ratios at the parent holding company level may be distorted by other, non-regulated balance sheet items and provides a completely inappropriate point of comparison. Mr. Coppola continues to avoid addressing this discrepancy. Perhaps the 780 basis point differential between the results of his analysis

on Exhibit AG-38 and his own recommendation points to Mr. Coppola's recognition that the analysis does not provide a relevant comparison. In addition, Mr. Coppola's analysis is further skewed because the sources for Mr. Coppola's debt and equity balances are Securities and Exchange Commission reported financial statements, which are prepared under GAAP. There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. These differences could easily further distort the equity ratios calculated on Mr. Coppola's Exhibit AG-38.

Q. Is Mr. Coppola's average peer group equity ratio analysis in line with the Commission's stated expectations?

A. No, the Company is the only party in this case that has provided peer equity ratio analysis that is in line with the Commission's stated expectations. In its Order in Case No. U-20963, the Commission stated that "regulatory and financial data should not be combined" in such an analysis. Further, the Commission deemed in its Order in Case No. U-20963 that such an analysis is invalid assuming one "could not verify that its data contained equity ratios set by a regulatory commission in a rate case." In his analysis of a proper equity ratio for the Company, Mr. Coppola ignores this Commission's direction by consistently utilizing equity ratios based, in part, on financial, and not regulatory, data. He consistently utilizes equity ratios that do not arise out of Commission orders, and he further fails to explain the basis or rationale for doing so. As a result, the AG's equity ratio analysis should be rejected as outside the methodology required by the Commission.

Q. If equity ratios on a financial basis are not considered relevant, what is the more appropriate comparison of average utility equity ratios?

A. It is clear from the Commission's Order in Case No. U-20963 that actual commission-authorized equity ratios is the preferred data source for an average equity ratio analysis. I refer to my Exhibit A-29 (MRB-10) in which I researched all rate case decisions from 2020 through mid-April 2025 of peer regulated companies and determined the authorized or approved equity ratio for each. The equity ratios used for comparison purposes were taken from commission orders and public filings and represent actual regulatory peer equity ratios authorized or approved by different commissions across the country. The average equity ratio for the peer group was 51.85%. This is significantly higher than the equity ratio recommended for Consumers Energy's capital structure in my rebuttal testimony and is also 185 basis points higher than the equity ratio Mr. Coppola recommends for the Company in this case. Despite this higher peer average, I am proposing a ratio of 50.75%, which balances the higher peer average with capital investment plans, credit metrics, customer rate impacts, and the guidance of this Commission, and which continues to support affordable utility infrastructure financing for the state of Michigan.

Q. On pages 123 through 126 of his direct testimony, Mr. Coppola attempts to discredit the Company's calculation of the peer group average commission-authorized equity ratios reflected on Exhibit A-29 (MRB-10). Do these arguments have merit?

A. No. The Company adhered to an established selection criteria outlined on Exhibit A-29 (MRB-10). Mr. Coppola's claims are false and divert attention away from his own lack of meaningful comparisons, meaningful criteria, and meaningful analyses of various utilities,

commission decisions, and basis for equity ratios. As explained in my direct testimony and earlier in my rebuttal testimony, the Company's data source is responsive to previous Commission orders and serves as a valid benchmark for the appropriate equity ratio for the Company in this case. As I will show in my following rebuttal testimony, Mr. Coppola's issues with Exhibit A-29 (MRB-10) are completely baseless and are an attempt to devalue the compelling evidence put forth by the Company that average peer company equity ratios are significantly higher than what Mr. Coppola proposes for the Company in this case.

Q. On page 124 of his direct testimony, Mr. Coppola argues that the inclusion of equity ratios awarded to gas utilities "inflates the outcome" of the Company's peer authorized equity ratio analysis. Does the inclusion of gas utilities in its analysis discredit the Company's peer authorized equity ratio analysis?

A. No. First, the Company calculates an average equity ratio for the gas utilities included in the exhibit as 52.51% and the average for the electric utilities as 51.58%. These are both approximately in line with the average for all companies in the exhibit of 51.85%. Therefore, Mr. Coppola's contention that the gas utility equity ratios are inflating the outcome of the analysis is exaggerated. Second, as explained earlier in my rebuttal testimony, the Company adhered to an established selection criteria outlined on Exhibit A-29 (MRB-10) which included a scope of <u>all</u> regulated subsidiaries of the Company's ROE proxy group. The purpose of the Company's Exhibit A-29 (MRB-10) is to provide a benchmark of equity ratios recently authorized by other commissions across the country. The fact that some of the regulated subsidiaries are gas utilities does not discredit or minimize the value of the analysis, as it is still a representative sample of recent rate case decisions.

Finally, it should be noted that in prior rate cases in which the Company presented this same exhibit, Mr. Coppola faulted the Company for including companies that were not part of the ROE proxy group in those cases. While the Company rejected that argument, in this instant case the Company ensured that all peer utility companies included in the analysis were regulated subsidiaries of the ROE proxy group. Regardless of this fact, Mr. Coppola continues to take issue with the composition of utilities in the Company's peer authorized equity ratio analysis.

Q. On page 124 of his direct testimony, Mr. Coppola claims that the Company's peer average authorized equity ratio reflected on Exhibit A-29 (MRB-10) is overstated as a result of the inclusion of smaller companies which "tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage." Do you agree with this conclusion?

A. No. Mr. Coppola presents no evidence showing a correlation between a company's size and its authorized equity ratio. Refer to Exhibit A-190 (MRB-25). When asked in discovery for analyses, studies, or reports supporting this statement, Mr. Coppola indicated that he "relied on his knowledge and experience." In his discovery response 3-CE-AG-5 Attach 1, Mr. Coppola also included an excerpt from Dr. Robert Morin's book New Regulatory Finance which discusses the relationship between company size and investment risk and return. This is a separate issue from the impact of a company's size on its authorized equity ratio and does not support Mr. Coppola's claim. Therefore, Mr. Coppola's assumption that the inclusion of certain "smaller" companies results in an overstatement of the peer average is unsupported and should be rejected. In addition, Exhibit A-29 (MRB-10) is intended to be an informative survey of <u>all</u>

commission-authorized equity ratios for utilities across the country and not filtered to adjust for or exclude companies with certain characteristics (customer count, rate base size, etc.). Finally, Mr. Coppola again presents a criticism of the Company's peer equity ratio analysis without offering an alternative analysis that he believes to be more representative of commission-authorized equity ratios. Mr. Coppola performs no analysis at all, but rather simply relies on the average equity ratio calculation for the parent holding companies of his proxy group of 42.2%. As explained earlier in my rebuttal testimony, this approach is flawed and should not be relied upon in this case.

Q. On page 125 of his direct testimony, Mr. Coppola claims that the equity ratio for Alliant Energy's Wisconsin Power & Light should be 53.7% instead of 55.09% as reflected on the Company's Exhibit A-29 (MRB-10). Is this a valid claim?

A. No. As shown on Exhibit A-14 (MRB-1), Schedule D-1, the Company's projected equity ratio of 50.75% excludes short-term debt. The 53.7% equity ratio for Wisconsin Power & Light referenced by Mr. Coppola is on a total capital structure basis which includes short-term debt and is therefore not comparable to the average peer authorized equity ratio analysis in this case. Wisconsin Power & Light's authorized equity ratio on a permanent capital basis (excluding short-term debt and comparable to the Company's 50.75%) is 55.09% and was correctly included in the Company's Exhibit A-29 (MRB-10).

Q. On page 125 of his direct testimony, Mr. Coppola claims that the equity ratio for Duke Energy Progress – North Carolina should be 50.5% instead of 53.0% as reflected on the Company's Exhibit A-29 (MRB-10). Mr. Coppola cites page 15 of Duke Energy's 2024 Form 10-K as support for this claim. Is this correct?

A. No. Duke Energy Progress – North Carolina was authorized a 53.0% equity ratio in August 2023. Page 15 of Duke Energy's 2024 Form 10-K validates this as shown below:

	Regulatory Body	Revenue Increase (Decrease) (in millions)	Return on Equity	Equity Component of Capital Structure	Effective Date
Approved Rate Cases:					
Duke Energy Indiana 2024 Rate Case	IURC	$ 385	9.75 %	53 %	March 2025
Duke Energy Florida 2024 Rate Case[a]	FPSC	203	10.3 %	53 %	January 2025
Duke Energy Carolinas 2024 South Carolina Rate Case	PSCSC	150	9.94 %	51.21 %	August 2024
Duke Energy Carolinas 2023 North Carolina Rate Case[b]	NCUC	768	10.1 %	53 %	January 2024
Duke Energy Kentucky 2022 Kentucky Electric Rate Case[c]	KPSC	48	9.75 %	52.145 %	October 2023
Duke Energy Progress 2022 North Carolina Rate Case[d]	NCUC	494	9.8 %	53 %	October 2023
Duke Energy Progress 2022 South Carolina Rate Case	PSCSC	36	9.6 %	52.43 %	April 2023
Duke Energy Ohio 2021 Ohio Electric Rate Case	PUCO	23	9.5 %	50.5 %	January 2023
Duke Energy Florida 2021 Settlement agreement[e]	FPSC	195	9.85 %	53 %	January 2022
Pending Rate Cases:					
Duke Energy Kentucky 2024 Kentucky Electric Rate Case	KPSC	70	10.85 %	52.728 %	July 2025

Contrary to Mr. Coppola's claim, Duke Energy Progress – North Carolina's authorized equity ratio of 53.0% was therefore correctly included in the Company's Exhibit A-29 (MRB-10).

Q. On page 125 of his direct testimony, Mr. Coppola claims that the Company's Exhibit A-29 (MRB-10) "excluded utility companies in the northeastern part of the United States where ROEs and equity ratios tend to be lower." Is this a valid claim?

A. No. In its analysis of peer group authorized equity ratios, the Company did not exclude any region of the country aside from in-state proxy DTE Energy and the Company. The Company's selection criteria included all regulated subsidiaries of the Company's ROE proxy group who had rate orders issued from January 2020 through mid-April 2025. Mr. Coppola's claim that the Company intentionally excluded certain Companies from its analysis is therefore without merit and should be rejected by the Commission.

Q. What evidence did Mr. Coppola provide in support of his claim that equity ratios for utilities in the northeastern part of the United States tend to be lower?

A. Refer to Exhibit A-190 (MRB-25). In a discovery response to the Company on this subject, Mr. Coppola provides a list of utilities in the northeastern part of the United States and the recently authorized equity ratios for each of those companies.

Q. Do you believe that the equity ratios presented by Mr. Coppola in his discovery response to the Company could be understated?

A. Yes. According to Mr. Coppola's discovery response, the source of the equity ratio data is RRA which tracks the authorized equity ratio as a percentage of total capitalization. As described earlier in my rebuttal testimony, total capitalization can be higher (thereby under reporting an equally comparable equity ratio) because, in addition to permanent capital components, items such as short-term debt, deferred taxes, and customer deposits can be included.

Q. Would the companies listed in Mr. Coppola's discovery response have been appropriate to include in the Company's peer average authorized equity ratio analysis?

A. No. While Mr. Coppola lists equity ratios for companies in the northeastern part of the United States, the companies listed do not meet the selection criteria set forth on the Company's Exhibit A-29 (MRB-10). In addition, several of the companies listed would be improper to include in the Company's average peer authorized equity ratio analysis according to Mr. Coppola's own stated criteria. For example, on page 124 of his direct testimony, Mr. Coppola argues that smaller companies (using customer count as a measure) should be excluded from the average equity ratio analysis. However, some of the

companies listed by Mr. Coppola in his discovery response are in fact smaller companies. Green Mountain Power, for example, serves approximately 275,000 customers. Versant Power serves approximately 165,000 customers, and Fitchburg Gas & Electric serves approximately 47,000 customers. In addition, as explained earlier in my rebuttal testimony, Mr. Coppola has insisted that all of the companies in the average authorized equity ratio analysis should be regulated subsidiaries of the ROE proxy group. However, several of the companies Mr. Coppola lists in his discovery response are not regulated subsidiaries of either Mr. Coppola's or the Company's ROE proxy group. In summary, Mr. Coppola has not provided sufficient evidence that the Company improperly excluded utility companies in the northeastern part of the United States in its peer average authorized equity ratio analysis or that these companies would have reduced the Company's overall result.

C. Rebuttal To Mr. Coppola's Recommendation Regarding the Cost of Long-Term Debt

Q. Starting on page 127 of his direct testimony, Mr. Coppola recommends that the Company's cost of long-term debt be lowered 15 basis points from 4.54% to 4.39%. Mr. Coppola states that his lower cost of long-term debt incorporates the Company's actual long-term debt issuances in May 2025 as well as a lower projected 30-year U.S. Treasury rate than assumed by the Company for the projected 2026 issuances. Do you agree with Mr. Coppola's adjusted cost of long-term debt rate?

A. No. Refer to my earlier rebuttal testimony to Staff witness Megginson and Exhibit A-188 (MRB-23). While I agree that it is appropriate to adjust the Company's projected cost of long-term debt for the May 2025 debt issuances and for current U.S. Treasury rate projections, the resulting adjusted cost of long-term debt is 4.43%. This adjusted cost of

long-term debt projection is reflected in Exhibit A-188 (MRB-23) – The Company Revision to Staff's Exhibit S-4, Schedule D-2 Alternative.

D. Rebuttal to Mr. Coppola's Recommendation Regarding the Working Capital Cash Balance

Q. On pages 99 to 105 of his direct testimony, Mr. Coppola discusses his recommendation to reduce the Company's projected test year working capital cash balance by $41.4 million to $9.0 million. How do you respond?

A. I will address specific issues raised by Mr. Coppola below, but I refer back to pages 38 to 43 of my direct testimony in which I provided extensive evidence that the Company's projection of the working capital cash balance of $50.4 million, equating to approximately 1% of test year electric revenues, is a level that is needed, reasonable, balanced, and adequately minimizes the Company's financial and credit risk.

Q. On page 101 of his direct testimony, Mr. Coppola attempts to discredit the Company's approach to projecting the cash balance for the test year in this case, stating that "cash on hand is not used to pay for revenues. It is used to pay operating expenses, capital expenditures and dividends to the parent company." Is this a valid argument against the Company's 1% of test year revenues rule of thumb?

A. No. The Company's cash estimation method is not intended to project all future cash outflows in order to determine the required cash balance. Rather, the 1% of test year revenues is a simple, efficient, and easily calculated benchmark that is useful in estimating a reasonable level of cash for the Company. As the size of the Company grows along with its associated operating revenues, the appropriate level of cash on hand also grows. Thus, the various uses of the Company's cash is not a valid argument against the Company's cash projection methodology.

Q. On page 101 of his direct testimony, Mr. Coppola again attempts to discredit the Company's approach to projecting the cash balance by stating that "every utility has different short-term borrowing facilities and different practices as to how they use or do not use them and may retain more or less cash on hand depending on those circumstances." Does the fact that different utilities have different practices with respect to short-term borrowing and cash on hand invalidate the Company's 1% of test year revenues rule of thumb?

A. No. Refer to the description of the Company's liquidity and financing strategy on pages 26 to 28 of my direct testimony. The Company's 1% of test year revenues rule of thumb is not intended to match other utilities' liquidity and financing practices. The Company acknowledges that different utilities hold different levels of cash and short-term debt based on their individual preferences and liquidity risk tolerance levels. The Company projects its cash balance at a level that is reasonable and appropriate for Consumers Energy, which equates to approximately 1% of test year revenues.

Q. On page 101 of his direct testimony, Mr. Coppola argues that the Company's cash analysis from Exhibit A-93 (AJD-13) in Case No. U-17990 was inappropriate because it used data on a GAAP financial basis. Does Mr. Coppola perform an analysis based on GAAP financial data in his testimony and exhibits?

A. Yes. Refer to pages 113 to 114 of Mr. Coppola's direct testimony and his Exhibit AG-44 in which he attempts a pro-forma calculation of the Moody's FFO-to-Debt ratio for the Company starting with an equity ratio sourced from Securities and Exchange Commission reported financial statements which are prepared on a GAAP basis. Also refer to Mr. Coppola's peer group equity ratio calculation of 42.2% on his Exhibit AG-38 which,

as explained earlier in my rebuttal testimony, is skewed by using GAAP financial statements. There are major differences in how components of the capital structure are classified on a ratemaking basis and on a financial basis. These differences could easily distort the equity ratios calculated in Mr. Coppola's peer group equity ratio analysis. Following Mr. Coppola's own reasoning on page 101 of his direct testimony, his Moody's pro-forma FFO-to-Debt ratio and his peer group equity ratio calculation of 42.2% are misleading and should not be used in determining the appropriate equity ratio for the Company in this case.

Q. On page 102 of his direct testimony, Mr. Coppola references the Commission's Order in Case No. U-21585 (the Company's previous electric rate case) as it relates to the Company's projected cash working capital balance. Has the Commission approved the Company's projected cash working capital balances in recent rate cases?

A. Yes. The Commission approved the Company's projected cash working capital balances (calculated using the 1% of test year revenues rule of thumb) in the prior two electric rate cases (Case Nos. U-21389 and U-21585) as well as the Company's most recent gas rate case (Case No. U-21806). In Case No. U-21585, the Commission found the Company's projected cash balance to be "reasonable and prudent." In that order, the Commission also instructed the Company in its next electric rate case to "provide further and a more specific explanation as to why its approach in determining its working capital cash balance remains appropriate and should continue to be approved." The Company satisfied this requirement on pages 38 to 43 of my direct testimony which describes the key factors and provides evidence that supports the Company's projected test year cash balance of $50.4 million, or approximately 1% of test year electric revenues. Mr. Coppola's proposed disallowance, as

in prior rate cases, should therefore again be rejected by the Commission in this instant case.

Q. On page 102 of his direct testimony, Mr. Coppola recommends that the level of cash in working capital in this case be equal to the average of the actual cash balances for 2022, 2023, and 2024. This equates to a balance of $25.1 million, $25.3 million lower than forecasted by the Company. Do you agree with this proposal?

A. No. Using the average of actual cash balances from 2022, 2023, and 2024 results in a cash balance much lower than is normally expected and required for the Company in the test year of this case. The spike in natural gas prices in 2022 resulted in cash balances that were lower than what is normally expected and required for the Company and are therefore not representative of typical cash balances historically or in the test year of this case. In addition, the Company experienced unfavorable weather in 2023, as well as storm restoration activity well beyond the five-year historical average. Both of these conditions negatively affected the Company's operating cash flows and cash balance. It is inconsistent that Mr. Coppola cites those "temporary" issues when discussing the Company's credit metrics from that period of time but ignores them for this argument. Since the Company's cash balance was abnormally low in 2022 and 2023, the average from those years should not be used in projecting the cash balance in this case. Also, the Company uses a forward looking test year in this case, projecting an adequate level of cash for the test year ending April 2027. Therefore, basing the projected cash balance on current or historical revenues would not be appropriate. Instead, the projected cash balance for the test year in this case should equate to approximately 1% of test year electric revenues,

which results in a cash balance of $50.4 million which is reflective of normal levels of cash on hand.

Q. On page 103 of his direct testimony, Mr. Coppola recommends that the level of cash in working capital in this case be reduced even further by an additional $16.1 million to account for "cash invested in interest bearing securities." Is this a valid argument?

A. No. Mr. Coppola mischaracterizes the $16.1 million as cash investment securities. While the $16.1 million is included in interest bearing operating cash accounts, these are not restricted "cash investments." This cash is unrestricted and available for the Company to draw on at any time. As explained in the Company's response to Mr. Coppola's discovery request U21870-AG-CE-0456, the Company has not included any restricted cash investments in its calculation of working capital for the instant case. Consistent with long-standing ratemaking practice, the cash accounts identified by Mr. Coppola for removal are properly included in the Company's working capital.

Q. On page 103 of his direct testimony, Mr. Coppola claims that acceptance of the Company's projected cash balance in this case would "further expand it cash investing activities to the benefit of the Company and at the expense of customers." Is this an accurate statement?

A. No. Any interest earned on rate base working capital cash balances is included as a reduction to the Company's revenue requirement. Mr. Coppola's claim that the Company is conducting "investing activities" with this cash to the benefit of the Company and at the expense of customers is false and should be rejected by the Commission.

Q. On pages 103 to 104 of his direct testimony, Mr. Coppola again claims that the Company improperly benefits by investing "extra" cash in short-term investments. Do you agree with this claim?

A. No. First, the Company is not projecting "extra" cash in this case but an amount that is reasonable and supportive of the Company's operating, investing, and financing activities. Second, the Company has not included any restricted cash investments in its calculation of working capital for the instant case. Finally, as explained earlier in my rebuttal testimony, any interest earned on rate base working capital cash balances is included as a reduction to the Company's revenue requirement. Mr. Coppola's claims are therefore false and misleading and should not be relied upon in this case.

Q. On pages 104 to 105 of his direct testimony, Mr. Coppola recommends that the Company maintain a low cash balance and rely on its short-term credit facilities to solve any significant liquidity challenges that may arise. Is this a prudent strategy?

A. No. A cash balance of $9.0 million or 0.2% of test year revenues is extremely low for the Company given the size of the business and its operating cash flows. Refer to pages 40 to 41 of my direct testimony in which I explain how the Company's projected cash balance for the test year in this case minimizes liquidity risk. Also refer to pages 42 to 43 of my direct testimony. The Company's cash balance is a component of rating agencies' assessment of credit quality. A low cash balance and relying more heavily on short-term debt as Mr. Coppola recommends is detrimental to the Company's credit quality. In summary, the Company has provided extensive evidence in direct testimony showing that the Company's projection of the working capital cash balance of $50.4 million, equating to approximately 1% of test year electric revenues, is a level that is reasonable, balanced,

and adequately minimizes financial and credit risk. Mr. Coppola's recommended reduction of projected working capital of $44.1 million to $9.0 million is excessively punitive, not supported by the evidence, unduly increases the Company's liquidity risk, and should therefore be rejected by the Commission.

IV. REBUTTAL OF ABATE WITNESS WALTERS

Q. On page 6 of his direct testimony, Mr. Walters presents Table CCW-2 – Trends in State Authorized Common Equity Ratios which lists average equity ratios by year from 2016 to 2025. What trend does the data in this table reveal?

A. As shown in Mr. Walters' Table CCW-2, the average equity ratio has been trending up over the last 10 years. In fact, Mr. Walters' table shows that the average equity ratio for electric utilities covering all years presented is 50.74%, virtually the same as recommended by the Company in this case. In addition, the Company's projected equity ratio of 50.75% is below industry averages for several of the years presented. Mr. Walters' table shows that his recommended equity ratio for the Company in this case of 50% is significantly understated when compared to his own calculation of industry average equity ratios and trends.

Q. Are the average equity ratios reflected in Mr. Walters' Table CCW-2 understated?

A. Yes. According to footnote 1 of Mr. Walters' Table CCW-2, the source of the equity ratio data is "S&P Global Market Intelligence." S&P Global Market Intelligence tracks the authorized equity ratio as a percentage of total capitalization. Total capitalization can be higher (making the equity ratio lower) because, in addition to permanent capital components, items such as short-term debt and customer deposits can be included. As described earlier in my rebuttal of Staff witness Megginson, the Company's proposed

equity ratio in this instant case as a percentage of total capitalization is 42.94%, 781 basis points lower than the 50.75% proposed as a percentage of permanent capitalization. Excluding short-term debt to be consistent with the equity ratio projected by the Company in this case (as a percentage of permanent capital), the order results in a higher equity ratio. Again, in order to make proper comparisons, the Company's equity ratio, based on a percentage of permanent capital, should be compared to utilities also using an equity ratio based on percentage of permanent capital. By utilizing utility equity ratios that are based on a percentage of total capitalization to support his recommended equity ratio for the Company in this case, Mr. Walters is not making a direct like-for-like comparison, and thereby understating his results, which therefore should not be relied upon.

Q. If the equity ratios reflected on Mr. Walters' Table CCW-2 are understated, what is the more appropriate comparison of average utility equity ratios?

A. Refer to my earlier rebuttal testimony to AG witness Coppola in which I explain that actual commission-authorized equity ratios is the preferred data source for an average equity ratio analysis. I refer to my Exhibit A-29 (MRB-10) in which I researched all rate case decisions from 2020 through mid-April 2025 of peer regulated companies and determined the authorized or approved equity ratio for each. Consistent with the Commission's Order in Case No. U-20963, the equity ratios used for comparison purposes were taken from commission orders and public filings and represent actual regulatory peer equity ratios authorized or approved by different commissions across the country. As stated above, the average equity ratio for the peer group was 51.85%. This is significantly higher than the equity ratio of 50.75% projected by the Company and is also 185 basis points higher than the equity ratio Mr. Walters recommends for the Company in this case.

Q. On pages 7 to 8 of his direct testimony, Mr. Walters presents data from S&P Global Market Intelligence which indicates that capital investments by regulated utilities are projected to continue to increase through 2027. Does this trend apply to the Company as well?

A. Yes. As set forth in the testimony and exhibits of the Company's multiple capital witnesses, the Company is making significant capital investments to maintain and improve utility infrastructure to improve reliability and resiliency to the benefit of customers. During this time, the Company must rely heavily on the capital markets to fund these investments. Therefore, it will be especially important for the Company to maintain strong credit ratings to ensure beneficial access to capital markets for funding to deliver these critical customer investments and enable the Company to do so at the lowest possible financing cost on their behalf.

Q. In addition to the data presented by Mr. Walters on projected utility capital investments, has S&P commented recently on the credit quality of utilities?

A. Yes. As highlighted on page 16 of Mr. Walters' direct testimony, in a January 2025 report on North American regulated utilities, S&P highlighted lower ratings headroom as "a high percentage of companies are operating with only minimal financial cushion from our downgrade threshold." Refer to Exhibit A-40 (MRB-21). S&P also notes that, in 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year. With regard to the industry credit outlook for 2025, S&P identifies risk that will pressure the industry's financial measures, including weak equity ratios, potential new tax legislation, and robust capital spending in challenging regulatory constructs. S&P also sights Michigan as one of the regulatory jurisdictions that they

"continue to carefully monitor." It is apparent from this report that an ROE and equity ratio combination higher than the current authorized level, and certainly higher than the continued degradation proposed by Mr. Walters, is critical to protect the Company from receiving a credit downgrade in light of the credit risks as described above.

Q. Have rating agencies other than S&P also commented on the credit quality of regulated utilities?

A. Yes. As referenced on page 18 of Mr. Walters' direct testimony, Moody's issued a report in which it revised its outlook on the U.S. regulated utilities sector from stable to negative citing "increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and interest rates." In addition, on page 18 of his direct testimony, Mr. Walters references a report by another credit rating agency, Fitch. In describing a "deteriorating outlook for North American utilities, power & gas in 2024," Fitch cited credit headwinds that are putting pressure on utilities' credit metrics. Specifically, Fitch concluded that "the sharp escalation in interest rates has significantly narrowed the headroom in FFO fixed-charge coverage for the sector." It is clear from these reports that rating agencies have recognized a deterioration in credit metrics and credit quality for regulated utilities. These rating agency comments highlight the importance for the Company to maintain strong financial metrics and to not manage toward the perceived low end of the credit metric bands.

Q. On page 22 of his direct testimony, Mr. Walters states that the Company's projected equity ratio of 50.75% is "relatively higher than the equity ratio for the proxy group used to estimate the cost of equity for Consumers Energy." Mr. Walters then references his Exhibit AB-6, which shows a proxy group average equity ratio of 40.1% (including short-term debt) and 43.8% (excluding short-term debt). This is also highlighted on page 30 of Mr. Walters' direct testimony. Are either of Mr. Walters' average equity ratios reflected on Exhibit AB-6 in any way relevant or comparable to the Company's projected equity ratio of 50.75% in this case?

A. No. Refer to my earlier rebuttal testimony to AG witness Coppola's Exhibit AG-38. Like Mr. Coppola's Exhibit AG-38, the average equity ratio calculations for the proxy group on Mr. Walters' Exhibit AB-6 uses the equity ratio at the parent holding company level which may be distorted by other non-regulated balance sheet items and provides a completely inappropriate point of comparison. Mr. Walters' equity ratio analysis is clearly not based on the Commission's regulatory authorization and is therefore not comparable or relevant in determining the appropriate equity ratio for the Company in this case. Further, it is not clear which peer average Mr. Walters recommends to use in determining the appropriate equity ratio for the Company in this case. Earlier in his direct testimony at page 6, Mr. Walters references average state authorized equity ratios in his Table CCW-2 which reflects an average of 50.74% for electric utilities. While the average equity ratios in this table are understated as explained earlier in my rebuttal testimony, they are dramatically higher than the 40.1% and 43.8% reflected on Mr. Walters' Exhibit AB-6. For these reasons, Mr. Walters' comparison of the average equity ratios on his Exhibit AB-6 to the

Company's projected equity ratio of 50.75% is not comparable or relevant and should be disregarded.

Q. On page 23 of his direct testimony, Mr. Walters references the Commission's Order in Case No. U-21585, the Company's last electric rate case, which authorized an evenly balanced equity ratio. Does the equity ratio authorized from a previous rate case necessitate a duplication of that capital structure in this instant case?

A. No. The appropriate equity ratio for the Company should be based on the facts and circumstances presented in this instant case and not predetermined based on prior Commission orders. Refer to my earlier rebuttal testimony to Staff witness Megginson (II.B.ii. Staff Fails to Consider New Circumstances That Justify a Deviation from an Evenly Balanced Capital Structure). While the Commission authorized an evenly balanced capital structure in the case referenced by Mr. Walters, the Commission has also made clear that there should be flexibility in its assessment, allowing for a deviation from an evenly balanced capital structure when circumstances warrant it. It is clear from these orders that the Commission does not consider an evenly balanced capital structure a mandate to be followed blindly, but rather as a basis from which a deviation may be justified upon consideration of the evidence and circumstances of each rate case.

V. REBUTTAL OF CUB WITNESS BANDYK

Q. On page 35 of his direct testimony and his Exhibit CUB-9, Mr. Bandyk calculates an interest coverage ratio for the Company using his recommended ROE and equity ratio as inputs. Mr. Bandyk then references a table from Dr. Damodaran showing interest coverage ratio ranges and the associated credit rating. Mr. Bandyk determines that his calculated interest coverage ratio falls within the range associated with the Company's current credit rating according to Dr. Damodaran's table. Mr. Bandyk then concludes that the Company should be able to maintain its current credit rating, assuming his recommended ROE and equity ratio. Do you agree with this conclusion?

A. No. First, the Company's credit rating is based on several different qualitative and quantitative factors including the regulatory environment, liquidity position, and the Company's business risk profile. Mr. Bandyk's assumption that the results of a single credit metric ratio should have no impact on the Company's credit rating is misguided, as a lower authorized ROE and equity ratio could very well negatively impact these other aspects of the rating agencies' evaluations. Second, while rating agencies track the Company's interest coverage ratio, they place a relatively higher weight on the Company's FFO-to-Debt ratio with respect to potential credit rating actions. The FFO-to-Debt ratio is consistently highlighted in rating agencies' credit opinions and is identified as a factor that could lead to a ratings upgrade or downgrade. I refer to page 15 to 16 of my direct testimony which shows that the Company's FFO-to-Debt ratio has been trending down in recent years. Finally, Dr. Damodaran's table used by Mr. Bandyk in his analysis is compiled with data from all credit rated companies in the U.S. This is an inappropriate

measure, as the credit risk considerations for Consumers Energy, a regulated utility, differ from those of all companies as a whole. The actual range for the Company's interest coverage ratio expected by rating agencies could therefore vary dramatically from Dr. Damodaran's table.

Q. If not Dr. Damodaran's table, what is the appropriate source for the expected interest coverage ratios for the Company?

A. The most relevant source for the expected interest coverage ratios for the Company comes from the credit rating agencies themselves and, more specifically, Consumers Energy's credit reports. These reports take into account all aspects of the Company's risk profile to determine the appropriate expected credit metric ranges.

Q. How do the interest coverage ratios expected by the rating agencies for the Company compare to the interest coverage ratio range determined by Mr. Bandyk based on Dr. Damodaran's table?

A. The actual interest coverage ratio ranges expected by the rating agencies for the Company's current credit rating are significantly higher than Mr. Bandyk calculates. Mr. Bandyk calculates an expected interest coverage range of 3 to 4.2499. Refer to page 5 of Exhibit A-36 (MRB-17) - S&P's August 2024 credit report. The expected FFO cash interest coverage ratio for 2027 is 5.2. The expected EBITDA interest coverage ratio for 2027 is 5.0, both well above Mr. Bandyk's range. Also refer to page 8 of Exhibit A-37 (MRB-18) – Moody's August 2024 credit report. Moody's 12- to 18-month forward view for the interest coverage ratio (CFO pre-WC + Interest / Interest) is 5 to 6, also significantly higher than Mr. Bandyk's range. For the reasons outlined above, Mr. Bandyk's claim that the

Company's credit rating will not suffer as a result of his lower proposed ROE and equity ratio is without merit and should be rejected by the Commission.

Q. On page 37 of his direct testimony, Mr. Bandyk states that the Company did not provide any evidence that the Company is at risk of a credit downgrade from a drop in regulatory environment rankings. Do you agree with this statement?

A. No. Refer to pages 19 to 20 of my direct testimony in which I explain how a component of rating agencies' evaluation of credit quality involves an assessment of the Company's regulatory environment and that the authorized equity ratio and ROE are two important components in that assessment. I presented evidence showing that in 2023 UBS downgraded Michigan's regulatory ranking and in 2024, S&P also lowered its ranking of Michigan's regulatory environment. It should be noted that these regulatory environment downgrades have come at a time when recent rate cases have resulted in a sharp decline in rate of return (equity ratio multiplied by the ROE) following a long period of stability. Contrary to Mr. Bandyk's statement, the Company has shown that rating agencies and analysts are taking note of the Company's regulatory outcomes and are viewing them unfavorably. A continuation or, even worse, a further degradation of the authorized equity ratio and ROE puts the Company at risk of dropping further in its regulatory environment rankings which could negatively impact the Company's credit quality and credit rating.

Q. On page 37 of his direct testimony, Mr. Bandyk states that "both Moody's and S&P have a 'stable' outlook for Consumers Energy, meaning they see little risk of a downgrade." Does a stable outlook necessarily indicate little risk of a downgrade in the future?

A. No. Refer to my earlier rebuttal testimony to Staff witness Megginson on this matter. In assessing credit quality, rating agencies must make certain assumptions with respect to the Company's outlook, including future financial results and regulatory outcomes. However, a stable outlook should not be interpreted as assurance that these assumptions will ultimately materialize, with no risk of a credit rating downgrade. For example, in June 2019, Moody's issued a credit opinion for the Company stating that "Consumers' stable outlook reflects our expectation that the Michigan legislative and regulatory environments will remain constructive." Moody's also stated that they expected the Company's FFO-to-Debt ratio to "range between 20% and 24% over the next few years." In May 2021, Moody's downgraded Consumers Energy's credit rating "due to its weakened credit metrics." Moody's also referenced the outcome of recent rate cases which put pressure on the Company's credit metrics. While rating agencies may assume that the Company will continue to operate in a constructive regulatory environment with credit metrics above the downgrade threshold, the Company's credit rating is continuously evaluated. A reduction in the Company's rate of return lowers cash flow, increases debt, and thereby weakens the Company's FFO-to-Debt ratio. These negative credit metric impacts place the Company's credit quality and credit ratings at risk. The authorized ROE and equity ratio in this case will be a key component of future rating agency evaluations.

Q. On page 38 of his direct testimony, Mr. Bandyk references a discovery response in which the Company did not identify a specific FFO-to-Debt ratio that would trigger a credit downgrade. Does this response invalidate the evidence presented in direct testimony which justifies the Company's recommended ROE and equity ratio?

A. No. As explained in the referenced discovery response, rating agencies have FFO-to-Debt ranges that they expect the Company to maintain based on its current risk category / credit rating. While continued underperformance may lead to a ratings downgrade, there is no specific FFO-to-Debt identified that would automatically trigger a negative credit rating action. As explained earlier in my rebuttal testimony, the Company's FFO-to-Debt metric is one of several qualitative and quantitative measurements that rating agencies consider before taking action on a credit rating. A reduction in authorized ROE combined with a lower equity ratio can lead to a deterioration of credit metrics and ultimately a downgrade. This reasoning was validated by Moody's 2021 credit rating downgrade, which specifically pointed to these issues and their associated negative credit metric impacts.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No.: A-187 (MRB-22)
Page: 1 of 1
Witness: MRBleckman
Date: October 2025

Company Revision to Staff's Exhibit S-4, Schedule D-1 Alternative

Consumers Energy Company (Electric Division)
Overall Capital Structure & Rate of Return
for the Test Year Ending April 30, 2027

Schedule D-1 Alternative

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line Description	Amount	Permanent Ratio	Total Capital Ratio	Cost Rate	Weighted Cost	Convrsn Factor	Pre-Tax Weighted Cost
1 Long Term Debt	$ 13,465,225,769	49.11%	41.55%	4.43%	1.84%	1.0000	1.84%
2 Preferred Stock	$37,315,000	0.14%	0.12%	4.50%	0.01%	1.3381	0.01%
3 Common Equity	$ 13,915,858,077	50.75%	42.94%	10.25%	4.40%	1.3381	5.89%
4 Total Permanent Capital	$27,418,398,846	100.00%					
5 Short Term Debt	$ 148,300,000		0.46%	4.92%	0.02%	1.0000	0.02%
6 Deferred FIT	$4,692,000,000		14.48%	0.00%	0.00%	1.0000	0.00%
7 Job Dev Invest Tax Credits	$148,000,000						
8 Def JDITC - Long Term Debt	$73,798,175		0.23%	4.43%	0.01%	1.0000	0.01%
9 Def JDITC - Preferred Stock	$201,260		0.00%	4.50%	0.00%	1.3381	0.00%
10 Def JDITC - Common Equity	$74,000,565		0.23%	10.25%	0.02%	1.3381	0.03%
11 Total JDITC	$148,000,000				0.03%		0.04%
12 Total Capitalization	$32,406,698,846		100.00%		6.30%		7.80%

Line Consumers Energy Adjustments

1, 8 Long-Term Debt balance changed from $13,682,687,000 to $13,465,225,769. See Exhibit A-14 (MRB-2) Schedule D-1a, page 2
Long-Term Debt cost rate changed from 4.37% to 4.43%. See Exhibit A-188 (MRB-23)

3, 10 Common Equity balance changed from $13,720,211,462 to $13,915,858,077. See Exhibit A-14 (MRB-2) Schedule D-1a, page 3
Common Equity cost rate changed from 9.75% to 10.25%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No.: A-188 (MRB-23)
Page: 1 of 1
Witness: MRBleckman
Date: October 2025

Company Revision to Staff's Exhibit S-4, Schedule D-2 Alternative

Consumers Energy Company (Electric Division)
Staff Long-Term Debt Balance and Cost Rate
for the Test Year Ending April 30, 2027

Schedule D-2 Alternative

Line	(a) Mortgage Bonds	(b) Original Issue Date	(c) Maturity Date	(d) Interest Rate	(e) Initial Amount (000)	(f) Cost Based On Net Proceeds	(g) Amount Outstanding (000)	(j) Annual Cost (000)	(k) Annual Cost (%)
1	5.800%	11-Aug-05	15-Sep-35	5.800%	175,000	5.888%	175,000	10,304	
2	6.170%	01-Sep-10	01-Sep-40	6.170%	50,000	6.243%	50,000	3,121	
3	4.970%	15-Oct-10	15-Oct-40	4.970%	50,000	5.005%	50,000	2,502	
4	3.390%	17-Dec-12	15-Dec-27	3.390%	35,500	3.436%	35,500	1,220	
5	4.310%	17-Dec-12	15-Dec-42	4.310%	263,000	4.342%	263,000	11,418	
6	3.950%	17-May-13	15-May-43	3.950%	425,000	4.019%	425,000	17,079	
7	4.350%	18-Aug-14	31-Aug-64	4.350%	250,000	4.443%	250,000	11,107	
8	4.100%	06-Nov-15	15-Nov-45	4.100%	250,000	4.167%	250,000	10,417	
9	3.250%	10-Aug-16	15-Aug-46	3.250%	450,000	3.347%	450,000	15,063	
10	3.950%	22-Feb-17	15-Jul-47	3.950%	350,000	4.035%	350,000	14,122	
11	3.18% (Private Placement)	28-Sep-17	28-Sep-32	3.180%	40,000	3.207%	40,000	1,283	
12	3.52% (Private Placement)	28-Sep-17	28-Sep-37	3.520%	125,000	3.550%	125,000	4,437	
13	3.86% (Private Placement)	28-Sep-17	28-Sep-52	3.860%	20,000	3.899%	20,000	780	
14	3.18% (Private Placement)	15-Nov-17	15-Nov-32	3.180%	60,000	3.207%	60,000	1,924	
15	3.52% (Private Placement)	15-Nov-17	15-Nov-37	3.520%	210,000	3.550%	210,000	7,454	
16	3.86% (Private Placement)	15-Nov-17	15-Nov-52	3.860%	30,000	3.899%	30,000	1,170	
17	4.050%	14-May-18	15-May-48	4.050%	550,000	4.170%	550,000	22,936	
18	3.68% (Private Placement)	01-Oct-18	01-Oct-27	3.680%	100,000	3.701%	100,000	3,701	
19	4.01% (Private Placement)	01-Oct-18	01-Oct-38	4.010%	215,000	4.041%	215,000	8,688	
20	4.28% (Private Placement)	01-Oct-18	01-Oct-57	4.280%	185,000	4.302%	185,000	7,959	
21	3.800%	13-Nov-18	15-Nov-28	3.800%	300,000	3.922%	300,000	11,765	
22	4.350%	13-Nov-18	15-Apr-49	4.350%	550,000	4.435%	550,000	24,390	
23	3.750%	28-May-19	15-Feb-50	3.750%	300,000	3.875%	300,000	11,625	
24	3.100%	03-Sep-19	15-Sep-50	3.100%	550,000	3.200%	550,000	17,600	
25	Floating Rate FMB	19-Sep-20	01-Sep-69	3.300%	75,650	3.760%	75,650	2,844	
26	3.500%	26-Mar-20	01-Aug-51	3.500%	575,000	3.550%	575,000	20,413	
27	2.500%	13-May-20	13-May-50	2.500%	525,000	2.534%	525,000	13,304	
28	Floating Rate FMB	20-May-20	20-May-70	3.300%	134,139	3.380%	134,349	4,541	
29	Floating Rate FMB	7-Oct-20	7-Oct-70	3.300%	126,497	3.760%	126,497	4,756	
30	2.650%	2-Aug-21	15-Aug-52	2.650%	300,000	2.703%	300,000	8,109	
31	3.600%	11-Aug-22	15-Aug-32	3.600%	350,000	3.670%	350,000	12,845	
32	4.200%	11-Aug-22	17-Aug-52	4.200%	450,000	4.268%	450,000	19,206	
33	4.650%	10-Jan-23	1-Mar-28	4.650%	425,000	4.868%	425,000	20,689	
34	4.625%	23-Feb-23	15-May-33	4.625%	700,000	4.730%	700,000	33,110	
35	5.24% (Private Placement)	15-May-23	15-May-26	5.240%	115,000	5.635%	8,845	498	
36	5.07% (Private Placement)	15-May-23	15-May-29	5.070%	50,000	5.281%	50,000	2,641	
37	5.17% (Private Placement)	15-May-23	15-May-32	5.170%	95,000	5.322%	95,000	5,056	
38	5.38% (Private Placement)	15-May-23	15-May-37	5.380%	140,000	5.491%	140,000	7,687	
39	4.90%	4-Aug-23	15-Feb-29	4.900%	500,000	5.060%	500,000	25,302	
40	4.60%	9-Jan-24	30-May-29	4.600%	600,000	4.798%	600,000	28,789	
41	4.70%	5-Aug-24	15-Jan-30	4.700%	700,000	4.898%	700,000	34,283	
42	4.500%*	2-May-25	15-Jan-31	4.500%	500,000	4.657%	500,000	23,285	
43	5.050%*	2-May-25	15-May-35	5.050%	625,000	5.208%	625,000	32,552	
44	New Debt Issue #3	1-May-26	1-Aug-56	6.260%	600,000	6.341%	553,846	35,117	
45	New Debt Issue #4	1-Aug-26	1-Aug-56	6.260%	725,000	6.341%	501,923	31,824	
46	Total Mortgage Bonds						$ 13,469,610	$ 588,916	
47	Other Long-Term Debt								
48	PCRB - MSF LORB - 19	01-Oct-19	01-Oct-49	3.350%	75,000	3.430%	75,000	$ 2,572	
49	PCRB - MSF LORB - 21	07-Oct-21	01-Apr-35	0.875%	35,000	0.994%	35,000	$ 348	
50	Total PCRB Debt						$ 110,000	$ 2,920	
51	Total All-Ecompassing Long-Term Debt						$ 13,579,610	$ 591,836	4.36%
52	Amortized Call Premium on reaquired debt							4,342	
53	Unamortized Debt Expense						$ (114,385)		
54	Long-Term Debt						$ 13,465,225	$ 596,178	4.43%
55	~~Ratemaking Long-term Debt (debt adjustment of plus $217,642,000)~~						~~$ 13,682,867~~		

Line ***Consumers Energy Adjustments***
44-45 Forecasted cost rate from 5.58% to 6.26%
55 Removed Long-term debt adjustment

	Staff Position	Consumers Energy Adjusted	
Projected 30-yr T-Bond Yield	4.58%	4.88%	Bloomberg 10/6/25
Credit Spread	1.00%	1.38%	Exhibit A-14 (MRB-4) Line 79
Cost Rate for 2026 Debt Issuances	5.58%	6.26%	

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **Consumers Energy Company** for authority to increase its rates for the generation and distribution of electricity and for other relief. /	Case No. **U-21870** **(e-file paperless)**

MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S ANSWER TO CONSUMERS ENERGY COMPANY'S FOURTH DISCOVERY REQUEST

Respectfully submitted,

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

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DATED: October 8, 2025

MPSC Staff's Answer to the Consumers Energy Company's
4th Discovery Request
MPSC Case No. U-21870
October 8, 2025

Question:

21870-CE-ST-0009:

Refer to the box at the bottom of Mr. Megginson's Exhibit S-4, Schedule D-2 Alternative. Please provide all supporting data and citations to sources for the 2026 projected credit spread of 1.00%.

Response:

Staff's 1.00% credit spread noted at the bottom of Exhibit S-4, Schedule D-2 Alternative, is shaped by the credit spreads of the Company's most recent debt issuances in May 2025 and the Company's last 30-year debt issuance in August 2022. The 30-year debt issuance had a credit spread of 125 basis points. The Company's two May 2025 issuances had an average credit spread of 77 basis points. Thus, a reasonable 30-year credit spread for the Company's 2026 debt issuances is 1.00%. The Company's 1.38% credit spread is based on outdated and outlier data.

Respondents: Kirk Megginson

MPSC Case No.	**U-21870**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**3-CE-AG-5**

3-CE-AG-5
Refer to page 124 of Mr. Coppola's direct testimony which states that "Smaller utilities tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage." Please provide all analyses, studies, or reports Mr. Coppola relied on in making this statement.

Response:

This same question was asked and answered in Case U-21806.

In establishing that smaller utilities tend to have higher equity ratios, Mr. Coppola relied on his knowledge and experience accumulated over the past nearly 50 years that he has been involved in the utility industry. Appendix A to Mr. Coppola's direct testimony shows his vast background as Chief Financial Officer, Treasurer, and financial manager involved in various aspects of financing and managing large and small utilities.

Mr. Coppola has also relied on research and a publication issued by financial expert, Dr. Roger A. Morin. The attached excerpt from Dr. Morin's book New Regulatory Finance provides supporting evidence on the higher business and financial risks faced by smaller utilities. See 3-CE-AG-5 Attach 1.

Date: 10/8/2025

MPSC Case No. **U-21870**
Responding Party: Attorney General
Respondent: Sebastian Coppola
Requestor: CECo
Question No.: **3-CE-AG-6**

3-CE-AG-6
On page 125 of his direct testimony, Mr. Coppola addresses Company witness Bleckman's Exhibit A-29 (MRB-10) – Peer Company Commission Authorized Equity Ratios. Mr. Coppola claims that the Company's analysis "excluded utility companies in the northeastern part of the United States where ROEs and equity ratios tend to be lower." Please provide all analyses, studies, or reports Mr. Coppola relied on in making this statement.

Response:

This same question was recently asked and answered in Case U-21806. The following table provides a list of utility companies in the northeastern part of the United States where ROEs and equity ratios tend to be lower than the list of utilities in Exhibit A-29. The ROEs for these utilities are also shown in Exhibit AG-40 and the equity ratios are from the respective year RRA reports to which the Company should have access.

Electric Company	Jurisdiction	& Order Date		ROE	Equity Ratio
Consolidated Edison of NY	NY	Jul. 20	2023	9.25%	48.0%
Green Mountain Power	VT	Aug. 23	2023	9.58%	49.9%
United Illuminating Group	CT	Aug. 25	2023	8.63%	50.0%
New York State Elec. & Gas	NY	Oct. 12	2023	9.20%	48.0%
Rochester Gas & Electric	NY	Oct. 12	2023	9.20%	48.0%
Atlantic City Electric	NJ	Nov. 17	2023	9.60%	50.2%
Jersey Central P & L	NJ	Feb. 14	2024	9.60%	52.0%
Delmarva Power	DE	Apr. 18	2024	9.60%	50.5%
Potomac Electric	MD	Jun. 10	2024	9.50%	50.5%
Fitchburg G & E	MA	Jun. 28	2024	9.40%	52.0%
Central Hudson G & E	NY	Jul. 18	2024	9.50%	48.0%
Massachusetts Electric	MA	Sep. 30	2024	9.35%	52.8%
Potomac Electric	DC	Nov. 25	2024	9.50%	50.5%
Versant Power	ME	Mar. 13	2025	9.35%	50.0%
Orange and Rockland	NY	Mar. 20	2025	9.75%	48.0%
Liberty Utilities	NH	Mar. 25	2025	9.10%	52.0%
Average				9.38%	50.0%

Date: 10/8/2025

PROOF OF SERVICE - U-21870

The undersigned certifies that a copy of the ***Attorney General's Response to Consumers Energy Company's Third Discovery Request*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 8th day of October 2025.

Celeste R. Gill Digitally signed by Celeste R. Gill Date: 2025.10.08 13:57:33 -04'00'

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S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Richard T. Blumenstock, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Richard T. Blumenstock who previously submitted direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Laura Maio; Attorney General witness Sebastian Coppola; Michigan Environmental Council and Citizens Utility Board of Michigan (collectively "MNSC") witness Tyler Comings; and Association for Businesses Advocating Tariff Equity ("ABATE") witness Jessica A. York. In addition, I will provide rebuttal to MNSC witness Richard J. Bunch; witness William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar (collectively the "Clean Energy Organizations" or "CEO"), and Great Lakes Renewable Energy Association ("GLREA") witness Richard Boehnke.

Specifically, I will provide rebuttal to address Ms. Maio's proposed adjustments to the bridge period capital projects over $1 million, the class estimate reduction in generation capital expenditures for the projected test year, and reduction to the test year operation and maintenance ("O&M") expense. I will provide rebuttal to Ms. York's proposed reductions in generation capital expenditures for long term service agreement ("LTSA") extra work

at the Covert, Jackson, and Zeeland Generating Stations and I will provide rebuttal to Mr. Comings' proposed reductions to two capital projects at the Jackson Generating Station, some modeling recommendations, and his analysis of the Jackson Generating Station. I will also provide rebuttal to Mr. Coppola's extensive list of unsupported proposed capital expenditure disallowances at the Covert, Jackson, and Zeeland Generating Stations as well as a disallowance of the capital expenditures for an environmental project at the J.H. Campbell ("Campbell") site. Finally, I will respond to Mr. Bunch's observations regarding the Company's generation O&M expense and also respond to Mr. Kenworthy and Mr. Boehnke regarding recommended Integrated Resource Plan ("IRP") modeling assumptions.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-191 (RTB-13)	Covert Generating Station Units 1 & 3 LTSA Extra Work;
Exhibit A-192 (RTB-14)	Ludington Pumped Storage Dike Load Center Replacement;
Exhibit A-193 (RTB-15)	Ludington Pumped Storage Oil Water Separator;
Exhibit A-194 (RTB-16)	Ludington Pumped Storage Pony Motor Rotor Cracking and Fretting;
Exhibit A-195 (RTB-17)	Ludington Pumped Storage Distributed Control System Control Relay Replacement;
Exhibit A-196 (RTB-18)	Ludington Pumped Storage Unit Governors;
Exhibit A-197 (RTB-19)	Ludington Pumped Storage Lower Penstock Expansion Joint Chamber Waterstop;

Exhibit A-198 (RTB-20)	Covert Generating Station spare Generator Step-Up ("GSU") transformer;
Exhibit A-199 (RTB-21)	Zeeland Generating Station Phase II Gas Turbine Advanced gas path replacement and axial fuel staging project;
Exhibit A-200 (RTB-22)	Zeeland Generating Station Phase I performance report;
Exhibit A-201 (RTB-23)	Emergent Reliability Investment for the years 2022 through 2025;
Exhibit A-202 (RTB-24)	Jackson Generating Station spare GSU transformer;
Exhibit A-203 (RTB-25)	Jackson Generating Station LM1-6 variable inlet guide vane;
Exhibit A-204 (RTB-26)	Year over Year Generation O&M Expense; and
Exhibit A-205 (RTB-27)	Copperleaf Value Model Methodology.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

REBUTTAL OF ABATE WITNESS YORK

Q. Please summarize ABATE witness York's testimony regarding the extra work associated with LTSAs with General Electric and Mitsubishi.

A. Based upon my review of Ms. York's direct testimony beginning at page 19 through page 24, Ms. York refers to the projected capital expenditures for LTSA extra work at Covert, Jackson, and Zeeland as speculative or highly speculative. As such, Ms. York recommended the disallowance of $34.781 million of Covert LTSA extra work in the bridge period and test year, the disallowance of $5.513 million of Zeeland LTSA extra work in the bridge period and test year, and the disallowance of $2.430 million of Jackson LTSA extra work in the bridge period and test year.

Q. Beginning at page 21, line 9, of her direct testimony regarding the Covert LTSA extra work, Ms. York states "[b]ecause 1) this category of cost is associated with issues that might be discovered that are not covered under the LTSA and 2) historical annual amounts vary significantly from year-to-year with no clear trend, I believe it is premature to include them in rates at this time." Do you agree with Ms. York's conclusion?

A. No. As discussed in my direct testimony beginning on page 26, line 19, the Company is conducting major inspections at Covert Units 1, 2, and 3 during the bridge period and test year. Again, beginning on page 61 of my direct testimony, I discuss the performance of 59-day major outage inspections for each of the three Covert Units. In addition, beginning on page 62, line 29, through page 68, line 8, I discuss the specific work to be performed during the major inspections including generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair.

Q. How frequently are major inspections performed on the Covert Units?

A. Pursuant to the LTSA with Mitsubishi, these inspections are required every 50,000 hours or approximately every six years. As indicated in my direct testimony, the major inspection on Covert Unit 2 was completed on May 25, 2025. The costs of LTSA extra work on Covert Unit 2 are neither speculative nor are they associated with issues that might be discovered; in fact, the work has been completed and the actual capital expenditures are known. As discussed in Exhibit A-191 (RTB-13), which was originally provided in response to discovery, the actual LTSA extra work performed at Covert Unit 2 totaled $12.7 million. It is unreasonable to disallow $12.153 million in projected capital

expenditures which already reflects an amount which is below the actual capital expenditures incurred.

Q. Were the actual LTSA extra work capital expenditures for Covert Unit 2 consistent with the pre-defined work scope?

A. Yes. A majority of the work performed during the major inspection represented pre-defined work scope. This same pre-defined work scope will be performed during the major inspections for all three units. In addition to the pre-defined work scope, there was both repair work and emergent work tasks (also known as Extra Work Assignments ("EWAs")) that were also performed. Exhibit A-191 (RTB-13) presents the various types of LTSA extra work capital expenditures including repairs and EWAs.

Q. Does the Company expect the work performed during the Covert Unit 2 outage to be similar to the work performed during the major inspections on Covert Units 1 and 3?

A. Yes. The units are identical, have similar operating history, and the pre-defined work scope is identical. It is also reasonable to expect that the same repair items and EWAs will be discovered during the major inspections on Covert Units 1 and 3. As such, the projected capital expenditures of $13.103 million for Covert Unit 3 and $9.525 million for Covert Unit 1 are reasonable and should not be disallowed.

Q. What is your recommendation regarding LTSA extra work for Covert Units 1, 2, and 3?

A. I recommend that the Commission reject Ms. York's proposed capital expenditure disallowances for the Covert Unit LTSA extra work. The work is well defined based upon recent experience with Covert Unit 2, the work is required pursuant to the Company's LTSA with Mitsubishi, and failure to perform the work prescribed by the LTSA would

negate any warranty provisions. The work does include work that, if not performed, would void equipment warranties if the Company continued to operate the units. The work scope that has been performed on Covert Unit 2 and is yet to be performed on Covert Units 1 and 3 is well defined in both my direct testimony and also the work scope presented in Exhibit A-191 (RTB-13). There is no uncertainty as to whether the capital expenditures will be incurred, actual costs support Covert Unit 2 and the performance of identical major inspections on Covert Units 1 and 3 will yield the same results.

Q. Beginning at page 11, line 15, of her direct testimony, Ms. York states "[t]hus, the amounts proposed by Consumers for inclusion in rates are speculative, and may or may not be incurred. As a result, it is premature to include them in rates at this time. Therefore, I recommend the Commission disallow all of Consumers' projected Bridge Period and Test Year capital expenditures for extra work not covered by the LTSA from recovery through customer rates at this time. A disallowance would be consistent with the Commission's findings in Consumers' prior electric rate case." Do you agree that these costs are speculative?

A. Absolutely not. The Company has carefully planned these major outage inspections and has coordinated their implementation with Midcontinent Independent System Operator, Inc. ("MISO"). The work to be performed by the Company during the major outage inspections has been clearly defined and the Company did provide the basis for the LTSA extra work in my direct testimony beginning on page 69, line 29, through page 70, line 23.

Q. Beginning at page 22, line 2, of her direct testimony, Ms. York discusses the Company's project for Zeeland LTSA extras not included in the contract and states that the projections are speculative and out of line with historical actuals. As a result, Ms. York states "[t]hus, there is no clear trend in the capital expenditures associated with this category, and the amounts proposed by Consumers for inclusion in rates are highly speculative and may or may not be incurred. Therefore, I recommend the Commission disallow Consumers' total proposed capital expenditures for this extra work not included in the LTSA from recovery through customer rates at this time." Do you agree with her recommendation?

A. No. First, the Company has revised its projected investments for this project for the bridge period. As reflected in Staff witness Maio's Exhibit S-8.1, the Company has reduced its projected bridge period spend from $4.703 million to $2.795 million. The LTSA extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. The work does include work that, if not performed, would void equipment warranties if the Company continued to operate the units. Based on historical outage experience and the work that is projected, there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components associated with the compressor as the compressor is not covered under the LTSA.

Q. What is the historical spend for the Zeeland LTSA extra work?

A. From 2021 through 2024, the Company invested $0.463 million in 2021, $0.522 million in 2022, $15.184 million in 2023, and nothing in 2024. At first glance, the trend in investment

has not been consistent as suggested by Ms. York. However, once you consider that the bulk of the LTSA extra work capital expenditure in 2023 was for the Zeeland Phase I Gas Turbine Advanced gas path replacement and axial fuel staging project and that this project was formally incorporated into the LTSA for 2024, the historic trend makes more sense.

Q. Has the Company incurred actual LTSA extra work capital expenditures at Zeeland in 2025?

A. Yes. As presented on Staff witness Maio's Exhibit S-8.0, the Company's actual capital expenditures through June 2025 totaled $2.120 million. As such the Company's reduced bridge period investment of $2.795 million is not highly speculative, rather it is relatively certain. The revised project amount of $2.795 million in the bridge period and projected amount of $0.810 million in the projected test year are both reasonable and prudent, and supported by the LTSA contract language. As such, I recommend that Ms. York's recommended disallowance be rejected by the Commission. Instead, the Commission should adopt the proposed amounts supported by Ms. Maio.

Q. Beginning at page 23, line 11, of her direct testimony, Ms. York discusses the Company's project for Jackson LTSA extras not included in the contract and on page 24, line 7, states "[s]imilar to Covert and Zeeland, these are speculative projections associated with issues that might be discovered during the bridge period and projected test year, based on Consumers' past experience." Ms. York goes on to state "the projected costs are significantly out of line with historical costs." Do you agree with Ms. York's conclusion?

A. No. I don't agree that the projected costs are significantly out of line with historical costs. The Company's 2021 capital expenditures amount for LTSA extra work was

$4.192 million as indicated by Ms. York; however, Ms. York's actual cost of a negative $180,921 for 2022 was incorrect. That negative amount was related to a credit to the 2018 LTSA extra work capital expenditure amount. As reflected on my workpaper WP-16, the 2022 LTSA extra work capital expenditure amount was $3.920 million. The LTSA extra work capital expenditure amounts for 2023 and 2024 were $0.497 million and $0.330 million, respectively.

Q. Has the Company updated its projected capital expenditures for Jackson LTSA extra work?

A. Yes. As presented on Staff witness Maio's Exhibit S-8.1, the Company has increased its projected bridge period spend from $2.115 million to $3.472 million. The Company has not changed its projected capital expenditure for LTSA extra work in the test year from $0.315 million.

Q. Has the Company incurred actual LTSA extra work capital expenditures at Jackson in 2025?

A. Yes. As presented on Staff witness Maio's Exhibit S-8.0, the Company's actual capital expenditures through June 2025 totaled $2.758 million ($3.426 million through September). As such the Company's increased bridge period investment of $3.472 million is not highly speculative, rather it is relatively certain. The revised project amount of $3.472 million in the bridge period and projected amount of $0.315 million in the projected test year are both reasonable and prudent, and supported by the LTSA contract language. As such, I recommend that Ms. York's recommended disallowance be rejected by the Commission. Instead, the Commission should adopt the proposed amounts supported by Ms. Maio.

REBUTTAL OF ATTORNEY GENERAL WITNESS COPPOLA

Q. Beginning at page 73, line 2, of his direct testimony, Mr. Coppola summarizes his review of the Company's presentation of proposed capital expenditures for the Covert Generating Station. Mr. Coppola appears to conclude that the Company bought the plant without completing satisfactory due diligence. Do you agree with Mr. Coppola's inference?

A. No. The Company performed a thorough evaluation of the Covert plant purchase and demonstrated that the acquisition was both reasonable and prudent in its 2021 IRP Case No. U-21090, a proposal to which no party contested. The Company's IRP presentation included a projected LTSA capital expenditure amount of approximately $43 million for the years 2025 through 2027 and a projected LTSA extra work capital expenditure amount of approximately $24 million.[1] These amounts did not include other capital work related to equipment which was not under warranty by Mitsubishi per the LTSA. The Company did not purchase a brand-new plant, otherwise the acquisition cost would have been significantly higher. Like the purchase of a used car, there is an expectation of incremental maintenance to maintain it; even a new car requires periodic maintenance. Mr. Coppola's hyperbole regarding the lack of technical due diligence should be ignored.

Q. Beginning at page 74, line 11, of his direct testimony, Mr. Coppola discussed two Covert Generating Station projects for which he recommends a disallowance. The first of these two projects is the replacement of the two Load Commutated Inverter ("LCI") Static Frequency Converters ("SFC"). The second project was the upgrade of the station control systems (Netmation). Mr. Coppola goes on to state that

[1] Exhibit A-55 (NJK-6)

"[c]ustomers should not pay for the cost of a recently purchased power plant and shortly thereafter pay for significant upgrades that should have been discovered in the technical due diligence and deducted from the purchase price. I recommend that the Commission disallows the total bridge period capital expenditures of $4,227,000 and remove the $11,454,000 for the projected test year for the two systems discussed above from inclusion in rate base." Do you agree with Mr. Coppola's conclusion and recommendation?

A. No. The conclusion that the Company did not perform sufficient due diligence is completely unsupported by Mr. Coppola. As provided in response to discovery, until the Company was in a position to operate the plant, it was not capable of performing the level of equipment condition assessments and detailed engineering evaluations which it employs at all of its other generating plants. The equipment being replaced for both projects is original to the plant, is obsolete, and is no longer supported. The failure to replace this equipment is a threat to continued reliability of the plant as well as supports the Company's requirements to comply with North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") standards, which emphasize regular updates and maintenance to safeguard control systems. This type of investment is routinely performed at all of the Company's generating facilities.

Q. Did the Company prepare business cases for each of these projects?

A. Yes. The Company prepared solid business cases for each of these projects which strongly support their implementation. The business case for replacement of the LCI SFCs was included in the Company's direct filing as Exhibit A-46 (RTB-7) and the business case for the upgrade of the Netmation station control systems was included in the Company's direct

filing as Exhibit A-48 (RTB-9). As such, I recommend that the Commission reject Mr. Coppola's unsupported recommendation to disallow each of these projects.

Q. Beginning at page 76, line 5, of his direct testimony, Mr. Coppola discusses the Company's projected capital expenditures for both the bridge period and test year at Ludington Pumped Storage Facility, postures that the work shouldn't be required so soon after the units were upgraded and states "The Company has not provided sufficient evidence to justify that the capital upgrades it seeks to recover in this rate case as [sic] necessary at this time given the recent overhaul of the plant. Therefore, I recommend that the Commission [remove] the forecasted bridge period capital expenditures of $15,225,000 and also remove the $13,282,000 for the projected test year from the Company's forecasted capital expenditures for the Ludington power plant." Do you agree with Mr. Coppola's conclusion and recommendation?

A. Absolutely not. First, as the Company indicated in discovery, the projects proposed for implementation in both the bridge period and test year were not part of the scope for the overhaul and upgrade and, as such, cost for these projects were not included or recovered in the overhaul and upgrade. The overhaul and upgrade project did not obviate the need for maintenance and other work at the plant going forward, particularly for components that were not part of the scope of the overhaul and upgrade. Second, an arbitrary and unsupported recommendation to disallow all capital expenditures at the Ludington facility is absurd and would jeopardize the Company's ability to maintain its Federal Energy Regulatory Commission ("FERC") operating license. The Company received a favorable 50-year extension of its operating license through 2069, and the Company has a responsibility to maintain the plant in compliance with that license.

Q. Are there reasons that these other projects were not included in the overhaul and upgrade?

A. Yes. There are at least two reasons that these current projects were not included in the overhaul and upgrade. First, the proposed projects were not necessarily required at the time the scope of the overhaul and upgrade project was developed more than 15 years ago. Second, integration of these projects into the overhaul and upgrade project would have made that project schedule significantly more difficult, likely requiring longer outage times and higher costs during that already complex project. The Company is not proposing in this case to recover costs for work previously performed during the major overhaul and upgrade, but instead proposing to recover costs for new and different work that is needed now.

Q. Is the Company performing other work, not included in this case, to address workmanship of the prior overhaul and upgrade contractor?

A. Yes. The Company is already performing corrective work to address workmanship performed by the prior contractor during the overhaul and upgrade project. Costs for that work are being settled to the regulatory asset approved by the Commission in Case No. U-21310 and are not included in this case. This highlights a clear distinction between the new projects being proposed in this case - which were not in scope for the prior major overhaul and upgrade - and the work actually performed during that prior major overhaul and upgrade, portions of which require corrective work.

Q. Has the Company supported each of the major Ludington projects presented on Exhibit A-12 (RTB-3), Schedule B-5.2?

A. Yes. Each of these projects were described in detail in my direct testimony, as acknowledged by Mr. Coppola. In response to discovery, the Company provided business cases for each of the Ludington projects presented on Exhibit A-12 (RTB-3), Schedule B-5.2, pages 8-9. I have attached those business cases as Exhibits A-192 (RTB-14) through A-197 (RTB-19). Each of these business cases fully support the decisions regarding the chosen project alternative and speak for themselves. Mr. Coppola argues that the Company didn't provide evidence that these projects weren't part of the overhaul, which I disagree with. Regardless, the business cases provide additional evidence that was already provided to Mr. Coppola.

Q. What is your recommendation regarding Mr. Coppola's recommended disallowance of the entirety of the Company's projected Ludington capital expenditures?

A. I recommend that the Commission reject Mr. Coppola's proposed disallowance. Mr. Coppola has not provided any sound basis for not moving forward with any of the projects, most of which are underway. As reflected on Ms. Maio's exhibit S-8.0, the Company has already invested approximately $3.8 million through June 2025. These projects are both well supported and necessary for the continued safe, reliable, and compliant operation of the Ludington facility.

Q. Beginning at page 79, line 6, of his direct testimony, Mr. Coppola discusses the Company's Waste Water Treatment System project noting that it is still in the planning phase of development and doesn't appear that it has advanced sufficiently to be completed in the rate case. Mr. Coppola goes on to state "In light of the continued operation of the Campbell plan, the uncertainty surrounding the length and manner of its operation under FERC jurisdiction, and the still preliminary phase of development of the project, I recommend that these costs be removed from the Company's forecasted capital expenditures for the bridge period and projected test year in the amount of $17,782,000 and $9,600,000, respectively." Do you agree with Mr. Coppola's conclusion and recommendation?

A. Not entirely. As an initial matter, the Company's projected bridge period capital expenditure for this project is $12.4 million rather than $17.782 million. This amount is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, and also on page 98 of my direct testimony. Further, the Company updated the bridge period projection to $12.420 million in response to discovery from Staff and this adjusted amount is presented on Staff Exhibit S-8.0.

The Company agrees that in light of the continuing operation of the Campbell plant pursuant to the emergency orders issued by the U.S. Department of Energy, the Company can no longer achieve project implementation before the end of the projected test year. Despite that fact, continuing operations at Campbell does not stop work on this project. The Company will continue to make progress toward completing this project during the bridge period and test year of this case as can be accommodated by the plant operating status. The continued operating status merely delays completion and project closure; it

does not stop work for this project. The capital expenditures associated with this project should not be disallowed as the project is still viable and necessary. Given the project closure status, the Company will offset the capital expenditure amounts incurred with Allowance for Funds Used During Construction ("AFUDC") such that there is no impact to the revenue requirement in this case. That change is reflected in the updated revenue requirement supported by Company witness Patrick D. Daly in his rebuttal testimony.

Q. Beginning at page 80, line 5, of his direct testimony, Mr. Coppola discusses the other capital projects for the generation fleet that are in the planning phase or recently entered the design/engineering phase. Mr. Coppola identifies three additional projects: (1) Covert spare GSU, (2) Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging project, and (3) Zeeland spare GSU which he recommends for disallowance. Mr. Coppola states "[t]he projects are still in the early stage of development and not sufficiently certain they will proceed at the forecasted cost and timeline. Therefore, I recommend that the Commission remove the $18,722,000 from the Company's forecasted capital expenditures for the projected test year." Do you agree with Mr. Coppola's conclusion and recommendation?

A. No. I do not agree that these projects should be disallowed. There is no validity to the reasons cited by Mr. Coppola. I will discuss each of these projects separately. As presented on Attorney General Exhibit AG-21, the next phase of the Zeeland spare GSU project is manufacturing and that phase is scheduled to end in April 2026. The spare GSU is not a piece of equipment which will be installed in the plant so the completion of manufacturing and the shipment and storage of the spare GSU at the site are the final steps for completion. As such, there is no uncertainty with respect to project delivery during the projected periods

in this case. The business case for this project was presented in the Company's initial filing as Exhibit A-47 (RTB-8).

Q. Please discuss the capital expenditures for the Covert spare GSU and the Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging project.

A. The Company has been planning for the implementation of these projects for some time; however, neither of the projects were projected to close prior to the end of the test year. As such, both of these projects have been offset with AFUDC such that the projected capital expenditures have no impact on the Company's revenue requirement. Each of the projects have been strongly supported with a business case in response to discovery in this proceeding and neither project should be disallowed. The business cases for the Covert spare GSU and Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging project are provided as Exhibits A-198 (RTB-20) and A-199 (RTB-21), respectively.

Q. Please discuss the projected benefits of the gas turbine advanced gas path replacement and axial fuel staging project on Zeeland Phase II.

A. As presented in Exhibit A-199 (RTB-21), the projected improvements for Phase II include a 51 MW increase in power output and a 2.5% improvement in heat rate, resulting in a $45.5 million net present value for customers. This improvement is in addition to the same project for Zeeland Phase I.

Q. Has the Company implemented the gas turbine advanced gas path replacement and axial fuel staging project on Zeeland Phase I?

A. Yes. The Company successfully implemented this project on Zeeland Phase I units earlier this year and the results of the project are very positive. I have attached the performance report for the Zeeland Phase I units as Exhibit A-200 (RTB-22).

Q. Please discuss the results of the gas turbine advanced gas path replacement and axial fuel staging project on Zeeland Phase I.

A. As presented in Exhibit A-200 (RTB-22), the project was implemented in the spring of 2025. Performance data was taken before and after project implementation to validate the effectiveness of the project. The performance data measured in June of this year reflects that Zeeland Unit 1A realized a 25.1 MW improvement in power output and a 131.9 Btu/kWh improvement in heat rate. Zeeland Unit 1B realized a 25.6 MW improvement in power output and a 332.5 Btu/kWh improvement in heat rate. Except for the targeted heat rate improvement for Unit 1A, the performance measures exceeded the improvements estimated by the OEM. The project completion allows the Company to serve its customers more reliably and economically for many years to come. The same project on Phase II should be fully supported by the Commission as it provides substantial value to customers.

Q. What is your recommendation for the following projects: (1) Covert spare GSU, (2) Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging project, and (3) Zeeland spare GSU?

A. I recommend that the Commission reject Mr. Coppola's proposal to remove the capital expenditures from the projected test year. The Company has provided a sound basis for

the completion of the Zeeland spare GSU and has offset the remaining two projects with AFUDC, resulting in no impact to the revenue requirement. All three projects are well supported with sound business cases and, as such, should not be disallowed.

REBUTTAL OF STAFF WITNESS MAIO

Q. Beginning on page 7, line 6, of her direct testimony, Ms. Maio discusses her adjustment to the bridge period capital expenditures presented on Staff Exhibit S-8.0. What are your thoughts about Ms. Maio's adjustment?

A. The Company concurs with Ms. Maio's recommendation regarding the Company's adjustments to projects greater than $1 million presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, in response to discovery question U21870-ST-CE-0002. As presented on Staff Exhibit S-8.0, the adjustments reflect a downward adjustment of $5.453 million.

Q. Did Ms. Maio's adjustment include all the updates that the Company provided in response to discovery question U21870-ST-CE-0002?

A. No. The Company identified three additional projects in its update to projects greater than $1 million, namely (1) D.E. Karn ("Karn") Unit 4 Transformer Fire Capital, (2) Covert Main Steam Tee Header Replacements, and (3) Covert Unit 3 Main Steam Tee Header Replacements totaling $6,920,267. Each of these projects reflect emergent work that was required to be performed and, through June 2025, represented a total actual capital expenditure of $3,238,054. While the Company's original investment plan included implementation of the projected bridge investment for the named projects, it had to re-prioritize work that was more critical to the generation fleet's continued safe and reliable operation.

Q. Why has the Company prioritized these emergent projects?

A. After the Company's initial filing in this case, the Company determined that the new projects are higher priority than some level of investment within the originally identified projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8. It would be inappropriate to disallow the $5.453 million originally requested in rates for the bridge period projects based upon the Company's re-prioritization of that capital to critical emergent projects totaling $4,078,267 for the 2025 calendar year and $6,920,267 for the entirety of the 16-month bridge period. The Company respectfully requests the Commission to consider inclusion of the emergent projects based upon the Company's re-prioritization. The Company consistently evaluates the priority of various projects and makes adjustments to accommodate the needs of its generation fleet.

Q. Please discuss the Karn Unit 4 transformer fire capital project.

A. In February 2025, the Company experienced a fire on its main unit transformer for Karn Unit 4. The capital expenditures incurred to restore the unit to operation were not originally planned as part of the Company's electric rate case request. However, due to the need to restore the unit to operability in a timely manner, the Company prioritized this investment in order to provide maximum customer value. The table below represents the capacity value that the unit provided in the MISO planning resource auction in March 2025.

	Summer	Fall	Winter	Spring	PY25
	6/1/2025	9/1/2025	12/1/2025	3/1/2026	6/1/2025
	8/31/2025	11/30/2025	2/28/2026	5/31/2026	5/31/2026
Karn 4 (ZRC)	539.0	437.9	390.8	374.2	1,742
ACP ($/MW-day)	666.5	91.6	33.2	69.6	62.8
Karn 4 ($k)	32,691	3,610	1,155	2,368	**39,824**

As can be clearly seen, the Company made a reasonable and prudent decision in its re-prioritization of capital and should not be penalized for making the best decision on behalf of customers.

Q. Please discuss the Covert Main Steam Tee Header Replacements projects.

A. During the spring 2025 major inspection outage at Covert Unit 2, the high energy piping surveillances ("HEPS") identified the following work requirements which could not be avoided:

- Both the main steam and hot reheat outlet header (external to the heat recovery steam generator ("HRSG")) were fully inspected via either dye penetrant and/or phased array ultrasonic testing down to their respective outlet isolation valves.
    - All rejectable indications, that were deemed not suitable for continued service, were either blended out and/or had welded repairs performed.
    - On the main steam line, the transition from the HRSG outlet manifold (downstream of the safety relief valve) to the low point drain were deemed not suitable for continued service and are being replaced.
- The branch connection connecting the IPS-105 line to the hot reheat line had linear indications at the toe of the weldolet to the 20" steam line. This indication was ground out and a weld repair performed.
- The branch connection connecting the 12" main steam line to the 4" gas turbine cooling steam line, was inspected with no findings and deemed suitable for continued service.
- The 12"x12" tee connecting the main steam line to the high-pressure bypass system was identified to have ID initiated linear cracking on either side of the transition into the branch connection as well as having rejectable indications in the connection welds. This component is being replaced by a fabricated tee assembly following consultation with industry experts.
- The 20" x 20" tee connecting the hot reheat steam line to the hot reheat bypass system was identified as having significant rejectable midwall indications in all three connection welds. This component is being replaced by a fabricated tee assembly following consultation with industry experts.

Based upon the findings during the Covert Unit 2 inspection, the same work is expected during the subsequent Covert Unit 1 and Covert Unit 3 inspections.

Q. Beginning on page 7, line 21, of her direct testimony, Ms. Maio discusses her second adjustment which reflects a proposed $7.455 million disallowance of test year capital expenditures based upon the Company's cost class estimates for each project. Does the Company agree with Ms. Maio's proposed disallowance?

A. Ms. Maio's second recommendation is a downward adjustment to 17 projects in the projected test year which are presented on my Exhibit A-12 (RTB-3), Schedule B-5.2, page 9. The proposed adjustment is based on the class cost estimate for these projects which have a class estimate of 2 or higher. In total, Ms. Maio proposes a disallowance for 17 projects, all but five of which are non-routine. The total recommended disallowance for the projected test year is $7.455 million. Ten of the projects are supported by the Company's Association for the Advancement of Cost Engineering ("AACE") Class 2 estimates with five projects having an AACE Class 3 estimate.

Q. How does Ms. Maio support Staff's proposed disallowances?

A. Ms. Maio primarily relies on the lower bound of the expected accuracy range for each project's estimate class to support Staff's recommended adjustments. The expected lower bound of the accuracy range for each project's estimate class is shown in Staff Exhibit S-8.4 for the 17 projects for which Ms. Maio proposed a class estimate reduction.

Q. Do you agree with the methodology employed by Ms. Maio to develop her recommendations?

A. No. It appears that Ms. Maio performed a thorough review of the various information that the Company included in its filing including direct testimony, exhibits, and Part III filing requirements, as well as the responses that the Company provided to Staff through discovery. Through this process, Staff supported the Company's historical capital

expenditures as well as most of the Company's updated cost projections for the bridge period. However, I disagree with the use of the low end of the accuracy range for every project in the test year for which Ms. Maio proposes a disallowance.

Q. Please explain what you mean by the low end of the accuracy range.

A. At page 7 of her direct testimony, Ms. Maio included Table 1 - Consumers Energy's Cost Estimate Classes. For each of the estimate class levels, Class 1 through Class 5, with Class 1 being the most mature, an expected accuracy range exists. For each project, Ms. Maio used the low end of the accuracy range to determine a proposed disallowance. For instance, Ms. Maio recommends a $1.392 million disallowance for the Phase II Gas Turbine Advanced gas path replacement and axial fuel staging project. The total projected capital expenditure for this project in the test year is $13.923 million and this projected amount includes no contingency. The project cost was based upon a Class 3 estimate, which has an expected accuracy range of -10% to +25%. Ms. Maio used the low end of the low range (-10%) to determine the total proposed disallowance.

Q. What is the impact of using the lower end of the accuracy range for all large generation projects?

A. This approach guarantees that, for the portion of costs the Company incurs above the artificially low estimate, the Company will not recover actual costs expended for the completion of those projects for at least the first year those projects are in service. The Company will begin depreciating that investment as soon as it is in service to reflect the amount of the investment "used up" in the first year of service, but will not be collecting compensation from the customers using it. Assuming the investment is put into rates in the second year, the Company will be compensated for the amount of the investment used

throughout the remaining life of the asset, but it will never be reimbursed for the first year of uncompensated use at a later time.

In addition, the use of the low end of the accuracy range guarantees that, for the portion of costs the Company incurs above the artificially low estimate, the Company will not recover any return for its reasonably and prudently incurred investments during the first year that investment is in service for customers.

Q. Do you have other concerns with the application of a disallowance for all 17 projects?

A. Yes. As I discussed in response to Attorney General witness Coppola earlier in this rebuttal testimony, not all of the test year projects are projected to close during the test year. Specifically, there are two projects (Covert spare GSU project and Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging project) which will not close and their revenue requirement is offset by AFUDC. As such, the $0.591 million for the Covert spare GSU and the $1.392 million for the Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging project should be rejected, regardless of any other determinations.

Q. What is the likely result of only awarding recovery of projects at the low end of the accuracy range?

A. The likely result is that the Company will de-prioritize several projects to account for the disallowance to reduce investment to the amount awarded by the Commission. Forgoing execution of the projects that are deprioritized will certainly result in degradation of reliability and safety that those projects would have produced had the projects been completed as planned. It is statistically improbable that all 17 of the Company's larger projects in the test year will result in actual costs at the bottom end of a range of accuracy

based on extent of project development. Because of what that range represents, it is statistically probable that some projects will result in actual costs at the higher end of the range and some at the lower end of the range, such that, collectively, the actual costs will come out about at the estimated value proposed by the Company.

Q. Do you have any other concerns with proposed class estimate disallowances?

A. Yes. As discussed in my direct testimony beginning on page 50, the Company accounts for the uncertainty of less mature estimates by including contingency in its cost estimates. However, based upon prior Commission orders which have consistently disallowed the recovery of contingency in projected capital expenditures, the Company has not included them in its request for investment recovery. As such, the Company's projected capital expenditure amounts already reflect a 5% reduction to the project cost based upon the removal of contingency. As such, the 5% contingency amount is being removed twice with the use of the low end of the accuracy range. At the very least, the recommended disallowance levels should be reduced by the 5% contingency amount that has already been removed from the projected capital expenditures.

Q. What is your recommendation?

A. I recommend that the proposed disallowance based upon the low end of the accuracy range be rejected by the Commission. Based on historical experience, actual cost for a portfolio of projects settle around the projected cost. In 2024, the total capital for all generation projects (excluding the battery storage energy system projects which are offset by AFUDC) implemented in that year was higher than the projected capital for those same projects. This can be validated by reviewing the 2024 projected and actual costs for all generation projects as sponsored in the Company's electric rate cases. Each of the ranges by class

level have an 80% confidence interval, as such, there is a very low to zero probability that 100% of the projects have an actual cost at the low end of the accuracy range. The probability represented by the range suggests that some estimates will turn out to be low and some will turn out to be right on or nearly right on. The assumption that every single Company estimate will turn out to be inaccurately high, such that the actual cost is at the very bottom of the accuracy range for the estimate, is unreasonable. To the extent that a disallowance is ordered by the Commission, the proposed disallowance amounts for the Covert spare GSU project and the Zeeland Phase II gas turbine advanced gas path replacement and axial fuel staging project should be removed and the disallowance for the remaining projects should be reduced by the 5% contingency amount that has already been removed by the Company.

Q. Beginning on page 12, line 17, of her direct testimony, Ms. Maio states: "Staff recommends the removal of $2.849 million related to the Emergent Reliability Funding expense included in the Admin/Generation Commons expense since this amount is in addition to the Emergent Reliability Fund expense already incorporated in the historical expense (2024), and there is no assurance that this additional requested amount is needed or will be spent in the test year." Do you agree with Ms. Maio's recommendation?

A. No. While it is a true statement that the actual emergent reliability expense was included in the historical expense for each plant that incurred this expense in 2024, it is not true that the historical amount of emergent reliability expense was included in the forecasted O&M expense for any of the plants in the projected test year. As I discussed in my direct testimony beginning on page 102 of my direct testimony, the O&M expense for the

projected test year is developed based on maintenance needs at each site or on specific units, rather than a simple escalation of historical year actual expenses. The fact that the projected test year O&M expense of $103.732 million reflects a $24.706 million decrease from the historical year, not including escalation, reflects that fact. When considering escalation, the projected test year O&M expense is reduced by $31.625 million when compared to an amount developed simply by escalating the 2024 actual amount. This result is illustrated on Exhibit A-43 (RTB-4), page 2 of 3, column (i).

Q. Has the Company consistently incurred emergent reliability expense?

A. Yes. For the years 2022 through 2024, the Company incurred emergent reliability expense of $9.452 million, $4.866 million, and $8.346 million, respectively. For 2025 year to date through September, the Company has incurred $12.744 million in emergent reliability expense. I have presented the details of this spending in Exhibit A-201 (RTB-23). Below is a breakdown of the 2024 emergent reliability expense by plant.

Site	Spend '$000
Covert	3,987
Hydro	463
Jackson	1,057
Karn	1,530
Ludington	844
Zeeland	465
Total	8,346

Q. Please provide an example of 2024 emergent reliability expense which demonstrates that this historical plant expense is not included in the test year for that same plant.

A. I will use Jackson Generating Station as an example. Of the $8.346 million emergent reliability expense for the generation fleet in 2024, a total of $1.057 million was allocated to Jackson Generating Station for both base O&M and major maintenance O&M (primarily major maintenance). The total O&M expense for Jackson Generating Station in 2024 was $11.616 million, including the $1.057 million of emergent reliability spending but the projected test year total O&M is only $10.269 million, a decrease of $1.347 million. As such, it is evident that the Company didn't simply escalate the historical year O&M expense to arrive at the projected test year O&M expense amount.

REBUTTAL OF MNSC WITNESS COMINGS

Q. Beginning at page 16, line 10, of his direct testimony, Mr. Comings states "I recommend that costs be disallowed for two projects at the Jackson plant. The first project is project ID 13478 – 'JGS - Generator Step Up Transformer (GSU) Site Spare,' where the Company is requesting $1.33 million in the bridge period and $2.33 million in the projected test period. The second project is project ID 13475, Jackson Plant 'LM1-6 VIGV(variable inlet guide vane),' where the Company is requesting $7,885 in the historic test period, $646,911 in the bridge period and $960,102 in the projected test period." Do you agree with Mr. Comings' recommendation?

A. No. As Mr. Comings indicated in his direct testimony, the Company received approval of these projects in its 2024 electric rate case, Case No. U-21585, and has continued to move forward with their implementation in good faith. Mr. Comings is not proposing to disallow the historical costs and is only recommending the disallowance of the costs which are

above those which were approved in Case No. U-21585. Neither project was projected to close before the end of the test year in Case No. U-21585 and, as such, the amount approved (and ultimately offset by AFUDC) did not reflect the entire cost of the projects.

Q. How much was approved for each project in Case No. U-21585?

A. The Commission approved the recovery of $1,036,667 in Case No. U-21585 for the Jackson LM1-6 variable inlet guide vane project and $916,667 for the Jackson spare GSU. The Company has requested a total of $3,666,667 for the Jackson spare GSU in this proceeding (which includes the $916,667 previously approved) and $1,614,698 for the Jackson LM1-6 variable inlet guide vane project (which includes the $1,036,667 previously approved).

Q. What is the basis for Mr. Comings' proposed disallowance of the capital expenditures for the Jackson spare GSU?

A. Mr. Comings identified several reasons for his proposed disallowance including overstatement of the derate (104 MW versus 47 MW), overstatement of the capacity factor, overstatement of the energy value during the potential outage resulting from a failure, and overstatement of the probability that failure will occur.

Q. How does the Company respond to Mr. Comings' concern regarding an overstatement of the capacity factor?

A. The Company agrees with this observation made by Mr. Comings. The original modeling projected a capacity factor between 65% and 84%, while historical operation has been between 31% and 39% due to NO_x emission limitations, which materially constrains dispatch and reduces achievable run hours compared to an unconstrained economic model.

Q. How did the Company remedy Mr. Comings' concern regarding an overstatement of the capacity factor?

A. To correct the capacity factor, the Company incorporated historical and forecasted capacity factors from the current Power Supply Cost Recovery ("PSCR") case. These values incorporate emissions constraints and represent the most accurate planning assumptions.

Q. How does the Company respond to Mr. Comings' concern regarding an overstatement of the derate?

A. The Company does not agree that the derate amount is overstated. After engineering review with plant operations, the Company confirmed that a 47 MW derate is not physically possible. Each LM GSU has one high-side and two low-side connections, serving two LM units. If the GSU fails, both LM units tied to that transformer must come offline; isolation of a single LM cannot be achieved. This configuration results in a conservative derate of approximately 104 MW based on loss of two LM units and associated loss of steam generation. Maintaining this assumption ensures the analysis reflects actual failure modes and electrical design, not an exaggerated worst case.

Q. How does the Company respond to Mr. Comings' concern regarding an overstatement of the probability of failure?

A. Mr. Comings indicated that the original analysis did not incorporate the probability of failure into the economic analysis. The Company's revised analysis now integrates probability into both the Lost Generation Risk Model and the Financial Risk Model (used for potential capacity losses).

The probability of failure curve was applied as follows:

- 5% in 2026;
- 10% in 2027; and

- 15% in 2028, increasing by 5 percentage points annually until December 2039.

This probability was applied to the previously calculated capacity loss exposure of $28 million, based on a 1,080-day derate of 104 MW and MISO's rolling three-year Zonal Resource Credit ("ZRC") accreditation methodology.

Q. Please summarize the actions the Company has taken for the spare Jackson GSU transformer project.

A. The Company has prepared a revised concept approval aligned with the Company's response to Mr. Comings. I have attached the updated concept approval as Exhibit A-202 (RTB-24) which reflects the following:

- Capacity factor assumptions now reflect emissions constraints using PSCR-based values;
- The 104 MW derate assumption is accurate given the GSU's configuration and failure mode; and
- Probability of failure is integrated into the economic model.

Q. Beginning at page 19, line 12, of his direct testimony, Mr. Comings states "I recommend a disallowance of the $3.66 million bridge and test period costs being requested for this project due to the Company vastly overstating the potential benefits of the project." Do you agree with this recommendation?

A. No. As discussed above, the Company has revised its economic modeling of this project and the resulting analysis supports the customer benefits of implementing this project. Beyond the additional modeling, the Company would also dispute the proposed disallowance amount. Of the total project cost, $916,667 was previously approved by the Commission in Case No. U-21585. Therefore, the maximum disallowance amount should be limited to the incremental amount of $2.75 million.

Q. What is the basis for Mr. Comings' proposed disallowance of the capital expenditures for the Jackson LM1-6 variable inlet guide vane project?

A. On page 20, line 14, of his direct testimony, Mr. Comings claims that the Company failed to provide satisfactory analytical support for this project.

Q. How has the Company responded to Mr. Comings' position regarding a lack of analytical support for the Jackson LM1-6 variable inlet guide vane project?

A. The Company has provided a revised concept approval which is attached as Exhibit A-203 (RTB-25). The revised concept approval corrects for the overstated capacity factor, like the Jackson spare GSU transformer project, and the results still fully support the economic viability of the project. In response to discovery, the Company provided a detailed explanation of the various models which support the economic calculations.

Q. What is your recommendation for this project?

A. I recommend that the Commission reject Mr. Comings proposed disallowance of $1.61 million for this project. While Mr. Comings indicated he was not recommending disallowance of any historical costs or amounts approved in Case No. U-21585, his recommended disallowance amount did just that. The Commission approved $1,036,667 in Case No. U-21585 and the Company is asking for $1,614,698 in this case, which includes that amount already approved. As such, while no disallowance amount is warranted, the amount should be no greater than $578,031. The Company has provided solid evidence that the performance of this project provides benefits to customers, just as it did when first presented in Case No. U-21585.

Q. Did Mr. Comings make any other recommendations?

A. Yes. Mr. Comings recommended that the Company provide more transparency with economic assessment calculations, including access to any models used in such calculations and auditable derivations of calculations done outside of those models. In addition, Mr. Comings disagreed with the Company's calculation of net energy value ("NEV"). I will address each of these topics separately.

Q. How does the Company respond to this request for increased transparency with economic calculations?

A. The Company employs a modeling tool called Copperleaf for its economic modeling for generation projects. The hard-coded calculations contained within Copperleaf are embedded into software and not able to be downloaded to a report or spreadsheet. The Company provided a procedure in response to discovery[2] which it developed to explain the assumptions made in each risk model and also provided multiple attachments in discovery which included both generic and specific examples of how the calculations are made for the two most used models. I have included the Company-prepared Copperleaf procedure as Exhibit A-205 (RTB-27). In addition, the Company provided attachments in discovery which included PSCR case values which are direct inputs for the models. This should be sufficient to represent that the Company is a employing systematic and conservative approach to quantifying the risks associated with not doing a particular project.

[2] U21870-MNSC-CE-0224_ATT_0001

Q. Beginning on page 7, line 8, of his direct testimony, Mr. Comings states "The Company overstates the NEV of the Jackson plant for 2020 through 2024 by assuming lower variable costs than what it reports elsewhere. The Company reported historical fuel costs in filing Attachments 126 B, D, F, and J. These documents also provide "total production costs." Do you agree with Mr. Comings' assessment?

A. No. While the Company does consider major maintenance expense as a cost that varies with equipment condition and operating hours, the Company's variable costs for purposes of calculating NEV only include variable costs which are directly attributable to operating the unit in the market such as chemical reagent costs.

Q. Do you have any other thoughts about Mr. Comings' direct testimony?

A. Yes. Mr. Comings's direct testimony seems to focus on the economics of the Jackson Generating Station as compared to the Company's other gas generating sites, Covert and Zeeland. The electric rate case is not the proper venue to make decisions about the future of generating assets. The Company's approved 2021 IRP reflected the operation of Jackson Generating Station through the foreseeable future. To the extent that Mr. Comings takes issue with the plant's continuing operation, the appropriate venue for that discussion is the Company's 2026 IRP.

REBUTTAL OF CEO WITNESS BOEHNKE

Q. Have you reviewed the direct testimony of CEO witness Boehnke?

A. Yes. Mr. Boehnke supports the opportunity to leverage virtual power plants ("VPPs") to serve customer load in a more affordable manner versus battery storage or gas generation. Mr. Boehnke provides a number of recommendations. I will address his immediate recommendation related to IRP modeling.

Q. Beginning on page 62 of his direct testimony, Mr. Boehnke states that "[t]he Commission can require that VPPs be included in the Company's Integrated Resource Planning (IRP) process, not only to support the fulfillment of the Company's past commitment that 20% of energy demand be met by EWR programs by 2030 but to expand up on it to deliver affordable services to ratepayers." Do you believe this instant case is the proper forum in which to establish IRP modeling requirements?

A. No. The Commission has approved IRP Filing Requirements and revisions to those requirements in Case No. U-18461. The Commission has also established Case No. U-21570 to consider updates to the Michigan Integrated Resource Planning Parameters ("MIRPP") and IRP Filing Requirements in response to Public Act 235 of 2008 ("Act 235") and Public Act 231 of 2023 ("Act 231"). See MPSC Case No. U-21570, February 8, 2024 Order, pages 6-8. The Commission should not adopt separate IRP filing requirements in this case that only apply to Consumers Energy, but should instead address IRP modeling requirements in the separate proceedings that the Commission has opened for that purpose.

REBUTTAL OF GLREA WITNESS KENWORTHY

Q. Have you reviewed the direct testimony of CEO witness Kenworthy?

A. Yes. Mr. Kenworthy's testimony supports a greater focus on the use of distributed energy resources and VPPs to provide less costly resources to serve customers. Mr. Kenworthy provides a number of recommendations. I will address his immediate recommendation related to IRP modeling.

Q. Beginning on page 22 of his direct, Mr. Kenworthy states "[i]n the Company's last IRP settlement, Consumers committed to develop a 'distributed generation as a resource' modeling approach. That commitment requires bundling customer-level distributed solar into a resource that can be evaluated alongside supply-side options, consistent with how the Company models energy waste reduction. I recommend that Consumers build on this commitment by also modeling Virtual Power Plants (VPPs). A VPP integrates distributed generation with storage and demand response, producing a more reliable, dispatchable resource with superior capacity value compared to distributed generation alone. Adapting the existing distributed generation model to include VPP portfolios would allow the Commission to evaluate their peak demand impact, transmission and distribution deferral value, and overall contribution to system reliability." Do you agree with Mr. Kenworthy's recommendation?

A. Not necessarily. As I stated earlier, I don't believe this is the proper forum in which to establish IRP modeling requirements. In addition to previously established IRP and MIRPP modeling requirements, the Commission has also established Case No. U-21570 to consider updates to the MIRPP and IRP Filing Requirements in response to Act 235 and Act 231. The Commission should not adopt separate IRP filing requirements in this case that only apply to Consumers Energy, but should instead address IRP modeling requirements in the separate proceedings that the Commission has opened for that purpose.

REBUTTAL OF MNSC WITNESS BUNCH

Q. Have you reviewed the direct testimony of MNSC witness Bunch?

A. Yes. Mr. Bunch performed a review of the Company's efforts to increase productivity and the associated support of those efforts in the Company's direct filing in this proceeding.

Q. Beginning on page 25, line 12, Mr. Bunch provides a summary of his review of your testimony with respect to efforts to reduce costs for the generation business. In reference to your direct testimony, Mr. Bunch states, "However, he provides no evidence clarifying the relative contribution from each factor, leaving it unclear whether the decrease reflects real operational efficiency or a shift of costs from the rate case to the REP." Do you agree with Mr. Bunch's summary?

A. Not entirely. While it is true that my direct testimony did not include an all-inclusive plant-by-plant breakdown of the change in O&M expense from the 2024 historical year to the projected test year, I did provide a discussion of the relative change for the major drivers of the change in O&M expense. For instance, I contrasted the change in expense at the Karn site beginning on page 105, line 16, of my direct testimony and showed that the actual increase in O&M expense for the plant was only 0.51% annually. Beginning on page 106, line 9, I discussed the change in O&M expense for the Cambpell site, followed by a discussion of the Covert Generating Station, the Ludington Pumped Storage Facility, and the River Hydros. The discussion of the O&M increase for the Covert Generating Station revealed that the increase was primarily due to major maintenance which is based upon both asset condition and also historic maintenance intervals, as discussed in my direct testimony at page 112. When considering the Covert base O&M expense, the total increase from 2024 to the projected test year reflects a total increase of 1.78% or much less than 1%

on an annualized basis. I have attached my workpaper WP-24 revised (corrected in response to discovery question U21870-ST-CE-0018), as Exhibit A-204 (RTB-26) which provides the year-over-year details for all of the O&M types by unit or plant.

Q. Please discuss the increase to Ludington Pumped Storage Facility base O&M expense.

A. As presented on Exhibit A-204 (RTB-26), the base O&M increased from $6.017 million in the 2024 historical year to $6.877 million in the projected test year, an increase of $0.860 million. As discussed in my direct testimony, there are three projects which led to that increase: (1) FERC Assessments, (2) license initiatives, and (3) fish protection. The Company's 51% share of 2024 historical O&M expense for these projects was $1.272 million, $1.872 million, and $2.135 million, respectively, for a total of $5.280 million. The Company's share of the projected test year O&M expense for these three projects is $1.442 million, $2.321 million, and $2.361 million, respectively, for a total of $6.123 million. The increase in projected expense for these three projects totals $0.843 million; basically comprising the entirety of the base O&M increase. Each of these projects are required as part of the Company's FERC 50-year license and, as such, cannot be avoided. This means the balance of the base O&M expense was basically held to historical levels.

Q. Does the Company's projected test year O&M expense reflect a reduction in expense associated with the removal of renewable energy assets?

A. Not exactly. While it is true that none of the O&M expense associated with renewable energy projects has been included in the projected test year O&M, the Company also removed that same historical expense in order to provide an apples-to-apples comparison.

In actuality, no portion of the 9% annual decrease in generation O&M expense is attributable to the renewable energy plan assets not being recovered through the renewable energy plan.

CONCLUSION

Q. What will be the impact if the Commission disallows funding based on disallowance recommendations from Staff, MNSC, ABATE, and the Attorney General?

A. The Company is requesting recovery for projects that support the ongoing safe and reliable operations of its equipment. The Company ultimately prioritizes its project plans based on funding approved by the Commission. If the Commission chooses to disallow the projects, the Company will not complete the projects and the reliability and safety benefits of the projects will not be realized. This could result in risk to reliability and safety of the generation system.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Covert Units 1 & 3 – LTSA Extra Work Scope Definition and Forecasted Cost

Prepared by: Paul Ohep

1. Purpose

This document outlines the scope of LTSA Extra Work anticipated for Cover Units 1 and 3, based on work completed during the 2025 outage at Unit 2. The intent is to provide clear definition and context for the types of activities that fall outside the base Long-Term Service Agreement (LTSA), explain why these activities are required to execute major outages, and present a forecasted cost based on recent historical data.

The scope and budget are based on detailed historical data from the Unit 2 outage in 2025, including actual execution costs, work scope breakdowns, and Extra Work Assignments (EWAs). These expenditures reflect Owner obligations under the LTSA and known outage requirements.

2. Background

The LTSA defines a division of responsibility between the Contractor (Mitsubishi) and the Owner. While the Contractor performs defined inspection and maintenance services, the Owner is responsible for:

- Enabling infrastructure and field support
- Supplying consumable and condition-based replacement parts
- Funding and managing any repairs or services resulting from inspections

These responsibilities are documented in the LTSA's Division of Responsibility (Attachment 5) and confirmed by prior outage experience.

During the 2025 Unit 2 outage, total LTSA Extra Work cost approximately $12.7 million, including both large pre-scoped work and smaller, necessary tasks that emerged during execution (documented as EWAs). This scope is representative of what will be required for Units 1 and 3.

3. Justification for LTSA Extra Work

A. Site Infrastructure & Logistics (Owner-Furnished)

These services are critical for OEM work execution but fall under the Owner's scope. For Unit 2, examples included:

- - Crane rentals
  - Office, restroom, and sanitation trailers
  - Potable water and safety stations
  - Laydown space prep and rigging
  - Building wall removal for generator access
  - Scaffolding, insulation, and electrical testing
  - Equipment/tool transport from offsite locations

B. Consumable & Condition-Based Parts

The LTSA does not cover routine outage consumables and condition-dependent replacements. For Unit 2, this included:

- - Gaskets, seals, thrust shims, and valve assemblies
  - HP valve rebuild kits
  - Turbine packing and alignment hardware
  - Small parts discovered as damaged or worn after disassembly

All such items are procured and installed by the Owner as part of standard outage execution.

C. Repairs Identified During Inspection

While inspections are covered under the LTSA, any resulting repairs are considered Extra Work. For Unit 2, this included:

- - Diaphragm and rotor machining
  - Bearing refurbishments
  - Hydrogen seal and steam shell repairs
  - Collector ring machining
  - Compressor hook fit machining
  - Oil deflector repairs

D. Extra Work Assignments (EWAs)

EWAs are smaller task-based scopes that arise during the outage and are not defined in the base plan. Examples from Unit 2 included:

- - Labor for valve disassembly and reassembly
  - Transport of tools and heavy equipment
  - Seal and bearing inspection and rebuild

- Field machining and turbine alignment services
- Miscellaneous parts procurement during outage execution

Together, these EWAs totaled approximately $500,000. Mitsubishi executes this work on a time-and-materials (T&M) basis, and charges are bundled by category, not individual activity.

4. Contractor Cost Structure Limitations

A critical constraint to note is that Mitsubishi does not provide a fully itemized breakdown of costs for each activity within the LTSA Extra scope. While they may offer pre-outage estimates, actual billing is based on T&M rates and grouped into summary-level invoices (e.g., 'EWAs' or 'extra parts/labor').

This means the Owner cannot precisely forecast or post-audit individual line-item costs. Instead, budgeting is based on:

- Historical outage records (e.g., Unit 2 actuals)
- OEM outage patterns and typical inspection findings
- Prior EWA structure and cost groupings

This dynamic makes proactive funding of LTSA Extra Work essential, even if some scopes are not explicitly known in advance.

5. Financial Summary- Planned LTSA Owner obligations (former LTSA extras)

The figures below represent forecasted costs for LTSA Extra Work based on historical outage practices, known contract obligations, and typical work scopes required to support major outages at Covert.

Unit	2026	2027
Unit 1	$8,176,300	$5,550,000
Unit 3	$12,726,000	$200,000

6. Conclusion

LTSA Extra Work is a required and recurring element of major turbine-generator outages at Covert. While not included in the base LTSA scope, these activities-ranging from enabling infrastructure to condition-based parts and repairs-are necessary to execute the defined work scopes and return units to safe, reliable operations.

Due to Mitsubishi’s T&M billing approach and lack of granular invoicing, the Owner must

rely on historicals, outage experience, and OEM expectations to estimate scope and funding needs.

The $12.7 million per-unit request reflects actual Unit 2 experience and contract-defined Owner responsibilities. This document formalizes the budget authorization needed to support outage execution for Covert Units 1 and 3.

Concept Approval

Ludington Pumped Storage Dike Load Center replacement.

Date: 6/10/2024

Prepared by: Paul Ohep

Figure 1. Ludington pumped storage station.

Executive Summary

Consumers Energy is undertaking a critical infrastructure upgrade at the Ludington Pumped Storage Station to replace aging and deteriorating Dike Load Centers (DLCs). These upgrades are essential for maintaining the operational efficiency, safety, and reliability of this vital energy facility. The project focuses on replacing the high-priority DLCs that are at significant risk of failure, ensuring continued support for the station's critical functions.

Current Equipment Issues:

The original Dike Load Centers were installed in the early 1970s and have been considered obsolete since the 1990s. Prolonged operational use and environmental exposure have led to significant corrosion and deterioration. Recent failures, including the replacement of DLC14 and DLC16 transformers, highlight the urgent need for this upgrade. Additionally, parts from the replaced DLC1 and DLC2 have been used for repairs, and a new transformer has been ordered to manage future defects.

Priority Assessment and Replacement Strategy:

Plant and dam safety engineers have categorized the DLCs into high, medium, and low priority for replacement. High-priority DLCs are those that are highly likely to become inoperable within five years and provide electricity to pumps that run frequently to maintain adequate drainage of the dike's asphalt liner. This project will replace 10 high-priority DLCs identified as critical for safe and reliable operation.

Financial and Operational Impact:

Failure to replace the high-priority DLCs could result in significant operational disruptions and extended downtimes, with estimated shutdowns potentially lasting up to a year due to obsolescence issues. The estimated financial impact ranges from $24 million up $55 million for Net Energy Value losses and $101.5 Million for potential capacity losses.

Conclusion:

The replacement of the outdated and deteriorating Dike Load Centers is crucial for preventing extensive damages and operational interruptions at the Ludington Pumped Storage Station. This targeted approach ensures that the most critical components are addressed promptly, supporting the facility's long-term operational efficiency and safety. By investing in this strategic upgrade, Consumers Energy is committed to maintaining the reliability of Michigan's energy infrastructure while mitigating potential financial and operational risks.

Financial Summary

Funding Type:	Capital
Initial approved cost:	51% dollars - $4,555,000. 100% dollars – $8,931,372
New revised cost:	51% dollars - $**10,286,051.** 100% dollars - $**20,168,728**

Proposed Start Implementation Year and span

2019, 8-year span.

Problem Description

The Ludington Pumped Storage facility, crucial for Michigan's energy infrastructure, includes twenty 480-volt Dike Load Centers and one 4160-volt Switchgear. These units power one hundred ninety-three dike pumps and additional support equipment critical to the facility's operations. Failure of a Dike Load Center would result in an area of the reservoir where the asphalt liner is inadequately drained, potentially leading to an increase in pore water pressure both on the upstream face and at the downstream toe of the dike.

Issues with Current Equipment:

- **Age and Obsolescence:** The original Dike Load Center equipment was installed in the early 1970s and has been considered obsolete since the 1990s.
- **Corrosion and Deterioration:** Prolonged operational use and environmental exposure have led to significant corrosion and deterioration.

Recent Failures:

- Dike Load Center 14 (DLC14) transformer failed and replaced in 2023.
- Dike Load Center 16 (DLC16) transformer failed and replaced in 2024.
- Other repairs have utilized parts from the old DLC1 and DLC2 load centers, which were replaced last year.
- Due to the lack of spares and long lead times, the current strategy to manage the existing risk involves ordering a new transformer to replace any future defects in the remaining 18 DLCs. This approach will bridge the gap until DLC3 is replaced at the end of next year as part of this project.

Risks Posed by Equipment Failure:

- **Operational Impact:** The Centers are essential for distributing power to the dike drain pumps and pumping relief wells that maintain the structural integrity and safety of the reservoir. For these reasons, Dike pumps are required to be operational.

Critical Functions of the Dike Load Centers:

- **Dike Drain Pumps:** They maintain the drained condition of the dike's upstream face, protecting the asphalt liner from pressure-induced damage.
- **Pumping Relief Wells:** These wells manage groundwater levels, maintaining them at preconstruction levels to prevent dike stability issues.

Consequences of Potential Failure:

- **Study Findings:** An engineering study completed in 2020 indicated that the Dike Load Centers are in poor condition, leading to operational hesitancy in cycling them due to potential recovery failures.

- **Operational Disruption:** Failure would lead to insufficient drainage in parts of the reservoir, increasing the risk of structural failures by elevating pore water pressure upstream and downstream.

Priority Assessment by Plant and Dam Safety Engineers:

- **Priority Categorization:** Plant engineers, along with dam safety engineers, have categorized the Dike Load Centers (DLCs) into high, medium, and low priority for replacement. High priority DLCs provide electricity to pumps that are in service for many hours due to the inherent drainage features of the dike itself. These pumps are critical for providing adequate drainage to the asphalt liner, a vital part of the dike's structural integrity. Therefore, the load centers that supply electricity to these frequently running pumps need to remain operational.
- **High Priority DLCs:** Out of the 20 DLCs, 10 have been identified as high priority based on the aforementioned criteria. This project is focused on replacing these 10 high-priority DLCs to ensure the continued safe and reliable operation of the Ludington Pumped Storage facility.

Conclusion: The necessity to replace the outdated and deteriorating Dike Load Centers is critical, not only for maintenance but also to ensure the facility's operational efficiency and safety. This replacement is needed to prevent possible extensive damages and operational interruptions, with a focused approach on the 10 high-priority DLCs identified by plant and dam safety engineers. The list of high, medium, and low priority DLCs is displayed in Figure 2.

Alternative Solutions/Alternatives Considered

1. Do Nothing - $101.5M in potential capacity losses + minimum $24M in Net Energy Value losses

This option involves not replacing the outdated and deteriorating 480-volt Dike Load Centers and the 4160-volt Switchgear at the Ludington Pumped Storage facility.

Immediate Implications:

- **Continued Deterioration:** The Dike Load Centers and Switchgear, already in a state of significant corrosion and obsolescence, will continue to degrade without any intervention.
- **Operational Reluctance:** As noted, the Operations Department is currently hesitant to cycle the Dike Load Centers due to concerns over their reliability and the potential inability to recover them if they fail.

Long-term Consequences:

- **Increased Risk of Failure:** Ongoing deterioration will likely lead to the eventual failure of the Dike Load Centers, which are critical for the operation of the dike pumps and related infrastructure.
- **Inadequate Reservoir Drainage:** Failure of the Dike Load Centers would result in inadequate drainage of the reservoir's asphalt liner. This can increase pore water pressure both on the upstream face and at the downstream toe of the dike, leading to structural vulnerabilities.

Impact on Facility Operations:

- **Operational Shutdown:** The most severe impact of this option is the potential complete loss of operational capability at the Ludington Pumped Storage Station. Due to obsolescence issues with the high-priority Dike Load Centers, there is no quick way to obtain replacement parts, which are essential for safe operation. Without these crucial components readily available, the pond/reservoir would not be safe for continued operation, resulting in an estimated downtime of a full year.
- **Extended Downtime and potential Capacity Losses**: The unplanned downtime not only involves higher direct repair costs but also results in significant operational and revenue losses due to the plant's inability to generate power during the period of inactivity. Given the obsolescence issues, the assumed shutdown would extend to a full year. From a capacity position, a forced outage would necessitate replacing the lost capacity to avoid future accreditation impacts. The potential capacity loss cost, based on capacity replacement costs valued at 75% of CONE (Cost of New Entry), would be substantial. With CONE set at $127K/MW-year, 75% of CONE equals $95K. Considering the average Zonal Resource Credits (ZRCs) for all Ludington units is 178, if all 6 units were lost for a year, the cost would be:

  178 ZRCs * 6 units * $95K = $101.5 million.

- **Net Energy Value (NEV) and Locational Marginal Prices (LMPs)**: In the event of a forced outage of all six units at the Ludington Pumped Storage Station for a full year, the financial impact can be assessed using Locational Marginal Prices (LMPs). LMP is the cost of supplying the next increment of electricity demand at a specific location in the grid, reflecting supply and demand balance, transmission constraints, and generation availability. The analysis compared similar high and low load days to estimate the impact on LMPs during the outage.
    - Analysis Details:

      During a recent outage period (9/27/23-10/13/23), the average LMP was $33.63/MWh, compared to an annual average of $30.65/MWh.

      Day-Ahead LMP Comparison:
        - Lower Load Days:
            - 29-Sep: $34.96/MWh (Delta: $3.65/MWh)
            - 5-Oct: $32.88/MWh (Delta: $1.57/MWh)
        - Higher Load Days:
            - 3-Oct: $47.02/MWh (Delta: $16.37/MWh)
            - 4-Oct: $39.64/MWh (Delta: $10.11/MWh)
        - The deltas represent the difference between the specific day's LMP and the average LMP for similar days based on load and weather profiles.
    - Financial Impact:
        - It is estimated by our internal economics forecast models that the net energy value (NEV) loss for this scenario would be a minimum of **$24 million** for one year. That estimate is based upon normal conditions. Based on load variability we can expect LMPs to increase by between $3/MWh and $16/MWh which will impact the NEV forecast.
        - At $3/MWh annual average increase in LMPs due to the loss of Ludington, the $24 million net energy loss would increase to **$30 million.**
        - At $16/MWh annual average increase in LMPs due to the loss of Ludington, the $24 million net energy loss would increase to **$55 million.**

Conclusion:

- The 'Do Nothing' option, while avoiding immediate expenditure, poses significant long-term risks including the potential for operational halt as well as significant costs for capacity and energy losses should the site be forced to shut down. The failure to replace the critical Dike Load Centers could lead to irreversible damages and operational challenges, making this approach highly inadvisable.

2. Replace as needed – Internal Estimated Cost of $28,236,219

Description of the Approach:

- **Reactive Replacement:** This alternative involves replacing individual Dike Load Centers at the Ludington Pumped Storage facility only as they fail. While this reactive approach has been previously applied to cabling, where failures were addressed on a case-by-case basis, it's important to note that cabling replacements are significantly simpler. In contrast, replacing Dike Load Centers involves a more complex process. Since the replacements are not like-for-like due to updates in technology and regulation, several additional steps, including system integration and infrastructure modifications, are necessary to facilitate these replacements.

Current State of Equipment:

- **Dike Load Center Maintenance:** Over the years, specific breakers within the Dike Load Centers have been maintained to extend their operational life without replacing entire units. However, this approach is increasingly becoming non-viable due to the growing obsolescence of the parts involved.

Risks and Challenges:

- **Increased Frequency of Failures:** Given the structural deterioration of the Dike Load Centers, failures are expected to become more frequent.
- **Risk of Operational Disruption:** The lengthy lead times required for the design, procurement, and installation of replacement units introduce significant risks. Should multiple Dike Load Centers fail simultaneously, the facility could experience substantial operational disruptions. The complex engineering planning necessary for each unplanned replacement extends these lead times further.
- **Inconsistency in Installations:** Replacing components on a piecemeal basis as they fail leads to non-standard, one-off installations. This inconsistency can complicate maintenance procedures, escalate costs, and diminish overall system efficiency.

Long-term Implications:

- **Continued Reliability Issues:** The approach does not address the underlying issue of aging and obsolescence across all Dike Load Centers but rather postpones comprehensive solutions.
- **Operational Inefficiency:** As more components are replaced on an as-needed basis, the system may become a patchwork of old and new technology, potentially decreasing operational efficiency and increasing maintenance complexity.

Financial Impact:

- **Cost Escalation:** Due to the inefficiencies of this option and the complexities involved in engineering planning and procurement of components, the cost estimates for replacing the high priority DLCs are escalated by an estimated 40%. These increased costs are attributed to the emergency nature of unplanned replacements, which require rapid response and often premium pricing for expedited services.

- **Estimated Project Cost:** Consequently, the total estimated project cost for this approach, factoring in all associated inefficiencies and complexities, is estimated at $28,236,219 in 100% dollars. This figure reflects the significant financial burden imposed by the ad hoc replacement strategy under conditions of urgency and operational necessity.

Conclusion:

- While this option allows for spreading out expenditures over time and addressing issues as they arise, it carries significant risks of unplanned operational halts and safety concerns. The piecemeal approach might also lead to increased costs over time due to emergency replacements and the inefficiencies of managing a non-standardized system. Therefore, this option, though seemingly less capital intensive initially, will lead to higher overall costs and operational challenges.

3. Option 3 - Staged Phased replacement of high priority DLCs only - Initial internal estimate of $8,931,372 (100% dollars), new revised internal estimate $20,168,728 (100% dollars)

This option proposes a structured and phased replacement of the ten most critical Dike Load Centers at the Ludington Pumped Storage facility. This plan is designed to prioritize the replacement of units that are most problematic first, with subsequent phases targeting units that are currently less prone to failure. The other 10 DLCs will be considered under a different project once the data suggests that replacement is warranted.

Planned Phases of Implementation:

- **Priority-Based Replacement:** The initial phase targets the Dike Load Centers that are in the worst condition or that have shown the most frequent issues. This approach mitigates the most immediate risks to facility operations.
- **Subsequent Phases:** Following the initial replacements, the remaining Dike Load Centers would be replaced in a planned sequence over the next six years, based on their assessed condition and risk of failure.

Benefits of the Staged Approach:

- **Risk Management:** By prioritizing the most critical replacements first, this plan not only effectively manages the risk of sudden failures that could disrupt operations but also ensures that the remaining Dike Load Centers continue to operate reliably for several years. The strategy includes utilizing parts from the DLCs that are being decommissioned to stock an inventory of spare and refurbished parts. This approach will provide a robust support system for the Dike Load Centers that are not scheduled for immediate replacement, thereby extending their operational lifespan and enhancing overall plant resilience.

- **Operational Continuity:** A phased approach ensures that replacements are done systematically, minimizing the impact on daily operations and allowing for better planning and resource allocation.
- **Equipment Compatibility:** Implementing a uniform replacement strategy across all units ensures that the new equipment is compatible, avoiding the complications associated with non-standard, one-off installations.

Long-term Strategic Advantages:

- **Enhanced System Reliability:** With new and compatible equipment installed in a phased manner, the overall reliability of the Dike Load Centers is greatly improved, ensuring stable operations for the foreseeable future.
- **Cost Efficiency:** Although this approach requires upfront planning and investment, it is more cost-effective in the long term compared to emergency replacements or piecemeal upgrades. It allows for budget predictability and can leverage bulk procurement discounts.

Option 4 – Full replacement of all 20 DLCs. Internal Estimated Cost - $37,827,823.(100% dollars)

Option 4 proposes a comprehensive replacement strategy for all 20 Dike Load Centers (DLCs) at the Ludington Pumped Storage facility. This option extends beyond the high-priority DLCs addressed in Option 3 to include the remaining 10 DLCs, which have exhibited significantly fewer failures and operational issues over the past five years.

Rationale for Exclusion from High Priority List:

- **Lower Failure Rates:** The 10 DLCs not included in the high-priority list have shown considerably lower failure rates. These units primarily consist of DLCs with dry wells where the pumps have not been operating frequently.
- **Operational Observations:** Due to the minimal operational demand on these DLCs, the wear and stress on components have been substantially less, leading to a decreased likelihood of immediate failures.

Financial Considerations:

- **Cost of Full Replacement:** The total cost for implementing Option 4, which entails replacing all 20 DLCs, is estimated at $37,827,823 (100% dollars). This figure represents a significant increase from the initial estimates made five years ago, which did not account for the escalated costs due to inflation, increased material costs, and more comprehensive engineering requirements now deemed necessary.
- **Comparison to Reduced Scope:** While Option 4 ensures that all components are uniformly modernized and potentially reduces future disparate maintenance schedules, the additional cost compared to Option 3 is considerable. Given the lower risk associated with the 10 non-high-priority DLCs, the additional expenditure does not proportionately increase the value or return on investment when compared to the focused scope of replacing only the high-priority units.

Conclusion: Option 4, while offering a uniform upgrade across all DLCs and potentially simplifying future maintenance, does not present a significantly higher value over Option 3 given the substantial additional costs involved. The decision by subject matter experts in engineering to prioritize Option 3 over Option 4 is based on a strategic assessment of risk, operational need, and financial efficiency. The comprehensive replacement of all 20 DLCs under Option 4 does not align sufficiently with the incremental benefits when weighed against the additional financial investment required.

Recommended Alternative: Option 3 - Staged Phased replacement of high priority DLCs only - Initial internal estimate of $8,931,372 (100% dollars), new revised internal estimate $20,168,728 (100% dollars)

In evaluating the options for addressing the critical condition of the Dike Load Centers at the Ludington Pumped Storage facility, a comprehensive analysis of operational, financial, and technical factors has been conducted. The following section outlines the justification for selecting Option 3, the staged phased replacement plan.

1. **Risk Mitigation:**
    - **Immediate Risk Reduction:** By prioritizing the replacement of the most deteriorated Dike Load Centers, this plan directly addresses the highest risk components within the system. This proactive measure prevents potential failures that could lead to significant operational disruptions or safety concerns.
    - **Controlled Risk Exposure:** The phased approach reduces the likelihood of encountering multiple failures simultaneously, a critical factor considering the long lead times required for designing, procuring, and installing new equipment.
2. **Operational Continuity and Efficiency:**
    - **Minimized Operational Disruption:** Staging the replacements ensures that the facility remains operational without significant downtime. Replacing equipment in a controlled, planned manner prevents the sudden loss of capacity that could result from emergency replacements following unexpected failures.
    - **System Uniformity and Standardization:** As replacements are made systematically, the new installations will be uniform and standardized, which significantly simplifies maintenance and operation. This uniformity ensures all components communicate and function optimally within the system, enhancing overall operational efficiency.
3. **Cost Management and Budget Planning:**
    - **Predictable Expenditure:** A phased plan allows for better financial planning and resource allocation. Budget impacts are spread over several years, which can be

accommodated more easily within annual capital budgets, avoiding the financial strain of unplanned, large-scale expenditures.

- **Economies of Scale in Procurement:** Purchasing equipment in planned stages rather than as one-off replacements can reduce costs through bulk buying and potentially negotiating more favorable terms with suppliers.

4. **Long-term Strategic Benefits:**

- **Enhanced Longevity and Reliability:** Systematically upgrading the Dike Load Centers ensures that all components are modern, robust, and capable of meeting the operational demands of the facility. This not only extends the life of the infrastructure but also boosts its reliability and performance.

Conclusion:

The selection of Option 3, a staged phased replacement plan, is justified based on its comprehensive approach to managing the inherent risks associated with the Ludington Pumped Storage facility's Dike Load Centers. This option balances the need for immediate action on the most critical components with the practicalities of budget, operational continuity, and long-term reliability.

Budget Revision Justification

The initial budget for the replacement of the Dike Load Centers (DLCs) at the Ludington Pumped Storage facility was set over five years ago, based on a 'like-for-like' replacement strategy. Since then, the project estimate has more than doubled, primarily due to significant changes in the technical requirements of the replacement units. The detailed analysis of these changes highlights several key factors contributing to the increased cost:

1. Changes in Size and Design Requirements:

- **Increased Physical Size:** The replacement DLCs are now 2.5 to 3 times larger than the original units. This size increase is mainly due to current industry standards and regulatory requirements not in place or anticipated during the initial budgeting.
- **Foundation Modifications:** The larger size of the new DLCs necessitates the demolition of the existing foundations and the construction of significantly larger ones. This requirement was not included in the original plan, which had assumed the new units would fit the existing foundations.

2. Infrastructure and Installation Adjustments:

- **Conduit and Wiring Changes:** The original project plan assumed that the new DLCs could use the existing pathways for wiring and cabling. However, due to the changed positioning and increased size of the new units, this is no longer feasible. Additional conduit installation is now necessary, along with more extensive wiring than previously planned.

- **Junction Box Installation:** The new layout and increased complexity of the electrical connections require the installation of additional junction boxes. These elements are essential to safely manage and distribute the electrical loads from the larger DLCs, further adding to the project cost.

3. Unforeseen Technical Challenges:

- **Engineering and Design Revisions:** The significant alterations in the project's scope, necessitated by the larger size and different configuration of the replacement DLCs, have required additional engineering and design work. This revision process has introduced delays and increased costs associated with specialized labor and technical expertise.

Conclusion:

The substantial increase in the budget estimate for the Dike Load Center replacement project at the Ludington Pumped Storage facility is a direct result of changes in the physical size of the units, enhanced regulatory requirements, and the complexities involved in retrofitting new technology into an existing infrastructure. These factors were not fully anticipated in the initial budget, resulting in the need for a revised financial plan that reflects the current project realities.

Scope of work

This scope of work details a revised strategy focusing specifically on the replacement of high-priority Dike Load Centers (DLCs) at the Ludington Pumped Storage facility. This initiative spans a four-year timeline and is designed to address the most critical DLCs that have experienced multiple failures over the past five years, ensuring reliable and safe operation of the plant.

Project Details:

High-Priority DLC Replacement:

- **Objective:** Implement a phased replacement of the ten most critical 480 Volt Dike Load Centers based on an assessment by the environmental and dam safety teams.
- **Tasks:**
    - Demolish existing structures and construct new foundations as needed for the modern DLCs.
    - Install new Dike Load Centers that comply with current regulatory standards and operational requirements.

Utilization of Existing Equipment:

- **Objective:** Efficiently utilize existing resources by repurposing used and recently replaced dry transformers and electrical equipment as spares for the remaining lower-priority DLCs.

Phased Implementation Schedule:

- **2023:** Complete the replacement of DLCs 1 & 2 (completed).
- **2025:** Replace DLCs 3 & 4, focusing on critical components and integration with existing plant systems.
- **2026:** Address DLCs 17 & 16, incorporating lessons learned and feedback from previous installations.
- **2027:** Update DLCs 15 & 5, ensuring continuity and system integrity.
- **2028:** Finalize replacements with DLCs 12 & 11, completing the priority updates.

This targeted approach allows for a focused upgrade of the most critical components within the facility, aligning resource allocation with the most immediate needs for reliability and safety. By prioritizing high-risk DLCs and strategically scheduling their replacement, the project ensures ongoing compliance with safety and operational standards while optimizing the use of existing resources. This phased strategy minimizes disruption and maximizes the efficacy of the upgrades, ensuring the long-term sustainability of the Ludington Pumped Storage facility's operations.

Funding and Timing

- Funding that has been previously committed for this project: $4,278,409 (51% dollars)
- A Scheduled outage is required for this project.
- Desired implementation year: first year spend 2019 with installation and closeout finishing 2029.
- System Engineer: Tarik Butrus

Conceptual Estimate

Year	Loaded Cost	Description
2019	**$43,747**	51% dollars. Engineering and planning
2020	**$668,263**	51% dollars. Engineering and planning
2021	**$1,013,244**	51% dollars. Engineering and planning. Procurement and preparation for installation
2022	**$1,665,599**	51% dollars. Engineering and planning. Procurement and preparation for installation
2023	**$887,558**	51% dollars. Engineering and planning. Installation of DLC 1 & 2
2024	**$679,492**	51% dollars. Engineering and planning.
2025	**$1,186,497**	51% dollars. Installation of DLC 3 & 4
2026	**$1,309,572**	51% dollars. Installation of DLC 17 & 16
2027	**$1,308,113**	51% dollars. Installation of DLC 15 & 5
2028	**$1,421,968**	51% dollars. Installation of DLC 12 & 11
2029	**$102,000**	Monitoring, Post Maintenance testing, Documentation and Closeout

Total Cost: 51% dollars - $10,286,052 100% dollars – $20,168,728

Asset Strategy Approval Comments

Asset Strategy endorses the reduced scope approach of Option 3, focusing exclusively on replacing high-priority Dike Load Centers at the Ludington Pumped Storage facility. This decision is based on a detailed risk assessment and cost-benefit analysis performed by our engineering experts, who recommend prioritizing replacements where they are most needed due to repeated failures in the last five years. By concentrating resources on the most critical areas, we ensure a cost-effective allocation of capital while maintaining operational reliability and safety.

This investment **is** included in the current electric rate case.

Amount set for Bridge year: $990,000

Amount set for test period: $852,000

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric supply		

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Consumers Energy Count on Us®

Concept Approval

Ludington Pumped Storage Oil Water Separator

Date: 12/11/2023

Prepared by: Paul Ohep

Figure 1. Ludington pumped storage station.

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Executive Summary

The Ludington Pumped Storage (LPS) Plant, co-operated by Consumers Energy Company (CEC) and DTE Energy, is a significant hydroelectric facility located on Lake Michigan. The plant, which began operations in 1973, plays a crucial role in energy production. Central to its operations is the Oil/Water Separator (OWS), tasked with removing oil and grease (O&G) from process water before discharge into Lake Michigan. The OWS's importance is underlined by its regulation under a National Pollutant Discharge Elimination System (NPDES) permit, which mandates specific limits on O&G levels in discharged water.

Recent incidents have raised concerns about the efficacy of the current OWS. These incidents occurred in the fourth quarter of 2021 and the first quarter of 2022 and were attributed to OWS upset conditions. Despite these releases, O&G levels have generally been non-detectable in effluent samples, indicating a need to address specific failure points rather than overall process inefficiency.

The primary objective of this project is to identify and implement a solution that ensures compliance with environmental standards through 2069. This requires modifications to the existing infrastructure.

Three main options were considered:

1. **Do Nothing**: Continuing with the current system, risking further environmental compliance violations.
2. **Enhance OWS & Modernize System**: Involving the installation of new equipment to make the OWS system efficient, modernized control systems, and necessary modifications to the existing infrastructure.
3. **Modify Existing OWS**: Entailing significant modifications to the current OWS, which poses challenges in meeting national rating requirements and necessitates extended outage times.

After a comprehensive evaluation, Option 2 - Enhance OWS & Modernize System - is recommended. This option not only addresses immediate compliance issues but also ensures the plant's operational readiness and environmental responsibility through the projected facility lifecycle. The investment in this option, estimated at $5,228,422 (100% dollars), is justified by the long-term benefits of improved environmental performance and compliance with evolving regulatory standards.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	51% dollars - $2,666,495. 100% dollars – $5,228,422

Proposed Start Implementation Year and span

2023, 3 year span.

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Problem Description

The Ludington Pumped Storage (LPS) Plant is currently grappling with maintaining environmental compliance with its existing Oil Water Separator (OWS) system. The OWS, a critical component of the plant since its inception in 1973, is responsible for removing oil and grease (O&G) from process water before its discharge into Lake Michigan. This discharge, regulated under a National Pollutant Discharge Elimination System (NPDES) permit, is subject to stringent limits of 6.5 million gallons per day (MGD) and a maximum of 15 milligrams per liter (mg/L) of O&G in monthly grab samples. Moreover, the discharge must adhere to a narrative standard prohibiting turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits in unnatural quantities that may harm designated uses of the receiving water.

With six turbines and associated wicket gates contributing oil and grease to the Station Drainage Sump (SDS), and a noted increase in SDS discharge since 2019, there is a pressing need for a robust solution. The plant aims to evaluate and implement new processes or retrofit the existing system to eliminate violations of the narrative standard. This objective is essential for the plant's compliance with its NPDES permit and the protection of Lake Michigan’s ecosystem.

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Alternative Solutions/Alternatives Considered

1. Do Nothing

The "Do Nothing" alternative involves maintaining the current status quo of the Oil Water Separator (OWS) system at the Ludington Pumped Storage (LPS) Plant without implementing any upgrades or modifications.

Key Points of Consideration:

1. **Continued Compliance Challenges:**
   - Under this approach, the plant would continue to operate with the existing OWS system, which has already shown inadequacies in handling hydraulic oil releases, as evidenced by two reportable incidents in December 2021 and January 2022 due to an observed oil sheen.
   - Persisting with the existing system could result in repeated non-compliance with the stringent NPDES permit requirements, particularly the narrative standard.
   - The plant risks facing regulatory penalties, enforcement actions, and potential legal challenges due to continued environmental compliance failures.
2. **Environmental Implications:**
   - Discharge of inadequately treated process water could have detrimental effects on the aquatic ecosystem of Lake Michigan, potentially harming the water quality and the diverse aquatic life.
   - The plant's environmental stewardship reputation could be compromised, leading to public concern and scrutiny.
3. **Operational Efficiency:**
   - Without improvements or upgrades, the existing OWS system may become increasingly inefficient as flow rates increase due to the wear of existing wicket gates.
   - This inefficiency might lead to higher operational costs, increased maintenance requirements, and potential unplanned downtimes.
4. **Financial Considerations:**
   - Although this option avoids the immediate capital expenditure required for upgrading the OWS system, it could result in higher long-term costs due to potential fines, legal fees, and increased maintenance expenses.
   - The plant might also incur financial losses due to unplanned shutdowns or reduced operational capacity as a result of compliance issues.

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Conclusion: The "Do Nothing" alternative, while avoiding immediate investment, poses significant risks in terms of regulatory compliance, environmental protection, operational efficiency, financial liability, and public perception. It fails to address the underlying issues with the OWS system and could result in more serious consequences for the LPS Plant and its stakeholders in the long term.

2. Enhance OWS & Modernize System for Facility Lifecycle – Internal estimate of $5,228,422 (100% Dollars)

Option 2 proposes a comprehensive approach to address the inefficiencies of the current Oil Water Separator (OWS) system at the Ludington Pumped Storage (LPS) Plant. This option involves making enhancements to the existing OWS and modernizing the system to align with the facility's lifecycle requirements.

Key Points of Consideration:

1. **System Replacement and Modernization:**
   - The existing OWS system, which has been prone to reportable releases, will be enhanced to address the flow rate and provide additional oil removal equipment.
   - The new system will be designed to meet the current and future operational demands of the plant, considering factors like increased flow rates due to wicket gate wear.
2. **Enhanced Compliance with NPDES Permit:**
   - The modernized system will aim to effectively eliminate any violations of the NPDES narrative standard.
3. **Environmental Benefits:**
   - Upgrading to a more efficient system will significantly reduce the risk of pollutants entering Lake Michigan, thereby protecting the aquatic ecosystem.
   - It demonstrates the plant's commitment to environmental stewardship and sustainable operations.
4. **Operational Efficiency and Reliability:**
   - It will enhance the reliability of the plant's operations, ensuring consistent power generation without interruptions due to compliance issues.
5. **Financial Considerations:**
   - The initial investment of $5,228,422 will cover the costs of purchasing and installing enhancements to the OWS system.
   - While this option requires a significant upfront capital expenditure, it could potentially save costs in the long term by avoiding regulatory fines, reducing maintenance expenses, and minimizing the risk of operational disruptions.

Conclusion: Option 2, with its focus on enhancing and modernizing the OWS system, presents a comprehensive and proactive solution to the current challenges faced by the LPS Plant. Despite the substantial initial investment, this option offers long-term benefits

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in terms of regulatory compliance, environmental protection, operational efficiency, and stakeholder relations.

3. Modify Existing OWS – internal estimate of $4,000,000 (100% dollars)

Option 3 proposes substantial modifications to the Ludington Pumped Storage (LPS) Plant's current Oil Water Separator (OWS). This plan focuses on retrofitting the existing system to enhance its oil and grease separation capabilities while addressing environmental compliance challenges.

Key Points of Consideration:

1. **Extensive Modification Requirements:**
    - Significant alterations to the current OWS are needed, which may include the integration of advanced technology and materials.
    - These modifications could necessitate extensive testing to ensure compliance with national standards, adding complexity to the project.
2. **Operational Challenges and Outage Duration:**
    - The OWS is integral to the plant's operations; hence, modifications mean prolonged outage periods.
    - The necessary downtime for these modifications could be considerably longer than other options, potentially impacting the plant's availability and power generation schedule.
3. **Limitations in Achieving Compliance:**
    - Despite the modifications, there is uncertainty regarding the modified system's ability to fully satisfy NPDES permit requirements, specifically the prevention of oil sheens at Outfall 007.
    - The risk of not fully addressing the regulatory concerns remains a significant consideration.
4. **Lack of Backup Functionality:**
    - Unlike Option 2, which proposes a system providing backup functionality, modifying the existing OWS does not offer this advantage.
    - In the event of system failure or maintenance, there would be no alternative system to ensure continuous compliance.
5. **Cost and Investment Efficiency:**
    - The estimated investment of $4,000,000 primarily funds the modifications without providing additional operational benefits like backup functionality.

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- When weighed against the potential for prolonged outages and uncertain compliance achievement, the cost-effectiveness of this option may be less favorable compared to others.

Conclusion: Option 3, involving the modification of the existing OWS, presents several challenges, including extended outage times, uncertainty in meeting compliance standards, and lack of backup functionality. Although it leverages existing infrastructure, the limitations and risks associated with this option, particularly in terms of operational disruption and regulatory compliance, make it a less favorable choice compared to a complete system replacement.

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Recommended Alternative: #2 Enhance OWS & Modernize System for Facility Lifecycle - $5,228,422 (100% dollars)

Rationale for Selection:

1. **Reliability and Compliance:**
    - The new system is designed to meet the National Pollutant Discharge Elimination System (NPDES) requirements. This aligns with Consumers Energy Company's (CEC) objective to eliminate violations of the narrative standard and ensures adherence to environmental regulations.
2. **Backup Functionality:**
    - Unlike modifying the existing OWS, this enhancement offers backup functionality. In the event of maintenance or unforeseen system failures, the plant's operation can continue unhindered, ensuring continuous compliance with environmental standards.
3. **Operational Efficiency:**
    - The enhancement and modernization of the OWS are expected to streamline operations at the Ludington Pumped Storage (LPS) Plant.
4. **Reduced Outage Time:**
    - Installation of a new system is more predictable and can be planned to minimize operational disruptions. This contrasts with the extensive outage times required for retrofitting the existing system as proposed in Option 3.
5. **Long-Term Cost-Effectiveness:**
    - While the upfront cost is significant, the long-term benefits such as reduced maintenance costs, enhanced operational reliability, and avoidance of potential fines for environmental non-compliance make this a cost-effective solution.
6. **Risk Mitigation:**
    - This option significantly reduces the risk of future NPDES reportable releases, thus protecting the integrity of Lake Michigan's ecosystem and maintaining the plant's compliance track record.

Conclusion: Given the critical need to address the environmental compliance issues at the LPS Plant, Option 2 stands out as the most viable and strategically sound choice. It offers a comprehensive solution that not only enhances operational efficiency and reliability but also aligns with CEC's commitment to environmental responsibility and regulatory compliance. The investment is justified by the long-term operational and environmental benefits it provides, making it the recommended alternative for the project.

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Scope of Work

1. **Installation of Advanced Skimming and Contaminant Capture System:**

   This system will enhance the initial treatment of process water, effectively removing oil, grease, and other pollutants before they enter the main OWS.

2. **Installation of Parallel Tank Organic Clay Pretreatment System:**

   This system will serve as an additional layer of treatment, targeting specific contaminants and enhancing the overall efficiency of the water purification process.

3. **Installation of Baffle/Divider System in the Collection Sump:**

   This addition will aid in the effective removal of fats, oils, and grease (FOG) contaminants from the water.

4. **Enhanced Instrumentation and Monitoring for Collection Pit and Pretreatment System:**

   This upgrade will provide real-time data and analytics, crucial for monitoring system performance and ensuring compliance with environmental standards.

5. **Installation of Isolation Valves in Transformer Secondary Containment Discharge Lines:**

   These valves will offer greater control over the flow and treatment of discharged water, enhancing safety and operational efficiency.

6. **Monitoring of Existing Plant OWS:**

   This will facilitate continuous assessment and management of the OWS's performance, ensuring that it meets the required environmental regulations and operates at optimal efficiency.

Funding and Timing

- Funding that has been previously committed for this project: $1,147,500
- A Scheduled outage is required for this project.
- Desired implementation year: 2024
- System Engineer: Steven Morris

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Conceptual Estimate

Year	Loaded Cost	Description
2023	**$** 1,147,500	51% dollars. Engineering and planning
2024	**$** 892,500	51% dollars. Procurement and preparation for installation
2025	**$**626,495	51% dollars. Monitoring, Post Maintenance testing, Documentation and Closeout

Total Cost: 51% dollars - $2,666,495. 100% dollars – $5,228,422

Asset Strategy Approval Comments

Asset Strategy recommends approval Based on regulatory requirement.

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

Approvals

Title	Approver Name	Date
Generation Planning Manager	George L. Mckenzie II DocuSigned by: George L. Mckenzie II C3EF130D...	12/21/2023 | 10:37 AM EST
Director of Generation Asset Strategy	Scott Hugo DocuSigned by: Scott Hugo ...	12/21/2023 | 10:36 AM EST
Exec Director of Electric Planning	Richard T. Blumenstock DocuSigned by: Richard T. Blumenstock ...	12/23/2023 | 9:39 AM EST
VP of Electric Grid Integration	Srikanth Maddipati DocuSigned by: Srikanth Maddipati 67DA622787D2488...	2/1/2024 | 4:58 PM EST

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References

1. WSP USA Inc. "Alternatives Evaluation for Oil-Water Separation at the Ludington Pumped Storage Plant." 27 June 2023. Prepared for Consumers Energy Company (CEC) and DTE Energy.

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy Company
LPS Corrective Work Project

Concept Approval

Pony Motor Rotor Cracking and Fretting

PH-00119-BSD-002

Revision 0.0

Circulated for Approval: 9/27/2024

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

1 Revision History

Revision	Date	Reason For Revision	By	Checked	Generation Planning	Legal
0.0	9/27/2024	Initial Release	KCG	DET	SAM	EJH

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

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Approvals

On approval, this document authorizes the EPM LPS Corrective Work Project to execute the work according to the budgeted Long Term Financial Plan or Change Log processes.

Approvals:

Approvals according to the Total Project Value listed below.

Title	Reviewer/Approver	Approval Limit	Signature	Date
Project Engineer - Ludington	Kyle Grassmid	Preparer	Signed by: Kyle Grassmid 24BCC7D2AF5C4F0...	9/27/2024 | 8:39 AM EDT
Gen Planning	Steven Morris	$100k	Signed by: Steven A. Morris 89F850CADAEC448...	9/27/2024 | 8:55 AM EDT
Project Manager	Kristopher Koster	EPM Reviewer	Signed by: Kristopher Koster DC10DD6B8392473...	9/27/2024 | 10:00 AM EDT
Sr Manager Plant Operations - LPS	Jason Durand	Site Reviewer	Signed by: Jason Durand 2C1456FD230B409...	9/27/2024 | 12:40 PM EDT
Assoc General Counsel	Emerson Hilton	Legal Reviewer	Signed by: Emerson Hilton E48267A0BA9F473...	9/30/2024 | 9:19 AM EDT
Dir Generation Engineering	David Thornock	$2,000k	DocuSigned by: David E Thornock 31C4AFE905164D3...	9/30/2024 | 10:13 AM EDT
Dir Generation Asset Strategy	Scott Hugo	$250k	DocuSigned by: Scott Hugo 31EC7A87F8F34C6...	9/30/2024 | 1:39 PM EDT
Exec Director Electric Supply Eng	Richard Blumenstock	2,000k	Signed by: Richard Blumenstock C3E2F0B9920949B...	9/30/2024 | 4:35 PM EDT
VP Electric Supply	Sri Maddipati	$8,000k	Signed by: Srikanth Maddipati 67DA622787D2488...	10/2/2024 | 10:20 AM EDT

Additional Supporting Information:
Though the work covered under this Concept Approval is intended to be executed in conjunction with the LPS Corrective Work Project, and the Company has outstanding claims against Toshiba in connection with failing to evaluate certain related issues at an earlier time, the work covered here was not initially within the scope of the LPS Overhaul Project and therefore is not considered repair of defective work.

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

General Information			
Project Title:	PH-00119 – LPS Corrective Work Project		
Generating Site / Plant:	Ludington Pumped Storage Facility	Unit(s):	1 & 6
Project Sub-Part Title:	Pony Motor Rotor Cracking and Fretting		
Budgetary Scoping Document (BSD) ID Reference:	BSD-002		
LPS System ID Reference:	Pony Motor		
Plant Asset ID: (Enter "NEW" as applicable)	Retirement Unit N/A		

System Description and Problem Statement:

The Ludington Pumped Storage Plant has six units that can be used to generate electricity, or by turning the units in the reverse direction, can pump water into a reservoir to be used later to generate electricity. To start in pump mode, a lead unit (either unit 1 or unit 6) operating in generator mode must be electrically coupled to the desired unit to be started. Pump starting is done with power provided from the lead unit until it is ready to be synchronized with the grid. As the units are started, the last unit remaining to start in pump mode is the lead unit. (unit 1 or unit 6). In order to start the last unit in pump mode, the unit needs to be spun up to speed using another motor, a pony motor. The pony motors are directly attached to the rotor shafts of units 1 and 6. These pony motors are large, and they cannot be started by simply closing a breaker. The technology installed in the 1970s to control large motor starts was a liquid rheostat. The liquid rheostat provides a variable resistance to the motor power supply, controlling the motor starting speed.

Since the pony motor is directly coupled to the main shaft, it rotates with the unit whenever the unit is in operation. Even when the motor is not being used to start the units, it spins up and down with every other unit start when acting as the lead unit.

During a Non-Destructive Examination (NDE) test performed on Unit 1's pony motor structure, linear indications, aka cracks, were noted in high stress locations. The indications have been monitored periodically since they were first discovered. Prior to re-assembly after the major overhaul, the linear indications were repaired. Subsequent inspections after being returned to service note the indications returned, and the indications continued to grow with use of the pony motor. Unit 1's pony motor was subsequently removed from service and the indications continue to be tracked with regular inspections. Since the pony motor is no longer used to start the unit in pump mode, the indications have not grown, nor have new indications been noted. However, an analysis has shown that the rotor material is beyond its fatigue life limit.

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

Project Description / Scope:

Project will remove and replace the existing Pony Motor rotors with new rotors that will provide another 50 years of service. It is assumed that the stators on both units can be reused, and that the new rotor will be designed to work with the existing stator and liquid rheostat. The new rotor will be redesigned to ensure that fatigue is no longer an issue for the remaining life of the plant.

Project Justification:

Project Justification: (Enter text for all areas of justification that are applicable. Place an X to the left of the justification that is driving the change. Only mark one field.)		
Safety:		
	If safety-driven, provide specific safety requirements (MIOSHA, etc.).	
Regulatory:		
	If regulatory-driven, provide specific requirements (EPA, EGLE, etc.).	
Compliance:		
	If compliance-driven, provide specific CEC compliance requirement.	
Economic: For economic projects provide inputs needed in the economic evaluation.		
	% ROR Reduction:	
	O&M and / or PSCR cost changes:	PSCR Cost Savings $90k per year 1.1M/year starting after 8 years
	Changes in periodic factor:	
	Heat Rate Improvements:	
Other: Provide basis.		
X	Broke/Fix	Unit 1's pony motor rotor structure has cracks that prohibit it from being used as a motor for pumping. It so far has been safe for the unit to operate normally as long as the pony motor is not used. Unit 6's pony motor is 50 years old and is not expected to last through the remaining life of the plant
	Condition-Based	
	Infrastructure, Facilities	
	Strategic, etc.	

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

NOTE: All costs are in 100% dollars.

Alternatives Considered:

- Do Nothing

  This option continues to utilize the one pony motor that is in operation, while not repairing the other. It is expected that over time, 8-10 years, the operational pony motor would develop similar indications in the rotor and would then also be removed from service. Once both pony motors are out of service, the site would only be capable of pumping with a maximum of 5 pumps. Normal unit maintenance and operation require units to be taken off line. Today, any time Unit 6 is off line the site is down two pumping units.

  Today, Unit 1's pony motor has significant indications in the rotor support structure. These indications are monitored quarterly to ensure safe operation. Currently indication growth is not occurring. If more growth occurs, the team will have to evaluate whether to take the unit out of service for both pump and generate. An in service failure could catastrophically damage the unit.

  Lead time to design, build and install a new pony motor is a minimum of 3 years. Funds must be secured, a bidding process must be completed with qualified vendors, the new rotor must be designed, manufactured, and installed. If the unit is unavailable for this amount of time in pump or generate, the cost impacts will be significant.

  A 3 year outage is expected to incur replacement power costs of 10M and lost capacity cost of $102M. The cost of executing a pony motor replacement as a standalone project is estimated to be $50M compared to $15M when executed during the upcoming LPS Corrective Work project. The differences in costs are due to shared engineering, supervision, and fabrication windows.

  Regular inspections for 30 years – $485k

  2022 annual replacement power cost for 1 Unit OOS - $3.3M or $10M for 3 years
  Cost for unplanned replacement - $37M + project costs + replacement power + capacity = $170M

- Alternative 1 – Replace One Pony Motor Rotor

  This option consists of engineering a new rotor to work with the existing stator. This would require a significant outage duration to remove the collector rings and brush rigging for both the generator and the pony motor. Then remove the air cover and upper bearing bracket to remove the existing rotor and then install a new rotor. Minimum unit outage duration of 200 days. This is planned to be completed in conjunction with the planned Unit 1 BOP overhaul corrective work, saving both outage costs and project implementation costs. The second motor is not expected to last for another 30+ years and therefore would need to be replaced at a later date.

  Capital Cost - $11.8M + Project costs = $23M

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Future Outage Replacement Power cost = $2M
Future replacement of Unit 6 pony motor rotor - $68M (project cost only)

- Alternative 2 – Replace Both Pony Motor Rotors

  This option would replace the pony motor rotors for both Unit 1 and Unit 6. The pony motor for Unit 1 is beyond end of life, the pony motor for Unit 6 has an estimated 8-10 years of life left. The next scheduled outage that could support this work would be in 2029-30. By 2029, the expected remaining life of the Unit 6 pony motor rotor will be 3-5 years. To execute a project at that time, in conjunction with the existing projects will cost $15M. To wait until the estimated end of life, the project would need to be executed as a standalone project, costing $50M plus the addition of another 200 day outage to perform the replacement. As shown in Alternative 1, while there is an existing project that can support the engineering and management the cost of installing the second pony motor is greatly reduced.

  Replacement of both pony motors - $11.8M + $11.8M + project costs =$46M

- Alternative 3 – Repair the existing rotor

  This option would attempt to repair the 31 indications that are currently being tracked. Per an American Welding Society standard, the cracks would need to be excavated to the end plus 2 inches. The indications range from 1/16th inch to 2-5/8th inches. Repairs were made to Pony Motor #1 during the overhaul, but the indications returned within 2 years. The proposed repairs would not bring pony motor #1 to usable condition, as welds from previous weld repairs have failed in service after a relatively short time. True repair is not practical due to the material being at the end of it's fatigue life for the service conditions. This also does not prevent Pony Motor #2 from the assumed failure in 8-10 years.

  This option was reviewed to assess whether repairing Pony Motor #1 rotor is worth repairing to reduce the inspection costs, NOT as a viable solution to the problem at hand.

- Alternative 4 – Remove Pony Motor and use SFC to start last pump

  This option would remove the need for the pony motor itself and replace the 1970s technology with new technology. The Liquid Rheostat would be removed, the pony motor would be removed and a Static Frequency Converter (SFC) would be installed. The SFC would energize the main generator as a motor. The SFC would require two new transformers and a large building to house the power electronics. The space required is not available. From a technical perspective, the generator was not designed to be used with a SFC and would require modifications to account for the harmonics created by the SFC.

  Based on the space and technical requirements this is NOT a viable option.

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

	Do Nothing	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Scope	Operate with one less pump	Replace One Pony Motor Rotor	Replace Both Pony Motors	Repair Pony Motor Rotor	SFC
Risk	Indications start to grow causing unit removed from service	Future replacement of 2nd pony motor will cost more		Alternative is not viable N/A	Alternative is not viable N/A
Costs					
Estimate Class	3	3	3		
O&M	485k			N/A	N/A
Capital		$15M	$46M	N/A	N/A
PSCR	$1.1M/year or $3.3M/year (future failure)	$2M			
Future Capacity Impact	$102M				
Future Project	$68M	$68M			
Total	$170M	$85M	$46M	N/A	N/A

Alternative Selected (Detail which option was selected and why)**:**

Alternative 2 was selected to replace both Pony Motor Rotors for the following reasons:

- Lowest long term costs
- Leverages on site existing engineering / contractor support
- Increases unit reliability
- Minimizes risk to the plant
- Returns the plant to original operational condition through the current license period
- Avoids future major outage and avoids lost capacity costs

Project Benefits (Include IRR, if applicable)**:**

- Reduced Replacement Power costs

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

- Pumping capacity redundancy during unit 1 & 6 outages
- Decreasing operational risk
- Reduces risk for catastrophic disassembly
- Replacement conducted during planned outage rather than forced outage.

Present Need (Describe current condition)**:**

Unable to use the pony motor #1 to start the last pump. Mitigate pony motor rotor structural fatigue and end of life damage for both pony motor rotors

Timing Impact – Is an outage required?

Outage Information	
Estimated Outage Duration, if needed:	200 days (two outages)
Desired implementation year:	2028-29 & 2029-30
Specify the impact if the recommended implementation year is changed:	1.1M/year

COST ESTIMATION

Engineering and Conceptual Development (Provide the status of engineering and conceptual development. Is additional engineering required to provide adequate cost/benefit information to fully evaluate the project? **NO**

Cost Summary (100% Dollars) (subject to change with input from 3rd parties) Preliminary and Subject to Change	
Estimate Class (DOE 413.3 Definition)	Class 3 (-%20/+%30)
Total Estimated Project cost (100%; Whole dollars)	$46M Capital
Identify funding that has already been spent or committed, if any. (Whole dollars)	$900K
Contingency included in the Total Estimated Project Cost above (Whole dollars)	$1.3M
• Was the estimate developed based on a previous project of similar size and scope? No • Was a formal estimate completed based on detailed engineering? No • Was a formal estimate completed based on a conceptual engineering design? Yes • Was an informal estimate done based on the recommended project concept? No • If an informal estimate was done, please identify the basis for having confidence in this estimated cost.	

Cash Flow Forecast (100%; whole dollar values): Preliminary and Subject to Change	
Year	Dollar Value

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

2024	$0.5M
2025	$4M
2026	$5M
2027	$11M
2028(Fall 2028 installation Unit 1)	$14M
2029 (Fall 2029 Installation Unit 6)	$7M
2030	$3M

51% CE Share Calculation:

Cash Flow Forecast (51% project total; whole dollar values):	Preliminary and Subject to Change
Year	51% Dollar Value
2024	$ 0.25M Capital
2025	$2M Capital
2026	$2.5M
2027	$5.5M
2028	$7M
2029	$3.5M
2030	$2.25M

Priority Code	
• Select a recommended project priority code and provide a basis.	
• Priority code table provided below	
Priority Code	**Basis**
5	The present situation impacts replacement power costs with $90k per year with a high potential to impact at $1.1M/yr and a maximum potential impact of $37.3M/yr

Priority Basis Chart		
Rank	Title	Definitions

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

Priority Basis Chart		
1	Legal, Regulatory	These are the items that CEC is required to do without flexibility.
2	Safety	Safety items that must be addressed within one year due to hazard to employees.
3	Strategic	These are board approved projects, submitted outside the standard budget and LTFP processes. This work instruction does not apply to these items.
4	Critical Reliability	Deferral has a high likelihood of significantly impacting asset reliability in the near term. This category also includes spending to address long-standing safety issues and regulatory commitments that have some flexibility with respect to implementation.
5	Important Reliability	Deferral has a high probability of impacting asset reliability. Projects that will significantly improve unit performance, key performance indicators will generally be in this category.
6	Desired Reliability	Repeated deferrals will impact long term reliability. One time short term deferral, while undesirable, is unlikely to impact reliability in a significant way. In general, items that are in this category in future years are good candidates for the up levers list.
7	Reliability and Performance Improvement	Spending that, while desirable, is a lower priority. These items will be the primary candidates for the capital and major maintenance down levers lists.

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Concept Approval

Consumers Energy
Electric Supply
PROJECT INITIATION & CONCEPT APPROVAL
Generation Planning
Capital

Generation Type: Hydro
Site: Ludington
Unit: 1-6
Date Created: 2/23/2022
Proposed Start Implementation Year: 2024
Project Span Whole Years: 6
Project Title: Ludington 1-6 DCS Control Relay Replacement CA

Problem Description (Section 1-Initial Information):

Ludington Pumped Storage (LPS) units are currently controlled and protected by the original (1970's technology) hardwired electromechanical relay control system, going forward referred to as "the system". The system is comprised of relays mainly in the auxiliary relay room and operator control handles located on the Main Control Board (MCB). The system has outlived its useful life and is failing. The system is not fail-safe in design; does not provide fault tolerance; and the redundancy is inadequate. There are gaps in the system protection scheme. The system is presenting plant operations and maintenance with problems. The Uninterruptable Power Supply (UPS) system is not currently segregated by unit pairs and presents a common point of failure for the plant.

The system is based on electromechanical devices (relays and operator control handles) that wear and have become less reliable over time. The relay contacts wear, and increased resistance has caused intermittent failures. The operator control handles are in a similar state of wear and age and have also experienced intermittent failures. The system will not last until End of Life (EOL) of the units.

The plant was designed using the control and protection methodologies available in the 1970's. Many of the relays in the system fail to a non-protective state. A small subset of examples is as follow:

Emergency Stop Relays (5E) – Each unit has an emergency stop relay. The relay is configured to energize to trip. A failure of this relay results in the unit not being shut down by the relay. There are fourteen legs in the design which energize this relay to trip the unit. A few of them are as follow:

- Turbine Overspeed (125%)
- 345 KV Bus Fault while pumping
- Upper reservoir water level high (Overtopping protection)
- Intake gate closed

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Many portions of the protective scheme are not fault tolerant. Fault tolerance refers to the ability of a system to continue operating without interruption when one or more of its components fail. As an example, master shutdown relays (5) do not provide fault tolerance. While there are five master shutdown relays for each unit they are not implemented in a redundant fashion. There are five of these relays because when the emergency shutdown function is asked for by the protection scheme there are so many different actions taken that one relay cannot implement them all. Thus, each of the five relays shut down different portions of the process. A failure of any one of the relays will directly affect only the portions of the process tied to that relay. This means that a portion of the equipment (a subset) can inadvertently be tripped while the balance remains in service.

Many critical trip inputs from the relays are not redundant. Redundancy is a system design principle that introduces duplicate components to provide fault tolerance. When a component fails, a backup takes over to ensure the system still performs as designed. A small subset of examples where we rely on one device to provide unit protections is as follow:

- Overspeed switch and aux relay (12X) – One relay contact energizes the emergency stop relay. If the relay fails, we will not shut the unit down as prescribed.
- High draft tube water level (71DWHX) – One relay contact energizes the emergency stop relay. If the relay fails, we will not shut the unit down as prescribed.
- Governor oil tank level low (71GTL) – One relay contact energizes the emergency stop relay. If the relay fails, we will not shut the unit down as prescribed.

Challenges for plant Operations and Maintenance

- The main control board switches are wearing. Even with lubrication and maintenance a number of these switches have the interface with their key or handle worn excessively. Many of our larger main control board switches are no longer in production. There are minimal spares available. Replacement for the more complex switches that have many contacts are no longer readily available and obsolete. We are reliant on custom assemblies for replacements and must commission custom builds. These custom builds also present a problem in long lead times. If failure is observed unit(s) and portions of the plant may remain out of service for extended durations

- The Relay Room is so densely populated with relays that just walking around has caused issues when relays get bumped. As part of the process of routine relays checks the covers are removed and replaced which has caused inadvertent circuit changes.

- Changing a relay(s) can affect multiple circuits and even other units (starting bus, Main Transformer Banks (MTB)) due to their common neutrals. Direct Current (DC) bus grounds can be difficult to find when there is no indication on cause (i.e., alarming).

- Intermittent issues can take months to find and correct. This is due to the lack of active monitoring/measurement that allows for troubleshooting to be performed timely. For each occurrence custom recordings must be setup with ad-hoc hardware to assess what the controls are executing and experiencing.

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- The system does not provide the proper diagnostic and troubleshooting capabilities.

- During the startup and shutdown process plant operations cannot see the operational state of the unit. Functionality and troubleshooting during start/stop sequences cannot be observed other than by individually observing and testing scenarios with personnel and recording devices (multimeters or digital recorders for electrical signals).

- Start permissives have limited visibility. Critical valve positions are not individually observable as they come to single relay collectively to provide the start permissive. Troubleshooting requires additional effort and resources.

- Several current manual processes cannot be automated preventing the removal of human error potential during startup, shutdown, and other equipment configurations.

- Any updates of equipment and systems that need to be integrated with the unit operation are difficult and expensive to integrate into the hardwired relay logic.

- Automation efforts prove to be difficult if at all even possible with the hardwired relay logic. Changes to operating criteria are difficult to implement, test and verify and costly and time-consuming.

- Training for Operations is limited to studying procedures as the system does not provide a testing and simulation environment.

- The unit overtopping protection needs improvements that can't easily, and cost efficiently be implemented into the current legacy relay-based control system (pump start lockout above 932’ reservoir elevation, overtopping protection and system control of how many units are allowed to pump above 940’ and 941’ respectively).

As a result of the system failing the unit can come off-line, become unavailable, or experience derates. In addition, as these devices also serve to provide equipment protection their failure can result in significant equipment damage up to and including destroying significant parts of the unit and/or plant potentially rendering the unit(s) and/or the entire plant unavailable for years. The potential costs of such repairs could easily rise to hundreds of millions of dollars. In addition, there are significant gaps in the original protection design. Consumers Energy is exposed to substantial risk due to the state of the system.

LPS will become more important to the stability of the grid as renewable generation (solar and wind) sources increase and as fossil generation (gas and coal) is decommissioned. LPS provides the Midcontinent Independent System Operator (MISO) grid support by delivering frequency and voltage support (reactive load generation) that replaces the support that will be lost when our gas and coal units are decommissioned. Providing grid stability in conjunction to our generation realignment is an important aspect to our corporate strategy.

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Alternative Solutions/Alternatives Considered

Alternative Solutions (Section 2):

Alternative #1 - Do nothing (20-Year Payback)

Total Cost of doing nothing: $29.6M (51% dollars)

The costs associated with doing nothing include costs associated with the damage occurring as a result of system failure(s) and the units not being available to run and support our renewable strategy. There are other costs related to doing nothing such as maintaining the plant and operational issues that can make the units unavailable for relatively short periods of time, however the major impacts are derived from system vulnerabilities with respect to their protection functions.

DAMAGE
The system provides the basis for personal and equipment protection. If we do nothing, we will continue to experience failures of the system. The frequency of errors is progressively getting worse as system components continue to age. Eventually a failure or combination of failures could result in catastrophic damage to a unit or the entire plant rending it unavailable for up to a year or more. This would cause significant impacts to our ability to serve our customers.

Relay fault probability used is based on data from the Overtopping Fault Tree analysis report. In the report the Savanna component fault probability database was consulted, and the component fault relay probability used as part of the overtopping fault tree analysis was 0.001 failures per day.

ALREADY OCCURED
Recently the plant experienced an incident where unit 4 entered shutdown as it went into pumping mode before the generator breaker was closed and the unit synchronized. As mentioned in the problem statement there are gaps in the logic, a pumping mode should not be permitted until unit 4 had been synchronized. In addition, as part of the event the cross trip to unit 1 did not take place and the unit 4 motor was operated synchronously (as its exciter had been taken offline when unit 4 went into shutdown). Damage to the unit 4 generator field along with other equipment may/could have occurred. The plant is still looking into the incident; however, it is difficult to ascertain what truly happened with the current system in that the protections are not all contained in one system. Portions of the protection are in the system relays and portions are in the protection relays. This event is indicative of the system risks. Damages for this event can easily reach $60M and make a unit unavailable for months which would cost another $15M depending on Local Marginal Price (LMP) and market demands. The total cost for an event of this nature could reach $75M (100% dollars).

POTENTIAL EVENTS
The following provides a description of three other scenarios that provide significant system failure(s) risk to the operation using the old technology. The three scenarios below are a small subset of the control system vulnerabilities. It should be noted that these are all low probability

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and high cost/consequence events. Based on data from the Overtopping Fault Tree analysis report the fault probability database was consulted and the relay fault probability of 0.001 failures per day was used.

Scenario 1: Turbine Overspeed Switch and Aux Relay (12X)
The system provides unit overspeed protection through a relay which is energized to trip. If the relay fails when needed during an overspeed event the damage associated with an overspeed event could be to damage the rotor bearings and the rotor itself. This would make the unit unavailable for years of time and costly repairs. It is estimated the repair cost could reach up to $160M and the loss of the unit for years another $70M for a total of $230M. Based on data from the Overtopping Fault Tree analysis report the fault probability database was consulted and the fault probability of a relay is 0.001 failures per day; the fault probability of the wicket gates failing to close is 0.0002 per day. This results in a total probability of failure of 2E-7 per day, which is 7.3E-5 per year.

7.3 E-5 x $230M = $16,790/year x 20 years = $336K x 6 units = $2M (100% dollars)

Scenario 2: Upper Reservoir Water Level High (Overtopping Protection)
As a FERC regulated facility, dam safety is of the utmost importance. Consumers Energy is under constant scrutiny by regulators to provide safe reliable operations. Overtopping protection is very high on the priority list. Proving the effectiveness and reliability of dam safety protection schemes for overtopping protection is a must do. The overtopping protection protects corporate and public, life and property. The current plant overtopping protection scheme has 4 levels of protection. A breach of the overtopping protection schemes would require disclosure to our regulators which could trigger a requirement to install an emergency spillway, which may cost in excess of $150M (100% dollars).

No cost with regard to this scenario has been placed into the cost of this solution as the probability is negligible, however this scenario demonstrates the magnitude of cost were the event to occur.

Scenario 3: Loss of the starting bus
As the system provides protection for the plant starting bus, a failure in its protection would leave the plant without many if not all of its units for years depending on the severity of the event. This estimate uses a loss of three units for 1 year It is estimated that the replacement of the starting bus would cost around $100M and losses in revenue of $25M (100% dollars).

No cost with regard to this scenario has been placed into the cost of this solution as the probability is negligible, however this scenario demonstrates the magnitude of cost were the event to occur.

HIGHER FUTURE PROJECT INTEGRATION COSTS
There are many projects being executed at the plant. The costs for these projects to integrate with the system is higher and costs projects an additional $70,000 per year. In total that amounts to $1.4M over the 20-year payback period.

The cost for the 20-year payback period is $1.4M (100% dollars) or $.7M (51% dollars).

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PLANT OPERATION AND MAINTENENCE COSTS

The operation and maintenance costs of maintaining and working with the system are estimated to be $100,000 per year per unit. This includes but is not limited to the extra time it takes to troubleshoot issues; the cost to maintain the system as best as possible; and the extra overhead related to operations. Over the period of 20 years the total is $12M (100% dollars).

The cost for the 20-year payback period is $12M (100% dollars) or $6.1M (51% dollars).

FORCED OUTAGES

Increased Random Outage Rates (ROR) due to continued failures of the system may cause unit outages and/or derates.

Using NERC Generating Availability Data System (GADS) data and supplemental knowledge of plant management that the units are worth $5M – $6M in the high season (July – September) and the expected forced outages based on past events it is estimated that there will be revenue loss of $1.75M (100% dollars) in the future year. It was then assumed that there will be a rise in forced outages due to the relays at the rate of approximately 3% per year. Projecting this out over a 20-year timeframe (the period that choice 2 & 3 would be expected to be in service before further action) would result in a cost of $42.9M in lost revenue.

Total cost breaks down for the 20-year payback period to:

Damage:	$2M (100% dollars) or $1M (51% dollars)
Project Integration:	$1.4M (100% dollars) or $.7M (51% dollars)
Operation & Maintenance:	$12M (100% dollars) or $6.1M (51% dollars)
Forced Outages:	$42.9M (100% dollars) or $21.8M (51% dollars)

The cost for the 20-year payback period is $29.6M (51% dollars).

Alternative #2 - Replace hardwire relay control system with Distributed Control System (DCS) and segregate the UPS (20-year payback)

Total cost of putting in a DCS: $13.4M (51%dollars)

Installing a modern Distributed Control System (DCS) will allow a system that will be able to be used and maintained for the life of the unit. It will increase site availability by reducing failures caused by aging relays and allowing better diagnostic tools such as historian trends, live logic viewing, alarm messages and related operator responses, and common Human-Machine Interface (HMI) control for all the plant equipment in a central system. A modern control system also allows for additional process automation further reducing error potential during operations and associated impacts.

The DCS Control Relay Replacement Study project (PH-20106) evaluated the detailed scope, budget, and schedule to replace the existing hardwired controls at the Ludington Pumped Storage (LPS) facility with full Emerson Ovation Distributed Control System (DCS) control. The study included the following scope:

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Modernization of the control room including removal of many of the operator control handles on the Main Control Board (MCB) to be implemented in the DCS as well as optimization of the layout of the control board for operational efficiency. In addition, the operator control console would be replaced with a modernized console with dedicated alarm displays and alarm response aids. The central alarming function the DCS provides enhances reliability of the units. As an example, DC bus grounds will be brought into the DCS for diagnostic and troubleshooting purposes.

A high fidelity DCS simulator will be provided for the project. The simulator will provide operator training capabilities prior to implementation of DCS control and monitoring at the plant. The simulator will be capable of replicating all logic and control schemes for all six (6) units. The simulator will allow testing of logic changes before they are implemented on the "actual" units which will enhance reliability. Simulation will be a primary means to test and verify logic operation before the implementation outages for each unit. This will help reduce risks during this project.

Turbine Supervisory Panels - Remote control functions associated with the turbine datalink will be migrated to hardwired DCS control as part of this project to replicate the existing plant hardwired controls from the MCB panels.

Pony motor control and monitoring will be migrated to the DCS.

The existing UPS system at the plant has a rating of 20KVA and provides 120VAC power to equipment for all six (6) units. This UPS system has reached its maximum capacity and requires an upgrade to support future loading requirements. The new DCS hardware installed as part of this project requires reliable and redundant power distribution for plant operations. An evaluation of the UPS system was performed. The results determined that a full upgrade of the UPS system is required to support the project and maintain sufficient spare capacity for future projects. Three (3) separate 20KVA UPS systems will be installed to allow unit pair separation (Unit 1 & 2, Unit 3 & 4, and Unit 5 & 6) to provide reliable and redundant power distribution throughout the plant.

The cost for the 20-year payback period is $13.4M (51% dollars)

Alternative #3 - Replace all Control Relays and a portion of the operator control handles with new ones and replace and segregate UPS (20-year payback)

Total cost of replacing the relays: $22.7M (51% dollars)

A complete replacement of all control relays to reach end-of-life (EOL) of the plant would require an immense undertaking to de-terminate the wiring on close to a thousand relays, replace the relay and rewire to the previous state. The system would require a complete recommissioning of the control system and post maintenance testing. Validity of the testing would be difficult. The amount of time required to do this work would require the work to be performed over multiple outages and would be difficult to perform without complete site outages. There would be increased risk of possible unit trips if attempted to perform under individual unit outages due to common systems and interrelated control signals.

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This option does not provide benefits to resolve all the issues mentioned in the problem definition. Trouble shooting issues are still limited by the lack of tools available as compared to a modern control system. Many of the problems that occur over time are the result of the system itself being comprised of hundreds of electro-mechanical relays that eventually wear out and fail. Common operator interface of a DCS, along with operating events and alarms brought into a system-wide historian and allowing full historic trending of the process leading up to the issue, is not available with the relay-based control system.

The cost of replacing the relays will also include the following costs as they are not mitigated by the solution as in reality there is no alternative that will do what a DCS does. The following items are detailed in the cost of doing nothing choice and have been scaled as to their associated costs with this choice.

Damage:	$2M (100% dollars) or $1M (51% dollars)	(Scale Factor 1)
Project Integration:	$1.4M (100% dollars) or $.7M (51% dollars)	(Scale Factor 1)
Operation & Maintenance:	$10.8M (100% dollars) or $5.5M (51% dollars)	(Scale Factor .9)
Forced Outages:	$21.5M (100% dollars) or $10.9M (51% dollars)	(Scale Factor .5)
Cost to replace relays:	$9.0M (100% dollars) or $4.6M (51% dollars)	(Scale Factor 1)

The cost for the 20-year payback period is $22.7M (51% dollars).

Recommended Alternative Benefits/Objectives (Section 3):

Recommended Alternative #: 2
Recommended Alternative: Replace hardwire relay control system with Distributed Control System (DCS)

Why was this Alternative chosen?

A DCS is recommended for full control of the units at Ludington Pumped Storage. This solution provides a reliable and sustainable method to control and operate the six units at LPS for the remainder of the life of the plant. The DCS solution mitigates gaps in the plant protection scheme. The DCS solution will therefore mitigate the potential of damage at the plant. The DCS will make integration with future projects less expensive. The DCS will reduce the plant operation and maintenance costs.

The architecture of a DCS allows the reduction of electromechanical relays and timers and replacement with electronic input/output (I/O) modules that do not rely on mechanical movements and physical contacts to control the equipment. The DCS can program the sequencing of the equipment using control logic sheets (SAMA - (Scientific Apparatus Makers Association) control functional diagrams) that represents the functionality of hardwired series and parallel relay circuits. The number of physical components that can fail is significantly reduced. Operation sequences can be changed and updated with greater ease and new equipment can be added to the DCS control with less effort and full integration into the system. A DCS also provides appropriate control and trip redundancy that currently does not exist.

The modern DCS provides a complete control solution. HMI graphics provide the operator with easy to use "mouse-click" control of the plant equipment. Process sequences can be automatically

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controlled to reduce and eliminate operator intervention. Troubleshooting tools such as live logic display, trending and historical review, and alarm with alarm responses improve the diagnostic capabilities and reduces the time required to resolve problems. The DCS can also improve efficiencies and performance by providing more accurate control and monitoring of equipment and processes. Integration of other equipment control systems can be brought into the DCS to provide a single user interface for the operators to monitor and control all equipment with a common alarm system.

There have been several engineering studies performed in the last 15 years to determine the best options for the extended operating life of Ludington Pumped Storage Facility. In 2007 a study was prepared by Devine Tarbell & Associates, Inc. (DTA) (DTA was acquired by HDR in 2009). The study was a condition assessment and life extension study along with a technology upgrade study report.

In 2019-2021 the Data Acquisition System was upgraded to Ovation DCS, also annunciator panels and the sequence of events (SOE) recorder were implemented into the DCS. These upgrades were implemented in three projects which resulted in a fully functional DCS (no equipment control) at the plant.

The recommended project is the natural next step in the migration to full control in the DCS.

Another engineering study was performed in 2021 and established a detailed scope, schedule, and budget to execute a project to expand the DCS to fully control the plant.

Project Benefits/Objectives

- Reduce the risk of potential damage due to the state of the current system.
- Replacement and elimination of worn and less reliable control relays and control board switches with new electronic input/output modules and new relays where needed.
- Future projects that have controls impact at Ludington will cost less
- The number of hardware control relays will be reduced due to the "control" being performed in logic instead of "hardwired" circuits. This will increase reliability and reduce outages and derates.
- Common control and monitoring of system equipment allows operation of the equipment from the HMI graphics and keeps the operator focused on one system instead of monitoring several the systems from several areas of the control room on different devices.
- Alarms are located in one alarm system with alarm management and responses based on International Society of Automation (ISA) 18.2 standards. Integration of external systems will be brought into the DCS for common operator experience.
- Automation of sequences can be programmed to reduce operator interface and improve on efficiency and performance of unit operation.
- Operational efficiencies and performance increases may be achieved by modern process control loops with Proportional Integral Derivative (PID) algorithms.
- Diagnostic and troubleshooting capabilities are greatly enhanced with the use of real-time control logic viewing, historian archive capability of process variables and operating parameters, trending graphs of process variables, start permissives, and logging of system messages.

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- Additional redundancy for critical trip controls for reservoir overtopping and equipment protections.
- A DCS will provide the long-term path to support the LPS units into the future and through operation towards their End-of-Life (EOL) dates.

Scope of Work

An engineering study was performed in 2021 to provide a detailed scope of work, schedule and budget to complete this project. The document was completed by Worley Energy and lists the scope in detail for the following items: Please refer to the attached engineering study for full details.

- Control Room -Consoles
- Control Room - MCB Panels (move existing Main Control Board devices to DCS graphics control and monitoring)
- Auxiliary Relay Room (relays replaced with DCS controller drops and I/O modules)
- UPS (Uninterruptible Power Supply replacement and reconfiguration for better redundancy and duration and backup of control systems)

Systems included:

- Creep Detector and Brake Control
- Depression Air Compressors 1 and 2 (common to all six (6) units)
- Electrical System (Unit 1 and Unit 2 common electrical equipment listed below, Unit 3 & 4 and Unit 5 & 6 are similar)
    - Station Power Transformer 1 4KV Breaker 1136
    - 4KV Bus No. 1 to Transfer Bus Tie Breaker 1135
    - 4KV Bus No. 1 to Station Power Transformer 11 Breaker 1199
    - 4KV Switchgear 1 Monitoring
    - 4KV Intake Breaker Feeder 1
    - Station Power Transformer 11 to 480V Bus No. 11 Breaker 1166
    - 480V Bus No. 11 Tie Breaker 1165
    - 480V Bus No. 11 Tie Breaker 1160
    - Standby Transformer No. 10 Breaker 1066
    - Generate/Pump Breaker 116
- Exciter
- Generator Motor Heater
- Governor Cabinet Interface
- HP Oil Pumps
- Intake Gate
- Load Break Switches
    - Load Break Switch 115
    - Load Break Switch 116
- Lockout & Protection Relays
- Miscellaneous Solenoid Control
- MT-1 Transformer (common between Unit 1 & 2, Unit 3 & 4 and Unit 5 & 6 are similar)
- Pony Motor (only applicable for Unit 1 and Unit 6)
- Steering Logic
    - All field inputs interfacing with existing control relays in the MCB and Auxiliary Relay Panels
- Water Depression

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- Engineering and Design and drawings
- DCS hardware, software and logic and engineering and commissioning
- Data links
- Hardwired cable and conduit design, installation, and commissioning
- Integration with current and future projects
- Updating/writing of operation procedures, alarm responses, job aids
- Schedule to be completed over a six-year time period coordinating with unit outages and other project scopes.

Future adaptability and control enhancements or changes are more readily implemented and in shorter time reducing additional future risk. Needs for control enhancements are expected based on lessons learned from events that occur and a needed change to the control logic (= standard work)

Project Justification (Section 4):

Priority Code Title: Critical Projects
Rank: 06
Definition: These projects, if deferred will have a high likelihood of significantly impacting asset reliability in the near term. This category also includes spending to address long-standing safety issues and regulatory commitments that have some flexibility with respect to implementation.

Basis Explanation:

This project removes substantial financial and reputational risks and will save the company money. It addresses the multiple issues presented in the problem description. The presented option provides the highest economical long-term benefit.

Economic Benefit Evaluation (Section 5):

X	**ROR Reduction:**	GADS historic data results can be very subjective on outage and derates with estimates of having a DCS and the amount of time to diagnose and repair the issues (along with the number of units the issue may affect). Estimate 0.3% ROR Reduction.
	O&M and/or PSCR Cost Changes:	
	Changes in Periodic Factor	
	Heat Rate Improvements	

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	Economics - Parameters for IRR Calculation	
	Other:	Reduction in O&M cost due to troubleshooting issues caused by hardwired relay failures and quicker repair and recover with a DCS will decrease resources and duration cause by the existing system components. This will provide more energy value for our customers in added unit availability and power production from our asset(s). The DCS will reduce risks and provide additional protection for dam safety through improved overtopping protection. This DCS project will provide added equipment protection against severe equipment failures.

Funding and Timing (Section 6):

Identify funding that has already been spent or committed, if any: $82,620.
Timing Impact – Is an outage required? YES
Estimated Outage Duration in Days: 120
Desired implementation year: 2023
Outage Type: Unit

Specify the impact if the recommended implementation year is changed:
Outages would be over a rolling 3-year period during the execution phases with approx. 120-day outage/two units each year and complete site outage of 30 days each year. The project would begin in 2023 and 2024 with engineering and planning. Execution of outages to install equipment would begin in 2025 with units 1&2, 2026 for units 3&4, and 2027 for units 3&4. 2028 would include project closeout.
An engineering study was performed in 2021/2022 to develop a detailed scope, schedule, and budget costing $82,620 (51% dollars).

System Engineer: Kevin A. Ortner

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Conceptual Estimate (Section 7):

Year	Loaded Cost (51% dollars)	Description	Total Project Cost (CE & DTE)
2023	$1,000,000	Engineering and Design for Units 1 and 2. Total project cost is $1,960,784.00, loaded cost is CE 51% share.	$1,960,784
2024	$2,106,300	Engineering and Design for Units 1 and 2. Total project cost is $4,130,000.00, loaded cost is CE 51% share.	$4,130,000
2025	$3,763,290	Engineering and Design for Units 3 and 4 and execution of project for units 1 and 2. Total project cost is $7,379,000.00, loaded cost is CE 51% share.	$7,379,000
2026	$3,855,090	Engineering and Design for Units 5 and 6 and execution of project for units 3 and 4. Total project cost is $7,559,000.00, loaded cost is CE 51% share.	$7,559,000
2027	$2,351,100	Execution of project for units 5 and 6 and project close out. Total project cost is$4,610,000.00, loaded cost is CE 51% share.	$4,610,000
2028	$250,000	Project closeout. Total project cost is $490,196.00, loaded cost is CE 51% share.	$490,196
	$13,408,400	Total project cost	$26,290,980

Total Cost: $ 13,408,400

Asset Strategy IRR & Justification

IRR:
Justification:
A/S recommends approval of this project based on obsolete equipment and no parts available for old control system. Due to the new license, we need a control system that will last the remainder of the life of the unit and this DCS system will meet those requirements.

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Approvals:

Concept Approval List

Present Need: On approval, this document authorizes the Generation Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization. EPM will begin work on this project when a completed and approved charter is in place.

Title	Approver	Approval Limit	Signature	Date
Generation Planning Supervisor	George McKenzie	$100K	DocuSigned by: George L. Mckenzie II F35F930DD948493...	4/19/2023 | 1:15 PM ED
Director of Generation Planning	David Thornock	$250K	DocuSigned by: David E Thornock 31C4AFE905164D3...	4/19/2023 | 2:50 PM ED
Director of Generation Asset Strategy	Scott Hugo	$250K	DocuSigned by: Scott A Hugo 7743CD0EABA24C0...	4/26/2023 | 9:46 AM ED
Exec Director of Electric Supply Engineering	Richard Blumenstock	$2M	DocuSigned by: Richard Blumenstock C3E2F0B9920949B...	4/26/2023 | 5:26 PM ED
VP of Electric Supply	Timothy Sparks	$5M	DocuSigned by: Timothy J Sparks 8016E70683B04D6...	5/1/2023 | 7:45 AM EDT
SVP of Transformation and ENG	Tonya Berry	$20M	DocuSigned by: Tonya L Berry BEAA3C1321D54C4...	5/1/2023 | 8:28 AM EDT

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Concept Approval

Ludington Pumped Storage Unit Governors

Date: 6/10/2024

Prepared by: Paul Ohep

Figure 1. Ludington pumped storage station.

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Executive Summary

The Ludington Pumped Storage Plant Unit Governor systems are essential for hydraulic control and overall plant safety. Currently, the system is obsolete and lacks redundancy, posing significant risks to reliability and safety. A comprehensive upgrade is needed to address these issues.

Problem Description

The governor system controls water flow through wicket gate adjustments, managing various operational modes, including emergencies. It is identified as high-risk due to its lack of redundant controls and mechanical defenses.

Current Challenges

The Atlas electrical controller, installed in the early 2000s, lacks OEM (Original Equipment Manufacturer) support and essential parts. Only one spare controller exists for all six units, and its reliability is uncertain. Additionally, the controller's limited compatibility with the plant's Ovation system complicates troubleshooting. Mechanical failures frequently impact wicket gate operations, and historical oil pump failures risk operational mechanisms.

Alternative Solutions Considered

Do Nothing: Estimated at $19.8M per occurrence, this option poses high failure risks, potential capacity, and NEV losses, and increased dam failure risk.

Controls Replacement Only: Estimated at $4.0M, this option does not address critical mechanical components, leading to incomplete risk mitigation.

Partial Replacement (Selected Option): Estimated at $17,719,930, this approach includes a selective upgrade of control and mechanical systems, integrating with the Ovation system. It enhances reliability, ensures spare part availability, and improves safety.

Conclusion

The partial replacement option is chosen for its balanced approach, addressing critical risks without unnecessary expenditure. It ensures long-term stability and safety by upgrading both control and mechanical components, aligning with industry best practices and leveraging modern technological advancements.

Financial Summary

Funding Type: Capital

Cost: 51% dollars - $**9,037,164**. 100% dollars - $**17,719,930**

Proposed Start Implementation Year and span

2022, 8-year span.

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Problem Description

The Ludington Pumped Storage Plant employs a sophisticated governor system responsible for hydraulic control over water flow through the plant's pump/turbine system. This system is critical for managing the unit's operations across various modes, including emergency scenarios, power generation, and mechanical safety.

System Description and Issues

1. **Governor System Functionality:**
    - **Primary Role:** Controls water flow through adjustments in wicket gate positions, influencing power output levels.
    - **System Components:** Utilizes high-pressure oil for operating servo motors linked to wicket gates.
    - **Operational Scope:** Ensures smooth transitions in operational modes such as generation control, pump operations, and emergency dewatering.
2. **Critical Risk Factors:**
    - **System Reliability:** Identified as a high-risk component in the "Issue-Specific Semi-Quantitative Risk Analysis for Emergency Overflow Spillway Operation" report due to its lack of redundant controls and mechanical defense in-depth components.
    - **Safety Implications:** Essential for preventing scenarios like reservoir overtopping and dam failure, which pose significant safety risks.

Current System Challenges

1. **Atlas Electrical Controller Issues:**
    - **Aging Technology:** Installed in the early 2000s; lacks current OEM support with essential parts no longer available from the original manufacturer, General Electric.
    - **Spare Unit Risks:** Currently, only one spare Atlas controller is available for all six units, which increases the risk of operational disruptions if the active unit is damaged by external factors like lightning strikes or overheating. Additionally, the spare controller is the same age as the original equipment and has not been used for several years, so its reliability cannot be fully guaranteed at this time.
    - **Integration and Maintenance Challenges:** The Atlas controller's limited capability with the plant's Ovation system complicates troubleshooting, leading to longer downtime during failures. This system's shortcomings are compounded by its inadequate production historian capabilities.
2. **Mechanical System Deterioration:**
    - **Operational Reliability:** Frequent mechanical failures have impacted the effectiveness of wicket gate operations, posing risks of "runaway" unit conditions under failure modes. The probability of a runaway unit condition under certain

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modes of operation does exist but could be minimized by modern design features.

- **Component Wear:** Historical oil pump failures could cause binding of the distributing valve, making the operating mechanism stuck in its current position.

3. Outdated Component Concerns:

- **Reliability Threats from Aging Components:** The existing electrical system contains various original relays, timers, and instruments that are beyond their service life, posing risks to unit reliability.
- **System Obsolescence:** Continuous reliance on these outdated components without readily available replacements heightens the risk of unexpected failures.
- **OEM Support Discontinuation:** Original system components are obsolete, with sporadic support transitions impacting long-term maintenance and parts availability.

4. Conclusion

The Unit governor systems at the Ludington Pumped Storage Plant are crucial for ensuring safe and efficient plant operations. Currently, the system is compromised by outdated components and a lack of redundancy, highlighting a pressing need for a comprehensive upgrade. A critical spare component of this system (Atlas) has become completely obsolete, significantly increasing the risk to the station. Fortunately, the past 50 years have seen significant technological advancements that address many of the issues historically experienced with the LPS governors. These modern solutions not only enhance the system's reliability but also correct previous deficiencies, providing a valuable opportunity to significantly improve the system’s performance and safety. Upgrading these components is crucial to mitigate the high level of risk associated with the current governor system.

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Alternative Solutions/Alternatives Considered

1. Do Nothing – Estimated cost of $19.8M per occurrence.

The "Do Nothing" alternative involves maintaining the current governor systems at the Ludington Pumped Storage Plant (LPS) without implementing the proposed upgrades. This option would forgo any modernization efforts and continue operations with the existing Atlas controllers and mechanical systems, which are significantly outdated and lack modern safety features.

Implications

1. **Reliability and Risk:**
    - **Failure Probability:** The current probability of a critical failure in this system is estimated at 20% within the next five years, with an annual increase of 5% thereafter. A critical failure is defined as an event that causes a forced outage lasting at least two weeks.
    - **Unit reliability:** A scenario in which our only spare Atlas controller failed if in use would result in one of the units being offline for 8 months.
2. **Increased Costs:**
    - **ROR and O&M Costs:** Continuing with the existing system will result in increased Repair, Operating, and Maintenance costs due to the aging components that are nearing or have reached the end of their service life.
    - **Component Replacement – cost of $4.4M (100% dollars):** As many parts are now obsolete, finding suitable replacements could be costly and potentially require custom solutions, further increasing expenses. If Atlas were to fail the plant only has 1 spare Atlas for all six units and no ability to obtain a new spare. The cost of replacement for one unit would be an estimated $4.4M. This considers all loadings and a 50% markup for emergency rush installation.
    - **Net Energy Value losses - $2.7:** An 8-month outage of a single unit at Ludington Pumped Storage Plant is estimated to result in a net energy value (NEV) loss of $2.7 million. This estimation is based on an annual NEV of $4 million per unit. The calculation assumes a worst-case scenario, as such an extended outage would result from an unplanned failure rather than scheduled maintenance.
    - **Potential Capacity losses - $12.7M:** If one unit is out of service for 8 months, the estimated potential capacity losses are $12.7 million. This is based on the following assumptions:
        1. Cost of New Entry (CONE): $127K/MW-year
        2. 75% of CONE: $95K/MW-year (used for calculation)
        3. With 178 average Zonal Resource Credits (ZRCs) for all Ludington units, the loss calculation is as follows:

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4. Replacement for 3 out of 4 seasons (75% of the year): 178 ZRCs * 75% * $95K = $12.7M

   This estimation assumes the need to replace capacity during a forced outage to avoid future accreditation impacts (no three-year penalty), valuing capacity at 75% of CONE.

- **Safety Concerns:** This option neglects one of the highest contributing systems to reservoir overtopping risks as identified in the "Issue-Specific Semi-Quantitative Risk Analysis for Emergency Overflow Spillway Operation" report. Continuing with the current system could significantly increase the risk of dam failure due to inadequate response capabilities during critical conditions.

3. **Technological Obsolescence:**

- **Outdated Technology:** The current unit governor systems use technology surpassed in efficiency, reliability, and safety. Better technology exists today that can substantially decrease the risk of failure and improve operational control.

Conclusion

While initially cost saving, the "Do Nothing" option presents substantial long-term risks and costs, making it an unsustainable choice. The increasing likelihood of failures on obsolete critical components, combined with the outdated nature of the current systems and the availability of advanced technology, strongly argues against this alternative.

2. Controls replacement only– Internal loaded estimate of $4.0M (100% Dollars)

Option 2 focuses on the replacement of the electrical control systems for all six units at the Ludington Pumped Storage Plant. This option is limited to updating the control systems without addressing any of the mechanical components.

Implementation Details

- **Cost and Timing:** The project is estimated to cost $4.0M in capital expenditure. Implementations are planned during the plant's scheduled outages, which occur every three years and last for three weeks, thereby minimizing operational disruptions.
- **Equipment Lifespan:** The upgraded electrical control systems are expected to last 20-25 years, significantly improving the reliability of control operations.

Limitations

- **Exclusion of Essential Mechanical Components:** Option 2 focuses solely on updating the electrical controls and does not address the critical mechanical components necessary for the plant's operational integrity. The following key components identified by internal subject matter experts as crucial for reliable operation remain unchanged and are not included in this upgrade:

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- **Distribution Valve (Secondary Mechanical Rate):** Essential for controlling the flow and pressure within the system.
- **EHI (Electro-Hydraulic Interface):** Crucial for interfacing between electrical signals and hydraulic operations.
- **Retarding Valves for Wicket Gate Servomotors**: Important for controlling the speed and positioning of the wicket gates.
- **Drain Oil Piping for Governor Pressure Tank:** Necessary for maintaining proper oil pressure and flow.
- **Governor Oil Sump Sight Glass and Sump Foaming**: Critical for monitoring and maintaining oil levels and quality (first unit only).
- **Emergency Distributing Valve Bypass:** Provides a critical safety mechanism during system failures.
- **Hydraulic Piping and Tubing:** Integral for the seamless transfer of hydraulic fluids throughout the system.
- **Air Brake System:** Essential for the safe operation and maintenance of mechanical movements within the governor system.
- **Incomplete Solution:** While the control upgrades may enhance certain operational aspects, critical mechanical issues remain unmitigated, which can lead to increased system vulnerability.

Risk Assessment

- **Initial Failure Probability Reduction:** The likelihood of critical failures is projected to decrease to 3% within the first five years post-implementation.
- **Long-term Risk Increase:** The probability of failures is expected to increase by 2.5% annually after the initial period, due to the aging and unreplaced mechanical components.

Conclusion

While Option 2 offers a less expensive alternative with minimal disruption to plant operations, it provides an incomplete solution by neglecting essential mechanical components of the system. This option's scope is limited to control replacement, which does not address the mechanical vulnerabilities crucial for reliable system operation. The failure to replace key components identified by our subject matter experts results in this option not being viable for ensuring the long-term operational stability and safety of the plant.

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3. Select Replacement – Internal estimate $17,719,930 (100% dollars).

Option 3 entails a selective upgrade of the control and mechanical systems at the Ludington Pumped Storage Plant, targeting components most critical for improving reliability and operational efficiency. This option integrates a new control scheme compatible with the upcoming Ovation system and replaces essential mechanical components that are nearing the end of their service life and have a history of damage or failure.

Implementation Details

- **Control System Upgrade:**
  - **Integration with Ovation System:** The new control system will be designed to pair seamlessly with the advanced Ovation system, enhancing the plant's operational capabilities through improved control and diagnostics.
  - **Electrical Components Replacement:** Critical electrical components and instruments will be updated to ensure ongoing spare parts availability and to maintain system reliability.
- **Mechanical System Upgrades:**
  - **Component Replacement:** Major mechanical components such as the distributing valve, pilot valve, unloader, and brake valve will be replaced due to their critical role in system operation and current end-of-life status.
  - **Retention of Key Components:** Servo motors, accumulators, significant portions of the power piping, and the existing cabinet structure will be retained, minimizing the scope and cost of physical changes.
- **Safety Enhancements:**
  - **Defense in Depth Improvements:** New safety features, including a distributing valve bypass, will be incorporated to enhance the system's overall safety profile and operational resilience.
- **Cost and Schedule:**
  - **Estimated Cost:** The total capital expenditure for this option is estimated at $17,719,930 for all units.
  - **Implementation Schedule:** The replacement work will be strategically planned to coincide with scheduled outages to minimize disruption to plant operations.

Industry Benchmarking

- **Sector Best Practices:** Feedback from major hydroelectric OEMs (Original Equipment Manufacturer) and budgetary assessments indicate that this partial replacement strategy is commonly adopted by utilities with similar units. This approach aligns with industry best practices and meets reliability targets effectively.

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Risk Assessment

- **Balanced Approach:** By selectively replacing and retaining components, this option strikes a balance between cost-efficiency and substantial system improvements. It addresses the most critical vulnerabilities without the need for a complete system overhaul.
- **Reliability and Spare Parts:** Updates to control and mechanical systems will significantly reduce the risk of failures and ensure easier maintenance through improved parts availability.
- **Reduced Initial Failure Probability:** Post-implementation, the probability of a critical failure is estimated to decrease to 1% within the first five years.

Conclusion

Option 3 presents a robust strategy for the governor system modernization at Ludington Pumped Storage Plant. It presents a comprehensive approach to upgrading critical components, ensuring compatibility with new technological standards, and adherence to industry best practices. This approach effectively addresses the plant's needs, proposing a solution that enhances long-term operational stability.

Recommended Alternative: Option 3 - $17,719,930 (100% dollars)

After thorough evaluation of all alternatives for modernizing the governor system at Ludington Pumped Storage Plant, Option 3 - Partial Replacement has been selected as the most viable and beneficial approach. This decision is grounded in a comprehensive analysis of the plant's needs, the potential risks associated with different strategies, and the overall goal of enhancing system reliability and safety while ensuring cost-effectiveness.

Rationale for Partial Replacement

1. **Balanced Approach to Modernization:**
    - **System Compatibility and Upgrades:** The partial replacement will integrate seamlessly with the new Ovation system, enhancing control and monitoring capabilities. This strategy allows for the retention of robust existing components such as servo motors and accumulators, while outdated and critical components like the distributing valve, pilot valve, unloader, and brake valve are replaced to address specific vulnerabilities.
    - **Reduction in Risks:** By replacing obsolete components and improving the system design, this option significantly decreases the likelihood of unit failure and the associated risk of dam failure. Additional safety measures and defense-in-depth features are incorporated to bolster system reliability during extreme conditions.

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2. **Cost and Efficiency Considerations:**
    - **Cost-Effective Solution:** Compared to a complete replacement, this option is less costly and avoids unnecessary expenditure on replacing still-functional components. It provides a targeted, effective upgrade without the extensive capital outlays required for a full system overhaul.
    - **Minimized Operational Disruption:** The upgrades can be implemented during scheduled outages, thereby minimizing disruption to plant operations, and reducing the downtime typically associated with more extensive refurbishments.
3. **Addressing Obsolescence and Enhancing Reliability:**
    - **Spare Part Availability:** The upgrade ensures that all replaced components are supported with readily available spare parts, addressing one of the critical vulnerabilities of the current system.
    - **Addressing Legacy Issues:** The existing control system and mechanical components have demonstrated increasing failure rates. This trend is poised to worsen, as highlighted by the rise in failures over the past decade and the expected continuation of this trend. Modernizing these components directly addresses these reliability issues.
    - **Improved OEM Support**: Transitioning to newer systems with robust OEM support from GE/Nexus facilitates better maintenance and quicker responses to system issues, which enhances overall plant reliability.
4. **Enhancements in Monitoring and Troubleshooting:**
    - **Improved Diagnostic Capabilities:** The integration with advanced systems like Ovation enhances the plant's ability to perform condition monitoring and decreases troubleshooting time, directly reducing operational costs and system downtime.
    - **Updated Documentation:** Replacing old, often illegible electrical drawings with updated, accurate documentation will further enhance maintenance efficiency and system operability.

Option 3 - Partial Replacement stands out as the most strategic approach for updating the governor systems at Ludington Pumped Storage Plant. It balances the need for modernization with cost considerations, addresses the critical risks associated with the current system's obsolescence, and aligns with industry best practices for reliability and safety enhancements. By choosing this option, the plant will not only meet current operational demands but also establish a foundation for sustainable long-term performance and safety.

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Budget Revision Justification

The initial estimate for the modernization of the governor systems at Ludington Pumped Storage Plant was set at $4.55 million (51% dollars). However, recent developments in the bidding process have necessitated a significant revision of the project budget. The current internal estimate has been adjusted to $9,890,751 (51% dollars), reflecting updated market conditions and actual bids received.

Reasons for Budget Increase

1. **Actual Bids Exceeding Initial Estimates:**

- The lowest cost bid received for the project was slightly under $13 million (100% dollars), significantly higher than the initially estimated $9.1 million. This discrepancy highlights a substantial underestimation in the original financial planning.
- The only other bid received was over $20 million, further indicating that the initial cost expectations were unrealistically low.

2. **Initial Budgeting Basis:**

- The original estimates were based on bids received four years ago. Since then, market conditions have changed, and costs for materials, labor, and technological components have increased, impacting the overall project cost.

Scope of work

The project aims to modernize the governor systems of all six units at Ludington Pumped Storage Plant (LPS). This comprehensive upgrade is designed to enhance operational reliability, safety, and compliance with current technological standards.

Components of Modernization

1. **Controller and Electrical System Upgrades:**
    - **Controller Replacement:** The current Atlas controllers will be replaced with state-of-the-art controllers featuring Human-Machine Interfaces (HMIs) for enhanced user interaction and monitoring.
    - **Auxiliary Electrical Equipment:** Introduction of new auxiliary electrical systems to support the upgraded controllers.
    - **PLC Enhancements:** Additional Programmable Logic Controller (PLC) functionalities will be incorporated to minimize failure modes and provide component redundancy.
2. **Mechanical System Redesign:**
    - **Hydraulic Control Devices:** Installation of new hydraulic controls tailored to address and rectify existing operational challenges.

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- **Safety Features:** Implementation of advanced safety features like a distributing valve bypass to mitigate risks associated with unit control loss.

3. **System Compatibility and Integration:**
    - **Ovation System Compatibility:** Ensuring new systems are compatible with the future Ovation system to enhance trending and troubleshooting capabilities.
    - **Drawing Package:** A new, clear drawing package will be provided to replace outdated and illegible documentation, facilitating better maintenance and operational procedures.
4. **Implementation Schedule:**
    - **Staggered Installation:** The upgrade will be executed on two units per year, aligned with each unit's scheduled periodic outage to minimize operational disruption.

Compliance and Longevity

- **Codes and Standards:** All modernization efforts will adhere to applicable international and industry-specific standards.
- **Service Life Specifications:**
    - **Mechanical Components:** Specified for a minimum of 50 years of mechanical service life.
    - **Electrical Controls:** Specified for at least 20 years of service life, ensuring long-term reliability and efficiency.

Funding and Timing

- Funding that has been previously committed for this project: $440,225
- A Scheduled outage is required for this project.
- Desired implementation year: first year spend 2022 with installation planned for 2025-2028.
- System Engineer: Steven Morris

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Conceptual Estimate

Year	Loaded Cost	Description
2022	**$ 96,011**	51% dollars. Engineering and planning
2023	**$ 128,504**	51% dollars. Engineering and planning
2024	**$777,250**	51% dollars. Engineering and planning. Procurement and preparation for installation
2025	**$1,431,751**	51% dollars. Final design and installation
2026	**$2,182,915**	51% dollars. Installation
2027	**$2,182,915**	51% dollars. Installation
2028	**$2,512,316**	51% dollars. Installation
2029	**$25,500**	51% dollars. Monitoring, Post Maintenance testing, Documentation and Closeout

Total Cost: 51% dollars - $9,037,164. 100% dollars – $17,719,930

Asset Strategy Approval Comments

The Asset Strategy team recommends approving Option 3 - Partial Replacement for the governor systems at Ludington Pumped Storage Plant due to critical concerns about part obsolescence and dam safety.

Key Points Supporting Approval

1. **Mitigation of Obsolescence and Reliability Issues:**
    - **End-of-Life Components:** Critical components have reached their service life and are obsolete, significantly impacting system reliability and necessitating their replacement to avoid Unit availability.
2. **Enhancement of System Redundancy and Reliability:**
    - **Redundancy Improvements:** The introduction of redundancies and defense in depth will provide a failsafe operational setup, crucial for maintaining operational integrity.

This investment **is** included in the current electric rate case.

Amount set for Bridge year: $345,000

Amount set for test period: $424,000

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Approvals

Title	Approver Name	Date
Generation Planning Manager George L. Mckenzie II	DocuSigned by: George L. Mckenzie II E35E930DD948493...	6/14/2024 | 9:34 AM EDT
Director of Generation Asset Strategy Scott Hugo	DocuSigned by: Scott Hugo 31EC7A87F8F84C0...	6/14/2024 | 7:41 AM EDT
Exec Director of Electric Supply Engineering Richard T. Blumenstock	DocuSigned by: Richard T. Blumenstock C3E2F0B9920940B...	6/15/2024 | 9:07 AM EDT
VP of Electric supply Srikanth Maddipati	DocuSigned by: Srikanth Maddipati 67DA622787D2488...	7/31/2024 | 12:41 AM EDT

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Project Process for input to the Business Planning System (BPS)

SELECT Project Initiation or Concept Approval Stage

○ Project Initation ◉ Concept Approval

SELECT Capital or Major Maintenance Funding

☒ Capital ☐ Major Maintenance

General Information	
Proposed Project Title:	LPS Lower Penstock Expansion Joint Chamber Waterstop
Generating Site / Plant/ Unit	

Problem Statement / Opportunity:

The Lower Penstock Expansion Joint (LPEJ) Chambers enclose the penstock expansion joints in concrete chambers below grade. The penstock expansion joints allow penstock expansion with seasonal temperature changes. There are six LPEJ chambers and seals aligning with each of the six units at LPS. The waterstop is a membrane intended to prevent groundwater from leaking into the LPEJ chamber. Some joints have been leaking since shortly following plant construction. In February 2017, a depression was discovered upstream of the powerhouse near Unit 3, which was caused by transport of soil into the chamber by inflowing groundwater through the waterstop. Historically, Consumers Energy sealed the waterstop leaks into the LPEJ chambers through the use of hydrophobic polyurethane grout. The waterstops are at the end of their expected life and grouting is no longer an effective solution. This is a threat to generation. If the settlement of the LPEJ chamber(s) and penstock reaches a defined threshold the affected unit(s) will remain in a forced outage until the LPEJ chamber(s)/penstock can be stabilized and re-adjusted back into an acceptable elevation / orientation impacting PSCR. This is Potential Failure Mode (PMF) number LPS–19–N– IV– 01, “Failure of the penstock resulting from settlement of the Lower Penstock Expansion Joint (LPEJ) encasement chamber initiated by internal erosion through a defect in the LPEJ concrete waterstop. “

Project Description / Project Scope:

The intent of the waterstop replacement is to prevent further loss of material fines and stabilize the chamber and penstock expansion joint movement. Scope would include engineering the design for the proposed waterstop strategy and dewatering plan, a dewatering pump test, replacement of the physical waterstop and dewatering the surrounding groundwater. The evaluated options include: installing a new waterstop in place of the current one, an interior surface seal on top of the current waterstop and an exterior surface seal. Following the completion of the Schnabel Engineering options study installation of a new conventional waterstop was the chosen option.

In 2021, the Unit 3 chamber was stabilized to allow for the Unit 3 waterstop to be replaced without impacting the penstock or impacting the long term ability to generate from Unit 3. The Unit 3 chamber was stabilized due to the 1.3" of offset due to settlement of the upstream side of the chamber; this impacted the steel expansion joint portion of the penstock. To mitigate the risk of the

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Project Description / Project Scope:
penstock binding and ensure continued operability of Unit 3, the Unit 3 chamber was stabilized by installing a secant pile shaft and placing grout underneath the chamber to raise it back to it's pre-2017 state. In addition, FERC required 3 PFMA (Potential Failure Mode Analyses) for the project, which resulted in an increase in engineering costs for 2021.

Project Justification: (place an X to the left of each justification)

	Safety: If safety provides specific safety requirement (MIOSHA, etc.,).	

	Regulatory: If regulatory provides specific requirement (EPA, MDEQ, etc.,).	

X	Compliance: If compliance provides specific CEC compliance requirement.	FERC compliance within Dam Safety requirements for probable failure mode idenfied per independent Engineering Analysis probable failure mode number LPS–19–N– IV– 01

Economic: For economic projects provide inputs needed the economic evaluation including:		
	ROR Reduction	
	O&M and / or PSCR cost changes:	
	Changes in periodic factor:	
	Heat Rate Improvements:	
	Other: Describe (Strategic, broke/fix, infrastructure, facilities, etc.,)	Broke Fix, Infrastructure, threat to generation

Alternatives considered: (all $$ values are in 100% Dollars)
Alternative 1: Replace Waterstop The options study came up with 3 options to replace the waterstop: 1. Replace Waterstop with a Conventional Waterstop 2a. Replace Waterstop with Interior Surface Seal in the Dry 2b. Replace Waterstop with Interior Surface Seal in the Wet 3. Replace Waterstop with Exterior Surface Seal Alternative 2: Do nothing

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Alternatives considered: (all $$ values are in 100% Dollars)

Alternative 2a was eliminated because it is more expensive than doing option 2b in the wet, with a total of $5,100,000 for all 6 chambers in the dry.
Alternative 2b is estimated to be $3,000,000 for all six chambers. Alternative 2b was eliminated because it would be high maintenance given the expected life of the components and the difficulty of properly aligning both sides of the expansion joint chamber during installation. As a course of normal maintenance the bolting would need to be retorqued every 5-10 years. The Teflon facings would need to be replaced every 10 years. The neoprene pads would need to be replaced every 20 years.

This would result in estimated major maintenance costs of $278,520 every 5-10 years, $472,560 in Years 10 and 30 after construction, and $736,980 in Years 20 and 40 after construction. These added maintenance costs would make the total cost of this option more expensive than Alternative 1, with an added risk of potential misalignment and requirement for mitigation actions. There are 6 chambers.

Alternative 3 was not selected due of the risks associated with excavating the shafts to nearby critical infrastructure, adjacent penstocks and adjacent chambers, the high cost associated to this option, the risk of misalignment during installation and risk of backfill of the shafts and gallery interfering with the movement of the expansion joint.

If we do not replace the waterstops, groundwater will continue to leak into the Lower Penstock Expansion Joint (LPEJ) Chambers, transporting fines and potentially causing settlement of the chamber that will require mitigation to maintain compliance to FERC Dam Safety requirements for LPS. We have observed settlement of the Unit 3 LPEJ Chamber at present. If the leakage issue and joint degradation is not addressed, fines will continue to be transported into the LPEJ chamber leading to continued settlement up to and including the requirement to be make unit(s) unavailable to prevent penstock binding and potential failure.

Additionally, if the “Do Nothing” option is selected, there will be continued O&M costs associated with injecting grout in the LPEJ chamber(s) waterstops to temporarily reduce the amount of leakage into the expansion joints, which has been proven to be a short term fix (see grouting history attachment).

Alternative Selected:

Alternative 1 was selected as it prevents groundwater and fine soils from being transported into the LPEJ Chamber(s), addressing the cause of voids in Transformer Alley. It prevents further settlement of the LPEJ Chamber(s), which ensures the units can continue operating through the next license period.

Alternative 1 (conventional waterstop) is a proven technology that is able to accommodate seasonal movements, requires minimal maintenance and has an expected life of 50 years. The groundwater would need to be dewatered, which is included in the cost. The estimated cost of Alternative 1 is $950,000 per chamber. Alternative 1 in total costs $7,500,000 and has minimal ongoing maintenance over the lifetime of the waterstop.

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Project Benefits:
Replacing the waterstops stabilizes the LPEJ chambers and penstocks from additional settling movement as fine soils will no longer be transported through the waterstop by groundwater and leading to undermining the LPEJ chambers. This also eliminates the threat to generation due to the penstock binding potential caused by LPEJ chamber settlement and reduces the risk of a potential dam safety failure mode further allowing the units to maintain expected operational goals for the next license period. This also eliminates the cause of voids / depressions in transformer alley allowing that area to be resurfaced that to date has been avoided due to risk of damage by depressions. This further eliminates O&M costs associated with grout injection in the expansion joint chambers that have proven to be only a temporary solution.

Present Need:
The waterstops need to be replaced in order to prevent the lower penstock expansion joint chambers from settling and stop the formation of new voids in transformer alley. This also reduces costs associated with additional inspection and monitoring of the LPEJ chambers and costs associated with additional sand removal from the station sump and oil/water separator.

Timing Impact – Is an outage required?	
Estimated Outage Duration if needed	NA
Desired implementation year:	2020
Specify the impact if the recommended implementation year is changed:	If the project is delayed, more settlement of the LPEJs could continue to the threshold where the unit(s) may need to remain unavailable until the problem is addressed and more expensive repairs may be necessary.

Engineering and Conceptual Development
Provide the status of engineering and conceptual development below. Is additional engineering required to provide adequate cost/benefit information to fully evaluate the project? If yet, has conceptual funding been requested for funding been built into this request?
A detailed engineering options study was conducted by Schnabel Engineering to determine three options to address this, but additional engineering will need to done in early 2020. Additional engineering will be needed for dewatering.

Cost Estimation	
Total Estimated Project cost (51% dollars)	~~$3,675,049~~ 14,630,000
Identify funding that has already been spent or committed, if any. (Whole dollars)	$96,200
Contingency included in the estimated project cost in $	$551,257

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• Was the estimate developed based on a previous project of similar size and scope? • Was a formal estimate completed based on detailed engineering? • Was a formal estimate completed based on a conceptual engineering design? • Was an informal estimate done based on the recommended project concept? • If an informal estimate was done, please identify the basis for having confidence in this estimated cost. • The project planning workbook provides an excellent tool to support this process. If an estimate has been completed, provide the estimate with the submittal.
The construction budget estimate was based on a preliminary estimate from a contractor working with Schnabel Engineering on constructability. This value was added into the planning workbook. Project management and overheads were added to this estimate to get spending for 2020 and 2021. The budget assumes three LPEJs would be done in 2020 and the remaining three will be done in 2021. The final dollars will be added to the LTFP after detailed engineering with more detailed cost estimates. This estimate is assuming we would do option 1. Updated based on actual costs for the waterstop replacement construction, engineering, associated dewatering, asset monitoring and Unit 3 stabilization in 2021. Costs went up due to bids coming in higher than originally estimated and the costs of stabilizing Unit 3 chamber were added in. Closeout dollars were added to 2024.

Requested Cash Flow (whole dollar values): 51% Dollars	
Year	Dollar Value
2020	$403,826
2021	$5,620,000
2022	$3,878,000
2023	$2,703,000
2024	$25,500

Priority Code	
• Select a recommended project priority code and provide a basis.	
• Priority code table provided below	
Priority code	**Basis**
5	If the Lower Penstock Expansion Joint Chambers continue to allow the transport of water and sediments, the chambers could continue to settle, which could lead to a penstock to bind and a forced unit outage or penstock failure.

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Priority Basis Chart		
Rank	Title	Definitions
1	Legal, Regulatory	These are the items that CEC is required to do without flexibility
2	Safety	Safety items that must be addressed within one year due to hazard to employees.
3	Strategic	These are board approved projects, submitted outside the standard budget and LTFP processes. This work instruction does not apply for these items.
4	Critical Reliability	Deferral has a high likelihood of significantly impacting asset reliability in the near term. This category also includes spending to address long standing safety issues and regulatory commitments that have some flexibility with respect to implementation.
5	Important Reliability	Deferral has a high probability of impacting asset reliability. Projects that will significantly improve unit performance, key performance indicators will generally be in this category.
6	Desired Reliability	Repeated deferrals will impact long term reliability. One time short term deferral, while undesirable, is unlikely to impact reliability in a significant way. In general, items that are in this category in future years are good candidates for the up levers list.
7	Reliability and Performance Improvement	Spending that, while desirable, is lower priority. These items will be the primary candidates for the capital and major maintenance down levers lists.

Project Initiation Submittal Date:	5/28/19 (PID) 10/1/219 (CAD)

Upload to SharePoint Site per workflow:

Concept Approvals Only

On approval, this document authorizes the Generation Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization. EPM will begin work on this project when a completed and approved charter is in place

Approvals:
Approvals will be obtained via SharePoint Workflow according to the Total Project Value listed below

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Director Generation Planning (Approval limit $250k)
Director Asset Strategy Generation (Approval limit $250k)
Executive Director of Planning (Approval limit $500k)
VP of Electric Grid Integration (Approval limit $2,000k)
SVP of Transformation, Engineering & Ops (Approval limit $10,000k)

Additional Supporting information:
LPS Lower Penstock Expansion Joint Grouting History

Change the Project Stage on SharePoint to appropriate Project Stage of workflow.

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Consumers Energy Count on Us®

Concept Approval

Covert Generating Station Generator Step-Up transformer replacement.

Date: 12/1/2023

Prepared by: John Slinkard and Paul Ohep

Figure 1. Covert Generating Station aerial view.

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

Executive Summary

Addressing the critical need for operational reliability at Consumers Energy's power generation facilities, this proposal explores the optimal strategy for ensuring a backup Generator Step-Up (GSU) transformer is readily available at Covert Generating Station. The urgency of this project stems from the increased risk of transformer failure due to the presence of corrosive sulfur, coupled with long procurement lead times of 2 to 4 years for GSU transformers.

Four options were meticulously evaluated: overhauling the existing GSU, procuring a new site-specific spare GSU, exploring leasing alternatives, and purchasing a single larger spare GSU that could serve both Covert Generating Station and Zeeland Generating Station.

Option 2, which proposes the procurement of a site-specific spare GSU, has emerged as the most viable solution. It ensures immediate availability of a replacement transformer, minimizing downtime and associated financial losses. This option mitigates potential complications arising from multiple installations associated with utilizing a leased GSU or usage of multi-site transformer. Moreover, it also offers the opportunity for CE to recover some costs through leasing agreements with other utilities.

This initiative, backed by the Asset Strategy Group, ensures that Covert Generating Station is equipped to address transformer failures swiftly and efficiently. Implementing this solution safeguards our ability to deliver reliable power to our consumers and demonstrates a strategic foresight in asset management.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$16,355,000

Proposed Start Implementation Year

2024

Project Span Whole Years

4 Years

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Problem Description

The Covert Generating Station features a combination of three gas turbine-powered plants and three steam turbine-powered plants, arranged in a one-on-one combined cycle configuration. This setup entails that each gas turbine unit powers the secondary winding of a three-winding transformer (GSU), while the corresponding steam-powered unit powers the tertiary winding.

GSU Explained: A Generator Step-Up (GSU) transformer is a critical component that steps up the voltage generated by a turbine before it is transmitted to the grid, ensuring efficient power transfer.

A GSU's failure can lead to significant power generation issues. Specifically, the GSUs at Covert are rated for 500 MVA and are equipped with forced oil and forced air cooling mechanisms. If a GSU were to fail, both the gas and steam turbine units connected to it would be unable to transmit power, leading to a potential loss of up to 400 MVA of generation capacity. This would prevent the generation of market value for Consumers Energy and its customers.

Further complicating the situation is the long lead time of 2 to 4 years for procuring a replacement GSU, and the lack of spare units at other facilities. The plant is projected to operating until at least 2040, thus making it crucial to have a reliable GSU ready for replacement.

Figure 2. Typical Step-Up transformer

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Alternative Solutions/Alternatives Considered

1. **Do Nothing – Cost: $130.9 million** **($16.4M for new GSU plus $114M in energy value and potential capacity lost)**

   This approach involves continuing the operation without procuring a spare GSU, essentially accepting the risks associated with a potential GSU failure. When under load, a failure of the GSU transformer is a serious concern, not only because of the high financial costs but also due to safety implications. Such a failure could lead to cascading consequences where other critical equipment, such as the generator or the 345kV breaker, could be damaged or fail.

   The GSU transformer is a critical component, and its failure would render the combined plant, consisting of one steam turbine and one gas turbine, inoperative. An overhaul or replacement of a GSU transformer, in the event of a failure, is expected to take a minimum of 12 months.

   There is an estimated 20% risk that the generator or the 345kV breaker might be damaged during an in-service failure of a GSU. The replacement cost for the generator is estimated at $20M and for a 345kV breaker, it is around $1M. These costs are not included in the alternative cost.

   The economic considerations for not having a spare GSU transformer on site, with an anticipated downtime of a full year, are significant. The breakdown for both potential capacity lost, and average energy value lost are as follows:

   Capacity value potential loss impacts - $66.6M:

   For this option, where the procurement and installation of the new GSU transformer are involved, a critical consideration is the multi-year financial impact, as determined by the Midcontinent Independent System Operator (MISO). MISO calculates and accredits capacity based on a rolling three-year average of historical capacity credits. Therefore, any outage that exceeds the 30-day threshold can significantly affect these calculations.

   Given the expected duration of the entire process is about one full year, this threshold will be exceeded. This prolonged downtime will, therefore, trigger the multi-year financial impact, altering the capacity accreditation and potentially affecting financial projections for several years.

   Average ZRC Reduction Post-Outage:

   - In the event of a 365-day outage, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for each season (based on 354 ZRCs per season).
   - This scenario leads to a potential annual daily loss of 118 ZRCs per season for each of these three years (354 ZRCs-236 ZRCs).

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2. **Cumulative Potential Loss of Capacity Value Over Three Years:**
    - The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the 365-day outage and the additional 118 ZRCs/day applied over 90 days times four seasons over the subsequent three years.
3. **Calculation of Total Potential Loss:**
    - To estimate the potential capacity loss for this option:
        1. Calculate the Reduced Capacity Credits:
            - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
            - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).
        2. Add the Immediate Loss:
            - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (354 in this case). This gives us the immediate loss in capacity credits for that outage (31,860).
        3. Calculate the Total Revenue Loss:
            - Add the results from steps 1 and 2 to get a combined figure (63,720).
        4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)
    - This leads to a total estimated potential loss of capacity value of an estimated $16.6 million per season over the three-year period following the outage.
    - The total potential capacity value impact for a one-year outage, accounting for all four seasons, and including the impact on the subsequent three years is given by multiplying $16.6 million times four, resulting in an estimated $66.6 million potential impact.

<u>Average energy value estimated loss - $47.9M:</u>

For the scenario of a transformer failure with no spare on-site, there is a substantial potential loss in energy production due to an assumed 365-day outage. This loss can be quantified by considering the Net Energy Value (NEV) for that station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

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This figure represents the potential average revenue loss for the Covert Generating Station during the outage period.

This analysis emphasizes the potential financial impact of not having a spare GSU on-site. Considering both the immediate potential loss of capacity value due to the outage, the reduced capacity credits in the subsequent three years as well as the energy value lost.

Overall advantages and disadvantages:

- **Advantages:** There is no immediate expenditure or need for storage.
- **Disadvantages:** This approach carries the highest long-term cost and risk, including the potential loss in revenue, safety hazards, and extended downtime for repairs or replacements.

2. Procure and Store a Spare GSU on-site Cost: $31.7M (including $15.3M in potential capacity value and energy value losses)

This alternative solution involves the strategic decision of procuring and maintaining a spare GSU transformer at the plant site.

- The procurement cost of the spare GSU is quoted at $12.5 million, based on an estimate from a well-known manufacturer of power transformers.
- The cost of constructing an appropriate foundation at the Covert site for the spare GSU is projected to be $200,000, as estimated by a specialized civil engineering company.
- Additional expenses related to engineering, Stand Up Transformer (SUT), and other logistical aspects are anticipated to be around $280,000.
- In the cost estimation process for large capital projects, it is a common industry practice to incorporate budget to account for unforeseen expenses that might occur during the project. The typical industry standard for such budgets can vary from 5% to 10% of the total project cost, depending on the project's complexity and risk level. For this specific project, we have included a conservative budget of 5% to the total estimated cost, considering our high predictability and control over project variables. Additionally, to cover regular operational and administrative expenses related to the project, a 20% overhead has been factored in. Consequently, the comprehensive cost estimate for this option now stands at $16.355 million (internal estimate).
- The economic considerations for procuring a spare GSU for the Covert Generating Station, with an assumed downtime of 31 days, are significant but more manageable when compared to leasing.

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The breakdown for potential capacity lost, and average energy value lost are as follows:

Capacity value potential loss impacts - $11.2M:

For this option, the installation of the new GSU transformer stored on-site is anticipated to take approximately 30 days or slightly more. Specifically, if an outage exceeds 30 days, it triggers a potential multi-year financial impact due to the way MISO calculates and accredits capacity over time.

In this scenario, we will assume a worst-case scenario outage duration of 31 days within a single season. This results in the Station losing all 354 ZRCs (Zonal Resource Credits) for the season. This loss of ZRCs would result in a multiyear capacity impact, as capacity accreditation by MISO is based on a three-year average of historical capacity credits. It is important to note that if the outage had been limited to 30 days or less, or if the outage spans across parts of two separate seasons there would be no loss of ZRCs for either season, and consequently, no capacity impact.

Average ZRC Reduction Post-Outage:

- In the event of a 31-day unplanned outage during a single season, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for that season (based on 354 ZRCs per season).
- This scenario leads to a potential daily capacity loss of 118 ZRCs across an entire season (90 days) for each of these three years (354 ZRCs-236 ZRCs).

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the 31-day outage and the additional 118 ZRCs/day applied over 90 days (full season) over the subsequent three years.
- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:
        - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
        - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).

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2. Add the Immediate Loss:
    - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (31 x 354 in this case). This gives us the immediate loss in capacity credits for that outage (10,974).
3. Calculate the Total Revenue Loss:
    - Add the results from steps 1 and 2 to get a combined figure (42,834).
4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)

- This leads to a total estimated potential loss of capacity value of an estimated $11.2 million over the three-year period following the outage.

Average energy value estimated loss – $4.1M:

For the Covert Generating Station, under the scenario of leasing a spare GSU, there is a substantial potential loss in energy production due to an assumed 31-day outage. This loss can be quantified by considering the Net Energy Value (NEV) of the station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 31-day outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($47.9M/year)/(365days/year)) x 31 days = $4.1M

This figure represents the potential average revenue loss for the Covert Generating Station during the outage period.

On-site spare overall advantages and disadvantages:

Advantages:

- Having a spare GSU on-site ensures rapid restoration of operations in case of a failure, thereby minimizing revenue losses.

Disadvantages:

- The approach necessitates a sizable upfront investment and requires additional storage space on-site.

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3. **Leasing a GSU Transformer - $36.8M in energy and potential capacity losses plus $720,000 over 20 years ($36,000/year):**

This alternative explores the feasibility of entering into a lease agreement for a GSU transformer. Leasing for units of this size is a standard approach, often entailing a reservation fee of an estimated $3,000 per month. Over a span of 20 years, which is the expected life expectancy of such units, the total cost amounts to $720,000. This translates to an annual expense of an estimated $36,000. However, leasing comes with certain conditions and restrictions:

- The owner of the leased equipment can request the unit back at any point, based on their requirements.
- Availability is not guaranteed as the unit may not be on hand when needed. An industry search and examination of the transformer strategic reserve indicated that there are currently no spare units available for lease.
- Potential capacity value and energy value impacts.

Capacity value potential loss impacts - $25.0M:

For the leasing option in the GSU project, we are assuming the occurrence of an unplanned outage at the most inopportune time, specifically a scenario where a 90-day outage spans across two MISO seasons. The outage is projected to last for 31 days in one season, with the remaining duration extending into the next season. This situation results in the loss of Zonal Resource Credits (ZRC) capacity value for two separate seasons, which, due to MISO's capacity accreditation method based on a three-year historical average, effectively doubles the amount of lost capacity value over the next three years.

Average ZRC Reduction Post-Outage:

- In the event the postulated scenario, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for that season (based on 354 ZRCs per season).
- This scenario leads to a potential daily capacity loss of 118 ZRCs across an entire season (90 days) for each of these three years (354 ZRCs-236 ZRCs).
- For the unplanned 90-day outage spanning across two seasons assumed in this case, the 354 ZRCs will be multiplied times two to yield 708 ZRCs.

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the first 31-day outage in one season and then for the 59-

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day outage on the following season. It also adds 118 ZRCs/day applied over 90 days (full season) over the subsequent three years.

- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:
        - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
        - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).
        - This result is multiplied times two to account for the impacts to a second season. (63,720)
    2. Add the Immediate Loss:
        - Next, multiply the number of days the plant is offline by the total ZRCs lost (354 in this case). This gives us the immediate loss in capacity credits for the 90-day outage (31,860).
    3. Calculate the Total Revenue Loss:
        - Add the results from steps 1 and 2 to get a combined figure (95,580).
    4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)
- This leads to a total potential loss of capacity value of an estimated $25.0 million over the three-year period following the outage.

<u>Average energy value estimated loss - $11.8M:</u>

For the Covert Generating Station, under the scenario of leasing a spare GSU, there is a substantial potential loss in energy production due to an assumed 90-day outage. This loss can be quantified by considering the Net Energy Value (NEV) of the station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 90-day outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($47.9M/year)/(365days/year)) x 90 days = $11.8M

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Leasing option overall advantages and disadvantages:

Advantages: Leasing could offer a lower upfront cost compared to purchasing a new or spare unit outright.

Disadvantages:

- Unpredictable Availability: The availability of a leased GSU is uncertain, which can pose a significant operational risk.
- Recall Risk: There's always a possibility that the unit's owner may recall the GSU at any time, potentially causing unplanned operational downtime.
- Financial Risk: In the event of a plant shutdown due to the unavailability of a GSU, there could be a substantial financial impact.

4. **Purchasing a Larger, Multi-Site GSU Transformer – Cost: $58M - $27.4M plus $30.6M in potential capacity and energy value losses:**

This alternative considers purchasing a single larger spare GSU transformer that is suitable for both Zeeland Generating Station (ZGS) and Covert Generating Station (CGS). Internal economic models project the final costs to be estimated at $58M when factoring in additional expenses such as reinstallation of original overhauled GSU, modifications needed to accommodate the larger GSU at ZGS, additional outage costs and potential capacity and energy value losses. The breakdown of the internal estimate includes:

- $14M for the larger GSU transformer.
- $3M for transportation from another site and modifications needed at ZGS to accommodate bigger transformer.
- $1.25M for design and installation needs.
- $4.1M overhaul and re-installation cost of original GSU.
- $3.75M overhead estimate.
- $1.3M contingent cost to ensure compatibility with the original infrastructure. (5%)

Financial impacts:

For this option, which involves utilizing a common spare GSU for both Covert and Zeeland Generating Stations, several scenarios need to be considered to understand the financial implications fully. These scenarios vary depending on where the spare transformer is stored, and which site experiences a transformer failure. For this analysis, the worst-case scenario is assumed: the spare transformer is staged at Covert Generating Station, and a failure occurs at Zeeland Generating Station's Phase 2 transformer.

Assumptions:

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For the multi-site spare option of the GSU project, the approach assumes two distinct outages, each with different implications for potential capacity value losses:

1. **First Outage - Unplanned and Single Season:**
    - The first outage, lasting 31 days, is considered unplanned and is expected to occur entirely within a single MISO season.
    - As this outage exceeds the 30-day threshold, it results in the complete loss of Zonal Resource Credits (ZRC) capacity value for that season. This loss also impacts the subsequent three years due to MISO's method of calculating capacity credits based on a three-year historical average.
    - This initial outage accounts for the period required to replace a failed GSU with the spare transformer.
2. **Second Outage - Planned and Spanning Two Seasons:**
    - The second outage, also spanning 31 days, is planned strategically to occur across the transition between two MISO seasons.
    - By dividing the outage between two seasons, each portion remains under the 30-day threshold in any single season, thereby avoiding additional ZRC capacity value penalties.
    - This outage involves reinstating the original GSU after its refurbishment, replacing the temporarily installed spare transformer.

<u>Capacity Value Potential Losses – $17.4M</u>

Average ZRC Reduction Post-Outage:

- In the event of a 31-day unplanned outage, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 366.7 ZRCs per year for that season (based on 550 ZRCs per season at Zeeland).
- This scenario leads to a potential daily capacity loss of 183.3 ZRCs across an entire season (90 days) for each of these three years (550 ZRCs-366.7 ZRCs).

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 550 ZRCs during the first 31-day unplanned outage and the additional 183.3 ZRCs/day applied over 90 days (full season) over the subsequent three years.
- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:

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1. We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (366.7 in this case) and the maximum possible ZRCs of 550.
2. Multiply this difference (183.3) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (49,491).

2. Add the Immediate Loss:
   - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (550 in this case). This gives us the immediate loss in capacity credits for that outage (17,050).
3. Calculate the Total Revenue Loss:
   - Add the results from steps 1 and 2 to get a combined figure (66,541).
4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)

This leads to a total estimated potential loss of capacity value of an estimated $17.4 million over the three-year period following the first unplanned outage.

For the multi-site spare option in the GSU project, the second outage is assumed to be planned to occur between MISO seasons. This careful timing ensures that the 31-day planned outage does not fall entirely within a single MISO season, thereby avoiding any loss of Zonal Resource Credits (ZRC) and potential capacity value.

Average energy value estimated loss - $13.2M:

For the Zeeland Generating Station, under the scenario of a multi-site spare GSU, there is a substantial potential loss in energy production due to two projected 31-day outages (62 total days). This loss can be quantified by considering the Net Energy Value (NEV) and the plant's generation capacity.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $77.5M per year for the Zeeland Phase 2 Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 62-day total outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($77.5M/year)/(365days/year)) x 62 days = $13.2M

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This figure represents a significant potential revenue loss for the Zeeland Generating Station during the outage period.

Overall advantages and disadvantages for the multi-site spare option:

Advantages:

- **Flexibility**: A single spare unit could cater to multiple sites, potentially offering more operational flexibility.

Disadvantages:

- **Higher Costs**: The overall cost is significantly more than the initial purchase price when factoring in the additional work required.
- **Complexity**: This option could entail more logistical and operational complexities due to the constant movement and installation work.

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Recommended Alternative: #2 – Purchase a spare Covert specific GSU

Option 2 emerges as the best long-term solution for ensuring a reliable spare GSU transformer at the Covert site. It eliminates dependencies on external variables and logistics that could influence the availability of the spare GSU. Additionally, the purchased unit could seamlessly be integrated as the new GSU at the location, thereby mitigating the need for multiple installations of temporary spares.

Project Benefits and Objectives:

1. **Reduction in Downtime and Financial Losses:** Opting for a dedicated spare GSU for Covert significantly reduces unit downtime in case of GSU issues or failures. This preemptive measure results in lowered financial losses during such events.
2. **Facilitation of Proactive Engineering Design and Planning:** Having a spare GSU readily available allows for easier engineering design and forward planning. This ensures that the installation of a spare or replacement GSU can be executed efficiently ahead of any emergent needs.
3. **Mitigation of Compatibility Issues:** This option mitigates potential challenges associated with installing GSUs not specifically designed for the Covert site, system, or application. It also prevents the complexities and risks of multiple installations within a short time.
4. **Revenue Recovery through Lease Agreements:** Owning a spare GSU provides Covert with the opportunity to enter lease agreements with other utilities that may require a spare, thereby enabling cost recovery over time.
5. **Addressing Increased Risk of Failure:** The oil analysis of Covert's transformers indicated the presence of chemicals for corrosive sulfur, putting them at an increased risk of failure. Having a spare GSU acts as a failsafe, ensuring continuity in operations while mitigating actions are taken.

Conclusion: Given the considerations, Option 2 proves to be strategically sound, financially prudent, and operationally efficient. It ensures reliability, provides contingency against unforeseen GSU failures, and aligns well with long-term planning objectives, making it the most favorable choice.

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Scope of Work

The aim of this project is to ensure continuous operation at the Covert site by procuring and installing a spare Generator Step-Up (GSU) transformer that can be readily deployed at any GSU location within the facility.

Scope Description:

- **Procurement of Spare GSU Transformer:**
  The project entails defining the technical specifications for a compatible GSU transformer, initiating a procurement process, and ensuring quality assurance and compliance testing for the selected unit.
- **Infrastructure Development:**
  A dedicated foundation will be designed and constructed to facilitate quick installation of the transformer at any GSU location in Covert. This includes establishing a power supply and installing necessary accessories to maintain the transformer in an operational, "ready to use" condition.

Funding and Timing

- No funding has been previously committed for this project.
- No outage is required for this project.
- Desired implementation year: 2024
- Impact if the recommended implementation year is changed: Changing the recommended implementation year could lead to potential delays in addressing and mitigating the risks associated with GSU failures at the Covert site. Consequently, this may result in extended downtimes and increased financial losses, while also potentially jeopardizing the reliability of power supply from the plant.

System Engineer

- System Engineer: Keith R. Grzegorczyk

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Conceptual Estimate

Year	Loaded Cost	Description
2024	**$1,765,000**	Project engineering for Spec/RFQ/Procurement activities/Pos to secure support, Initial payment.
2025	**$25,000**	Engineering and resource needs (no payments required to SMIT)
2026	**$4,763,000**	Estimated progress payment, construction of spare GSU storage foundation, engineering, quality assurance travel.
2027	**$9,802,000**	Final payment, delivery, construction of storage foundation, closeout.

Total Cost: $16,355,000

Asset Strategy Approval Comments

The Asset Strategy Group strongly recommends approval, given the challenges currently faced at Zeeland Station and Covert Station and the extended lead times for transformers, now ranging from 2 to 4 years. Ensuring that our key capacity plants have a spare GSU on hand is of utmost importance.

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Approvals

Title	Approver Name	Date
Generation Planning Manager John D Slinkard	DocuSigned by: John D Slinkard D640D95639854BE...	1/9/2024 | 7:55 AM EST
Director of Generation Asset Strategy Scott Hugo	DocuSigned by: Scott Hugo 31EC7A87E8E34C6...	1/8/2024 | 9:46 AM EST
Exec Director of Electric Planning Richard T. Blumenstock	DocuSigned by: Richard T. Blumenstock C3E2F0B9020949B...	1/10/2024 | 9:16 AM EST
VP of Electric Grid Integration Srikanth Maddipati	DocuSigned by: Srikanth Maddipati 67DA622787D2488...	1/10/2024 | 10:00 AM EST

Concept Approval

Zeeland Phase 2 Gas Turbine upgrades.

Date: 5/23/2025

Prepared by: Paul Ohep

Figure 1. Zeeland Generating station.

Executive Summary

The Zeeland Generating Station, a critical asset in Consumers Energy's portfolio, is set to undergo significant upgrades to enhance its performance and reliability. This project focuses on the Zeeland Phase 2 gas turbines, leveraging advanced technologies to support the transition to a more renewable energy portfolio.

Problem Description

The Zeeland Generating Station operates with a combination of four gas turbines and one steam turbine in a combined cycle configuration. These units are maintained under a Long-Term Service Agreement (LTSA) with GE, ensuring their periodic overhaul. In 2028, the Zeeland Phase 2 site is scheduled for Major Inspection outages, presenting an opportunity to implement substantial improvements. The primary goal is to replace the "hot" or combustion components of the turbines, which degrade over their 32,000-hour design lifespan.

Proposed Solution

The project proposes the implementation of two advanced technologies:

- **Advanced Gas Path (AGP)**: This technology aims to elevate the output and efficiency of the turbines by replacing existing parts with high-performance components, resulting in notable improvements in output and heat rate efficiency. Specifically, the AGP upgrade is expected to improve output by 51 MW at full/base load and enhance heat rate efficiency by 2.5%.
- **Axial Fuel Staging (AFS)**: This upgrade enhances the turbines' output turndown capability, allowing for lower load operations while maintaining emissions compliance. This flexibility is crucial as Consumers Energy moves towards a diverse energy portfolio reliant on renewable sources.

Alternative Solutions Considered

- **Do Nothing**: Maintaining the current setup without upgrades would result in unrealized savings of $40.7M and a decrease in market competitiveness and operational flexibility.
- **Install AGP Only**: This option involves an initial capital investment of $51.0M, with projected incremental revenue of $121.8M through 2040 and a favorable NPV gain of $45.5M.
- **Install AFS Only**: This option was not pursued further due to significant financial hurdles and the lack of additional capacity revenue.

Recommended Option

The recommended option is to install both AGP and AFS technologies, with an initial investment cost of $55.7M. This comprehensive upgrade is expected to provide superior flexibility, emissions compliance, future market competitiveness, and standardization benefits. The potential NPV savings are estimated at $40.8M from 2025 through 2040.

Funding and Timing

- **No prior funding committed**.
- **Scheduled outage required**.
- **Desired implementation year**: First year spend in 2025, installation in 2028.
- **Impact of delay**: Delaying implementation beyond 2028 poses significant risks and missed opportunities, potentially delaying benefits realization by 5-6 years.

Conclusion

The AGP-AFS upgrade is a forward-thinking approach that promises significant performance enhancements, substantial long-term financial benefits, and improved adaptability to support Consumers Energy's energy portfolio. This investment is justified by the considerable potential savings and the strategic alignment with the transition to renewable energy sources.

Financial Summary

Estimated investment: **$55.7M total NPV cost based on 13.59% charge rate ($44.9M budget for LTFP)**

Proposed Start Implementation Year and duration

First year spend 2025, installation year 2027.

Problem Description

The Zeeland Generating Station, a key asset in Consumers Energy's portfolio, operates using a combination of four gas turbines and one steam turbine, configured as a combined cycle plant. These critical units are maintained under a Long-Term Service Agreement (LTSA) with GE, which ensures their periodic overhaul and upkeep, restoring them to near-original condition. A crucial aspect of these overhauls, conducted during major outages managed by GE, involves replacing the "hot" or combustion components of the turbines. These components typically degrade over their 32,000-hour design lifespan.

In 2028, the Zeeland Phase 2 site is scheduled for Major Inspection outages, presenting an opportune moment to undertake substantial improvements in both Phase 2 gas turbines. This project is centered around the implementation of upgraded replacement parts that significantly enhance performance and reliability.

Advanced Gas Path (AGP): This technology aims to elevate the output and efficiency of the turbines. AGP involves replacing existing turbine and combustion parts with high-performance, technologically advanced parts. The enhancement is expected to deliver notable improvements in output and heat rate efficiency, while maintaining the same level of reliability.

Axial Fuel Staging (AFS): In conjunction with AGP, AFS is another important upgrade. It enhances the turbines' output turndown capability, crucial for flexible operation. This is achieved by replacing and adding advanced combustion hardware, allowing for lower load operations while still adhering to emissions compliance. Such advancements are increasingly vital as Consumers Energy moves towards a diverse energy portfolio heavily reliant on renewable sources. The AFS technology is instrumental in ensuring that the Zeeland Phase 2 combined cycle gas turbines maintain operational flexibility to support this transition, accommodating the variability inherent in renewable energy sources.

Alternative Solutions/Alternatives Considered

1. Do Nothing – Cost: $40.8M (unrealized savings)

This alternative involves maintaining the current status quo at Zeeland Generating Station, where there is no immediate requirement to replace the turbine and combustion parts with higher performing components.

Cost Implication

- **Cost:** $40.8M (Unrealized Savings) + Unrealized AFS benefits
- **Impact:** Choosing this option results in forgoing the potential savings that could be achieved through Alternatives #2 and #3.

Detailed Analysis

- **Unrealized Potential Savings:** If neither Alternative #2 (AGP installation) nor Alternative #4 (AGP & AFS installation) is selected, Zeeland Phase 2 stands to lose potential savings $40.8M with AGP & AFS over the period from 2025 to 2040. These savings are detailed in the AGP & AFS alternative description.
- **Market Competitiveness and Flexibility:** Without implementing either of these advanced technologies, there is a significant risk that Zeeland Phase 2 will become less competitive and flexible in the rapidly evolving electrical generation market. The introduction of renewable energy sources demands greater flexibility from conventional generation assets, which this option fails to address.
- **Opportunity Cost:** The cost of this "Do Nothing" option is effectively the lost opportunity to save and improve. While not investing in upgrades might seem to save money in the short term, it equates to a considerable loss in terms of unrealized savings and market adaptability.

Opting to maintain the current setup without upgrades translates into a significant loss of potential savings and a decrease in market competitiveness and operational flexibility. This option, while seemingly cost saving, could lead to substantial opportunity costs and a failure to adapt to the changing dynamics of the energy market.

2. Install AGP only- Cost: initial capital investment of $51,011,000

This alternative entails the installation of an Advanced Gas Path (AGP) in Zeeland Phase 2's gas turbines, a significant upgrade to enhance performance and efficiency.

Financial Overview:

- **Cost:** Total customer cost of $51M over the life of the upgrade in today's dollars based on a fixed charge rate of 13.59% (Based on internal estimates incorporating contractor quotes and overhead loadings).
- **Revenue:**
  - The projected incremental revenue for this project is estimated to be $121.8M through 2040.
  - The projected incremental capacity revenue is projected to be $34.8M through 2040.
- **Impact:** The AGP only option will provide a favorable NPV gain of $45,524,000 through 2040. This is based on an Aurora internal economic model performed in February of 2025.

Table 1 below summarizes the incremental revenues and costs for the AGP only option.

Net Present Value Results	AGP Only case with 588 MW Capacity Revenue Cap
Current Nameplate Capacity (MW)	553
Upgraded Capacity (MW)	604
NPV, Incremental Energy Revenue AGP only (K$)	($121,803)
NPV, Incremental Capacity AGP only (K$)	($34,846)
NPV, Incremental Operating Costs AGP only (K$)	$60,114
NPV, Investment AGP only (K$)	$51,011
NPV, Total Value of Phase 2 Upgrade (K$)	**($45,524)**

Table 1. Revenue and costs table for AGP only option

Economics modeling assumptions:

The economic model for this option is based on the following AGP assumed features:

- Capacity value is assumed at 75% of the cost of new entry.
- Capacity accreditation is estimated at 90% for all seasons.

Output Improvement

- **Improvement:** +51MW at Full/Base Load, based on GE's quotes.

Heat Rate Improvement

- **Improvement:** -2.5% Efficiency Improvement across Load Range.

Components and Work Scope:

- AGP Parts: Includes all necessary AGP components, new Gas Control Valves (GCVs), and Stop-Ratio Valve (SRV). The cost is escalated from the 2025 base by 3% per year.
- Comprehensive Upgrade: The upgrade involves replacing hot parts with AGP components, transitioning from DLN2.6 combustors to DLN2.6+ to enable AGP performance enhancements, increasing the shaft torque limit rating, revising control curves, and adjusting control constants.
- Turbine Model Change: These modifications will upgrade the turbine model from 7FA.03 to 7FA.04.
- GCVs/SRV Replacement: To realize the full potential of the AGP/DLN2.6+ work, replacing the GCVs/SRV is crucial. This will also address the gas supply pressure limitations in the upper output range by reducing approximately 25 psi of pressure drop across these components.

Financial Outlook:

The AGP-only upgrade, with a comprehensive scope of work to elevate turbine efficiency and performance, represents a strategic investment towards modernizing the Phase 2 turbine. The project is anticipated to result in significant Net Present Value (NPV) savings of $45.5 million over a fifteen-year period, to 2040. This includes considerations for incremental energy and capacity revenue, along with a detailed analysis of operating costs and investment requirements.

3. Install Advance Fuel Staging only

The AFS-only option explores the introduction of Axial Fuel Staging technology to the turbines at Zeeland Generating Station, focusing solely on this upgrade without the inclusion of Advanced Gas Path (AGP) components. The AFS technology is designed to enhance combustion efficiency and reduce emissions, aligning with operational improvements and environmental compliance objectives.

Although the AFS-only upgrade offers notable operational benefits, such as enhanced emissions control, it encounters significant financial hurdles. These challenges stem from a lack of additional capacity revenue and the inability of increased energy revenue alone to cover the substantial upfront investment and ongoing operational costs. Crucially, the AFS-only strategy misses out on the considerable operational improvements associated with AGP enhancements, including a capacity boost of 51MW and a heat rate improvement of 2.5%.

Based on prior experience with modeling AFS only upgrade with Phase 1 and vendor recommendations, it was decided not to look further into this option as it is not typically installed on its own and will most certainly result in losses over time (as modeled for phase 1 upgrade).

4. Install AGP and AFS – initial investment cost - $55.7M – Recommended option

This alternative proposes a comprehensive upgrade to the Zeeland Phase 2 gas turbines by installing both Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies.

Financial Overview:

- **Cost:** Long term financial budget of $44.9M. Total customer cost of $55,669,000 over the life of the upgrade in today's dollars based on a fixed charge rate of 13.59% (Based on internal estimates incorporating contractor quotes and overhead loadings).
- **Impact:** Potential Net Present Value savings of an estimated $40.793M from 2025 through 2040 from the upgrade. This is based on an Aurora internal economic model performed in February of 2025.

Components and Work Scope:

- **AGP Parts and Work:** AGP components include new Gas Control Valves (GCVs), Stop-Ratio Valve (SRV), and related replacement work.
- **Comprehensive Turbine Upgrade:** Incorporates the scope of Alternative #2 (AGP installation) while adding AFS components. This includes replacing hot parts with AGP components, upgrading combustors to DLN2.6+, and making necessary revisions to control curves and constants.
- **Turbine Model Change:** These upgrades will transform the turbine model from 7FA.03 to 7FA.04.
- **Enhanced Gas Supply Efficiency:** Replacement of GCVs/SRV will mitigate gas supply pressure limitations in high output ranges by reducing pressure drop.

AGP + AFS upgrade Economic benefits breakdown and assumptions:

Table 3 below shows a summary of the NPV incremental costs and revenues for this option.

Net Present Value Results	AGP+AFS full upgrade
Current Nameplate Capacity (MW)	553
Upgraded Capacity (MW)	604
NPV, Incremental Energy Revenue Full upgrade (K$)	($120,623)
NPV, Incremental Capacity Full upgrade (K$)	($34,846)
NPV, Incremental Operating Costs Full upgrade (K$)	$59,007
NPV, Investment Full upgrade (K$)	$55,669
NPV, Total Value of Phase 2 Full Upgrade (K$)	**($40,793)**

Table 3. Revenue and costs table for AGP and AFS option

Economics modeling assumptions:

The economic model for this option is based on the following AGP assumed features:

- Capacity value is assumed at 75% of the cost of new entry.
- Capacity accreditation is estimated at 90% for all seasons.

Differences between AGP only and AFG+AFS upgrades:

Tables 2 and 3 above show that, based solely on quantitative modeling, the AGP-only upgrade appears to be more valuable by $5M over the next 15 years compared to the full AGP+AFS upgrade. The reason for this is that our model doesn't assign an appreciable impact from lowering the minimum load (when adding AFS) as units are typically chosen based on mid- and max-load capabilities rather than minimum load. Dispatch decisions are made when there is an expected increase in demand.

However, when considering both quantitative and qualitative impacts, the full AGP+AFS upgrade offers significantly more value than the additional ~$4.7M provided by the AGP-only option.

Below is a breakdown of the full benefits of AGP+AFS upgrade over AGP-only option:

1. Flexibility
    - For a Renewable Grid – The flexibility that will be offered in the real world is difficult to model, and we believe it will be very valuable to support a grid that requires its baseload generation (like Ph2) to respond to the flexibility required by Renewable Generation. One main reason we believe this is masked by the modeling is because the model doesn't show the peak LMP highs and lows as much as what actually happens in the real world.
    - Leading to Equipment Reliability – The cost avoidance in equipment reliability due to cycling could be significant (Heat Recovery Steam Generator (HRSG) failures usually add up to many millions of dollars, and Ph2 has two HRSGs) in the future for an extra $4M now due to reducing the number of future shut-downs because Ph2's minimum load can go low enough for a few critical hours, namely for the "shoulder-month" days in Fall and Spring where LMP prices drop significantly for a few hours at night. That critical load reduction could also start to occur more in the afternoon as additional solar generation comes online, requiring two major load-following events where a lower min load capability could be the difference between shutting down for a few hours or staying at minimum load (spinning reserve).

2. Emissions Compliance – AFS will be valuable operationally and legally / for regulatory factors because during start-up, AFS will help Phase 2 get into emissions compliance mode much earlier into the start-up process. This is important, because Ph2's air permit will most likely change as it is changing for Ph1 (due to the AGP part of the upgrades) to include much more strict emissions compliance standards during start-ups (potentially lower emissions rates but also less exceptions for start-up emissions).

3. Future Market Competitiveness – AFS is a relatively new technology, and the growth rate in gas plants adding the technology (and newer plants being built with the technology) is trending toward exponential. By the early 2020s, GE had only 4-5

examples of the technology being used, but 2024 saw two more installations, with 2025/2026 seeing numerous more installations according to GE as stated at the May 2024 7F Users Conference. Utilities are starting to see the major value of the flexibility offered by AFS, and as more plants retrofit or are built new with the technology, ZGS Ph2's flexibility value will remain competitive with the market supporting a more Renewable grid.

4. Standardization and Capital Spares Reduction – The Full Upgrade case would standardize the parts between our Phase 1 and Phase 2 units as they would then be the exact same turbines. That benefit is somewhat difficult to quantify value-wise, but it goes a long way to benefiting reliability, troubleshooting when issues arise, and having spare parts.
5. Installation timing efficiency - Installing the AFS upgrades simultaneously with the AGP (and DLN2.6+) is recommended due to the significant amount of additional fuel routing required for the AFS upgrade.

Overall, the Full Upgrade (AGP & AFS) provides superior flexibility for supporting a grid that is going quickly to Renewables for ~$5M less value out of around $40M savings to our customers over the next 15 years.

Scope of Work

Scope of Work Activities for Erickson's and GE's Major Inspection at Zeeland Phase 2:

1. Erickson's Responsibilities:

- Provide cranes and lifting services as part of the already scheduled and budgeted GE Long-Term Service Agreement (LTSA) Major Inspection work.

2. GE Parts/Software Scope of Supply:

Advanced Gas Path (AGP) Components:

- AGP Stage 1 Nozzle Kit and Support Ring.
- AGP Stage 2 and 3 Nozzle Kits.
- AGP Stage 1, 2, and 3 Bucket Kits.
- AGP Stage 1, 2, and 3 Shroud Kits.
- Cooling and sealing air orifice modification.
- Provision of installation and modification documents.
- OpFlex Enhanced Transient Stability Model-Based Controls platform.
- Firing temperature increase and revised Model-Based Control (MBC) software changes.
- 7FA.04 length 1AO, 2FO, 2AO wheelspace thermocouples.

DLN 2.6+ Components:

- ML A033 Major Disassembly Tool Kit.
- ML 0513 Gas-Only Fuel Nozzle Assembly.
- ML 0572 Fuel Gas Emergency Stop Valve.
- ML 0701 Combustion Chamber Arrangement.
- ML 0702 Transition Piece Assembly.
- ML 0703 Combustion Liner Arrangement.
- ML 0717 Transition Piece Arrangement.
- ML 0719 Aft Combustion Case Arrangement.
- ML 0726 Combustion Tuning Piping.
- ML 1214 Spark Plug Assembly.

Gas Control Valves (GCVs) / Stop Ratio Valve (SRV):

- High Recovery Gas Control Valves (GCVs).
- Stop Ratio Valve (SRV).
- Supporting piping, conduit, and hydraulic components.
- Modifications to Gas Turbine Controls.

Axial Fuel Staging (AFS) Components:

- AFS injectors and sealing.
- Fuel delivery tubing and valving.
- Additional 5th fuel circuit and manifold for AFS.
- Manway covers.

3. GE Work Scope:

- Removal of old turbine parts.
- Installation of new AGP and AFS components.
- Modifications to existing parts as required.
- Revision of control curves and constants to integrate the new upgrades.

This comprehensive scope of work outlines the key activities and components involved in the upgrade project for Zeeland Phase 2, ensuring the successful integration of Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies.

Funding and Timing

- No funding has been previously committed for this project.
- A Scheduled outage is required for this project.
- Desired implementation year: First year spend 2025, installation year 2028
- Impact if the recommended implementation year is changed:
    - Delaying the implementation of Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies at Zeeland Phase 2 to a year beyond the recommended 2028 poses significant risks and missed opportunities. Postponing these upgrades until the next outage of opportunity, potentially 5-6 years later during the next Hot Gas Path Inspection, would result in a considerable delay in realizing the benefits for Consumers Energy's customers.
- System Engineer: Tim D. Boerema

Conceptual Estimate

Year	Loaded Cost	Description
2025	**$60,000**	Initial engineering work
2026	**$7,969,033**	25% Payment for Lump Sum
2027	**$24,834,311**	AGP/AFS Payment for Design and engineering
2028	**$12,036,656**	AGP/AFS 75% payment, installation, and closeout

Total Cost: $44,900,000

Asset Strategy Approval Comments

The Asset Strategy Group recommends approval. The AGP-AFS upgrade is a forward-thinking approach that not only promises significant performance enhancements but also substantial long-term financial benefits and improved adaptability of the turbines to support Consumers Energy's energy portfolio. This investment is justified by the considerable potential savings.

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

Zeeland Generating Station, Unit 1A&B Advanced Gas Path Upgrade

AGP Upgrade Performance Report

July 18, 2025
Revision: Final

Test Engineer: Timothy J. Miller
Equipment Performance Testing Section
Asset Strategy Department

TABLE OF CONTENTS

1.0 Summary 1
1.1 Unit 1-A Performance 1
1.2 Unit 1-B Performance 2
2.0 Overview and Test Objectives 3
3.0 Introduction 3
3.1 Design Conditions 3
3.2 Expected Performance Improvement 4
4.0 Results 5
4.1 Unit 1-A Performance 6
4.2 Unit 1-B Performance 8
5.0 Conclusions and Recommendations 10
5.1 Unit 1-A Performance 10
5.2 Unit 1-B Performance 11
5.3 Recommendations 11

LIST OF FIGURES

Appendix A: Zeeland Unit 1-A EBSILON Outputs 1
Figure 1: Zeeland Unit 1-A (7FA) June 24, 2024 GVTC 2
Figure 2: Zeeland Unit 1-A (7FA) Corrected to June 27, 2025 Conditions 3
Figure 3: Zeeland Unit 1-A (7FA) Corrected to Design Conditions 4
Figure 4: Zeeland Unit 1-A (7F.04) June 27, 2025 5
Figure 5: Zeeland Unit 1-A (7F.04) Corrected to Design Conditions 6
Appendix B: Zeeland Unit 1-B EBSILON Outputs 1
Figure 6: Zeeland Unit 1-B (7FA) June 24, 2024 GVTC 2
Figure 7: Zeeland Unit 1-B (7FA) Corrected to June 29, 2025 Conditions 3
Figure 8: Zeeland Unit 1-B (7FA) Corrected to Design Conditions 4
Figure 9: Zeeland Unit 1-B (7F.04) June 29, 2025 5
Figure 10: Zeeland Unit 1-B (7F.04) Corrected to Design Conditions 6

LIST OF TABLES

Table 1: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions 1
Table 2: Zeeland Unit 1-A Corrected to Design Conditions 1
Table 3: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions 2
Table 4: Zeeland Unit 1-B Corrected to Design Conditions 2
Table 5: Zeeland Unit 1-A & 1-B Design Conditions 4
Table 6: Zeeland Unit 1-A & 1-B Expected Performance Improvement – Evaporative Cooler Off 5
Table 7: Zeeland Unit 1-A & 1-B Expected Performance Improvement – Evaporative Cooler On 5
Table 8: Zeeland Unit 1-A Pre-Outage and Post-Outage Observed Conditions 6
Table 9: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions 7
Table 10: Zeeland Unit 1-A Corrected to Design Conditions 7
Table 11: Zeeland Unit 1-B Pre-Outage and Post-Outage Observed Conditions 8
Table 12: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions 9
Table 13: Zeeland Unit 1-B Corrected to Design Conditions 9
Table 14: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions 10
Table 15: Zeeland Unit 1-A Corrected to Design Conditions 10
Table 16: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions 11
Table 17: Zeeland Unit 1-B Corrected to Design Conditions 11

APPENDECIES

Appendix A: Zeeland Unit 1-A EBSILON Outputs
Appendix B: Zeeland Unit 1-B EBSILON Outputs
Appendix C: Zeeland Unit 1-A & 1-B Advanced Gas Path Contract
Appendix D: GE 7FA Correction Curves
Appendix E: GE 7F.04 Correction Curves

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1.0 SUMMARY

Zeeland Units 1-A and 1-B received the Advanced Gas Path (AGP) upgrade in the spring of 2025. Data from the June 24, 2024 GVTC was used to represent the pre-outage state of the Unit 1-A and 1-B 7FA gas turbines. Data from June 27, 2025, and June 29, 2025 was used for the post-outage comparison of Unit 1-A and 1-B 7F.04 respectively.

1.1 UNIT 1-A PERFORMANCE

For Unit 1-A, the AGP upgrade achieved a +25.1 MW improvement in power output and a -131.9 Btu/kWh Gross Heat Rate improvement in terms of Higher Heating Value (HHV). The full set of results are summarized below in Table 1.

Table 1: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions

Zeeland Unit 1-A Corrected to 6/27/25: 12:00 – 13:00 (89.6°F, 55% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	157.97	183.02	25.05	15.86
Gross Ht Rate (HHV) [Btu/kWh]	10,278.3	10,146.4	-131.9	-1.28

Both the pre-outage 7FA and post-outage 7F.04 gas turbine data were then corrected to the design conditions listed in Table 5 including fuel composition. Correcting to design conditions showed a power output improvement of +25.6 MW and a gross heat rate improvement of -147.0 Btu/kWh. The full set of results are summarized below in Table 2.

Table 2: Zeeland Unit 1-A Corrected to Design Conditions

Zeeland Unit 1-A Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.04	179.66	25.62	16.63
Gross Ht Rate (HHV) [Btu/kWh]	10,384.6	10,237.5	-147.0	-1.42

This is a power output improvement of +16.6%, which exceeds the GE estimate of +13.2%. Likewise, the gross heat rate improved by -1.42%, but fell short of the GE estimate of -2.5%. As discussed in Section 4.1, Unit 1-B power output and heat rate improvement much better aligns with the GE estimate which brings to question the accuracy of the station fuel flow orifice for Unit 1-A.

1.2 UNIT 1-B PERFORMANCE

For Unit 1-B, the AGP upgrade achieved a +25.6 MW improvement in power output and a -332.5 Btu/kWh Gross Heat Rate improvement in terms of HHV. The full set of results are summarized below in Table 3.

Table 3: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions

Zeeland Unit 1-B Corrected to 6/29/25: 15:45 – 16:45 (95.8°F, 45% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	155.85	181.43	25.58	16.41
Gross Ht Rate (HHV) [Btu/kWh]	10,302.1	9,969.7	-332.5	-3.23

Both the pre-outage 7FA and post-outage 7F.04 gas turbine data were then corrected to the design conditions listed in Table 5 including fuel composition. Correcting to design conditions showed a power output improvement of +24.3 MW and a gross heat rate improvement of -313.1 Btu/kWh. The full set of results are summarized below in Table 4.

Table 4: Zeeland Unit 1-B Corrected to Design Conditions

Zeeland Unit 1-B Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.71	178.99	24.28	15.70
Gross Ht Rate (HHV) [Btu/kWh]	10,359.8	10,046.7	-313.1	-3.02

Unit 1-B achieved a power output improvement of +15.7%, which exceeds the GE estimate of +13.2%. Likewise, the Unit 1-B gross heat rate improved by -3.02%, which also exceeds the GE estimate of -2.5%.

2.0 OVERVIEW AND TEST OBJECTIVES

Zeeland Units 1-A and 1-B were upgraded from their original 7FA combustion turbine design with the GE Advanced Gas Path (AGP) hardware during the spring of 2025. Per the contract, a power improvement of +13.2% and a heat rate improvement of -2.5% was expected when corrected to design conditions with the evaporative cooler in service. In addition to the power and heat rate improvements, the upgrade included the Axial Fuel Staging (AFS) system which will allow for a minimum load of 50 MW_n while maintaining emissions compliance. This is down from the 100 MW_n minimum load from the original design and offers greater dispatch flexibility. A copy of the contract is included in Appendix C.

For comparison purposes, data from the June 24, 2024 Generator Verification Test Capacity (GVTC) was used to compare with post-upgrade. The GVTC data was chosen since the run would have occurred only a few weeks following the spring compressor wash, thereby the original design would not be additionally penalized for operating in a "dirty" state. Post-outage data was chosen from full load operation with evaporative coolers on after a few weeks following the return to service.

Both data sets would be input into the Consumers Energy EBSILON model of the Zeeland gas turbines to correct to the same set of conditions. The EBSILON model utilizes the full set of correction curves for both the original 7FA design and the post-upgrade 7F.04. For this analysis, the 2024 GVTC data was corrected to the 2025 ambient conditions and both data sets were corrected to design conditions.

3.0 INTRODUCTION

The Zeeland Generating Station, located in Zeeland, MI, is a natural gas simple cycle and combined cycle power plant. The simple cycle units were commissioned in 2000, followed by the combined cycle in 2002. Consumers Energy purchased the entire facility in 2008. The original plant construction plan consisted of three "Phases". Phase 1 was the construction of two simple cycle GE 7FA gas turbines, Units 1-A and 1-B. Phase 2 was the construction of a 2x1 combined cycle unit which includes two identical GE 7FA gas turbines, Unit 2-A and 2-B, and one steam turbine, Unit 2-C. The 2x1 configuration refers to two gas turbines exhausting into two heat recovery steam generators and driving a single steam turbine. The power block for the combined cycle is comprised of three major components: two gas turbine-generators, two Heat Recovery Steam Generators (HRSGs), and one steam turbine generator. Phase 3 of construction was never completed and was to convert the two simple cycle units into an identical 2x1 combined cycle.

The gas turbine-generators for Units 1-A and 1-B were originally General Electric Model PG7241(FA) and rated for 174.0 MWg at ISO conditions. Both Units 1-A and 1-B received the Advanced Gas Path (AGP) upgrade in the spring of 2025 and are now considered General Electric Model 7F.04-0922T-L4.

3.1 DESIGN CONDITIONS

For the AGP upgrade, the plant design conditions were used in the contract as opposed to gas turbine ISO conditions. For the Zeeland Plant, the design conditions are 92°F ambient temperature and 60% relative

humidity. With evaporative coolers in service and performing at design efficiency, this provides compressor inlet conditions of 81.8°F and 92.2% relative humidity. Table 5 below is the complete set of design conditions specified in the contract and/or post-upgrade correction curves.

Table 5: Zeeland Unit 1-A & 1-B Design Conditions

Parameter	Units	Pre-Uprate Value	Post-Uprate Value
Ambient Air Inlet Temperature	°F	92.0	92.0
Ambient Air Relative Humidity	%	60.0	60.0
Compressor Inlet Temperature	°F	81.8	81.8
Compressor Inlet Relative Humidity	%	92.2	92.2
Barometric Pressure	psi_a	14.35	14.35
Shaft Speed	RPM	3,600	3,600
Generator Power Factor	—	0.85	0.85
Inlet Pressure Drop	inH_2O	4.0	4.1
Exhaust Pressure Drop	inH_2O	5.8	6.1
Fuel Temperature	°F	51	51
Fuel LHV	Btu/lb	20,159.0	20,159.0
Fuel Composition (Natural Gas)			
Methane (CH_4)	% mol	93.256	93.256
Ethane (C_2H_6)	% mol	2.953	2.953
Propane (C_3H_8)	% mol	0.442	0.442
N-Butane (C_4H_{10})	% mol	0.113	0.113
N-Pentane (C_5H_{12})	% mol	0.036	0.036
Hexanes, Avg. (C_6H_{14})	% mol	0.033	0.033
Nitrogen (N_2)	% mol	2.405	2.405
Carbon Dioxide (CO_2)	% mol	0.761	0.761

3.2 EXPECTED PERFORMANCE IMPROVEMENT

The expected performance improvement per the contract is for the case with 92°F ambient temperature, 60% relative humidity, and with the evaporative cooler in service targeting a 92.2% relative humidity at the gas turbine compressor inlet. The performance improvement was stated within the contract as what to expect from the pre-outage state of the 7FA, meaning the existing machine will have approximately 25 years of degradation included in the estimated performance improvement.

It should be noted that the contract does not state if the heat rate improvement is based upon the Lower Heating Value (LHV) or Higher Heating Value (HHV) of natural gas. Since gas turbine OEM's usually state heat rate in terms of LHV, it is assumed this is the basis for the percentage improvement listed. For the purposes of this performance evaluation, all heat rate improvements and values will be reported in terms

of HHV since this is how the plant is dispatched. Table 6 and Table 7 show the expected performance across the load range both without and with the evaporative cooler in service.

Table 6: Zeeland Unit 1-A & 1-B Expected Performance Improvement – Evaporative Cooler Off

Ambient Temperature	**°F**	**-20**	**0**	**30**	**59**	**75**	**92**	**105**
Gas Turbine Output	%	8.0	11.3	16.2	14.5	13.3	12.5	9.6
Gas Turbine Heat Rate	%	-1.4	-1.8	-2.2	-2.9	-2.5	-2.6	-2.7

Table 7: Zeeland Unit 1-A & 1-B Expected Performance Improvement – Evaporative Cooler On

Ambient Temperature	**°F**	**59**	**75**	**92**	**105**
Compressor Inlet Temp	°F	53	67	81.8	90
Gas Turbine Output	%	15.1	13.4	13.2	13.3
Gas Turbine Heat Rate	%	-2.6	-2.5	-2.5	-2.6

4.0 RESULTS

As stated previously, data from the June 24, 2024 GVTC was used to represent the pre-outage state of the Unit 1-A and 1-B 7FA gas turbines. Data from June 27, 2025, and June 29,2025 was used for the post-outage comparison of Unit 1-A and 1-B 7F.04 respectively.

All operating conditions were first input into the Consumers Energy EBSILON model of Units 1-A and 1-B. Heat rate and power output corrections were then applied to the gas turbine to align fuel flow and power output measured during the 2024 GVTC for each unit. The measured natural gas composition from the station gas chromatograph was used within the model to define the fuel stream and calculate heat content on a mass basis. EBSILON utilizes the GERG-2008 methodology to determine the physical properties of the natural gas composite mixture. The 7FA gas turbines were then corrected to the 2025 conditions being used for comparison following the original set of correction curves which are included for reference in Appendix D. Finally, the 2024 GVTC data was then corrected to the design conditions listed in the contract.

For the post-outage 7F.04, the EBSILON gas turbine component was updated to revise the correction curves with the new set provided by GE (24A-167 Rev A) which are included for reference in Appendix E. All operating conditions were first input into the Consumers Energy EBSILON model from their respective 2025 run. Heat rate and power output corrections were then applied to the gas turbine to align fuel flow and the measured power output. Likewise, the measured natural gas composition from the station gas chromatograph was used within the model to define the fuel stream and calculate heat content on a mass basis. The 2025 data set was then corrected to design conditions listed in the contract, including natural gas composition. Both data sets corrected to design conditions were then directly compared to determine the realized gains from the AGP upgrade.

It is worth noting that some of the "design" conditions listed in the contract do not align with the "design" conditions listed in the GE correction curves for the 7F.04. For example, the contract states an exhaust pressure drop of 6.1 inWC where the curve set states 4.91 inWC at rated compressor inlet temperature. For the purposes of this analysis, the conditions agreed upon and listed in the contract will be used.

4.1 UNIT 1-A PERFORMANCE

Pre-outage data from the June 24, 2024, from the 14:00 — 16:00 GVTC was used to directly compare with the Unit 1-A post-outage run on June 27, 2025, from 12:00 — 13:00. The pre-outage data set was chosen because the ambient conditions were relatively close to the design conditions it will be corrected to and thereby minimize correction curve error. In addition, the pre-outage data set would have been from a run a few weeks following the spring compressor water wash and summer readiness outage. Similarly, the post-outage data was chosen for the same reasons. The operating conditions for both data sets are summarized in Table 8 below.

Table 8: Zeeland Unit 1-A Pre-Outage and Post-Outage Observed Conditions

Observed Conditions	**6/24/2024**	**6/27/2025**	**Units**
	14:00 – 16:00	**12:00 – 13:00**	
Temperature	85.50	89.58	°F
Atmospheric Pressure	29.21	29.21	$inHg_a$
Relative Humidity	42.67	54.95	%
Evap Cooler Out Temperature	69.20	78.18	°F
Air Inlet Pressure Drop	2.95	2.79	inWC
Exhaust Pressure Drop	4.80	3.99	inWC
Fuel Gas Temp	78.26	77.22	°F
Fuel Gas Pressure	469.79	480.14	Psi_a
Fuel Flow	20.24	22.17	lb/sec
Fuel HHV [Btu/SCF]	1,085.21	1,070.52	Btu/SCF
Fuel HHV [Btu/lb]	22,677.57	23,276.33	Btu/lb
Generator Output	162.15	183.02	MW_g
Gross Heat Rate (HHV)	10,190.6	10,146.4	Btu/kWh
Fuel Composition			
Nitrogen (N_2)	1.4753	0.6064	% mol
Carbon Dioxide (CO_2)	0.6086	0.2649	% mol
Methane (CH_4)	86.4233	90.9505	% mol
Ethane (C_2H_6)	11.0484	7.9348	% mol
Propane (C_3H_8)	0.3962	0.2003	% mol
n-Butane (C_4H_{10})	0.0257	0.0189	% mol
n-Pentane (C_5H_{12})	0.0041	0.0036	% mol
Isobutane ($HC(CH_3)_3$)	0.0103	0.0161	% mol
Isopentane ($CH(CH_3)_2(C_2H_5)$)	0.0080	0.0046	% mol
Specific Gravity	0.6253	0.6012	

The Consumers Energy EBSILON model of the original GE 7FA gas turbine was set to "Design" mode with the June 24, 2024 data set. By having the model in "Design" mode, the evaporative cooler, inlet pressure drop, and exhaust pressure drop components would hold and replicate their 2024 performance when correcting to a new set of conditions. The natural gas composition was set within the EBSILON model on a percent mole basis to match the pre-outage conditions. Correction factors for the gas turbine power output and heat rate were then adjusted to align the model with the power output and fuel flow observed.

After the "Design" run, a separate "Off-Design" model profile was created which utilized the pre-outage power output correction, heat rate correction, evaporative cooler performance, inlet pressure drop, exhaust pressure drop, and natural gas composition with the June 27, 2025 observed conditions. This allowed for a direct comparison from pre-outage to post-outage in which the AGP upgrade achieved a +25.1 MW improvement in power output and a -131.9 Btu/kWh Gross Heat Rate improvement in terms of HHV. The full set of results are summarized below in Table 9.

Table 9: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions

Zeeland Unit 1-A Corrected to 6/27/25: 12:00 – 13:00 (89.6°F, 55% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	157.97	183.02	25.05	15.86
Gross Ht Rate (HHV) [Btu/kWh]	10,278.3	10,146.4	-131.9	-1.28

To determine if the contractual estimates were achieved, the EBSILON model was updated to utilize the new set of correction curves for the upgraded GE 7F.04 gas turbine. Similar to the pre-outage, a "Design" profile was used to determine the power output correction, heat rate correction, evaporative cooler performance, inlet pressure drop, and exhaust pressure drop from the June 27, 2025 post-outage data set. The natural gas composition was again set to what was measured by the station gas chromatograph during the post outage run.

Both the pre-outage 7FA and post-outage 7F.04 gas turbine models were then run to correct all variables to the design conditions listed in Table 5 including fuel composition. Correcting to design conditions showed a power output improvement of +25.6 MW and a gross heat rate improvement of -147.0 Btu/kWh. The full set of results are summarized below in Table 10.

Table 10: Zeeland Unit 1-A Corrected to Design Conditions

Zeeland Unit 1-A Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.04	179.66	25.62	16.63
Gross Ht Rate (HHV) [Btu/kWh]	10,384.6	10,237.5	-147.0	-1.42

This is a power output improvement of +16.6%, which exceeds the GE estimate of +13.2%. Likewise, the gross heat rate improved by -1.42%, but fell short of the GE estimate of -2.5%. All EBSILON model outputs For Unit 1-A are shown in Figure 1 through Figure 5 in Appendix A. As will be seen in the following section,

the Unit 1-B heat rate improvement better aligns with the GE estimate which raises the question as to the accuracy of the station fuel flow orifice for Unit 1-A.

4.2 UNIT 1-B PERFORMANCE

Pre-outage data from the June 24, 2024, from the 14:00 — 16:00 GVTC was used to directly compare with the Unit 1-B post-outage run on June 29, 2025, from 15:45 — 16:45. The pre-outage data set was chosen because the ambient conditions were relatively close to the design conditions that it will be corrected to and thereby minimize correction curve error. In addition, the pre-outage data set would have been from a run a few weeks following the spring compressor water wash and summer readiness outage. Similarly, the post-outage data was chosen for the same reasons. The operating conditions for both data sets are summarized in Table 11 below.

Table 11: Zeeland Unit 1-B Pre-Outage and Post-Outage Observed Conditions

Observed Conditions	**6/24/2024**	**6/29/2025**	**Units**
	14:00 – 16:00	**15:45 – 16:45**	
Temperature	85.50	95.84	°F
Atmospheric Pressure	29.21	29.21	$inHg_a$
Relative Humidity	42.67	44.93	%
Evap Cooler Out Temperature	67.79	77.48	°F
Air Inlet Pressure Drop	5.21	2.58	inWC
Exhaust Pressure Drop	4.64	4.27	inWC
Fuel Gas Temp	77.16	75.58	°F
Fuel Gas Pressure	469.79	479.97	Psi_a
Fuel Flow	20.11	21.95	lb/sec
Fuel HHV [Btu/SCF]	1,085.21	1,074.84	Btu/SCF
Fuel HHV [Btu/lb]	22,677.57	22,887.51	Btu/lb
Generator Output	161.00	181.43	MW_g
Gross Heat Rate (HHV)	10,198.2	9,969.7	Btu/kWh
Fuel Composition			
Nitrogen (N_2)	1.4753	1.1726	% mol
Carbon Dioxide (CO_2)	0.6086	0.4937	% mol
Methane (CH_4)	86.4233	88.6602	% mol
Ethane (C_2H_6)	11.0484	9.3213	% mol
Propane (C_3H_8)	0.3962	0.2989	% mol
n-Butane (C_4H_{10})	0.0257	0.0264	% mol
n-Pentane (C_5H_{12})	0.0041	0.0046	% mol
Isobutane ($HC(CH_3)_3$)	0.0103	0.0130	% mol
Isopentane ($CH(CH_3)_2(C_2H_5)$)	0.0080	0.0092	% mol
Specific Gravity	0.6253	0.6136	

The Consumers Energy EBSILON model of the original GE 7FA gas turbine was set to “Design” mode with the June 24, 2024 data set. By having the model in “Design” mode, the evaporative cooler, inlet pressure

drop, and exhaust pressure drop components would hold and replicate their performance when correcting to a new set of conditions. The natural gas composition was set within the EBSILON model on a percent mole basis to match the pre-outage conditions. Correction factors for the gas turbine power output and heat rate were then adjusted to align the model with the power output and fuel flow observed. For Unit 1-B, the measured evaporative cooler outlet temperature was lower than the wet bulb temperature, which is not possible, and that data is considered erroneous. With the bad temperature measurement, the evaporative cooler was set in the model to target 91.0% relative humidity at the outlet which is similar to what Unit 1-A achieved.

After the "Design" run, a separate "Off-Design" model profile was created that utilized the pre-outage power output correction, heat rate correction, evaporative cooler performance, inlet pressure drop, exhaust pressure drop, and natural gas composition with the June 29, 2025 observed conditions. This allowed for a direct comparison from pre-outage to post-outage in which the AGP upgrade achieved a +25.6 MW improvement in power output and a -332.5 Btu/kWh Gross Heat Rate improvement in terms of HHV. The full set of results are summarized below in Table 12.

Table 12: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions

Zeeland Unit 1-B Corrected to 6/29/25: 15:45 – 16:45 (95.8°F, 45% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	155.85	181.43	25.58	16.41
Gross Ht Rate (HHV) [Btu/kWh]	10,302.1	9,969.7	-332.5	-3.23

To determine if the contractual estimates were achieved, an EBSILON model was updated to utilize the new set of correction curves for the upgraded GE 7F.04 gas turbine. Similar to the pre-outage, a "Design" profile was used to capture the power output correction, heat rate correction, evaporative cooler performance, inlet pressure drop, and exhaust pressure drop from the June 29, 2025 post-outage data set. The natural gas composition was again set to what was measured by the station gas chromatograph during the post outage run.

Both the pre-outage 7FA and post-outage 7F.04 gas turbine models were then run to correct all variables to the design conditions listed in Table 5 including fuel composition. Correcting to design conditions showed a power output improvement of +24.3 MW and a gross heat rate improvement of -313.1 Btu/kWh. The full set of results are summarized below in Table 13.

Table 13: Zeeland Unit 1-B Corrected to Design Conditions

Zeeland Unit 1-B Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.71	178.99	24.28	15.70
Gross Ht Rate (HHV) [Btu/kWh]	10,359.8	10,046.7	-313.1	-3.02

Unit 1-B achieved a power output improvement of +15.7%, which exceeds the GE estimate of +13.2%. Likewise, the Unit 1-B gross heat rate improved by -3.02%, which also exceeds the GE estimate of -2.5%. All EBSILON model outputs for Unit 1-B are shown in Figure 6 through Figure 10 in Appendix B.

5.0 CONCLUSIONS AND RECOMMENDATIONS

Zeeland Units 1-A and 1-B received the Advanced Gas Path (AGP) upgrade in the spring of 2025. Data from the June 24, 2024 GVTC was used to represent the pre-outage state of the Unit 1-A and 1-B 7FA gas turbines. Data from June 27, 2025, and June 29, 2025 was used for the post-outage comparison of Unit 1-A and 1-B 7F.04 respectively.

5.1 UNIT 1-A PERFORMANCE

For Unit 1-A, the AGP upgrade achieved a +25.1 MW improvement in power output and a -131.9 Btu/kWh Gross Heat Rate improvement in terms of HHV. The full set of results are summarized below in Table 14.

Table 14: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions

Zeeland Unit 1-A Corrected to 6/27/25: 12:00 – 13:00 (89.6°F, 55% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	157.97	183.02	25.05	15.86
Gross Ht Rate (HHV) [Btu/kWh]	10,278.3	10,146.4	-131.9	-1.28

Correcting to design conditions showed a power output improvement of +25.6 MW and a gross heat rate improvement of -147.0 Btu/kWh. The full set of results are summarized below in Table 15.

Table 15: Zeeland Unit 1-A Corrected to Design Conditions

Zeeland Unit 1-A Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.04	179.66	25.62	16.63
Gross Ht Rate (HHV) [Btu/kWh]	10,384.6	10,237.5	-147.0	-1.42

This is a power output improvement of +16.6%, which exceeds the GE estimate of +13.2%. Likewise, the gross heat rate improved by -1.42%, but fell short of the GE estimate of -2.5%. As discussed in Section 4.1, Unit 1-B power output and heat rate improvement much better aligns with the GE estimate which brings to question the accuracy of the station fuel flow orifice for Unit 1-A.

5.2 UNIT 1-B PERFORMANCE

For Unit 1-B, the AGP upgrade achieved a +25.6 MW improvement in power output and a -332.5 Btu/kWh Gross Heat Rate improvement in terms of HHV. The full set of results are summarized below in Table 16.

Table 16: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions

Zeeland Unit 1-B Corrected to 6/29/25: 15:45 – 16:45 (95.8°F, 45% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	155.85	181.43	25.58	16.41
Gross Ht Rate (HHV) [Btu/kWh]	10,302.1	9,969.7	-332.5	-3.23

Correcting to design conditions showed a power output improvement of +24.3 MW and a gross heat rate improvement of -313.1 Btu/kWh. The full set of results are summarized below in Table 17.

Table 17: Zeeland Unit 1-B Corrected to Design Conditions

Zeeland Unit 1-B Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.71	178.99	24.28	15.70
Gross Ht Rate (HHV) [Btu/kWh]	10,359.8	10,046.7	-313.1	-3.02

Unit 1-B achieved a power output improvement of +15.7%, which exceeds the GE estimate of +13.2%. Likewise, the Unit 1-B gross heat rate improved by -3.02%, which also exceeds the GE estimate of -2.5%.

5.3 RECOMMENDATIONS

It was discovered for Unit 1-B that the measured evaporative cooler outlet temperature (compressor inlet) was lower than the wet bulb temperature which is not possible. This issue has been previously seen with Unit 1-B, and it is ***strongly recommended*** to replace the compressor inlet temperature thermocouples with new ones. The compressor inlet temperature is a critical measurement for any performance analysis and is also used for GVTC corrections.

Additionally, it is recommended the Unit 1-A fuel flow orifice and differential pressure measurement be checked for accuracy. The Unit 1-B performance results very closely align with the GE estimates for both heat rate and power output. It seems unlikely that both units are able to achieve essentially the same increase in power output but only one of the two can meet the heat rate estimates. The fuel flow orifice is the only measurement for gas flow and therefore a small amount of uncertainty will cascade through the analysis.

Appendix A: Zeeland Unit 1-A EBSILON Outputs

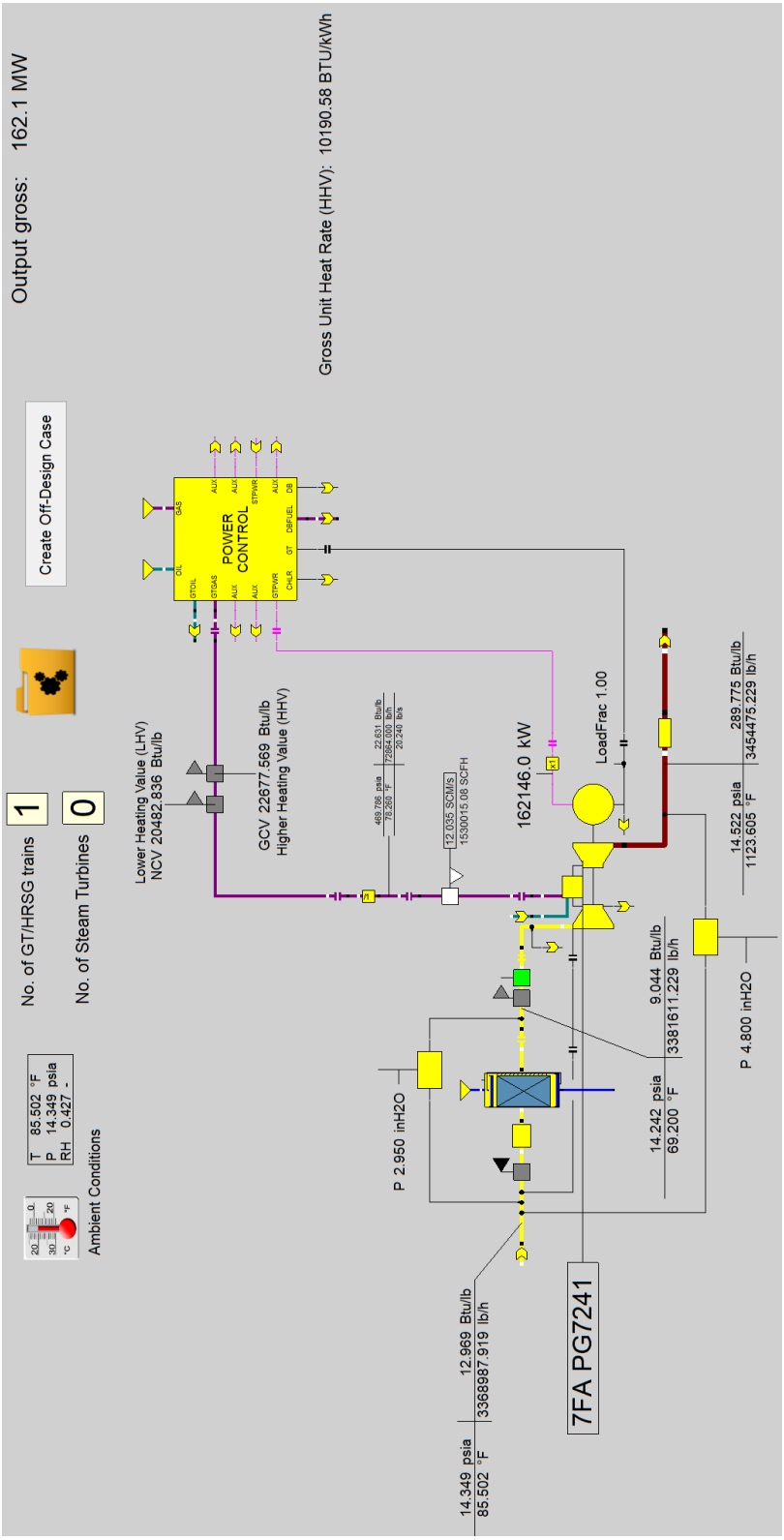

Figure 1: Zeeland Unit 1-A (7FA) June 24, 2024 GVTC

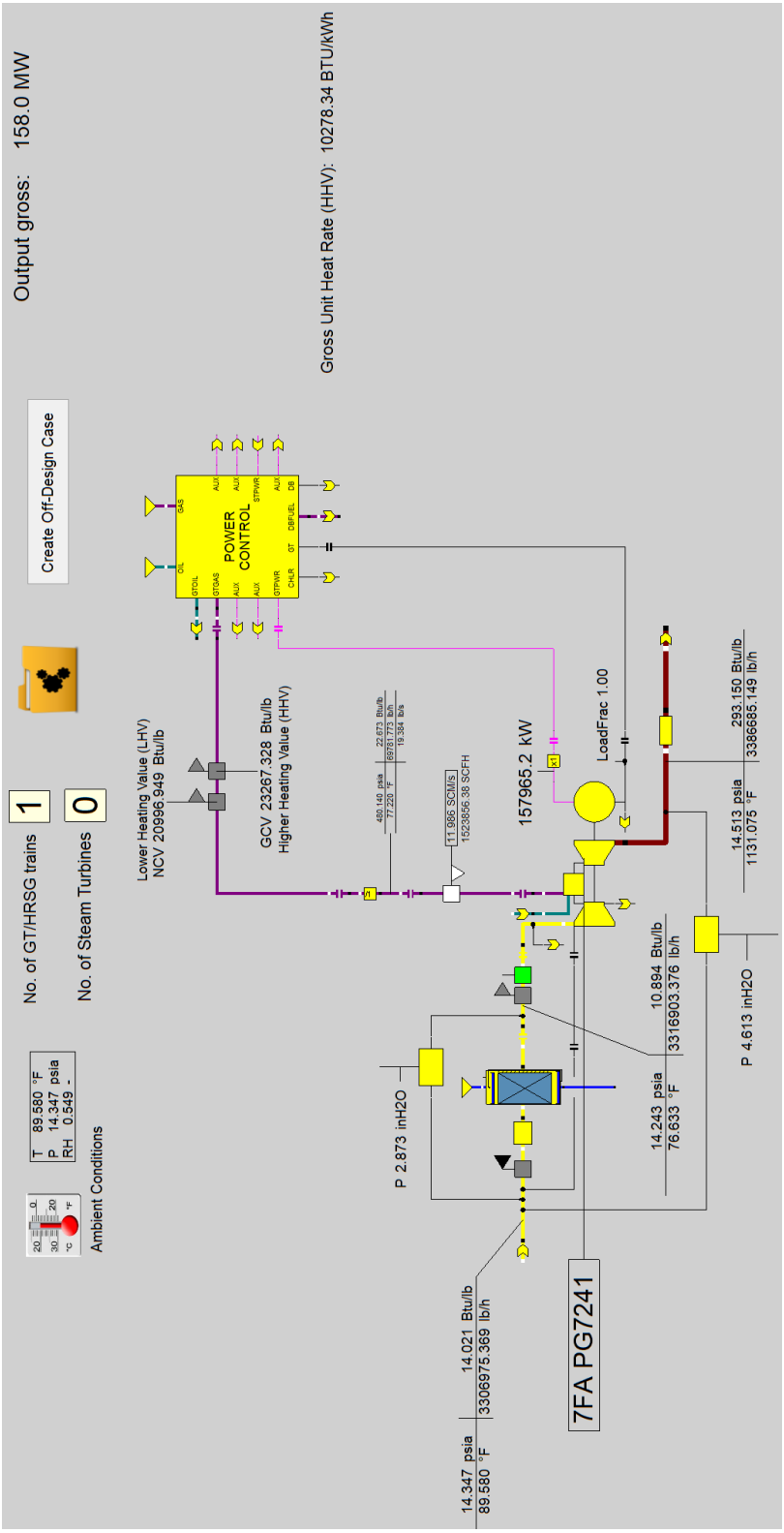

Figure 2: Zeeland Unit 1-A (7FA) Corrected to June 27, 2025 Conditions

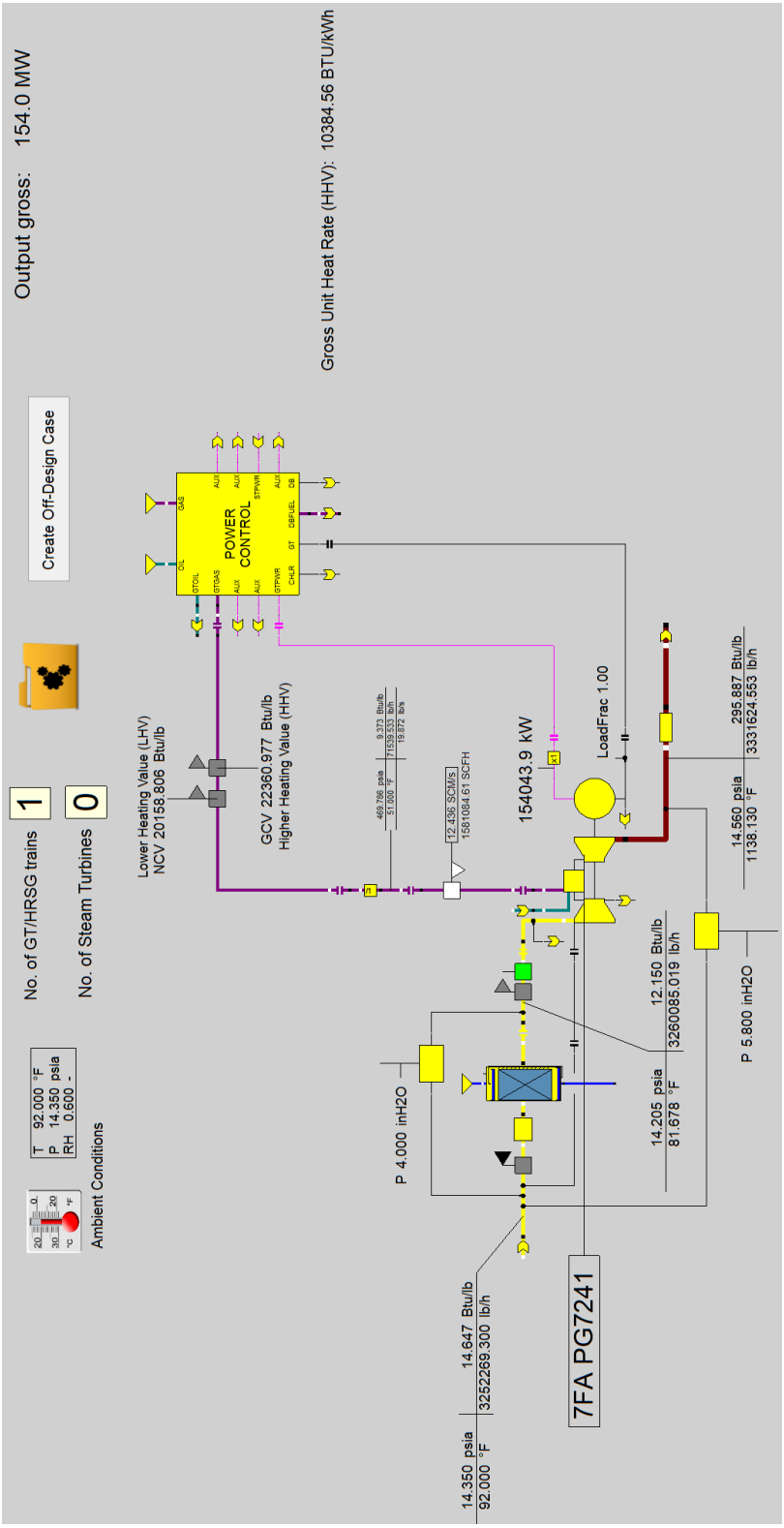

Figure 3: Zeeland Unit 1-A (7FA) Corrected to Design Conditions

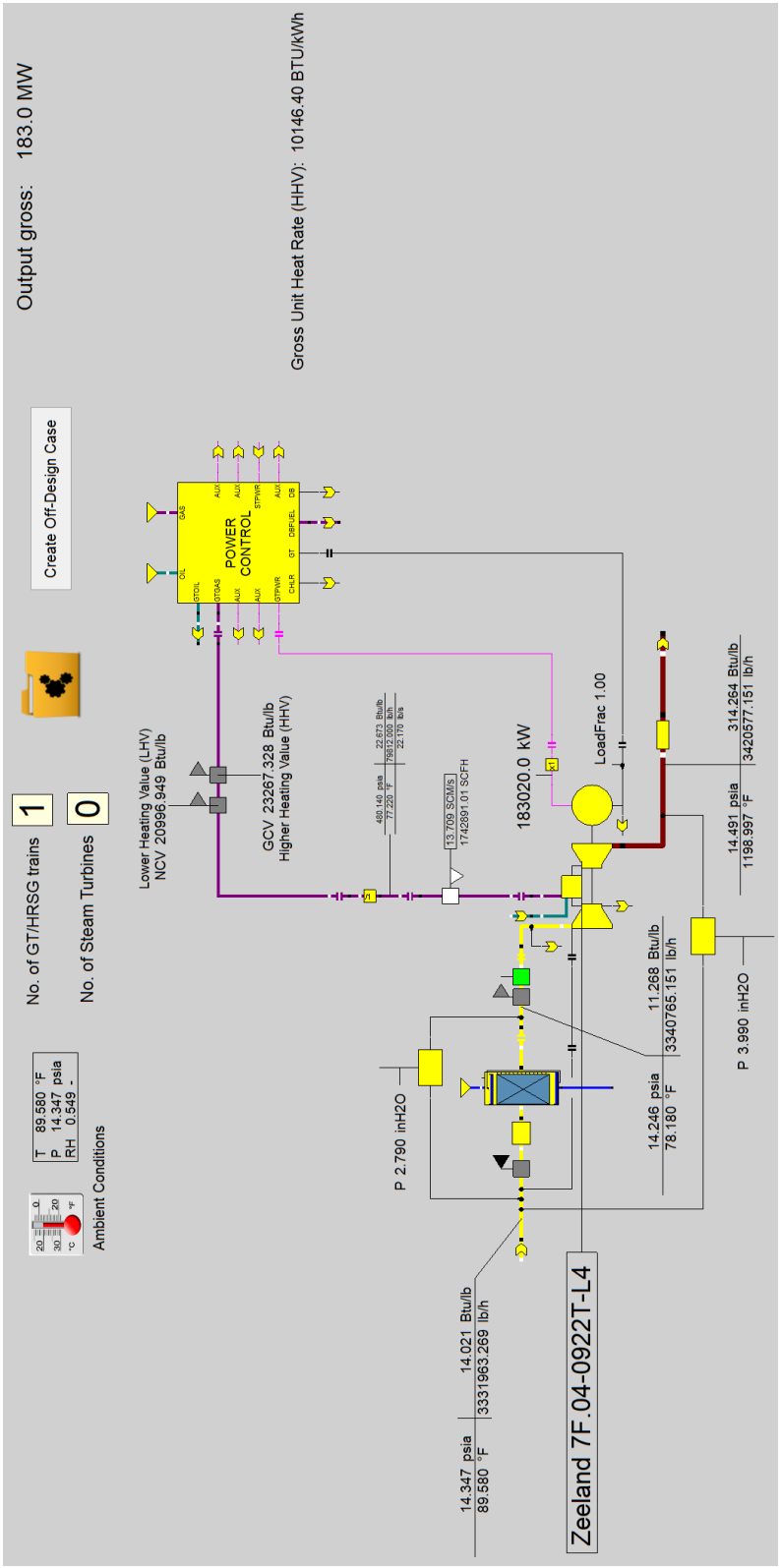

Figure 4: Zeeland Unit 1-A (7F.04) June 27, 2025

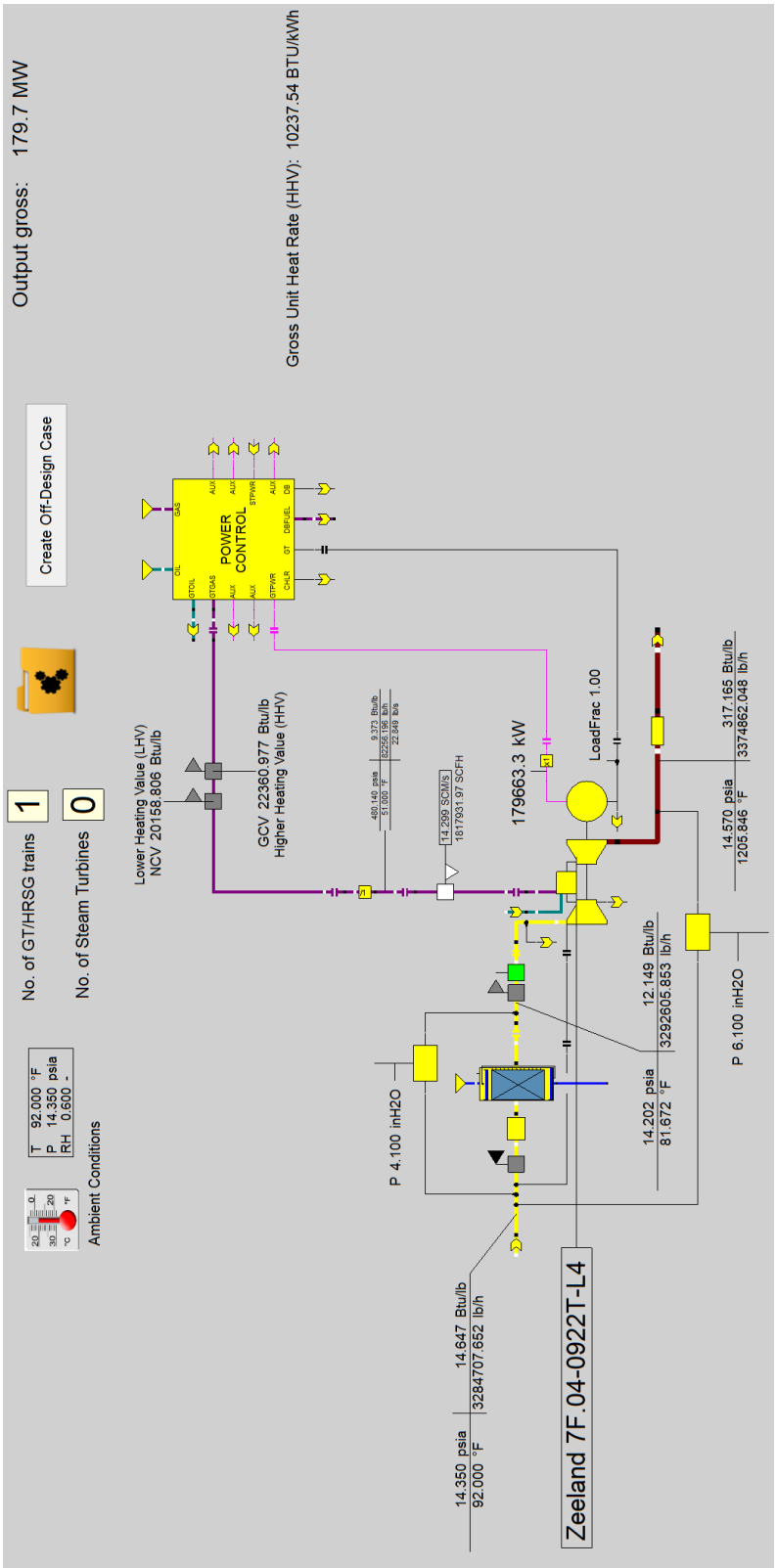

Figure 5: Zeeland Unit 1-A (7F.04) Corrected to Design Conditions

Appendix B: Zeeland Unit 1-B EBSILON Outputs

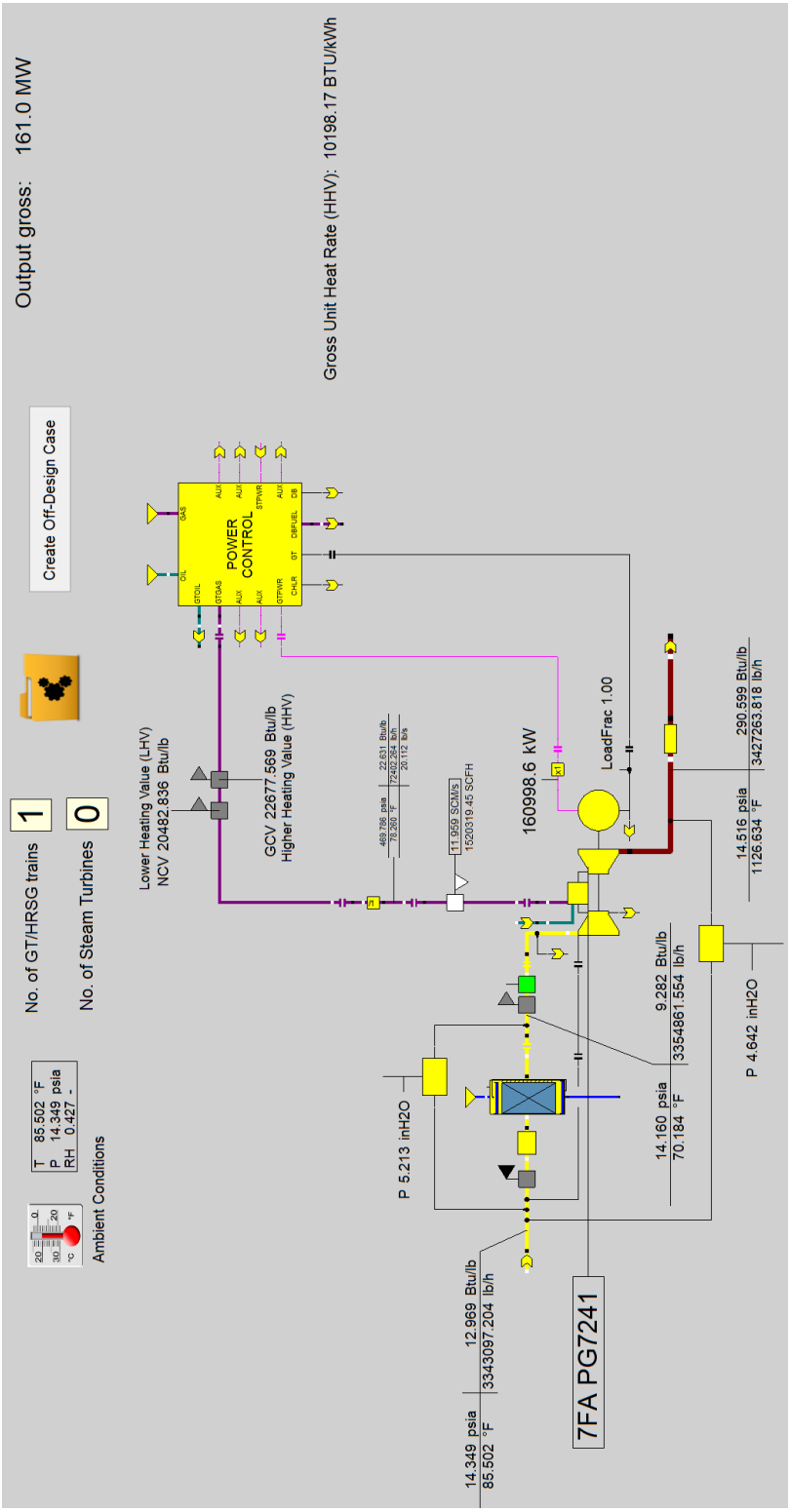

Figure 6: Zeeland Unit 1-B (7FA) June 24, 2024 GVTC

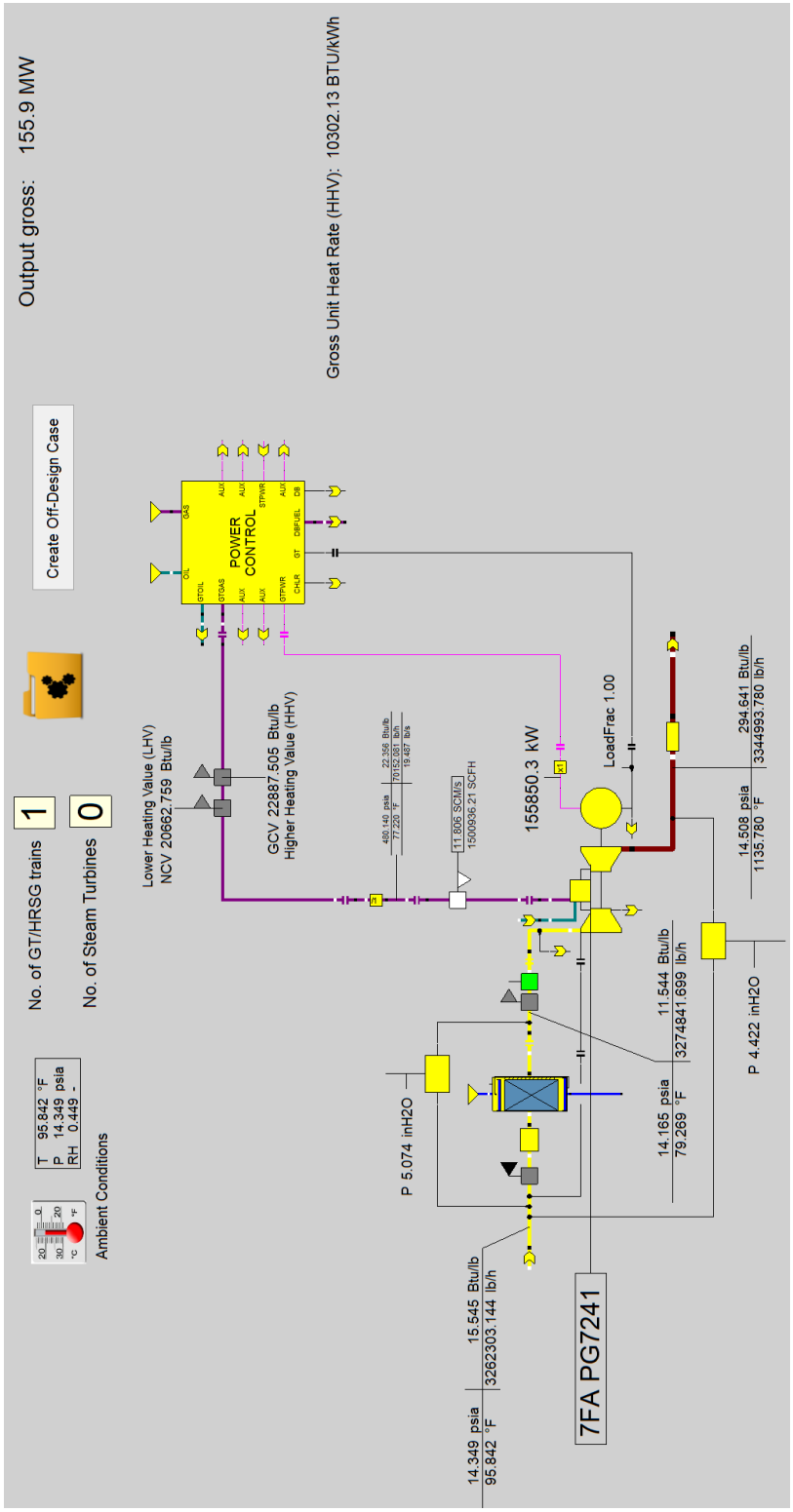

Figure 7: Zeeland Unit 1-B (7FA) Corrected to June 29, 2025 Conditions

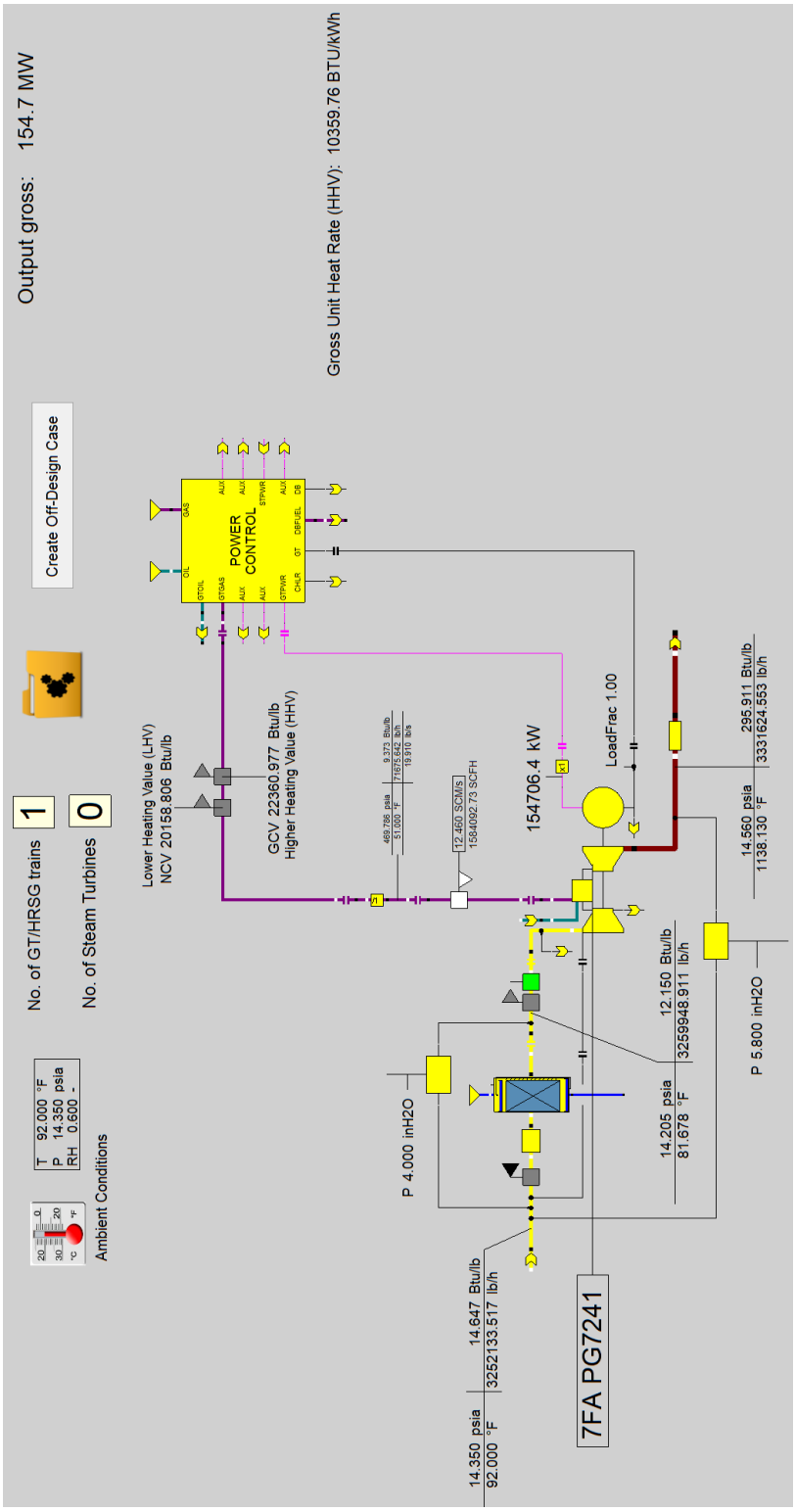

Figure 8: Zeeland Unit 1-B (7FA) Corrected to Design Conditions

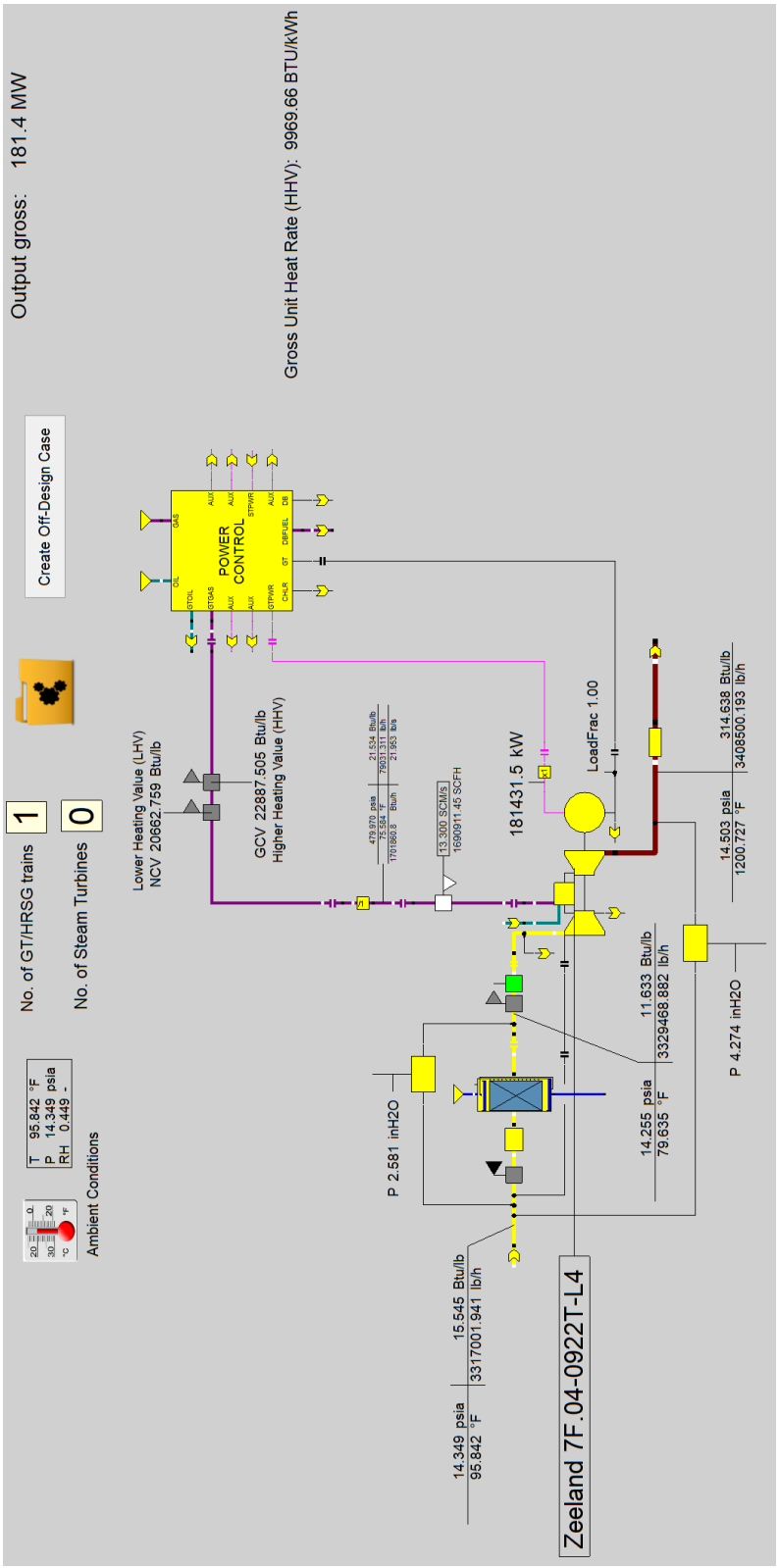

Figure 9: Zeeland Unit 1-B (7F.04) June 29, 2025

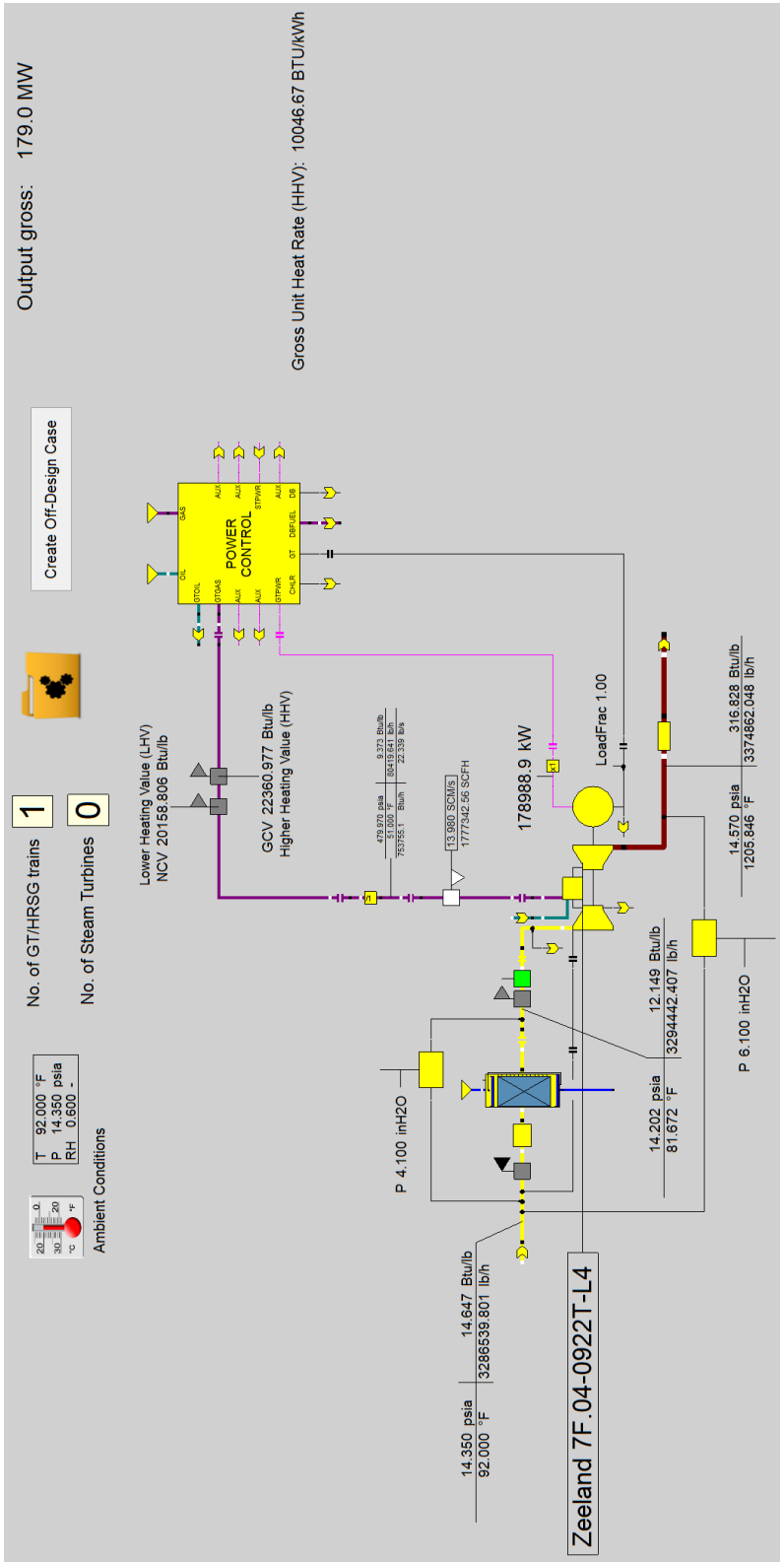

Figure 10: Zeeland Unit 1-B (7F.04) Corrected to Design Conditions

Appendix C: Zeeland Unit 1-A & 1-B Advanced Gas Path Contract

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AMENDMENT NO. 4 TO THE LONG TERM SERVICE AGREEMENT FOR ZEELAND SIMPLE CYCLE FACILITY BETWEEN CONSUMERS ENERGY COMPANY AND GE VERNOVA INTERNATIONAL LLC.

THIS AMENDMENT NO. 4 ("Amendment 4") dated as of March 1, 2024 (the "Amendment 4 Effective Date", is made by and between GE Vernova International LLC, successor to General Electric International, Inc. ("Contractor") and Consumers Energy Company ("Owner") (each individually a "Party" and together the "Parties").

RECITALS

WHEREAS, Mirant Zeeland, L.L.C. (which later changed its name to Zeeland Power Company, LLC) and Contractor entered into that certain Long Term Service Agreement for the Zeeland Simple Cycle Facility dated June 16, 2004 (the "Agreement"); and

WHEREAS, Owner is the successor by merger to Zeeland Power Company, LLC; and

WHEREAS, the Parties have heretofore amended the Agreement by a letter agreement dated August 29, 2013 (which letter agreement can be considered to be "Amendment No. 1" to the Agreement); and

WHEREAS, the Parties have heretofore amended the Agreement by Amendment No. 2 dated January 2, 2014; and

WHEREAS, the Parties have heretofore amended the Agreement by Amendment No. 3 dated March 24, 2021; and

WHEREAS, the Parties have mutually agreed to further permanently modify certain provisions of the Agreement as set forth herein below; and

NOW, THEREFORE, in consideration of the mutual promises described herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

1. Defined Terms. Unless otherwise defined herein, all capitalized terms used in this Amendment 4 that are defined in the Agreement shall have the meanings given to them in the Agreement.

2. Owner shall have the option, in its sole discretion, to cancel this Amendment 4 upon written notice to Contractor at any time prior to March 15, 2024. Any such cancellation shall be effective upon Contractor's receipt of written notice.

   In the event that Owner cancels this Amendment 4 following the Amendment 4 Effective Date, Owner shall pay Contractor a cancellation amount equal to the following:

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Cancellation Date			Cancellation Fee per Gas Turbine
Amendment 4 Effective Date	to	March 15, 2024	$2,907,000

Contractor shall invoice Owner immediately upon receipt of notice for cancellation of Amendment 4. The Parties agree that the damages likely to be incurred by Contractor in the event of a cancellation by Owner will be difficult to measure, that the cancellation amount is reasonable, and that the cancellation amount shall be paid as liquidated damages in lieu of all such actual damages and not as a penalty.

2. Amendments to the Agreement. As of the Amendment 4 Effective Date, the Agreement is hereby modified as follows:

A. Section I (Definitions) of the Agreement is hereby modified by changing or adding the following definitions:

"AGP Tech Upgrade Scope" shall mean Contractor's scope of supply to upgrade the Gas Turbines with upgrades including, but not limited to, AGP Capital Parts and DLN2.6+ Capital Parts, included in Attachment 1 to this Amendment 4.

"AGP Capital Parts" shall mean those upgraded buckets, nozzles, and shrouds Capital Parts, that shall replace such existing Capital Parts, as further set forth in Attachment 1 to this Amendment 4.

"DLN 2.6+ Capital Parts" shall mean those upgraded fuel nozzles, combustion caps, liners, and transition pieces Capital Parts, that shall replace such existing Capital Parts, as further set forth in Attachment 1 to this Amendment 4.

"AGP Tech Upgrade Installation Milestone Payment" shall mean, subject to Section VIII.P, eighteen million, four-hundred and twenty-five thousand dollars (US$18,425,000) for each Gas Turbine.

"AGP Tech Upgrade Maintenance Milestone Payment " shall mean, subject to Section VIII.J.6, the eleven million, two hundred thousand ($11,200,000).

B. Section II (Scope of Contractor's Obligations) of the Agreement is hereby amended by adding the following Section II. Q

Q. AGP Tech Conversion.

1. Contractor shall provide all Parts and Services as necessary to complete the AGP Tech Conversion (as outlined in the AGP Tech Upgrade Scope). The "AGP Tech Conversion" means (i) the

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installation of a full set of new AGP Capital Parts and associated hardware to replace such then installed Capital Parts and (ii) the installation of a full set of new DLN2.6+ Capital Parts and associated hardware to replace such then installed Capital Parts, for each Gas Turbine, and (iii) all other items listed in Attachment 1 AGP Tech Upgrade Scope, in order to support the AGP Tech Conversion. Payment for the AGP Tech Conversion shall be in accordance with the provisions of Section VIII of the Agreement.

2. Such AGP Tech Conversion shall occur as the next scheduled Hot Gas Path or Major Inspection for each Gas Turbine.

C. Section VIII (Price And Payment Terms) of the Agreement is hereby amended by adding the following Section VIII. P:

P. AGP Tech Conversion Price and Payment.

1. In consideration of the AGP Tech Conversion, Owner shall pay Contractor the AGP Tech Upgrade Installation Milestone Payment for each Gas Turbine to have such AGP Tech Conversion.
2. Contractor shall invoice Owner for the AGP Tech Upgrade Installation Milestone Payment as follows:

   a. $4,606,250 on April 1, 2024 for each Gas Turbine
   b. $12,897,500 on January 15, 2025 for each Gas Turbine
   c. $921,250 upon mobilization to site for the AGP Tech Conversion for each Gas Turbine

3. Escalation for the AGP Tech Upgrade Installation Milestone Payment shall be calculated per Section VIII.C, except for the Base Index, which shall be the Composite Index for the year 2023.

D. Section VIII (Price And Payment Terms), sub-section J (Milestone Payments) of the Agreement is hereby amended by adding the following Section VIII.J.6:

6. In consideration of the AGP Tech Conversion, Owner shall pay Contractor the AGP Tech Upgrade Maintenance Milestone Payment. Contractor shall invoice Owner for such AGP Tech Upgrade Maintenance Milestone Payment approximately six (6) months prior to the first Hot Gas Path Inspection of the first Gas Turbine after the AGP Tech Conversion. For purpose of clarification, this one (1) payment and not intended to be per Gas Turbine. Escalation for the AGP Tech Upgrade Maintenance Milestone Payment shall be calculated per Section VIII.C, except for the Base Index, which shall be the Composite Index for the year 2023.

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3. Entire Agreement. Except as expressly set forth in this Amendment 4, all other provisions of the Agreement (as previously amended by the letter agreement referenced hereinabove) remain unchanged and in full force and effect. In the event of a conflict between the terms of the Agreement and this Amendment 4, the terms hereof shall control. This Amendment 4 may be amended only by an instrument in writing executed by the Parties hereto.

4. Counterparts; Signatures. This Amendment 4 may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute one instrument. Any signature page of any such counterpart, or any electronic facsimile thereof, may be attached or appended to any other counterpart to complete a fully executed counterpart of this Amendment 4. Any electronic facsimile transmission of any signature of a Party shall be deemed an original and shall bind such Party.

5. Governing Law. This Amendment 4 shall be governed and construed in accordance with the laws of the Agreement, without regard to its conflicts of laws provisions.

6. No Third-Party Beneficiary. This Amendment 4 is intended solely for the benefit of the Parties and is not intended for the benefit of any third parties.

IN WITNESS WHEREOF, the Parties have caused this Amendment 4 to be executed as of the date first above written.

CONSUMERS ENERGY COMPANY

DocuSigned by:
By: Jason L Ricketts
4CDFDAB92EF14DF...
Name: Jason L Ricketts
Title: Sr Manager Plant Operations
Date: 2/26/2024 | 10:07 AM EST

GE VERNOVA INTERNATIONAL LLC.

DocuSigned by:
By:
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Date: 2/23/2024 | 1:25 PM EST

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Attachment 1

AGP Tech Upgrade Scope

CONSUMERS ENERGY

Site: ZEELAND GENERATING STATION

Unit Serial: 297502; 297503

Proposal Number: 1628149-440825

Revision: 1

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Section 1: Scope of Supply

1.1 Scope of Supply

DLN 2.6+ GO Combustion System

Combustion System:

This upgrade includes an entirely new combustion system, except for the Transition Pieces (TPs) if the unit has a TIL 1774 compliant 24k EI combustion system. If the unit does not have DLN2.6e 24k EI combustion system, new TPs will be required. Here is the list of the combustion components within the Scope of Supply:

- ML A033 Major Disassembly Tool Kit
- ML 0513 Gas-Only Fuel Nozzle Assembly
- ML 0572 Fuel Gas Emergency Stop Valve
- ML 0701 Combustion Chamber Arrangement
- ML 0702 Transition Piece Assembly
- ML 0703 Combustion Liner Arrangement
- ML 0717 Transition Piece Arrangement Combustion
- ML 0719 Aft Combustion Case Arrangement
- ML 0726 Combustion Tuning Piping
- ML 1214 Spark Plug Assembly

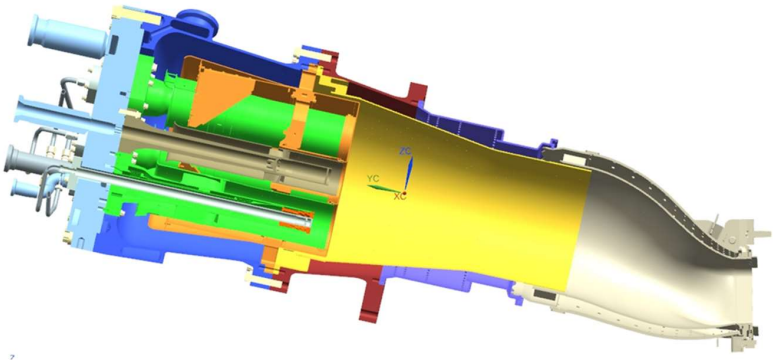

Figure 1: DLN2.6+ Combustion System

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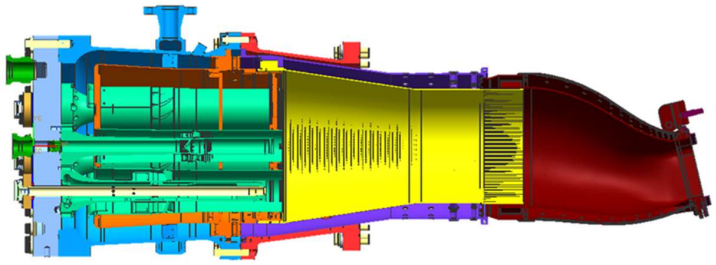

Figure 2: DLN2.6+ Combustion System, Gas Only Cross-section.

Accessories:

The following items will be provided as new or as an upgrade.

1. For 7FA cold fuel sites- Replace PM1 and Quat valves with no piping changes
2. New Gas piping arrangement, interconnect piping (MLI 0962/969G)
3. New air extraction piping (MLI0924)
4. New TMR ATID sensors
5. New spark plugs (MLI 1214)
6. Modifications to;
    - WW/FSD Drain
    - Cooling Water piping including aft leg cooling removal.
    - CDM Probe Holder
    - Strainer
    - COP Structure (removal)
    - Transducer Arrg
    - Manway Cover Arrangement (If required)
    - Cooling and Sealing Piping Arrangement
    - SPA Power Step Up Ignition Transformer
    - Static Starter Analysis
    - Control Oil Interconnect Piping
    - Field Temporary Sensor

Controls Systems:

Continuous Dynamics Monitoring (CDM) system, Enhanced Transient Stability (ETS), CLEC and AutoTune DX are required for this new combustion system. In case an existing MKVI is being migrated to a MKVIe system, an aux panel might be required to provide additional IO capability.

7F DLN 2.6+ AFS

AFS requires an additional GCV in the gas module as well as additional interconnect piping, manifold & pigtails. Because of variability in GT compartment layouts a laser scan will be performed to facilitate installation and limit field modifications if a recent laser scan has not already been completed.

Scope of supply includes:

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1. AFS injectors
2. Modifications required to TP/impingement sleeve to accommodate AFS injector.
3. Routing of fuel circuit inside of unit to fuel AFS system
4. Modifications to manway covers to accommodate fuel circuit routing.
5. Flow sleeve assembly (for existing DLN2.6+ units only)
6. Controls integration
7. Accessories modifications required to fuel AFS.
    - Modification to fuel skid for AFS Valve
    - Downstream and Interconnecting Piping
    - Additional Fuel Gas Manifold Pressure Differential Transmitters
    - AFS Valve (VCG-5)

Impacted Components:

1. Gas supply skid
2. GT Instrumentation
3. Gas Control Valves
4. Gas fuel manifolds & pigtails
5. Combustor transition pieces
6. Combustion liner
7. Turbine shell arrangement
8. AFS fuel delivery and injectors
9. Combustor flow sleeve

7F AGP Tech Package

This modification will include the following:

- AGP Stage 1 Nozzle Kit and Support Ring
- AGP Stage 2 and 3 Nozzle Kits
- AGP Stage 1, 2, and 3 Bucket Kits
- AGP Stage 1, 2, and 3 Shroud Kits
- Cooling and sealing air orifice modification
- Installation and modification documents
- Firing temperature increase and revised Model Based Control (MBC) software changes (formerly known as control curve change)
- 7FA.04 or 7FA.05 length 1AO, 2FO, 2AO wheel space thermocouples (as appropriate)

High Output Stage 0

The implementation of high-output stage 0 upgrade on gas turbines with flared-enhanced compressor package 3 configuration (or higher) involves the following modifications:

- Redesigned stage R0 compressor rotor blades arrangement
- Redesigned stage S0 compressor stator vanes arrangement
- Replacement R0 staking inserts (if modification has been already implemented)
- Replacement S0 stator keys
- Control software updates

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Enhanced Little Foot Aft Stator Vanes

The implementation of the enhanced little-foot aft stator modification includes the following compressor hardware:

- Stage S14 enhanced little-foot stator vanes arrangement.
- Stage S15 enhanced little-foot stator vanes arrangement.
- Stage S16 enhanced little-foot stator vanes arrangement.
- Retaining rings for all three stages
- Stator vanes' installation hardware (stator keys and shoulder pins)

Enhanced Compressor – Package 4

- Software modifications to upload the Optimum Start (also known as Strategic Anti-Rotating Stall Schedule, or STARSS) software.
- Modification of the IGV stop blocks *
- Enhanced IGVs (including assembly hardware)
- Enhanced R0 rotor blades with graphite coating on the dovetail
- Enhanced S0 thru S4 stator vanes (S0 and S1 retain the NUVS configuration)
- Enhanced-robust S5 stator vanes and S5 casing pins, also known as "load dams."
- MCC modification* for drilling provisions for the S5 pins
- S6 thru S8 stator vanes with full airfoil shot peening [optional]
- Enhanced S14 thru S16 stator vanes with shot peening. There are two options:
    - Vanes with larger bases and hook fits that require CDC machining (bit-foot design)
    - Vanes with original bases and retaining rings that do not require CDC machining (little-foot design)
- CDC S14 thru S16 stator grooves modification* [if implementing big-foot vanes only]
- CDC patch ring [if a previous patch ring in S14/S15/S16 requires replacement]

- **7FA Shaft HP Limit Increase (214MW)** Controls software modifications to increase GT shaft torque limit.
- New or modified load coupling (as required) depending on the existing configuration.
- 96GW 4-20 mAmp analog transducer mounted in the GPP(recalibration or replacement), if needed.
- Excitation software requires update due to the new shaft torque limit.

OpFlex Cold Day Performance

This modification includes the following:

- OpFlex Cold Day performance software

Variable IGV Angle Optimization

This modification will include the following:

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- OpFlex™ Variable IGV Angle Optimization software
- OpFlex™ Variable IGV Angle Optimization HMI screens
- Controls Specifications update.

F-Class OpFlex Advantage Variable Peak Load

This modification includes the following:

- Modifications of Mark VIe Software.
- Advanced Fuel Scheduling
- OpFlex Peak Load
- Installation and modification documents.

Revised Control Curve

GE Performance Engineering will develop and document the revised exhaust temperature control curves that correspond to the new machine characteristics. This effort may include one or all of the curves as required: base load, peak load or part load. The exhaust temperature control curve information is then used by GE Controls Engineering to convert the curves into a control specification. The control specification is provided in documentation to the customer.

Performance Curves

GE will create gas turbine correction curves based on a thermal site-specific model.

TTKX Coefficient Modification

This modification includes the following:

- Installation and modification documents if any.
  - Requisition Management support.

Note: The TTKX Coefficient adjustment will be performed in collaboration with a scheduled DLN tuning.

Safety Shutoff Valve (SSOV) and Vent Valve (SSOVV)

The Safety Shut Off System (Valves + Engineering + Support + Accessories) includes the following:

- Safety Shut-off Isolation Valve (SSOV) [Qty.1]
- Safety Shut-off Vent Valve (SSOVV) [Qty.1]
- Vent Line Interconnect Piping
- Silencer
- Compressed Air Piping
- Supporting Structures
- Provision for Junction Box Interconnecting Cabling and Cable Trays
- Accessories Engineering for SSOV/SSOVV, supporting structures, and interconnect piping/cabling.
- Modifications to provide access (ladder, gratings, handrails, etc.) as required.
- Drawing Updates

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- Controls Modifications
- Requisition Management
- Laser Scan

Triple Modular Redundant (TMR) Pressure Monitoring

The redundant sensor ventilation system upgrade includes:

- On base conduit and wiring for TMR pressure transmitters in the turbine compartment-(3) transmitters required per ventilation fan.
- Software modifications for the new transmitter configuration to incorporate lead/lag function as well as the trip functions for the ventilation fans.

Combustion Dynamics Monitoring (CDM) – Dual

CDM Equipment (typical)

- Dynamic Pressure Probes & Probe Holder
- Signal conditioner
- UCSx Cards as applicable
- Dual PAMC Acoustic Monitoring Card
- Cables and Tubing to make necessary connections.
- Conduit required for collection of probe cables to signal conditioner.
- Installation and Modification Documents including Controls Modifications

Field Laser Scan - 3D image.

DLN 2.6+ combustion system upgrade would require a scan of the areas outside (interconnecting piping) and inside of the gas turbine enclosure (fuel manifolds, interior geometry (turbine casing/combustion can interface) and the accessory compartments. This would include the top, bottom, both ends and left & right sides of the interiors and exteriors.

The key is to capture the as-built detail for each system or MLI (Model List Item) affected by the modification. Detailed scanning requirements will be defined by an ordering drawing created by GE Requisition Engineering.

Typical scope includes the following: Onsite survey, Scan, Registration, UG Model Generation, Estimated T&L, Equipment. All T&L, Equipment Rental, Targets, and extra baggage charges charged at actual cost.

1.2 Performance Effect

Expected Relative Performance Improvement- Evaps Off

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	deg F	**-20**	**0**	**30**	**59**	**75**	**92**	**105**
GT Output	*%*	8.0%	11.3%	16.2%	14.5%	13.3%	12.5%	9.9%
GT Heat Rate	*%*	-1.4%	-1.8%	-2.2%	-2.6%	-2.5%	-2.6%	-2.7%

Expected Relative Performance Improvement- Evaps On

Ambient Temperature	*deg F*	**59**	**75**	**92**	**105**
Inlet Temperature	*deg F*	53	67	81.8	90
GT Output	*%*	15.1%	13.4%	13.2%	13.3%
GT Heat Rate	*%*	-2.6%	-2.5%	-2.5%	-2.6%

7F.04 Tech HOR0 AFS MECL Estimates -

Ambient Temperature	deg F	-20	0	30	59	75	92	105
Turndown Output	%	50.3%	38.0%	25.3%	24.9%	25.8%	28.3%	31.0%
Turndown Output	MW	103.8	79.2	52.6	48.1	47.1	47.8	47.7

Unit Operation & Site Conditions

	Pre-Uprate	**Post-Uprate**
Load Condition	Base	Base
Compressor Configuration	7F.03 UF EC2	7F.04 ECP4 HOR0
Combustor Configuration	DLN 2.6	DLN2.6+ (AFS Option)
Turbine Configuration	7FA.03	7F.04 Tech
Fuel Type	Natural Gas	Natural Gas
Exhaust Configuration	Simple Cycle	Simple Cycle
Diluent Injection Status	None	None
Inlet Air Treatment	Evaps (On or Off)	Evaps (On or Off)
Gas Turbine Condition	Clean, ≤25 FH since offline WW	Clean, ≤25 FH since offline WW

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Rated Conditions

Parameter	Units	Pre-Uprate Value	Post-Uprate Value
Compressor Inlet Temperature	deg F	81.8	81.8
Compressor Inlet Relative Humidity	%	92.2%	92.2%
Barometric Pressure	psia	14.35	14.35
Shaft Speed	rpm	3600	3600
Generator Power Factor	ratio	0.85	0.85
Inlet Pressure Drop	inH2O	4.0	4.1
Exhaust Pressure Drop	inH2O	5.8	6.1
Fuel Temperature	deg F	51	51
Fuel Composition (Natural Gas)			
Methane (CH4)	% mol	93.256	93.256
Ethane (C2H6)	% mol	2.953	2.953
Propane (C3H8)	% mol	0.442	0.442
N-Butane (C4H10)	% mol	0.113	0.113
N-Pentane (C5H12)	% mol	0.036	0.036
Hexanes, Avg. (C6H14)	% mol	0.033	0.033
Nitrogen (N2)	% mol	2.405	2.405
Carbon Dioxide (CO2)	% mol	0.761	0.761

1.3 Emissions Effect

Estimated emission at base load:

- 9 ppmvd NOx @15% Oxygen.
- 9 ppmvd CO

1.4 Generator Evaluation

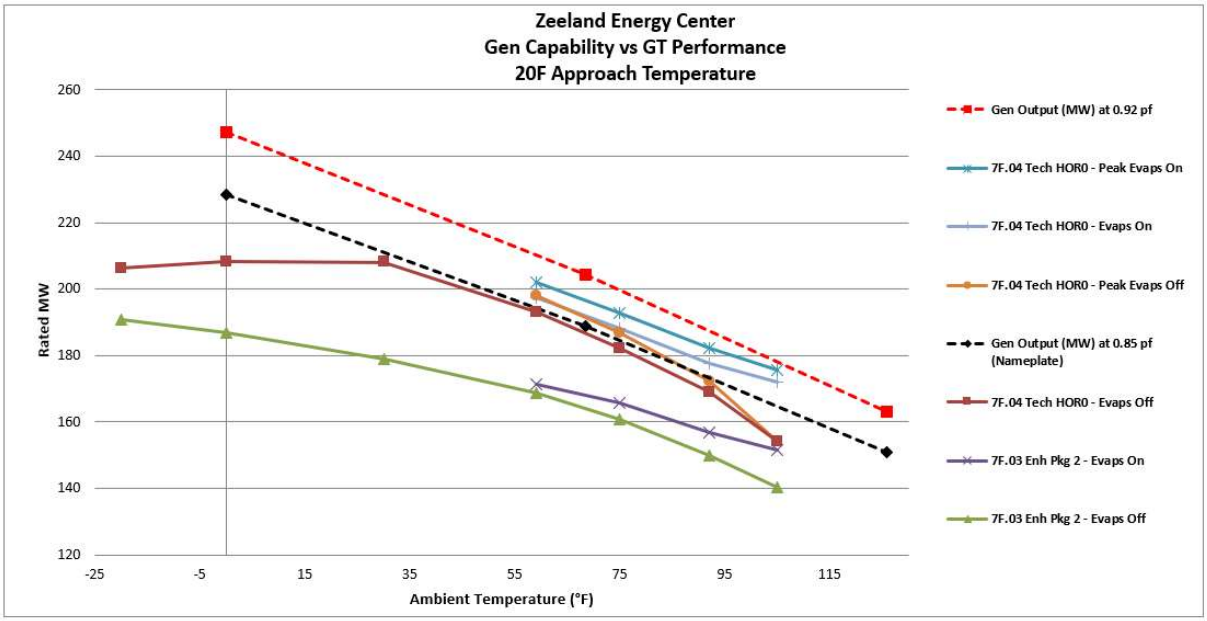
Conclusion, Generator Capability vs. Proposed GT Uprate:
A cursory review of Zeeland Generating Station Generator SNs 337X125 and 337X126 was performed to assess the ability of the generators to accommodate the following gas turbine configuration cases:

Pre-upgrade cases:
7F.03 Enh Pkg 2 - Evaps Off
7F.03 Enh Pkg 2 - Evaps On
Post-upgrade cases:
7F.04 Tech HOR0 - Evaps Off
7F.04 Tech HOR0 - Evaps On
7F.04 Tech HOR0 - Peak Evaps Off

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

7F.04 Tech HOR0 - Peak Evaps On
The review indicates that generator can meet gas turbine uprate cases with power factor as shown in the table and graph below.

Cases	Power Factor Required
7F.04 Tech HOR0 - Evaps Off	0.85 (nameplate)
7F.04 Tech HOR0 - Evaps On	0.90
7F.04 Tech HOR0 - Peak Evaps Off	0.88
7F.04 Tech HOR0 - Peak Evaps On	0.92



For the cases where Power Factor float is not required: This evaluation approach does not require uprated generator hardware changes (main generator, exciter, and other generator auxiliary equipment), as the generator will operate within its original design capabilities.
For the cases where Power Factor float is required: Operating at the higher power factor will reduce reactive power (VAR) output. This evaluation approach does not require uprated generator hardware changes (main generator, exciter, and other generator auxiliary equipment), as the generator will operate within its original design capabilities. If the reduced VAR output is unacceptable to the Customer (this could be due to a regulatory organization requirements and restrictions, as an example), and an uprate in MVA is desired, a Generator Detailed Study would have to be performed to thoroughly review this possibility.

Critical Assumptions:

1. Cooling Liquid Data – Needs Customer Confirmation
    a. Cooling Liquid Composition: 50% Ethylene Glycol / 50% Water with Fouling Factor of 0.001 - per C907 585A1304

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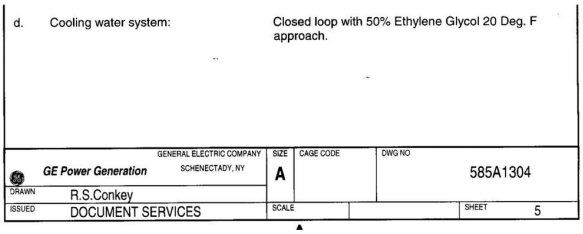
b. Approach Temperature per C907 585A1304



2. Generator components are in their "New and Clean" conditions.
    a. The generator review does not take into consideration any generator component degradation due to age, environment or maintenance practices. The analysis assumes that the condition and performance of the generator is as it was when it was shipped.
3. The study is based on GE internal design records and deviations, which would not account for any hardware changes the unit experienced that were not performed by GE. The Customer shall advise if there was any 3rd party work performed (e.g., stator rewind, field rewind, exchange rotor, core repair, etc.)
4. Increased Power Factor is acceptable for the cases where Power Factor Float is required.
5. The graph shown above is for the reference only and does not provide any contractual guarantee with respect to overall GT-Generator performance.

Reliability Considerations:

This uprate assessment was based on GE internal design records and deviations, which does not account for any hardware changes outside of GE knowledge and experience.
It is strongly recommended that the generator undergo a thorough Test and Inspection per GEK 103566 to establish the current generator condition before increasing in MW operation, as the increase in MW will result in the generator experiencing higher than previous current loads and component temperatures. GE would be pleased to discuss this and other key reliability issues with the Customer.

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Appendix 1 – Technical Assumptions

Original Manufacturing Information		
Serial Number(s)	297502	297503
Design Memo(s)	DM-GR0526	
MPL/ML#	ML-7A1WFA106-1	ML-7A1WFA106-2
Manufacturer	GE	
Equipment Code	7FA.03	
Product Line	F Fleet	
Nameplate	297502	297503
Site Location	ZEELAND GENERATING STATION	
Controls OEM	GE	
COD Date	21-05-2001	
Ship Date	19-09-2000	23-09-2000
Control System	Mark VIe TMR	
Starter OEM	GE	
Crossover	YES	
Service Relationship	CSA	

Site Information

Site Information	
Market Segment	Power Generation
Operation Cycle	GT
Country	UNITED STATES
Altitude	670 ft
Min Ambient Temp	-20 ºF
Design Ambient Temp	92 ºF
Max Ambient Temp	105 ºF
Relative Humidity	60 %

Current Configuration

Inlet/Exhaust	
Inlet Pressure Drop	4.04 in H_2O

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Inlet/Exhaust	
IBH System	Yes
Exhaust Pressure Drop	5.75 in H_2O

Combustor	
Fuels	NATURAL GAS
Nox/Diluent	DLN
Augmentation	NONE
Combustion System	DRY LOW NOX 2.6

Operating Data

Region/PGS Service Region	NAM North America
PGS Service Sub Region	North America North
Sales Channel	Power Services Sales

Previous Requisitions:

Serial Number	FDM	ICN	SCOPE	Date
297502	F4694G3	CR135666	Comb Dynamics Monitoring w/RDLNT	07-12-2004
297502	F4694G4	CR135666	Comb Dynamics Monitoring w/ RDLNT	07-12-2004
297502	F4694G8	DR429878-1	Combustion Spread Monitor Upgrade (TIL 1524-3)	27-04-2009
297502	F6014G12	1555351-372427- 6 (ADDED SCOPE)	ADDED SCOPE: 7FA.03 OpFlex Sliding Fuel Pressure Control+(96FG-1 Sensor)	31-08-2021
297502	F6014G12	1555351-372427- 4	7FA.03 OpFlex Sliding Fuel Pressure Control	31-08-2021
297502	F6014G10	CR587328-1	7FA.03 TIL 1287 Excessive Gas Fuel Flow at Start-up	09-06-2014
297502	F6014G8	CR578567-1	7FA.03 2-Piece Uncambered IGVs (CID Minor)	12-03-2014

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Serial Number	FDM	ICN	SCOPE	Date
297502	F6014G8	CR477059C-6	7FA.03 Enhanced Compressor Package 2/Bellows Crossfire Tubes (CID Minor)	12-03-2014
297502	F6014G7	CR477059C-3	7FA+e/s OP FLEX BALANCE AUTOTUNE, SS CBV (CID=minor)	30-05-2013 17:00:00
297502	F6014G9	CR551830-3	7FA.03 Exhaust Thermocouples Upgrade (CID Minor)	03-05-2013 17:00:00
297502	F6014G9	CR551830-1	7FA.03 Exhaust Thermocouples Upgrade (CID Minor)	03-05-2013 17:00:00
297502	F6014G2	CR437650-1	TIL 1345 - Over Speed Trip Test Procedure Automation	19-06-2009
297502	F4694G7	DR416814-1	HMI Upgrade	10-12-2008
297502	F4694G4	CR135666	Comb Dynamics Monitoring w/ RDLNT	07-12-2004
297502	F4694G3	CR135666	Comb Dynamics Monitoring w/RDLNT	07-12-2004
297503	F4694G4	CR135670	Comb Dynamics Monitoring w/ RDLNT	07-12-2004
297503	F4694G8	DR429878-2	Combustion Spread Monitor Upgrade (TIL 1524-3)	27-04-2009
297503	F6014G12	1555351-372427- 5	7FA.03 OpFlex Sliding Fuel Pressure Control	31-08-2021
297503	F6014G12	1555351-372427- 7 (ADDED SCOPE)	ADDED SCOPE: 7FA.03 OpFlex Sliding Fuel Pressure Control+(96FG-1 Sensor)	31-08-2021
297503	F6014G10	CR587328-2	7FA.03 TIL 1287 Excessive Gas Fuel Flow at Start-up	09-06-2014
297503	F6014G2	CR437622-1	TIL 1345 - Over Speed Trip Test Procedure Automation	19-06-2009
297503	F6014G4	DR494058-2	Mk V to Mk Ve upgrade w/Phase 2 Life Extension Package Beta Application	27-05-2011
297503	F6014G8	CR555489-1	7FA+e/s ENH CMPRS PKG-2 with UNCAMBERED 2PC IGV (CID=minor)	19-07-2013 17:00:00

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Serial Number	FDM	ICN	SCOPE	Date
297503	F6014G8	CR477059C-5	7FA+e/s ENH CMPRS PKG-2 with UNCAMBERED 2PC IGV (CID=minor)	19-07-2013 17:00:00
297503	F6014G7	CR477059C-4	7FA+e/s OP FLEX BALANCE AUTOTUNE, SS CBV (CID=minor)	30-05-2013 17:00:00
297503	F6014G9	CR551830-2	7FA.03 Exhaust Thermocouples Upgrade (CID Minor)	03-05-2013 17:00:00
297503	F6014G9	CR551830-4	7FA.03 Exhaust Thermocouples Upgrade (CID Minor)	03-05-2013 17:00:00
297503	F4694G7	DR416814-2	HMI Upgrade	10-12-2008
297503	F4694G4	CR135670	Comb Dynamics Monitoring w/ RDLNT	07-12-2004

TIL Affected Units List:

Unit Serial Number	TIL No.	TIL Title	Status	CMU Required	Compliance Type	TAG
297502	1509-R4	F-CLASS FRONT END (R0, S0, AND R1) COMPRESSOR INSPECTIONS	INCOMPLETE	Yes	C - Compliance Required	FS5V
297503	1509-R4	F-CLASS FRONT END (R0, S0, AND R1) COMPRESSOR INSPECTIONS	INCOMPLETE	Yes	C - Compliance Required	FS5V
297502	1320-R2	INLET BLEED HEAT (IBH) PIPE SYSTEM INSPECTION AND CORRECTIVE ACTION	COMPLETE / RECURRING	Yes	M - Maintenance	FD4L
297502	1363-2R1	MODIFICATION TO MARK V TRIP COUNTER	COMPLETE / RECURRING	Yes	O - Optional	FW4Y
297502	1456-2R1	LUBRICATION PUMP MAINTENANCE PRACTICES	COMPLETE / RECURRING	Yes	M - Maintenance	FW4C
297502	1576-R1	GAS TURBINE ROTOR INSPECTIONS	COMPLETE / RECURRING	Yes	S - Safety	FS4PC - REV4, FS4PC

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

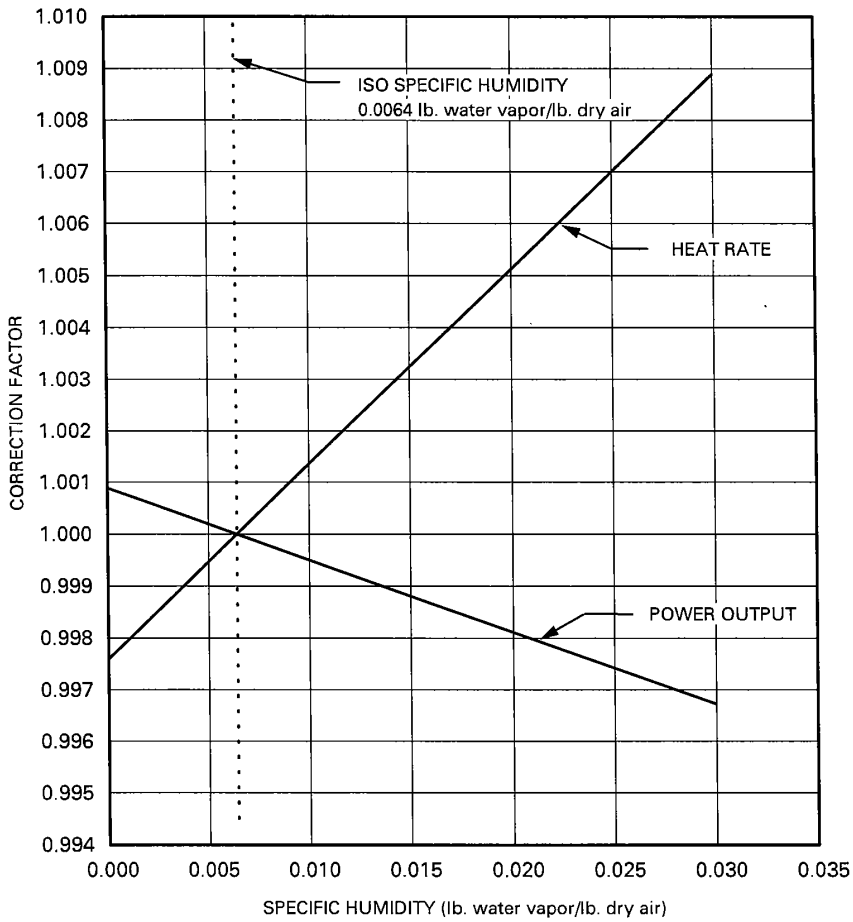
Unit Serial Number	TIL No.	TIL Title	Status	CMU Required	Compliance Type	TAG
297502	1582-R2	F AND H CLASS LIFT OIL HOSE INSPECTION AND REPLACEMENT	COMPLETE / RECURRING	Yes	C - Compliance Required	FW4O
297502	1619	TURBINE COMPARTMENT HIGH TEMPERATURE	COMPLETE / RECURRING	Yes	O - Optional	FW4Q
297502	1700	POTENTIAL GAS LEAK HAZARD DURING OFFLINE WATER WASHES	COMPLETE / RECURRING	Yes	S - Safety	FW4T
297502	2058	HAZGAS PROTECTION - GAS FUEL COMPARTMENT	COMPLETE / RECURRING	Yes	S - Safety	FW5P
297503	1320-R2	INLET BLEED HEAT (IBH) PIPE SYSTEM INSPECTION AND CORRECTIVE ACTION	COMPLETE / RECURRING	Yes	M - Maintenance	FD4L
297503	1363-2R1	MODIFICATION TO MARK V TRIP COUNTER	COMPLETE / RECURRING	Yes	O - Optional	FW4Y
297503	1456-2R1	LUBRICATION PUMP MAINTENANCE PRACTICES	COMPLETE / RECURRING	Yes	M - Maintenance	FW4C
297503	1576-R1	GAS TURBINE ROTOR INSPECTIONS	COMPLETE / RECURRING	Yes	S - Safety	FS4PC-REV4,FS4PC
297503	1582-R2	F AND H CLASS LIFT OIL HOSE INSPECTION AND REPLACEMENT	COMPLETE / RECURRING	Yes	C - Compliance Required	FW4O
297503	1619	TURBINE COMPARTMENT HIGH TEMPERATURE	COMPLETE / RECURRING	Yes	O - Optional	FW4Q
297503	1700	POTENTIAL GAS LEAK HAZARD DURING OFFLINE WATER WASHES	COMPLETE / RECURRING	Yes	S - Safety	FW4T
297503	2058	HAZGAS PROTECTION - GAS FUEL COMPARTMENT	COMPLETE / RECURRING	Yes	S - Safety	FW5P

Appendix D: GE 7FA Correction Curves

General Electric MS6001, MS7001 And MS9001 Gas Turbines

Corrections To Output And Heat Rate
For Non-Iso Specific Humidity Conditions

For Operation At Base Load On Exhaust
Temperature Control Curve



10/10/89
DA JAQUEWAY

498HA697
REV B

General Electric Model PG7241(FA) Gas Turbine

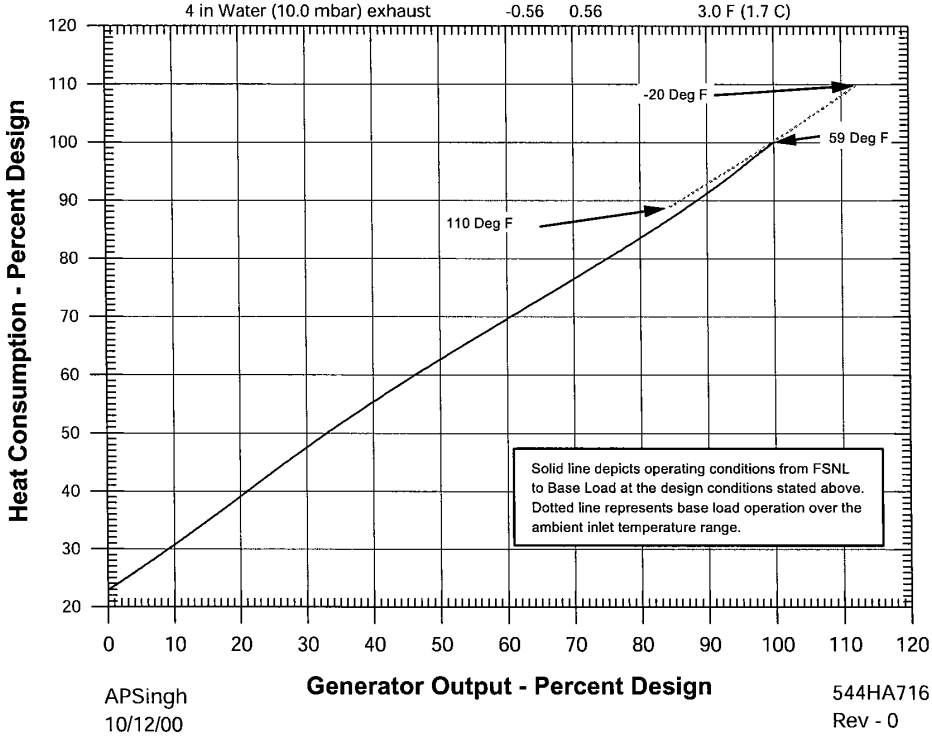
Estimated Performance - Configuration: DLN2.6 Combustor

Ambient Temperature 59 Deg F (15 Deg C), 60% Relative Humidity
Atmospheric Pressure 14.7 psia (1.013 Bar)

Fuel	Methane Gas @ 80 Deg.F , LHV = 21515 BTU/lb	
MODE:		Baseload
Evaporative Cooler Status:		ON
Design Output	kW	174000
Design Heat Rate (LHV)	Btu/kWh	9335
Design Heat Cons (LHV)x10^6	Btu/h	1624.3
Design Exhaust Flow x 10^3	lb/h	3629
Exhaust Temperature	deg. F	1112

Notes:
1. Altitude correction on curve 416HA662.
2. Ambient temperature and humidity correction on curve 544HA717 thru 544HA720.
3. Humidity effects on curve 498HA697 (use if evap. cooler is off).
4. Effect of modulating IGV's on Exhaust temperature and flow on curve 544HA721.
5. Plant Performance is measured at the generator terminals and includes allowances for the effects of excitation power, shaft driven auxiliaries, and 4.0 in H_2O (10.0 mbar) inlet and 5.5 in H_2O (13.75 mbar) exhaust pressure drops, evaporative cooler turned on @ baseload and a DLN combustor.
6. Additional inlet and exhaust pressure loss effects:

	% Effect on Output	% Effect on Heat Rate	Effect on Exhaust Temp.
4 in Water (10.0 mbar) inlet	-1.54	0.56	3.0 F (1.7 C)
4 in Water (10.0 mbar) exhaust	-0.56	0.56	3.0 F (1.7 C)

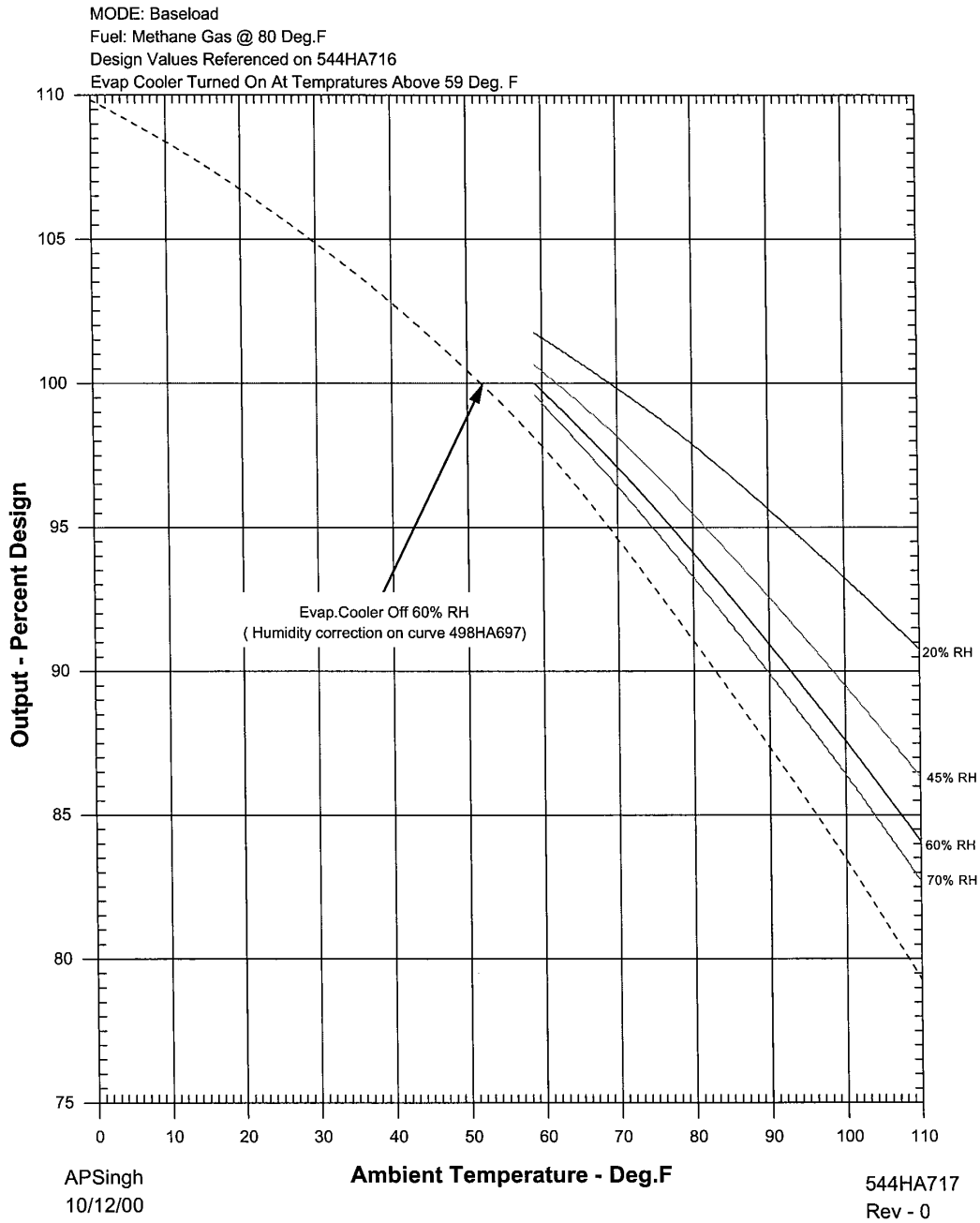


APSingh
10/12/00

544HA716
Rev - 0

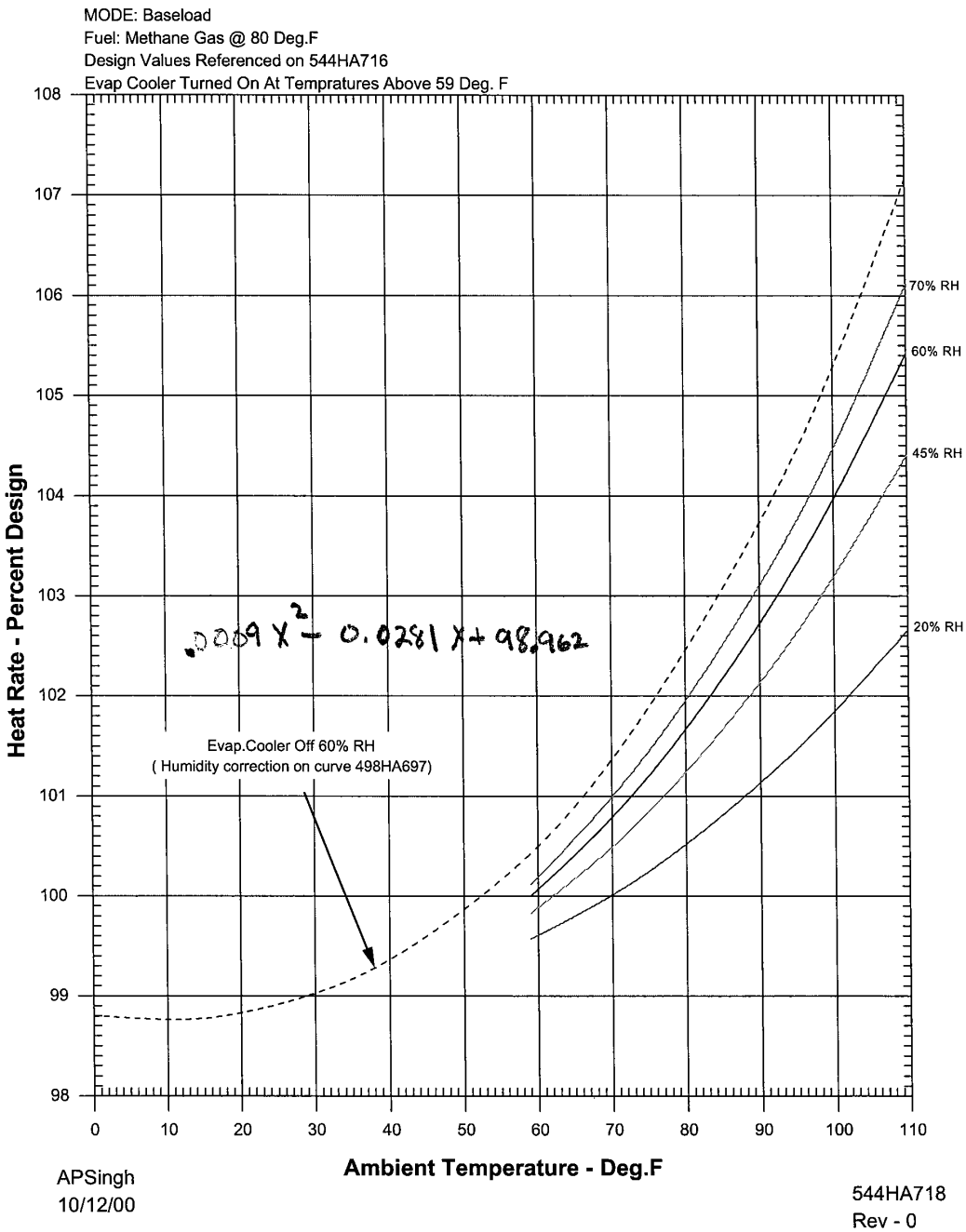
General Electric Model PG7241 (FA) Gas Turbine

Estimated Performance - Configuration: DLN 2.6 Combustor



General Electric Model PG7241 (FA) Gas Turbine

Estimated Performance - Configuration: DLN2.6 Combustor

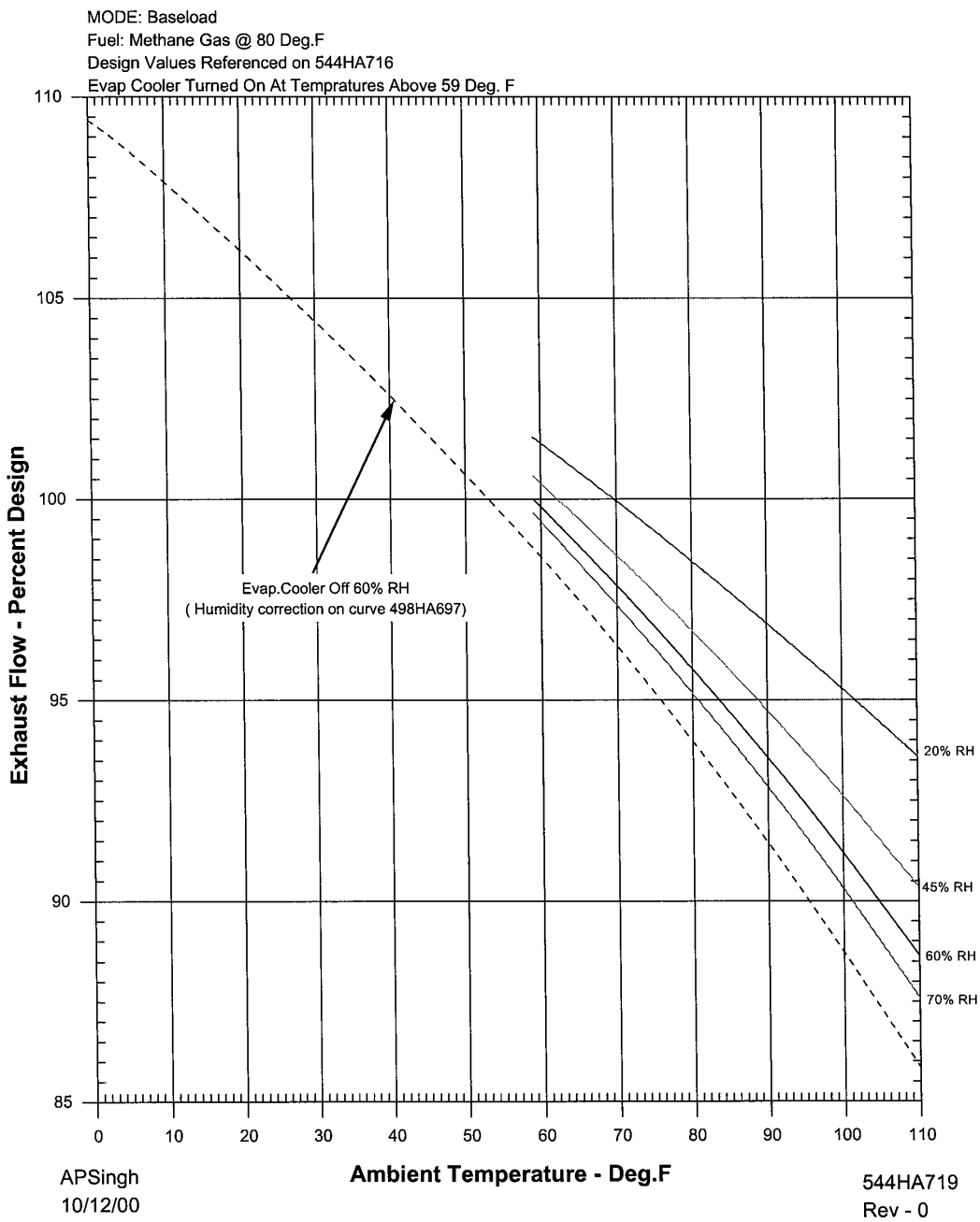


APSingh
10/12/00

544HA718
Rev - 0

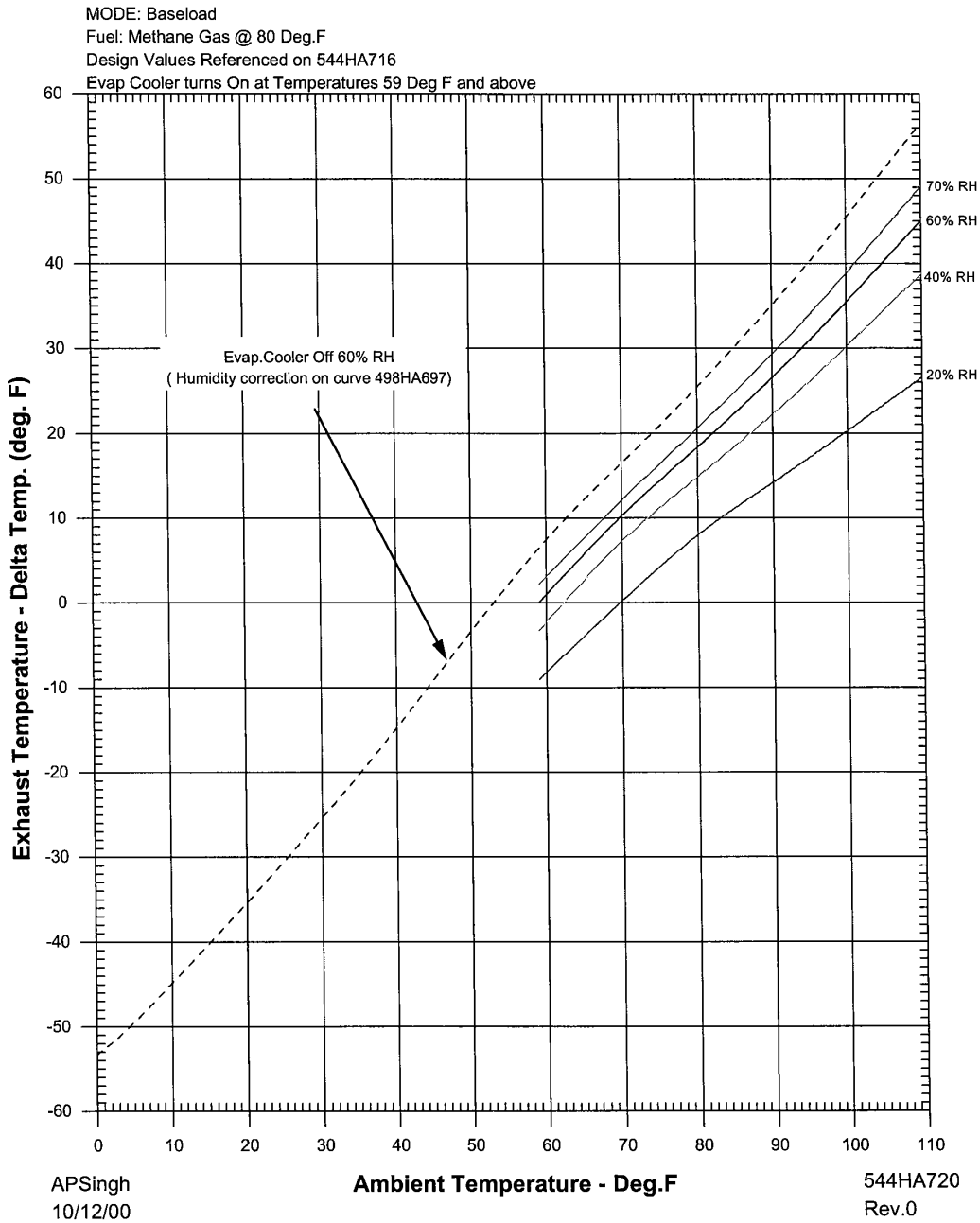
General Electric Model PG7241 (FA) Gas Turbine

Estimated Performance - Configuration: DLN 2.6 Combustor



General Electric Model PG7241(FA) Gas Turbine

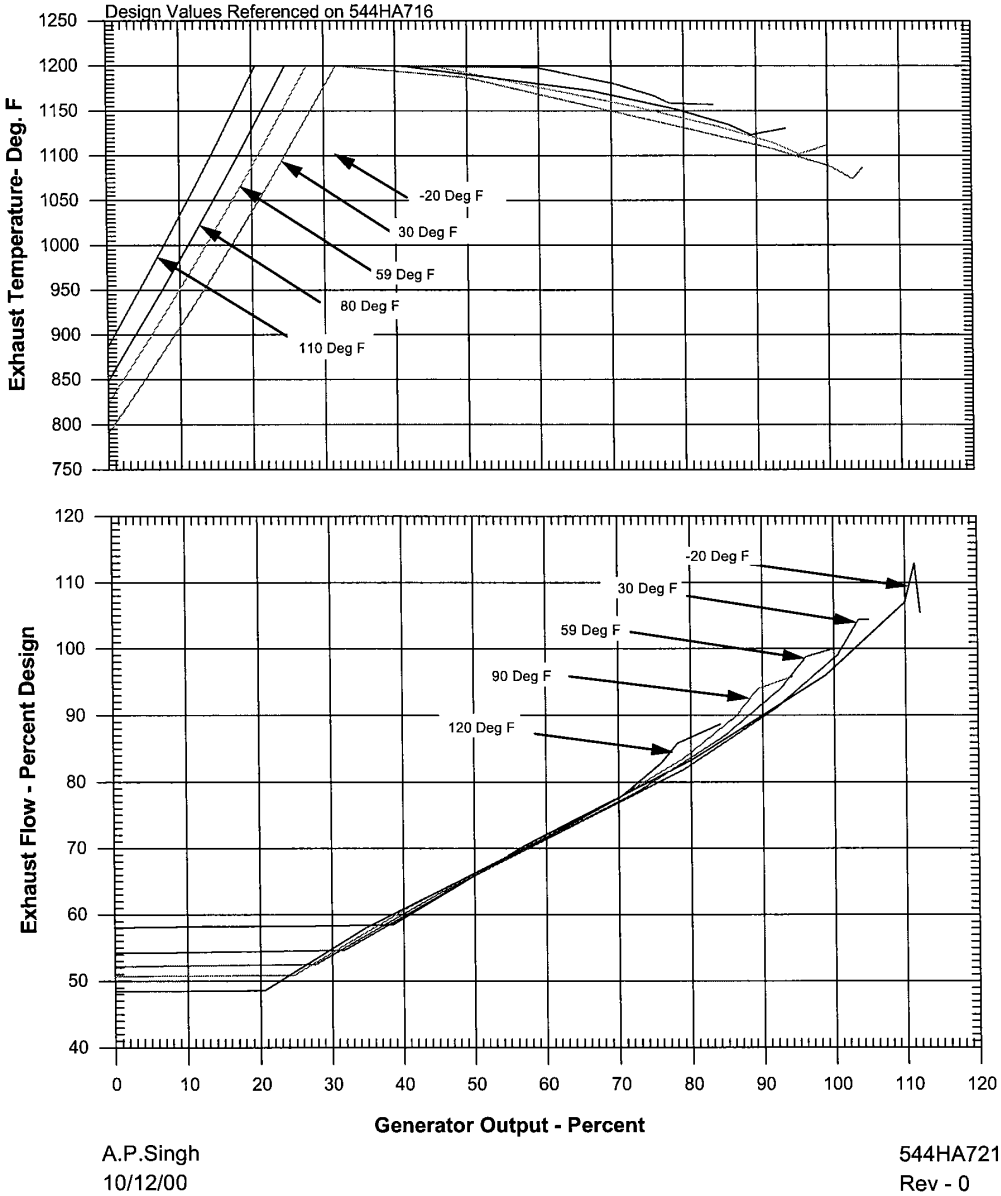
Estimated Performance - Configuration: DLN2.6 Combustor



GENERAL ELECTRIC MODEL PG7241(FA) GAS TURBINE

Estimated Performance - Configuration: DLN 2.6 Combustor

Mode: Baseload
Fuel: Methane Gas @ 80 Deg.F
Design Values Referenced on 544HA716



A.P.Singh
10/12/00

544HA721
Rev - 0

Appendix E: GE 7F.04 Correction Curves

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14
Estimated Performance
Gas Turbine Generator(s) 297502-3 ONLY

Reference Conditions and Corresponding Correction Curves

	Units	
Fuel		Gas
Fuel LHV	Btu/lb	See Gas Constituents
Load		Base
IGV Angle	degrees	On Schedule, See sheet 2
Diluent Injection Fluid		None
Generator Frequency	hertz	60
Generator Power Factor	ratio	0.85
Cycle Deck Version Used		7F.04-0922T-L4

	Applicable Correction Curve Sheet Numbers
Summary Page	Sheet 1
Control Curve Definition	Sheet 2
Reference SC Exhaust DP	Sheet 3

	Units	Value	Output	Heat Rate	Exhaust Flow	Exhaust Temp	Heat Consumption
Ambient Temperature & Humidity (Evap or SPRITS)		92 F 60 % RH	Sheet 4	Sheet 5	Sheet 6	Sheet 7	Sheet 8
Ambient Wetbulb Temperature	F	80.03	N/A	N/A	N/A	N/A	N/A
Compressor Inlet Temperature	F	81.84	Sheet 9	Sheet 10	Sheet 11	Sheet 12	Sheet 13
Compressor Inlet Relative Humidity	%	92.2%	Sheet 14	Sheet 15	Sheet 16	Sheet 17	Sheet 18
Shaft Speed	rpm	3600	N/A	N/A	N/A	N/A	N/A
Fuel Temperature	F	51	Sheet 19	Sheet 20	N/A	N/A	Sheet 21
Inlet Pressure Loss	in H2O	4.04	Sheet 22	Sheet 23	Sheet 24	Sheet 25	Sheet 26
Exhaust Pressure Loss (Rated)	in H2O	5.75	Sheet 27	Sheet 28	N/A	Sheet 29	Sheet 30
Exhaust Pressure Loss (Reference @ Rated CIT)	in H2O	4.91	Sheet 31	Sheet 32	N/A	Sheet 33	N/A
Barometric Pressure	psia	14.35	Sheet 34	Sheet 35	Sheet 36	Sheet 37	Sheet 38
Gas Fuel Composition		See Gas Constituents	Sheet 39	Sheet 40	Sheet 41	Sheet 42	Sheet 43
Wobbe Index	Btu/scf	See Gas Constituents	N/A	N/A	N/A	N/A	N/A
Inlet Bleed Heat Flow	lb/sec	0	N/A	N/A	N/A	N/A	N/A
Inlet Bleed Heat Tx Suppression	F	0	N/A	N/A	N/A	N/A	N/A
Partload Effects			N/A	N/A	N/A	N/A	N/A

Fuel Composition (Used for Gas Fuel)	Units	Value
METHANE (CH4)	mol frac	0.9326
ETHANE (C2H6)	mol frac	0.0295
PROPANE (C3H8)	mol frac	0.0044
iso-BUTANE (C4H10)	mol frac	0.0004
n-BUTANE (C4H10)	mol frac	0.0007
iso-PENTANE (C5H12)	mol frac	0.0002
n-PENTANE (C5H12)	mol frac	0.0002
HEXANE (C6H14)	mol frac	0.0003
HEPTANES (C7H16)	mol frac	0.0000
CARBON MONOXIDE (CO)	mol frac	0.0000
CARBON DIOXIDE (CO2)	mol frac	0.0076
HYDROGEN SULFIDE (H2S)	mol frac	0.0000
HYDROGEN (H2)	mol frac	0.0000
OXYGEN (O2)	mol frac	0.0000
NITROGEN (N2)	mol frac	0.0241
WATER (H2O)	mol frac	0.0000
NITRIC OXIDE (NO)	mol frac	0.0000
NITROGEN DIOXIDE (NO2)	mol frac	0.0000
METHANOL (CH3OH)	mol frac	0.0000
OCTANE (C8H18)	mol frac	0.0000
DISTILLATE (C12H26)	mol frac	0.0000
ETHYLENE (C2H4)	mol frac	0.0000
ACETYLENE (C2H2)	mol frac	0.0000
AMMONIA (NH3)	mol frac	0.0000
ARGON (AR)	mol frac	0.0000
CARBONYL SULFIDE (COS)	mol frac	0.0000
ETHYL ALCOHOL (C2H5OH)	mol frac	0.0000
DECAHYDRONAPTHALENE (C10H18)	mol frac	0.0000
Gas Fuel LHV - per ASTM D3588	Btu/lb	20159
Gas Fuel H/C Ratio	ratio	3.911
Wobbe Index	Btu/scf	1314.591

Additional Notes:

Inlet bleed heat may be active during very cold ambient conditions for compressor protection

Evaporative Cooler can be either ON or OFF

Post Uprate Correction Curves

Hot ambient conditions may reach the compressor discharge temperature limit

NOTE: These performance test correction curves and tables are provided for the sole purpose of correcting performance test data from the boundary conditions present at the time of test to the design, guarantee, or reference conditions listed on this sheet. The performance characteristics on these sheets do not constitute any new performance guarantee(s) or any change to existing performance guarantee(s).

Please refer to the GE Vernova Thermal Performance Test Procedure for proper interpretation and use of these sheets.

David Walters
06/20/25

GE Vernova Test Correction Curve Tool: Version 11.1.0

24A-167 Rev A
Sheet 1

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GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14
Estimated Performance
Gas Turbine Generator(s) 297502-3 ONLY

Cycle Deck Definition		
Fuel		Gas
Fuel LHV	Btu/lb	See Gas Constituents
Load		Base
IGV Angle	degrees	On Schedule, See below
Diluent Injection Fluid		None
Generator Frequency	hertz	60
Generator Power Factor	ratio	0.85
Cycle Deck Version Used		7F.04-0922T-L4

MBC Control Curve Definition			
Base Load Max Tfire Array (Encoded)			
CTIM, Tfire Array (X's) Control Tag °F		**Tfire Array (Y's) Control Tag °F**	
KCA_CTIM_TF[0]	-25.00	96.346	KCA_GFTF_MX[0]
KCA_CTIM_TF[1]	5.00	96.346	KCA_GFTF_MX[1]
KCA_CTIM_TF[2]	25.00	96.346	KCA_GFTF_MX[2]
KCA_CTIM_TF[3]	55.00	96.346	KCA_GFTF_MX[3]
KCA_CTIM_TF[4]	200.00	96.346	KCA_GFTF_MX[4]
KCA_CTIM_TF[5]	200.00	96.346	KCA_GFTF_MX[5]
KCA_CTIM_TF[6]	200.00	96.346	KCA_GFTF_MX[6]
Exhaust temperature Isotherm Limit			
Isotherm Control Tag		**Isotherm Limit (°F)**	
TTK_I[0]		1215.000	
Generator MW Max			
Gen Output Limit Control Tag		**Gen Output Limit (MW)**	
LK90MAX		214.000	
Base Load IGV Constant			
Base Load IGV Control Constant Tag		**Base Load Max IGV Limit**	
CSKGVMAX		86.000	
Base Load Max TCD Limit (Deg F)			
TCD Control Constant Tag		**Max TCD Limit °F**	
KCA_TCD_MX		805.000	

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06/20/25

GE Vernova Test Correction Curve Tool: Version 11.1.0

24A-167 Rev A
Sheet 2

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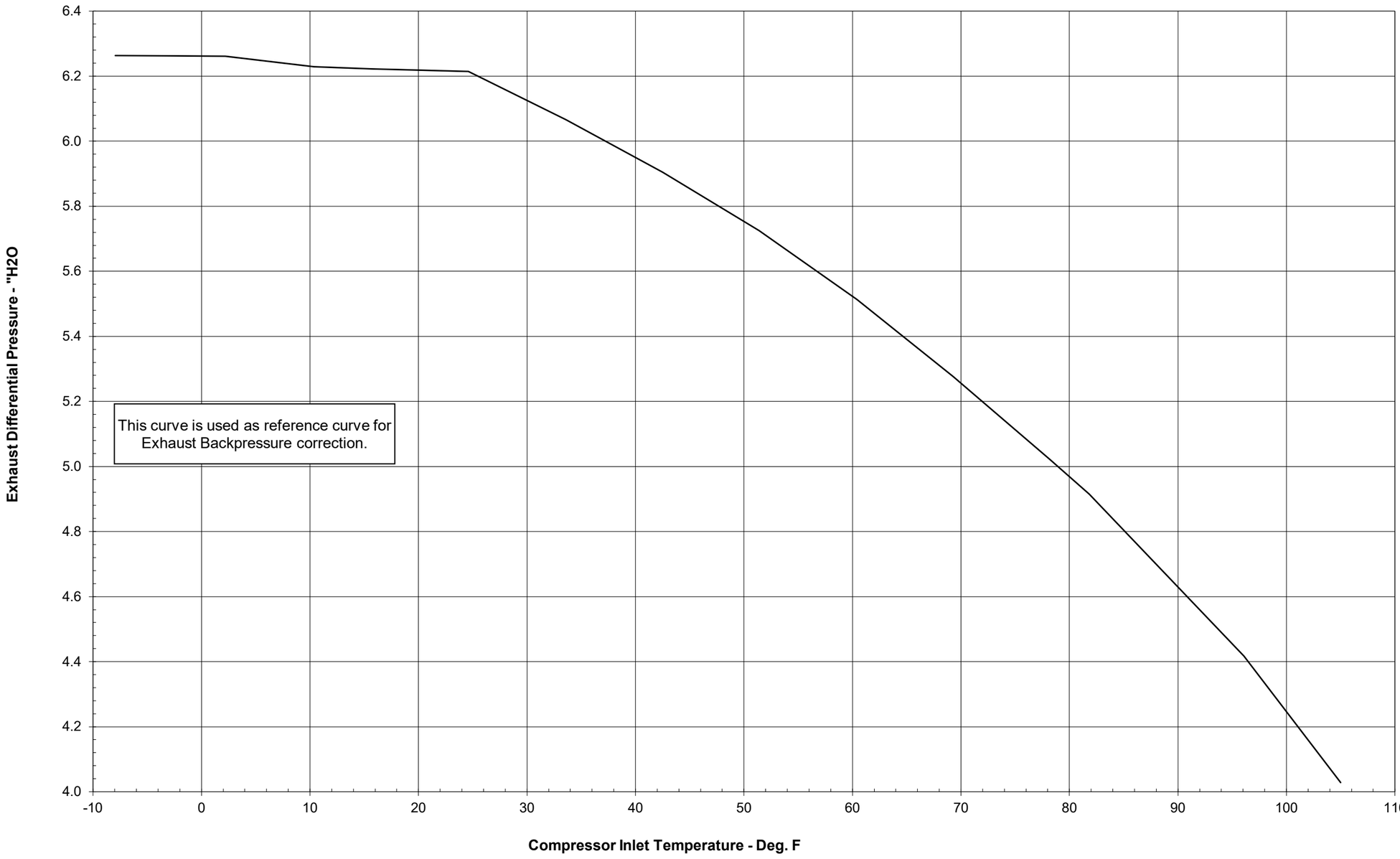
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Simple Cycle Exhaust Pressure

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Exhaust DP	inH2O	6.26	6.26	6.26	6.23	6.22	6.21	6.07	5.90	5.72	5.51	5.28	5.02	4.91	4.42	4.03

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Sheet 3

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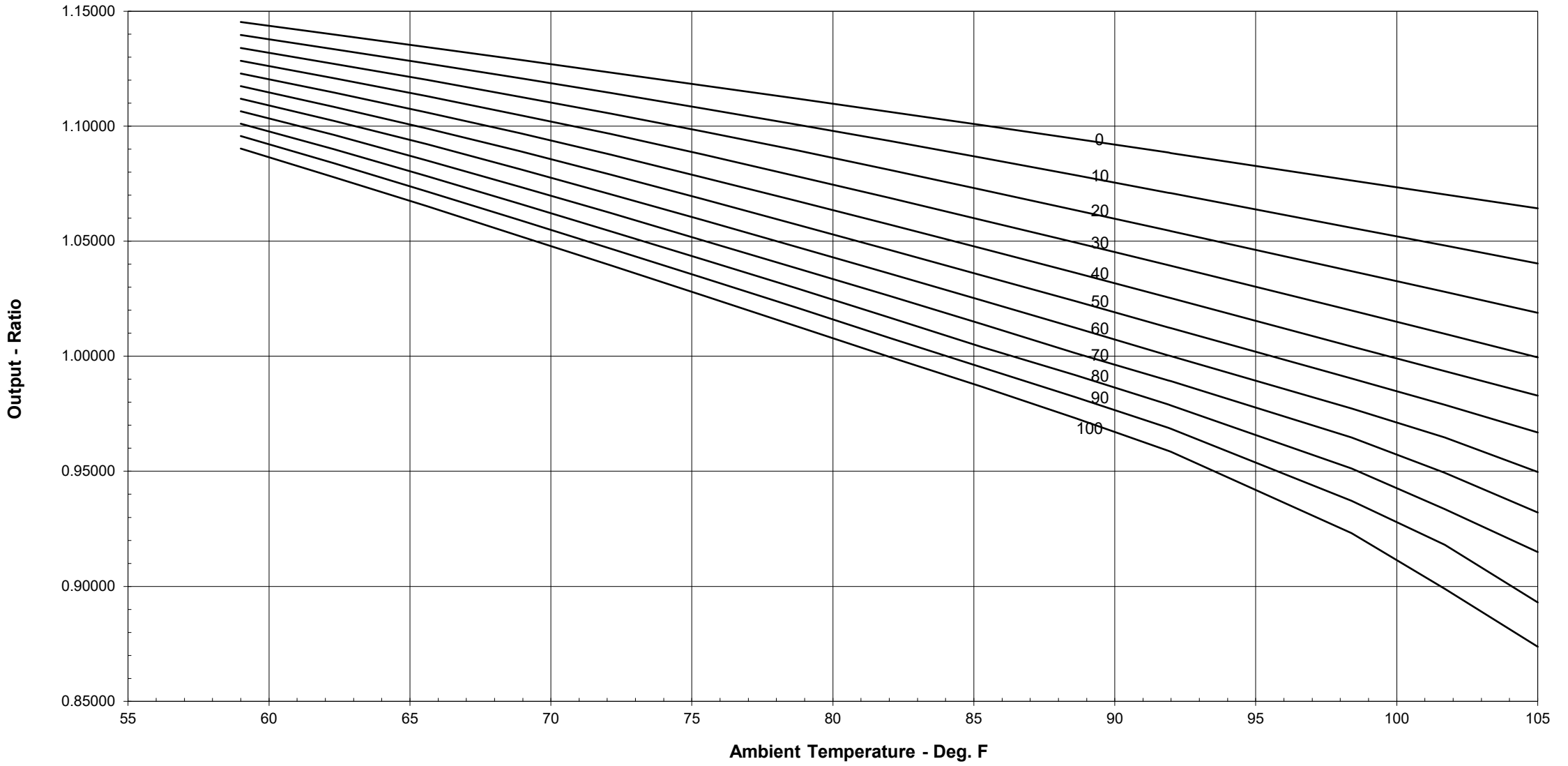
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Ambient Temperature and Humidity on Output

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Ambient Temperature - Deg. F

Relative Humidity - %	59.0	62.3	65.6	68.9	72.1	75.4	78.70	82.00	85.30	88.60	91.90	92.00	98.40	101.70	105.00
0	1.14534	1.13990	1.13440	1.12885	1.12343	1.11780	1.11212	1.10631	1.10046	1.09455	1.08858	1.08839	1.07647	1.07038	1.06432
10	1.13970	1.13353	1.12726	1.12087	1.11453	1.10776	1.10083	1.09374	1.08635	1.07876	1.07110	1.07087	1.05589	1.04813	1.04035
20	1.13404	1.12721	1.12016	1.11288	1.10553	1.09771	1.08959	1.08104	1.07236	1.06358	1.05470	1.05444	1.03706	1.02802	1.01891
30	1.12847	1.12093	1.11311	1.10491	1.09666	1.08771	1.07836	1.06884	1.05918	1.04942	1.03959	1.03929	1.01997	1.00983	0.99953
40	1.12293	1.11472	1.10607	1.09704	1.08779	1.07780	1.06761	1.05727	1.04681	1.03626	1.02561	1.02528	1.00420	0.99357	0.98290
50	1.11745	1.10850	1.09910	1.08917	1.07899	1.06827	1.05737	1.04635	1.03521	1.02396	1.01256	1.01221	0.99030	0.97893	0.96689
60	1.11198	1.10233	1.09219	1.08131	1.07050	1.05915	1.04765	1.03602	1.02429	1.01238	1.00034	1.00000	0.97727	0.96470	0.94971
70	1.10652	1.09623	1.08518	1.07369	1.06232	1.05042	1.03840	1.02625	1.01393	1.00143	0.98953	0.98916	0.96473	0.94939	0.93210
80	1.10111	1.09008	1.07834	1.06632	1.05446	1.04209	1.02959	1.01693	1.00404	0.99174	0.97906	0.97867	0.95120	0.93360	0.91491
90	1.09576	1.08393	1.07169	1.05919	1.04691	1.03411	1.02117	1.00800	0.99520	0.98230	0.96891	0.96849	0.93721	0.91808	0.89301
100	1.09031	1.07792	1.06522	1.05231	1.03964	1.02645	1.01305	0.99971	0.98667	0.97314	0.95889	0.95844	0.92309	0.89889	0.87374

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24A-167 Rev A
Sheet 4

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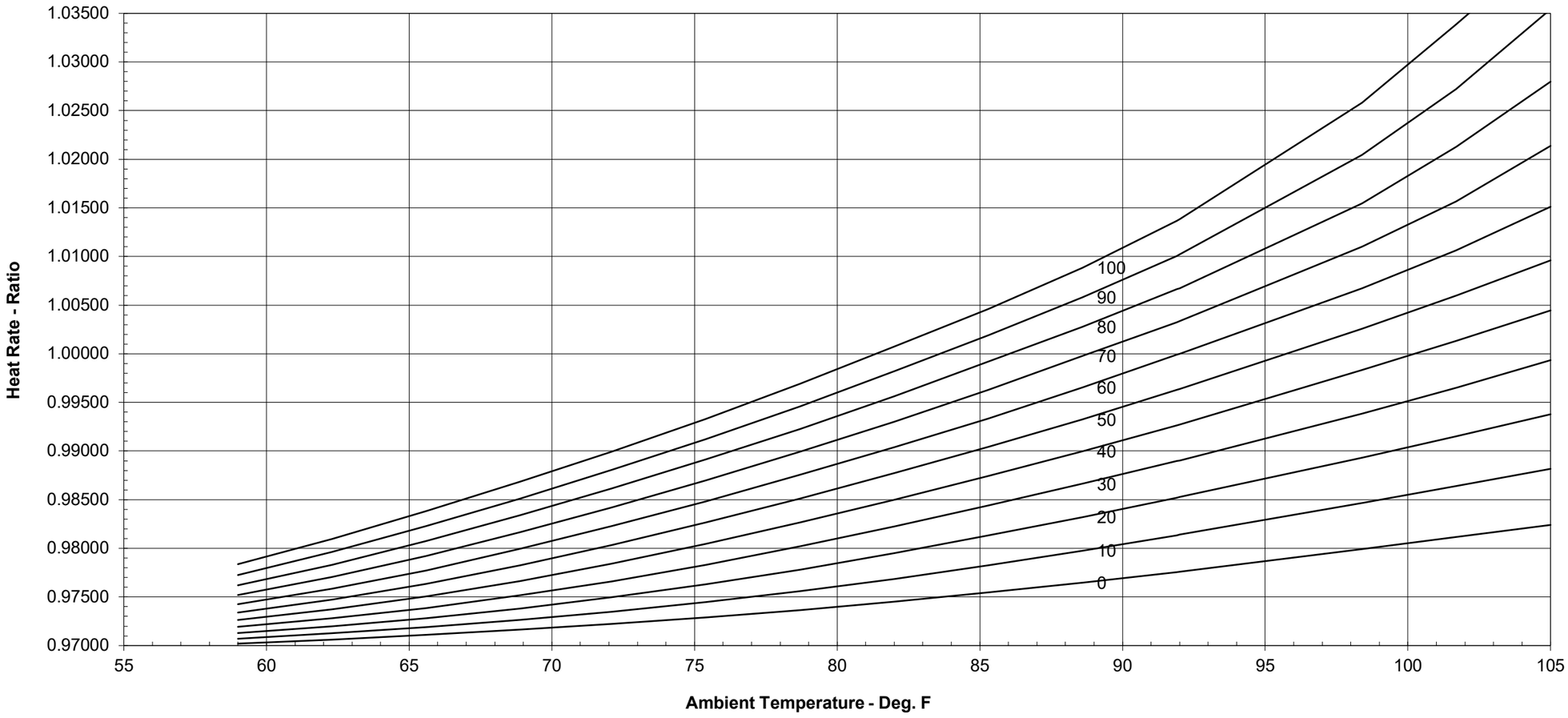
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Ambient Temperature and Humidity on Heat Rate

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Ambient Temperature - Deg. F

Relative Humidity - %	59.0	62.3	65.6	68.9	72.1	75.4	78.70	82.00	85.30	88.60	91.90	92.00	98.40	101.70	105.00
0	0.97020	0.97061	0.97110	0.97164	0.97223	0.97290	0.97366	0.97453	0.97547	0.97649	0.97757	0.97760	0.97992	0.98115	0.98240
10	0.97070	0.97127	0.97191	0.97265	0.97346	0.97447	0.97561	0.97686	0.97825	0.97976	0.98135	0.98140	0.98464	0.98638	0.98817
20	0.97129	0.97200	0.97283	0.97381	0.97496	0.97630	0.97780	0.97950	0.98131	0.98322	0.98520	0.98526	0.98931	0.99150	0.99378
30	0.97193	0.97281	0.97387	0.97517	0.97661	0.97831	0.98022	0.98226	0.98440	0.98664	0.98897	0.98904	0.99384	0.99651	0.99934
40	0.97263	0.97371	0.97507	0.97665	0.97842	0.98047	0.98268	0.98501	0.98745	0.98999	0.99265	0.99273	0.99834	1.00133	1.00446
50	0.97340	0.97474	0.97636	0.97824	0.98033	0.98266	0.98513	0.98772	0.99043	0.99327	0.99629	0.99638	1.00256	1.00597	1.00960
60	0.97425	0.97586	0.97774	0.97994	0.98228	0.98484	0.98755	0.99039	0.99336	0.99653	0.99990	1.00000	1.00674	1.01066	1.01512
70	0.97520	0.97704	0.97922	0.98167	0.98422	0.98700	0.98993	0.99301	0.99628	0.99979	1.00323	1.00334	1.01102	1.01566	1.02137
80	0.97620	0.97829	0.98074	0.98340	0.98615	0.98914	0.99228	0.99561	0.99921	1.00276	1.00663	1.00675	1.01548	1.02130	1.02798
90	0.97725	0.97962	0.98227	0.98513	0.98806	0.99124	0.99460	0.99823	1.00190	1.00580	1.01007	1.01020	1.02045	1.02724	1.03542
100	0.97837	0.98097	0.98381	0.98684	0.98995	0.99332	0.99693	1.00073	1.00461	1.00886	1.01366	1.01382	1.02579	1.03386	1.04223

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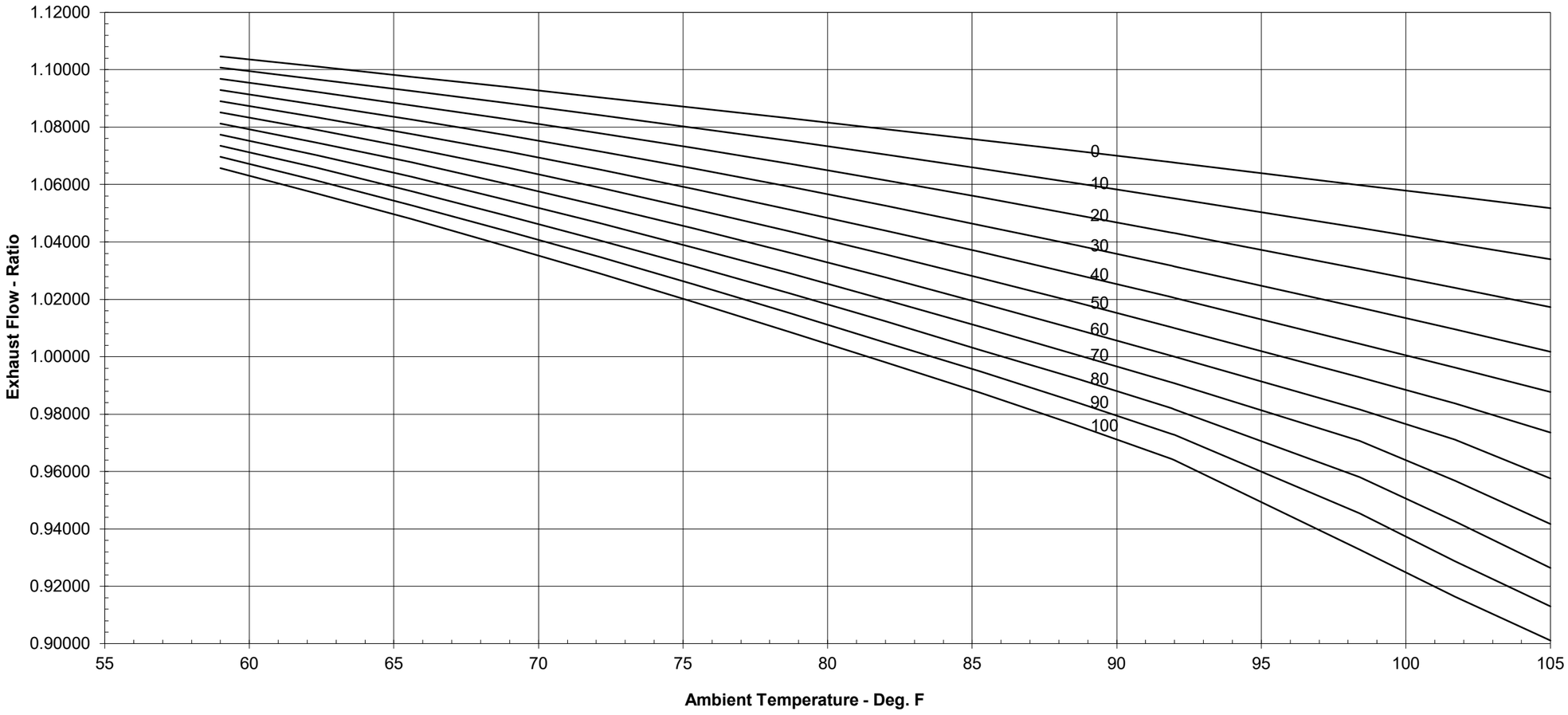
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Ambient Temperature and Humidity on Exhaust Flow

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Ambient Temperature - Deg. F

Relative Humidity - %	59.0	62.3	65.6	68.9	72.1	75.4	78.70	82.00	85.30	88.60	91.90	92.00	98.40	101.70	105.00
0	1.10466	1.10114	1.09757	1.09398	1.09045	1.08677	1.08307	1.07931	1.07552	1.07169	1.06780	1.06767	1.05984	1.05580	1.05177
10	1.10076	1.09674	1.09261	1.08840	1.08420	1.07976	1.07519	1.07052	1.06559	1.06049	1.05531	1.05516	1.04487	1.03946	1.03397
20	1.09684	1.09232	1.08763	1.08277	1.07790	1.07270	1.06725	1.06146	1.05553	1.04945	1.04323	1.04304	1.03061	1.02401	1.01728
30	1.09294	1.08790	1.08265	1.07717	1.07164	1.06557	1.05917	1.05258	1.04580	1.03884	1.03172	1.03150	1.01718	1.00955	1.00172
40	1.08904	1.08349	1.07768	1.07159	1.06528	1.05840	1.05129	1.04397	1.03643	1.02869	1.02074	1.02050	1.00449	0.99618	0.98770
50	1.08514	1.07909	1.07273	1.06594	1.05891	1.05140	1.04364	1.03564	1.02741	1.01896	1.01027	1.01000	0.99285	0.98369	0.97356
60	1.08125	1.07471	1.06778	1.06025	1.05267	1.04457	1.03621	1.02760	1.01873	1.00961	1.00027	1.00000	0.98165	0.97110	0.95757
70	1.07738	1.07035	1.06270	1.05466	1.04656	1.03792	1.02900	1.01982	1.01036	1.00064	0.99106	0.99076	0.97068	0.95684	0.94168
80	1.07352	1.06590	1.05770	1.04917	1.04059	1.03144	1.02201	1.01229	1.00226	0.99236	0.98200	0.98167	0.95808	0.94258	0.92637
90	1.06967	1.06143	1.05278	1.04379	1.03475	1.02513	1.01521	1.00498	0.99475	0.98421	0.97308	0.97273	0.94536	0.92874	0.91296
100	1.06572	1.05702	1.04794	1.03851	1.02905	1.01899	1.00860	0.99804	0.98741	0.97616	0.96428	0.96392	0.93276	0.91640	0.90107

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Sheet 6

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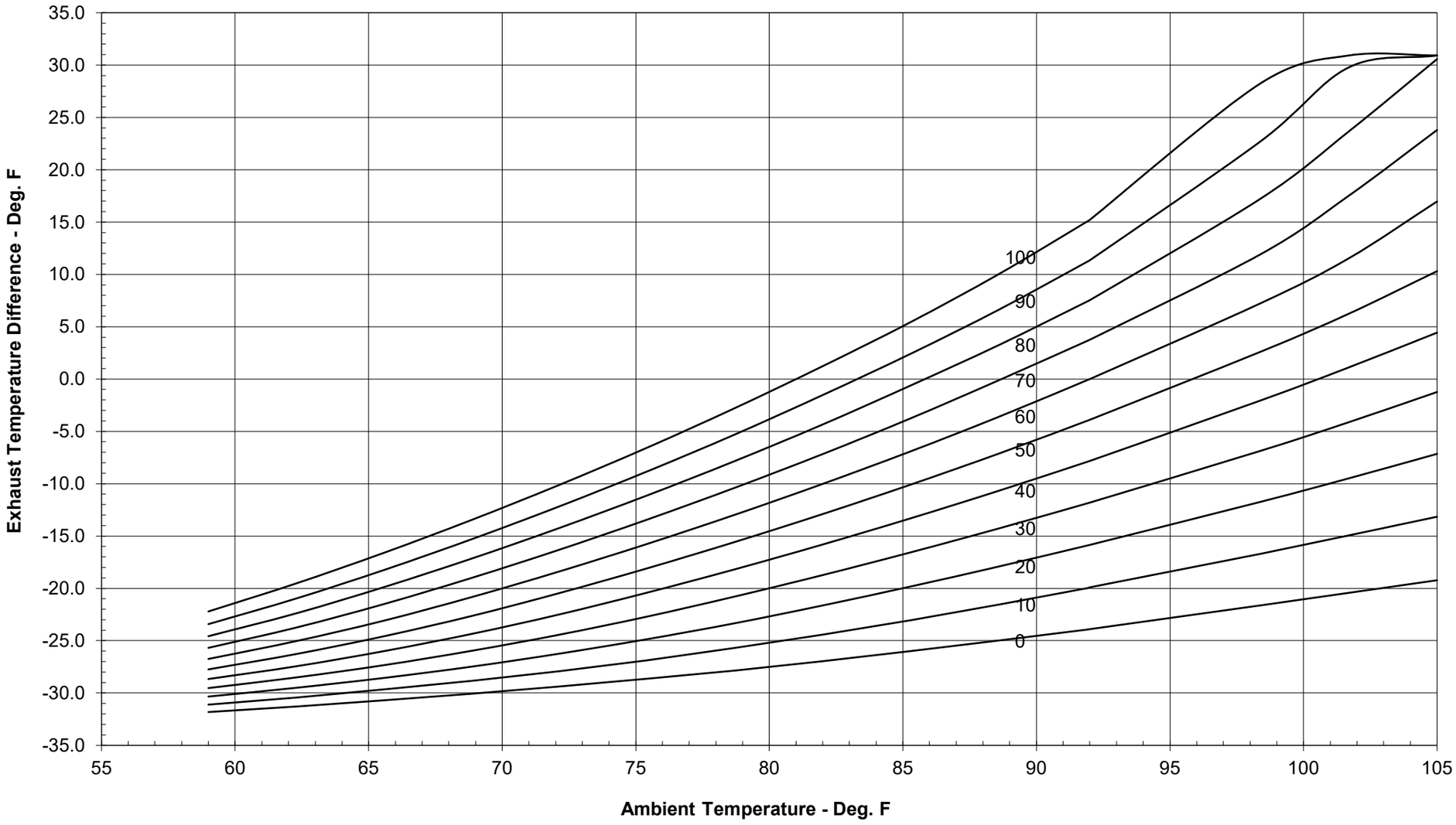
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Ambient Temperature and Humidity on Exhaust Temperature

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Ambient Temperature - Deg. F

Relative Humidity - %	59.0	62.3	65.6	68.9	72.1	75.4	78.70	82.00	85.30	88.60	91.90	92.00	98.40	101.70	105.00
0	-31.82	-31.28	-30.68	-30.05	-29.39	-28.65	-27.84	-26.95	-25.99	-24.98	-23.92	-23.88	-21.64	-20.44	-19.23
10	-31.11	-30.42	-29.66	-28.83	-27.93	-26.87	-25.70	-24.43	-23.04	-21.54	-19.97	-19.92	-16.69	-14.95	-13.16
20	-30.34	-29.50	-28.55	-27.47	-26.25	-24.87	-23.34	-21.63	-19.82	-17.91	-15.91	-15.85	-11.73	-9.48	-7.15
30	-29.53	-28.51	-27.33	-25.95	-24.45	-22.71	-20.79	-18.73	-16.55	-14.27	-11.88	-11.81	-6.85	-4.12	-1.24
40	-28.66	-27.44	-25.98	-24.33	-22.51	-20.43	-18.19	-15.81	-13.30	-10.67	-7.91	-7.82	-2.04	1.12	4.43
50	-27.74	-26.27	-24.56	-22.61	-20.48	-18.11	-15.58	-12.90	-10.08	-7.12	-3.99	-3.89	2.62	6.25	10.31
60	-26.75	-25.03	-23.07	-20.81	-18.42	-15.78	-12.98	-10.02	-6.90	-3.60	-0.11	0.00	7.25	11.54	16.97
70	-25.68	-23.74	-21.48	-18.97	-16.34	-13.46	-10.40	-7.17	-3.75	-0.11	3.64	3.76	11.93	17.53	23.80
80	-24.57	-22.38	-19.86	-17.12	-14.27	-11.15	-7.84	-4.34	-0.61	3.25	7.41	7.54	17.25	23.67	30.57
90	-23.42	-20.96	-18.22	-15.27	-12.21	-8.86	-5.31	-1.53	2.42	6.63	11.21	11.35	22.73	29.78	30.92
100	-22.21	-19.52	-16.58	-13.42	-10.15	-6.59	-2.79	1.23	5.45	10.04	15.05	15.21	28.27	30.92	30.92

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24A-167 Rev A
Sheet 7

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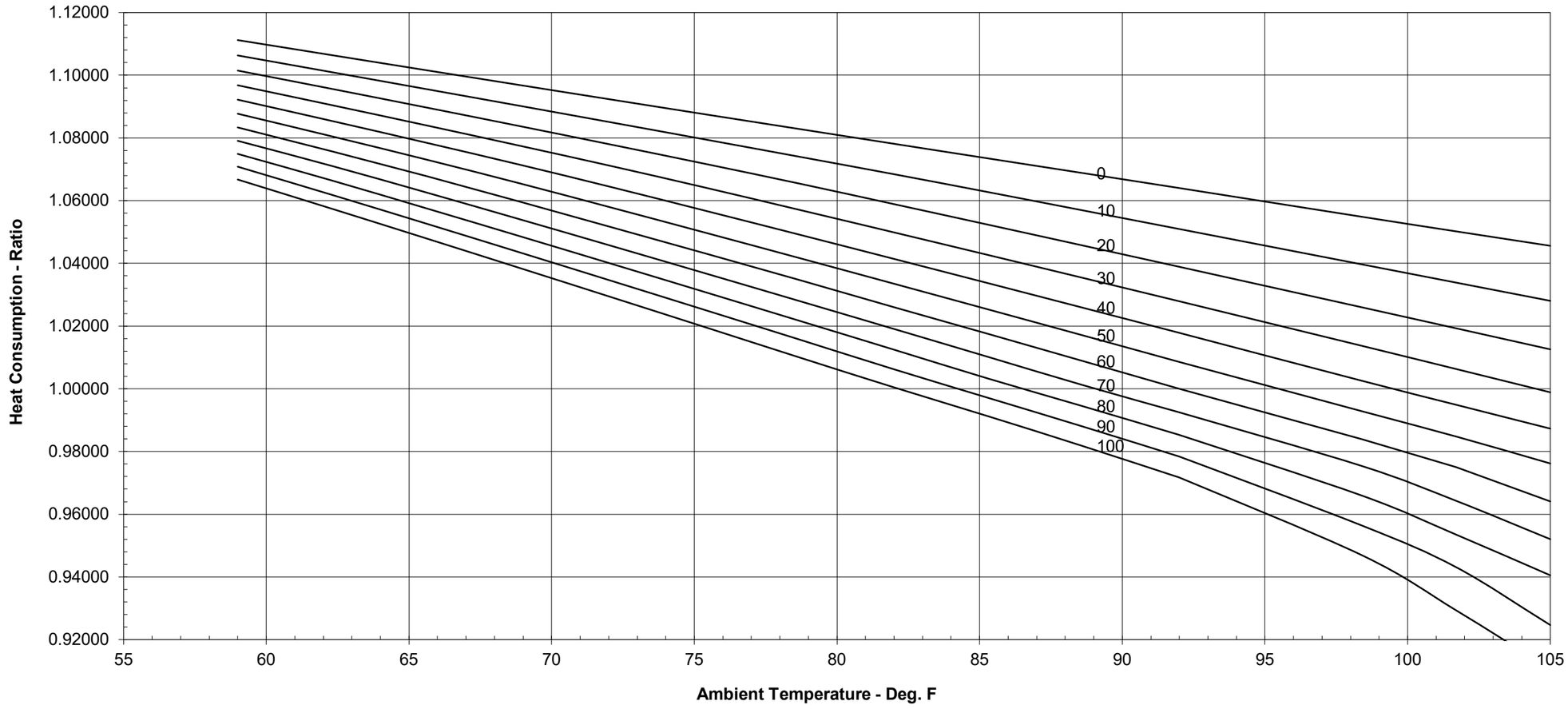
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Ambient Temperature and Humidity on Heat Consumption

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Ambient Temperature - Deg. F

Relative Humidity - Percent	59.0	62.3	65.6	68.9	72.1	75.4	78.70	82.00	85.30	88.60	91.90	92.00	98.40	101.70	105.00
0	1.11121	1.10640	1.10161	1.09684	1.09223	1.08751	1.08282	1.07813	1.07347	1.06882	1.06416	1.06401	1.05485	1.05020	1.04560
10	1.10631	1.10097	1.09559	1.09021	1.08495	1.07948	1.07398	1.06843	1.06272	1.05693	1.05112	1.05095	1.03967	1.03386	1.02805
20	1.10148	1.09565	1.08973	1.08374	1.07785	1.07170	1.06541	1.05889	1.05233	1.04573	1.03910	1.03889	1.02597	1.01928	1.01257
30	1.09679	1.09046	1.08402	1.07748	1.07102	1.06412	1.05703	1.04987	1.04266	1.03541	1.02812	1.02790	1.01369	1.00630	0.99887
40	1.09220	1.08541	1.07849	1.07142	1.06431	1.05675	1.04912	1.04142	1.03367	1.02589	1.01807	1.01783	1.00254	0.99489	0.98728
50	1.08772	1.08050	1.07312	1.06547	1.05777	1.04975	1.04165	1.03350	1.02530	1.01707	1.00880	1.00855	0.99283	0.98477	0.97617
60	1.08335	1.07572	1.06788	1.05962	1.05153	1.04309	1.03460	1.02606	1.01749	1.00887	1.00025	1.00000	0.98386	0.97498	0.96407
70	1.07908	1.07106	1.06263	1.05401	1.04556	1.03677	1.02794	1.01907	1.01015	1.00121	0.99273	0.99247	0.97536	0.96425	0.95202
80	1.07491	1.06642	1.05757	1.04862	1.03986	1.03077	1.02164	1.01247	1.00325	0.99448	0.98555	0.98527	0.96592	0.95348	0.94050
90	1.07083	1.06185	1.05269	1.04344	1.03441	1.02505	1.01566	1.00621	0.99709	0.98800	0.97866	0.97837	0.95637	0.94309	0.92464
100	1.06673	1.05741	1.04798	1.03846	1.02919	1.01959	1.00995	1.00044	0.99123	0.98176	0.97199	0.97168	0.94690	0.92933	0.91064

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24A-167 Rev A
Sheet 8

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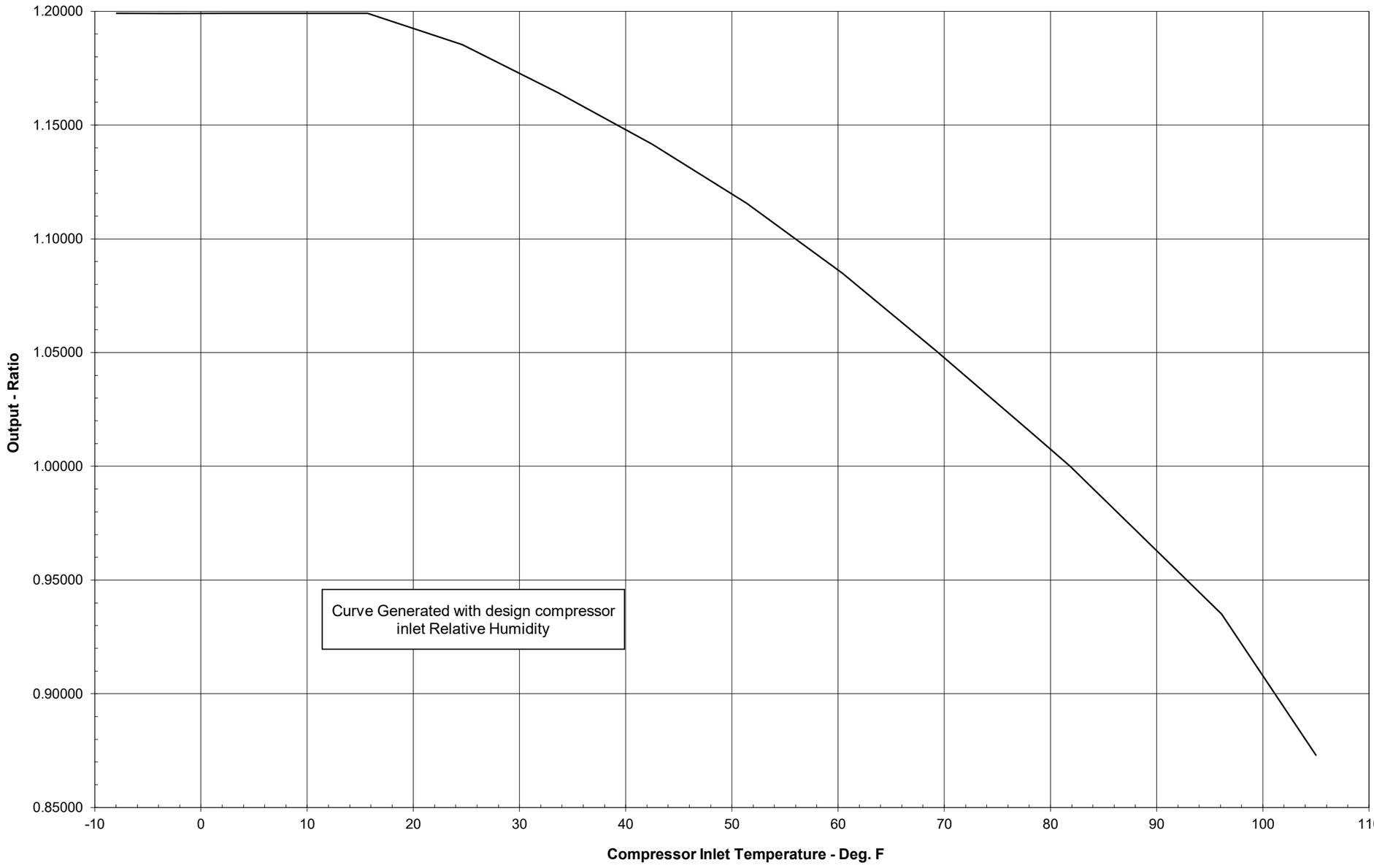
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Output

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Output Ratio		1.19906	1.19906	1.19905	1.19905	1.19905	1.18528	1.16429	1.14160	1.11567	1.08479	1.05044	1.01487	1.00000	0.93512	0.87305

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24A-167 Rev A
Sheet 9

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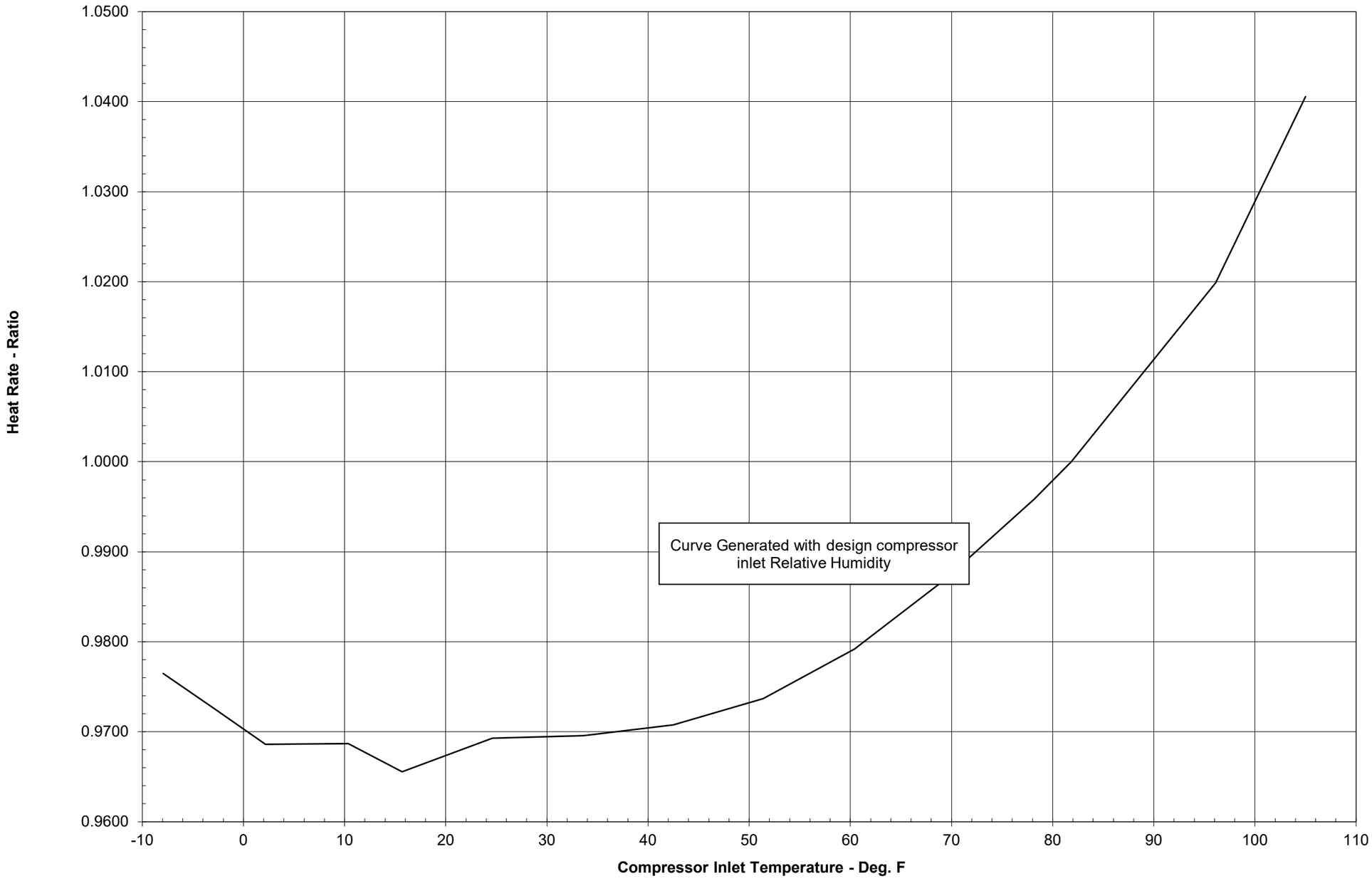
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Heat Rate

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Heat Rate Ratio		0.97648	0.97257	0.96860	0.96869	0.96556	0.96928	0.96956	0.97077	0.97369	0.97921	0.98688	0.99585	1.00000	1.01986	1.04056

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Sheet 10

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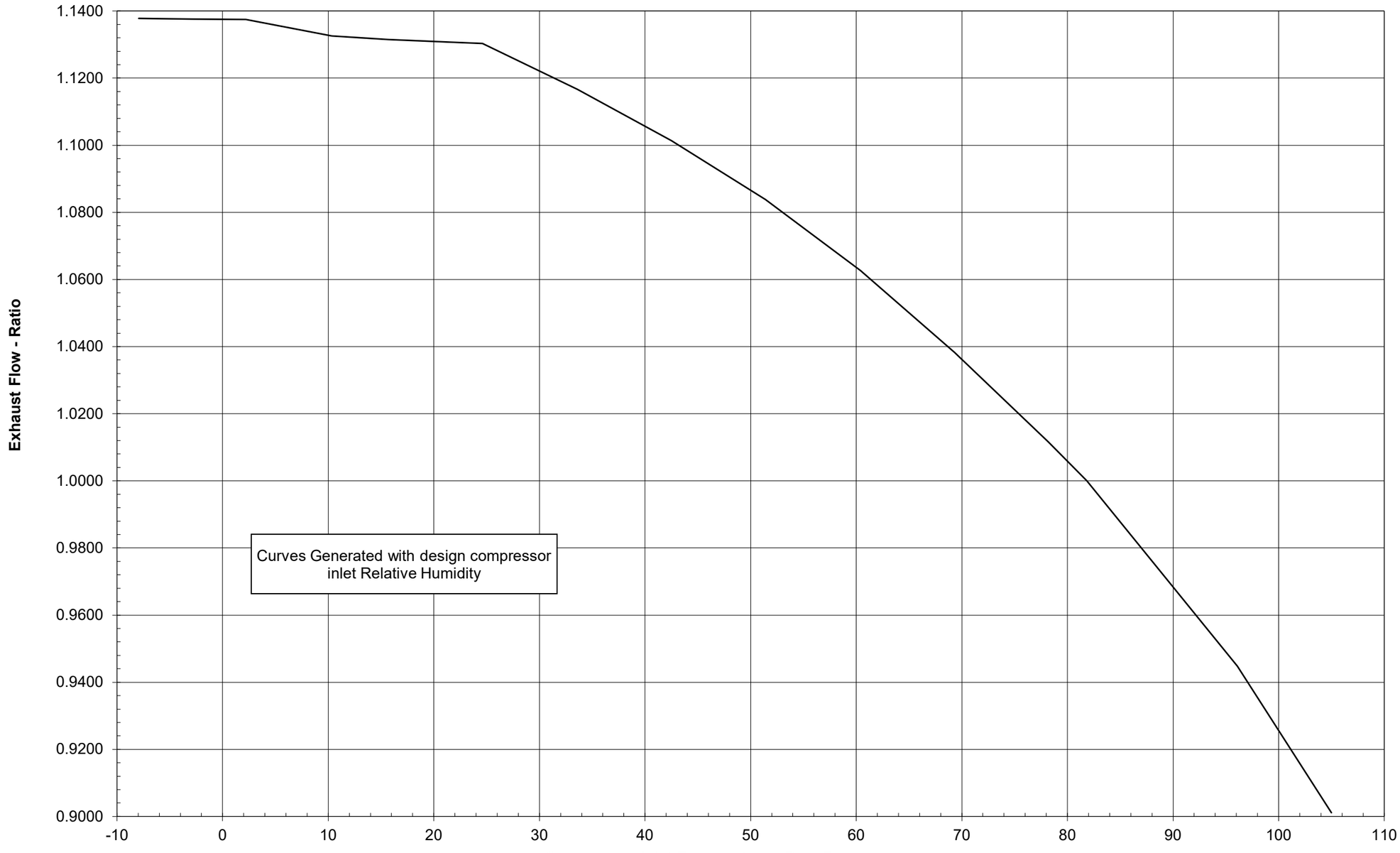
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Exhaust Flow

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Exhaust Flow Ratio		1.13778	1.13759	1.13741	1.13253	1.13143	1.13030	1.11665	1.10129	1.08379	1.06269	1.03827	1.01153	1.00000	0.94475	0.90111

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24A-167 Rev A
Sheet 11

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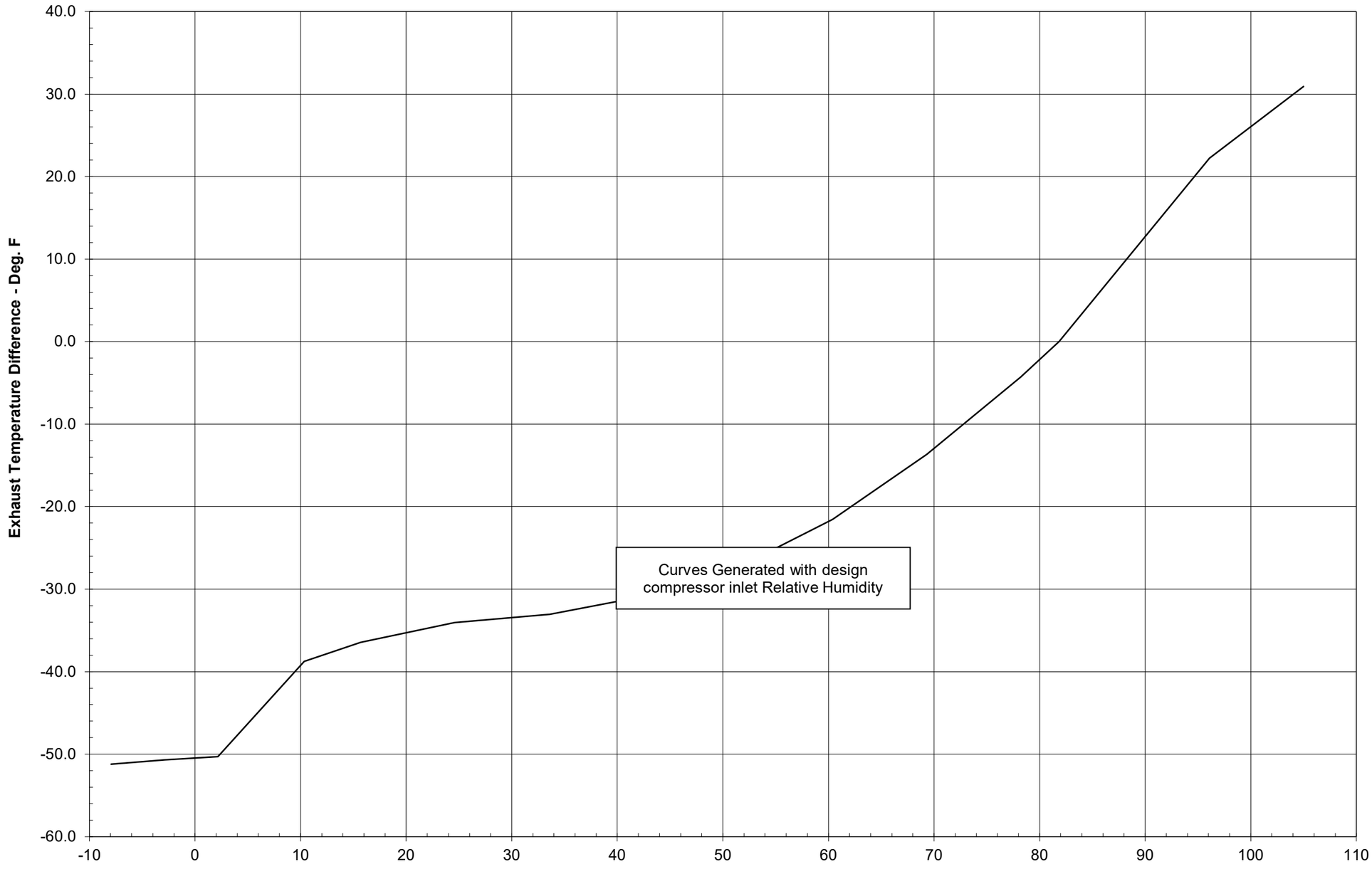
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Exhaust Temperature

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Tx Difference	F	-51.2	-50.7	-50.3	-38.8	-36.5	-34.0	-33.0	-30.9	-27.4	-21.6	-13.7	-4.3	0.0	22.2	30.9

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24A-167 Rev A
Sheet 12

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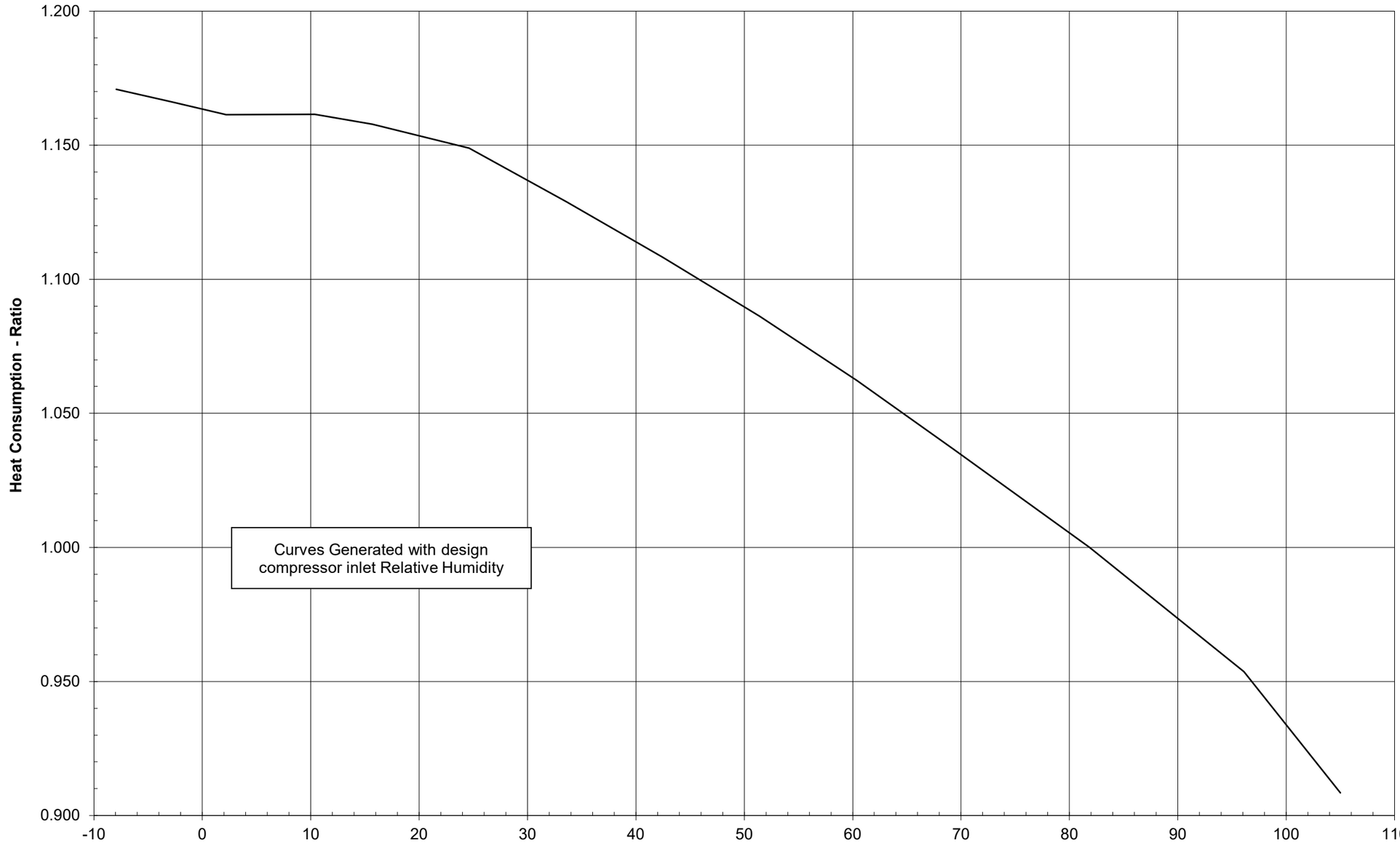
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Heat Consumption

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Heat Consumption Ratio		1.17085	1.16617	1.16140	1.16152	1.15776	1.14888	1.12885	1.10823	1.08631	1.06224	1.03666	1.01066	1.00000	0.95370	0.90846

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24A-167 Rev A
Sheet 13

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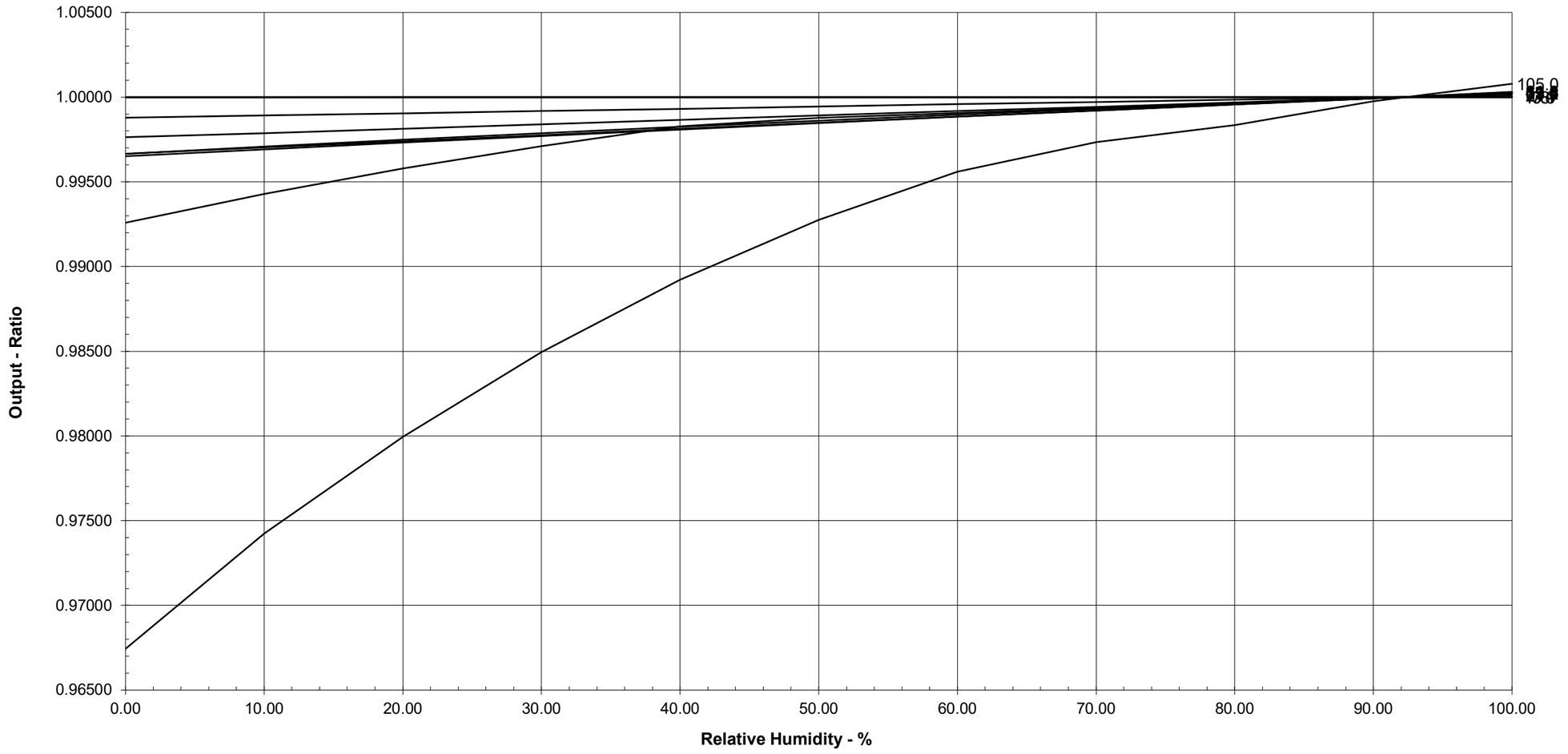
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Relative Humidity on Output at Different Compressor Inlet Temperatures

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Relative Humidity - %	-7.9	-0.1	7.8	21.7	35.6	49.4	63.3	77.2	81.8	105.0
92.2	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
0	1.00000	1.00000	1.00000	0.99879	0.99764	0.99666	0.99651	0.99665	0.99259	0.96743
10	1.00000	1.00000	1.00000	0.99892	0.99788	0.99703	0.99691	0.99707	0.99428	0.97425
20	1.00000	1.00000	1.00000	0.99905	0.99814	0.99739	0.99731	0.99748	0.99579	0.97995
30	1.00000	1.00000	1.00000	0.99918	0.99840	0.99776	0.99770	0.99787	0.99711	0.98494
40	1.00000	1.00000	1.00000	0.99931	0.99866	0.99812	0.99808	0.99825	0.99826	0.98921
50	1.00000	1.00000	1.00000	0.99945	0.99891	0.99848	0.99846	0.99862	0.99878	0.99275
60	1.00000	1.00000	1.00000	0.99958	0.99917	0.99885	0.99884	0.99897	0.99907	0.99559
70	1.00000	1.00000	1.00000	0.99971	0.99943	0.99921	0.99921	0.99931	0.99935	0.99735
80	1.00000	1.00000	1.00000	0.99984	0.99969	0.99957	0.99957	0.99963	0.99961	0.99836
90	1.00000	1.00000	1.00000	0.99997	0.99994	0.99992	0.99992	0.99994	0.99991	0.99975
100	1.00000	1.00000	1.00000	1.00010	1.00020	1.00028	1.00027	1.00022	1.00031	1.00079

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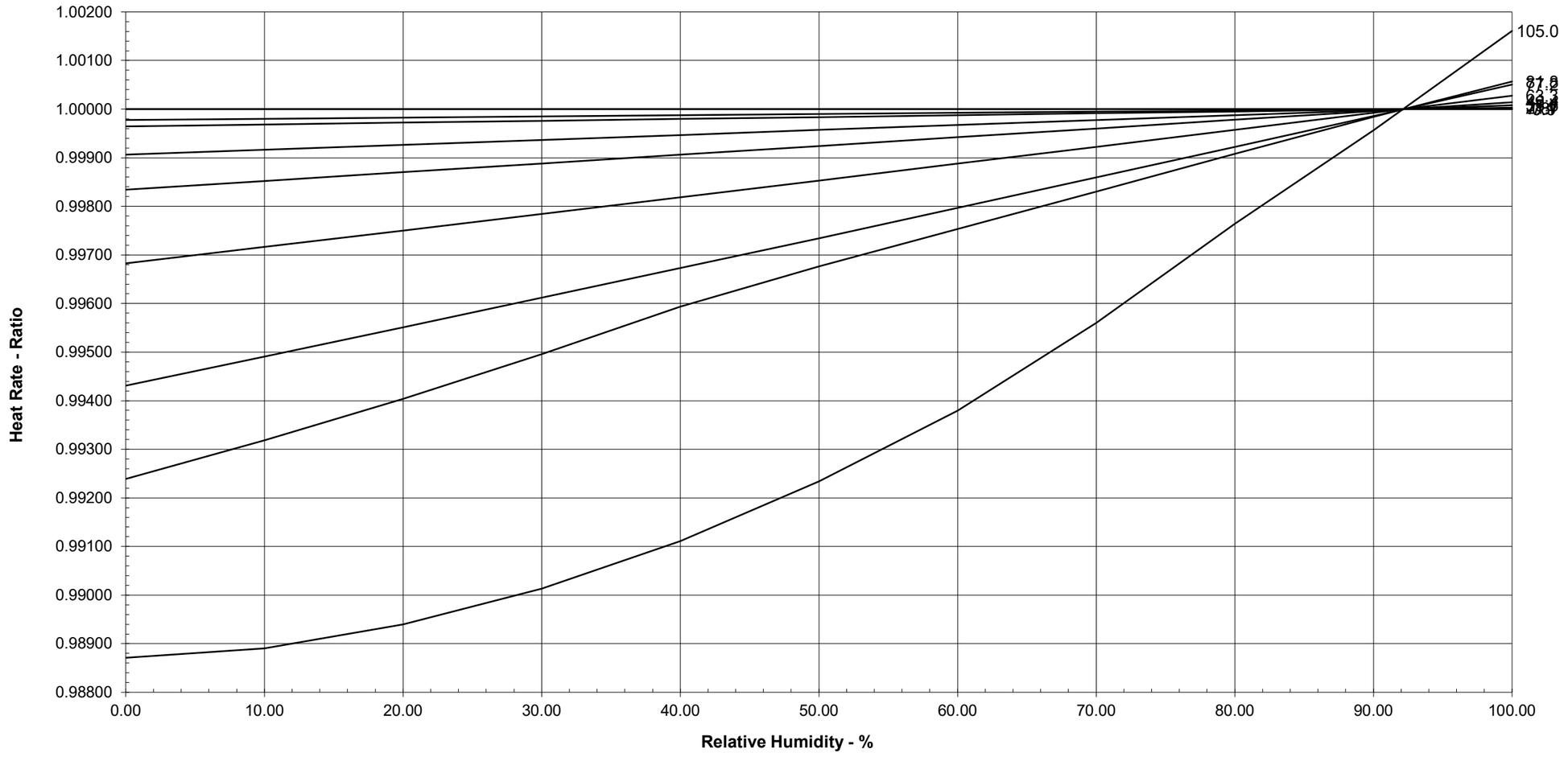
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Relative Humidity on Heat Rate at Different Compressor Inlet Temperatures

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Relative Humidity - %	-7.9	-0.1	7.8	21.7	35.6	49.4	63.3	77.2	81.8	105.0
92.2	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
0	1.00000	1.00000	0.99978	0.99964	0.99906	0.99834	0.99683	0.99431	0.99239	0.98871
10	1.00000	1.00000	0.99980	0.99968	0.99917	0.99852	0.99716	0.99491	0.99318	0.98891
20	1.00000	1.00000	0.99983	0.99972	0.99927	0.99870	0.99750	0.99551	0.99404	0.98939
30	1.00000	1.00000	0.99985	0.99976	0.99937	0.99888	0.99784	0.99612	0.99496	0.99013
40	1.00000	1.00000	0.99987	0.99980	0.99947	0.99906	0.99819	0.99673	0.99594	0.99111
50	1.00000	1.00000	0.99990	0.99984	0.99957	0.99924	0.99853	0.99735	0.99677	0.99234
60	1.00000	1.00000	0.99992	0.99988	0.99967	0.99942	0.99888	0.99797	0.99753	0.99380
70	1.00000	1.00000	0.99995	0.99991	0.99977	0.99960	0.99922	0.99859	0.99830	0.99560
80	1.00000	1.00000	0.99997	0.99995	0.99988	0.99978	0.99957	0.99922	0.99908	0.99764
90	1.00000	1.00000	0.99999	0.99999	0.99998	0.99996	0.99992	0.99986	0.99984	0.99957
100	1.00000	1.00000	1.00002	1.00003	1.00008	1.00014	1.00028	1.00051	1.00057	1.00161

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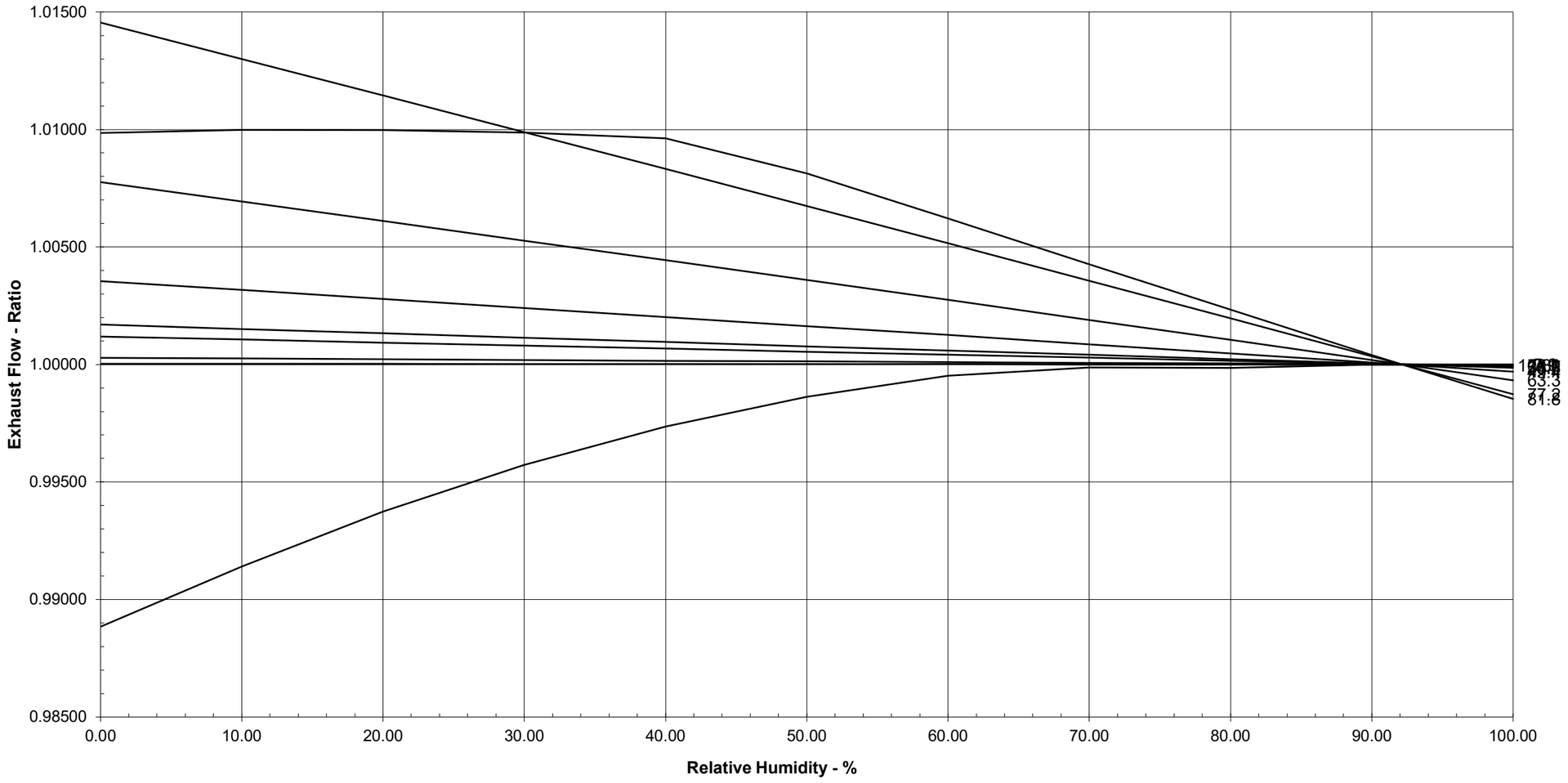
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Relative Humidity on Exhaust Flow at Different Compressor Inlet Temperatures

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Relative Humidity - %	-7.9	-0.1	7.8	21.7	35.6	49.4	63.3	77.2	81.8	105.0
92.2	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
0	1.00001	1.00003	1.00028	1.00119	1.00170	1.00354	1.00776	1.01455	1.00985	0.98884
10	1.00001	1.00003	1.00025	1.00106	1.00150	1.00317	1.00693	1.01300	1.00998	0.99141
20	1.00001	1.00002	1.00022	1.00093	1.00132	1.00279	1.00610	1.01145	1.00998	0.99375
30	1.00001	1.00002	1.00019	1.00080	1.00114	1.00240	1.00527	1.00989	1.00986	0.99573
40	1.00001	1.00002	1.00016	1.00067	1.00096	1.00202	1.00443	1.00832	1.00962	0.99735
50	1.00001	1.00001	1.00013	1.00054	1.00077	1.00164	1.00359	1.00674	1.00814	0.99862
60	1.00000	1.00001	1.00010	1.00041	1.00059	1.00125	1.00275	1.00515	1.00621	0.99952
70	1.00000	1.00001	1.00007	1.00029	1.00041	1.00086	1.00190	1.00356	1.00427	0.99988
80	1.00000	1.00000	1.00004	1.00016	1.00022	1.00047	1.00104	1.00196	1.00232	0.99985
90	1.00000	1.00000	1.00001	1.00003	1.00004	1.00008	1.00019	1.00035	1.00040	0.99999
100	1.00000	1.00000	0.99998	0.99990	0.99986	0.99969	0.99933	0.99873	0.99853	0.99996

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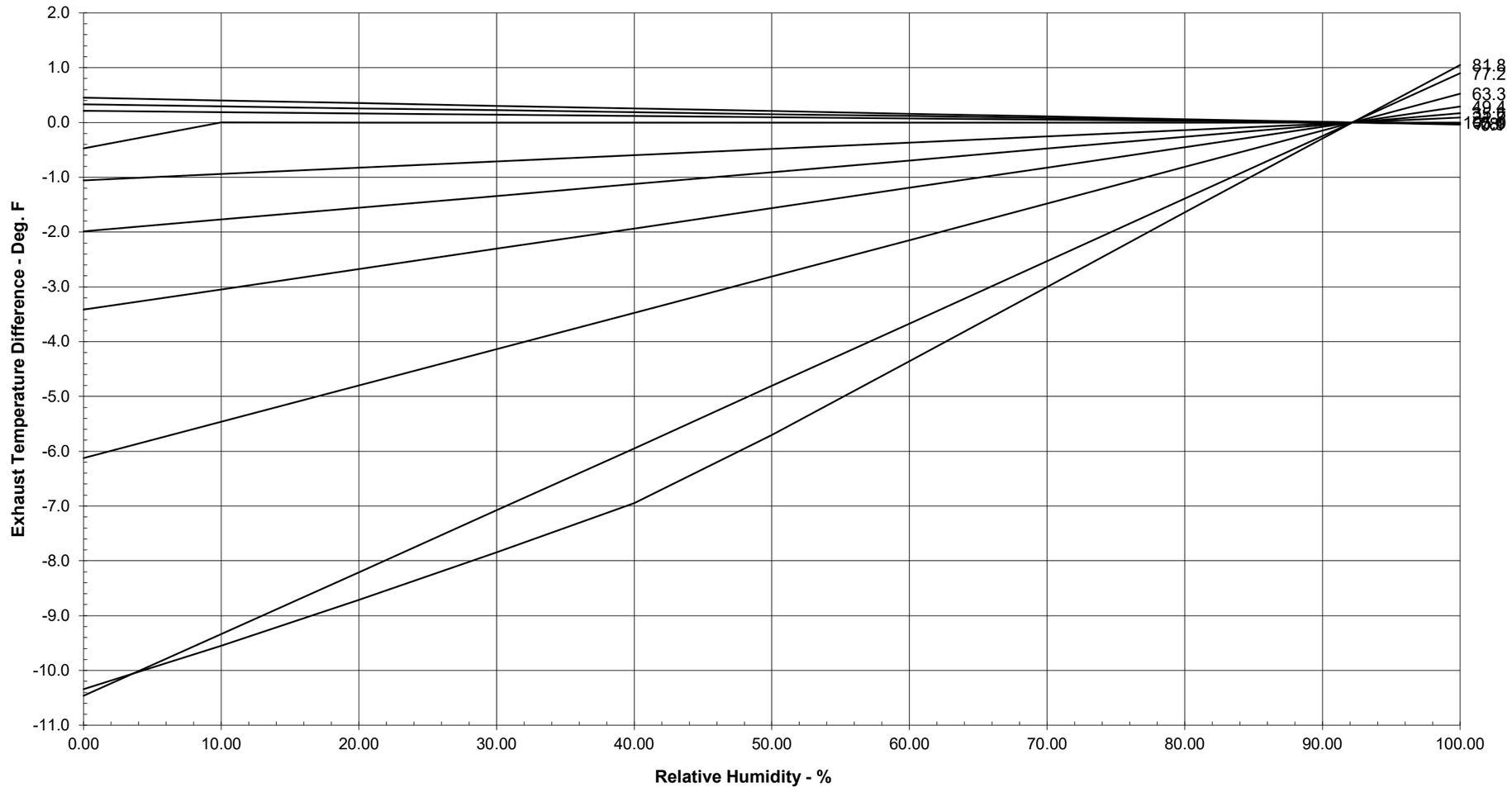
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Relative Humidity on Exhaust Temperature at Different Compressor Inlet Temperatures

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Relative Humidity - %	-7.9	-0.1	7.8	21.7	35.6	49.4	63.3	77.2	81.8	105.0
92.2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	0.21	0.45	0.33	-1.06	-1.99	-3.42	-6.12	-10.46	-10.34	-0.47
10	0.19	0.40	0.30	-0.94	-1.77	-3.05	-5.46	-9.34	-9.55	0.00
20	0.17	0.35	0.26	-0.83	-1.56	-2.68	-4.80	-8.21	-8.71	0.00
30	0.14	0.30	0.22	-0.71	-1.34	-2.30	-4.14	-7.08	-7.85	0.00
40	0.12	0.26	0.19	-0.60	-1.12	-1.93	-3.48	-5.95	-6.94	0.00
50	0.10	0.21	0.15	-0.48	-0.91	-1.56	-2.81	-4.81	-5.71	0.00
60	0.07	0.16	0.12	-0.37	-0.69	-1.19	-2.15	-3.67	-4.36	0.00
70	0.05	0.11	0.08	-0.25	-0.48	-0.82	-1.48	-2.53	-3.00	0.00
80	0.03	0.06	0.04	-0.14	-0.26	-0.45	-0.81	-1.39	-1.64	0.00
90	0.01	0.01	0.01	-0.02	-0.05	-0.08	-0.15	-0.25	-0.29	0.00
100	-0.02	-0.04	-0.03	0.09	0.17	0.29	0.52	0.90	1.05	0.00

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24A-167 Rev A
Sheet 17

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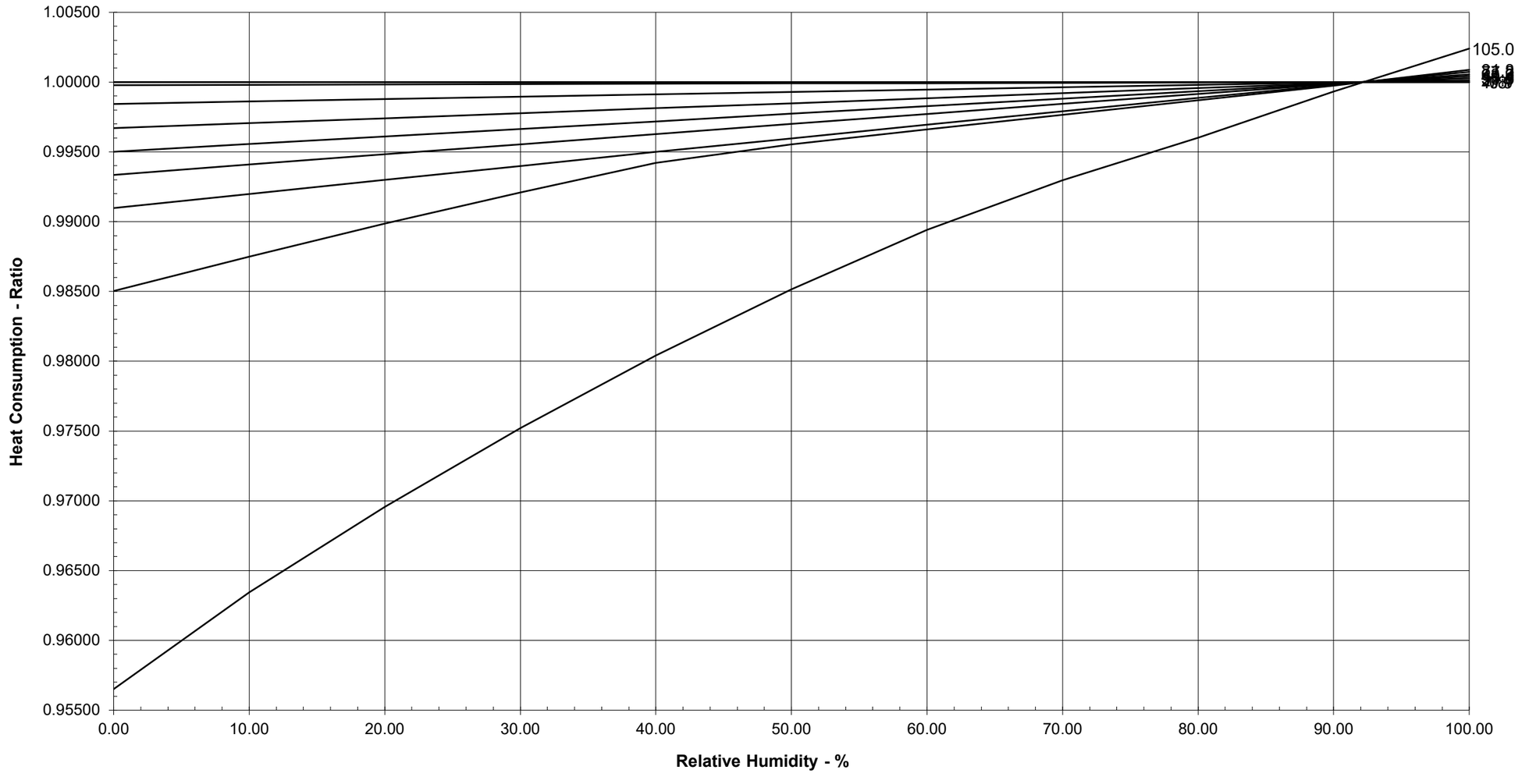
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Relative Humidity on Heat Consumption at Different Compressor Inlet Temps
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Relative Humidity - %	-7.9	-0.1	7.8	21.7	35.6	49.4	63.3	77.2	81.8	105.0
92.2	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
0	1.00000	1.00000	0.99978	0.99843	0.99670	0.99501	0.99335	0.99097	0.98503	0.95651
10	1.00000	1.00000	0.99980	0.99860	0.99705	0.99555	0.99409	0.99199	0.98750	0.96344
20	1.00000	1.00000	0.99983	0.99877	0.99741	0.99610	0.99482	0.99300	0.98985	0.96956
30	1.00000	1.00000	0.99985	0.99894	0.99777	0.99664	0.99555	0.99400	0.99209	0.97522
40	1.00000	1.00000	0.99987	0.99911	0.99813	0.99719	0.99628	0.99499	0.99421	0.98042
50	1.00000	1.00000	0.99990	0.99928	0.99849	0.99773	0.99700	0.99597	0.99555	0.98515
60	1.00000	1.00000	0.99992	0.99945	0.99885	0.99827	0.99772	0.99694	0.99661	0.98942
70	1.00000	1.00000	0.99995	0.99962	0.99920	0.99881	0.99843	0.99790	0.99765	0.99296
80	1.00000	1.00000	0.99997	0.99979	0.99956	0.99935	0.99914	0.99885	0.99869	0.99601
90	1.00000	1.00000	0.99999	0.99996	0.99992	0.99988	0.99985	0.99980	0.99976	0.99931
100	1.00000	1.00000	1.00002	1.00013	1.00028	1.00042	1.00055	1.00073	1.00088	1.00240

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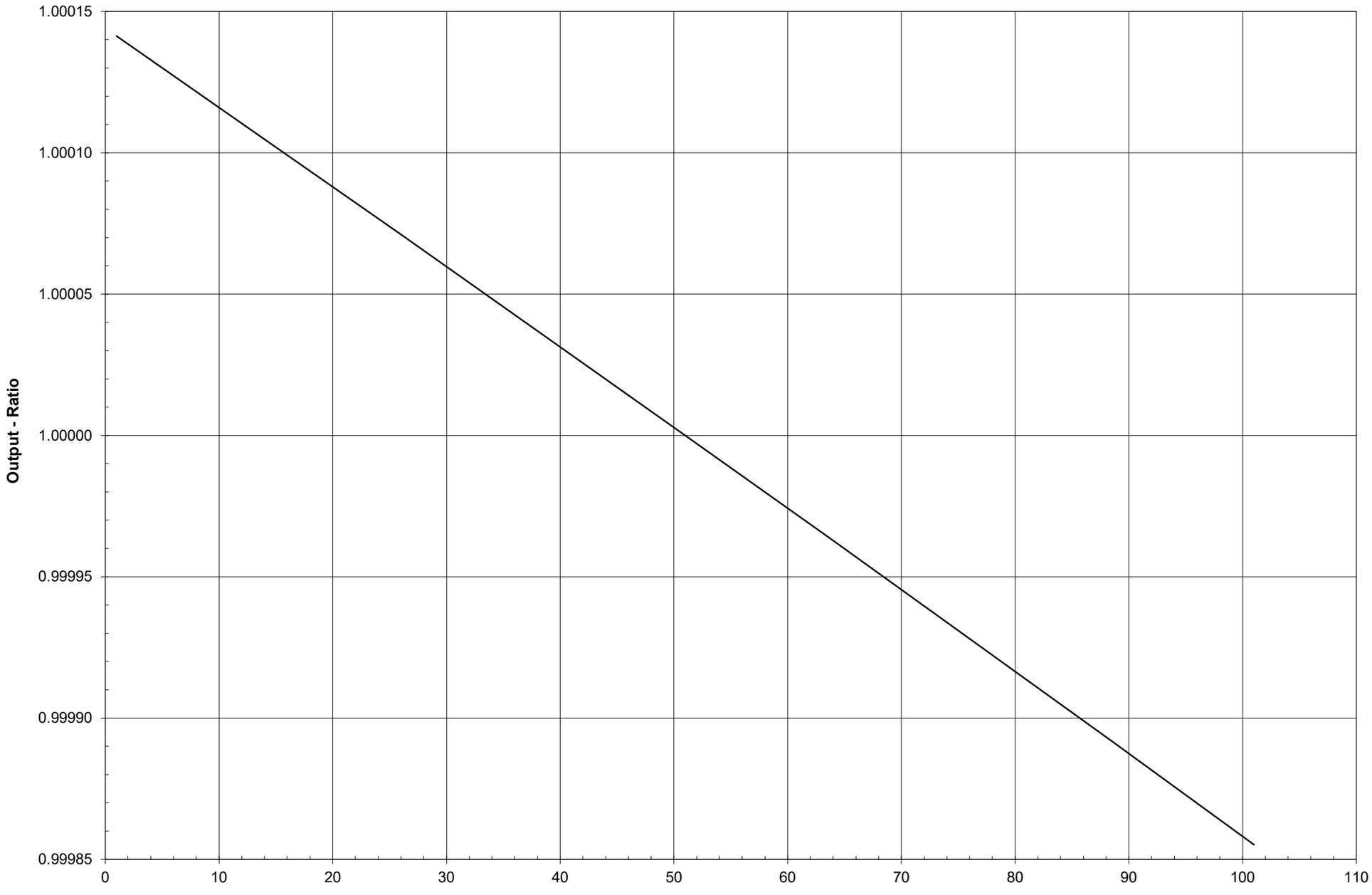
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Fuel Temperature on Output

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units									
Fuel Temperature	F	1.0	13.5	26.0	38.5	51.0	63.5	76.0	88.5	101.0
Output Ratio		1.00014	1.00011	1.00007	1.00004	1.00000	0.99996	0.99993	0.99989	0.99986

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24A-167 Rev A
Sheet 19

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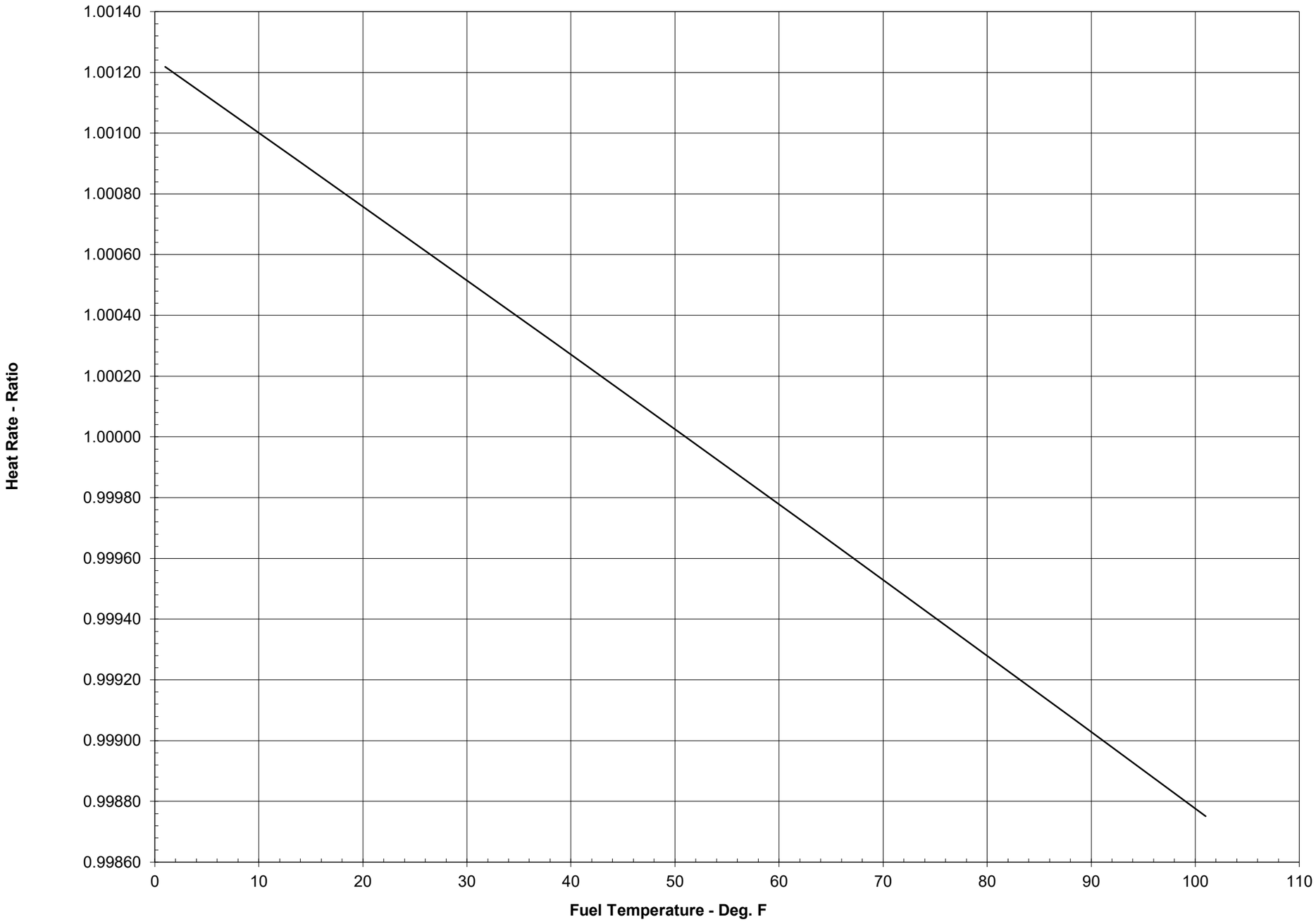
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Fuel Temperature on Heat Rate

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units									
Fuel Temperature	F	1.0	13.5	26.0	38.5	51.0	63.5	76.0	88.5	101.0
Heat Rate Ratio		1.00122	1.00092	1.00061	1.00031	1.00000	0.99969	0.99938	0.99907	0.99875

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24A-167 Rev A
Sheet 20

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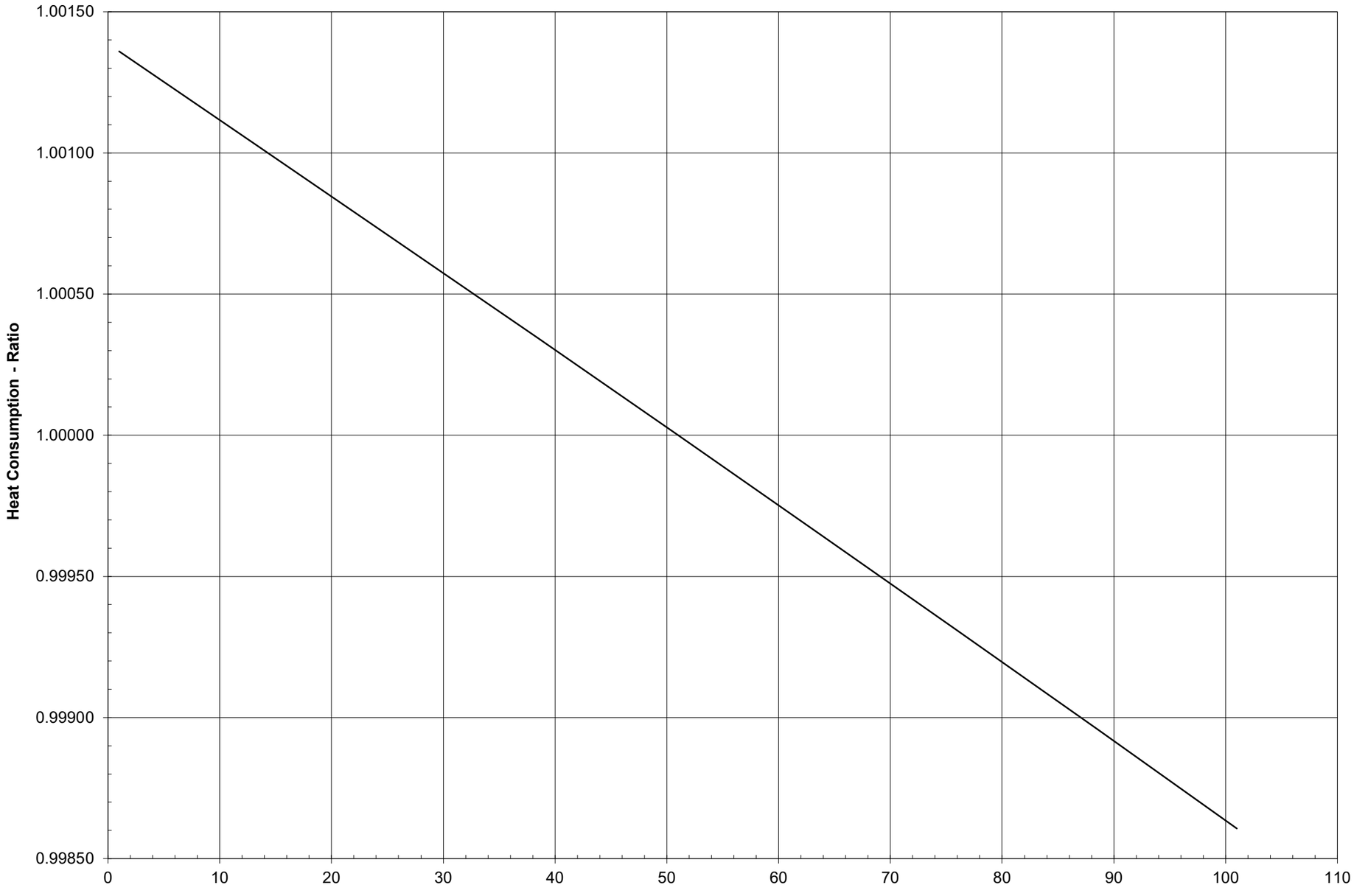
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Fuel Temperature on Heat Consumption

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units									
Fuel Temperature	F	1.0	13.5	26.0	38.5	51.0	63.5	76.0	88.5	101.0
Heat Consumption Ratio		1.00136	1.00102	1.00068	1.00034	1.00000	0.99966	0.99931	0.99896	0.99861

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24A-167 Rev A
Sheet 21

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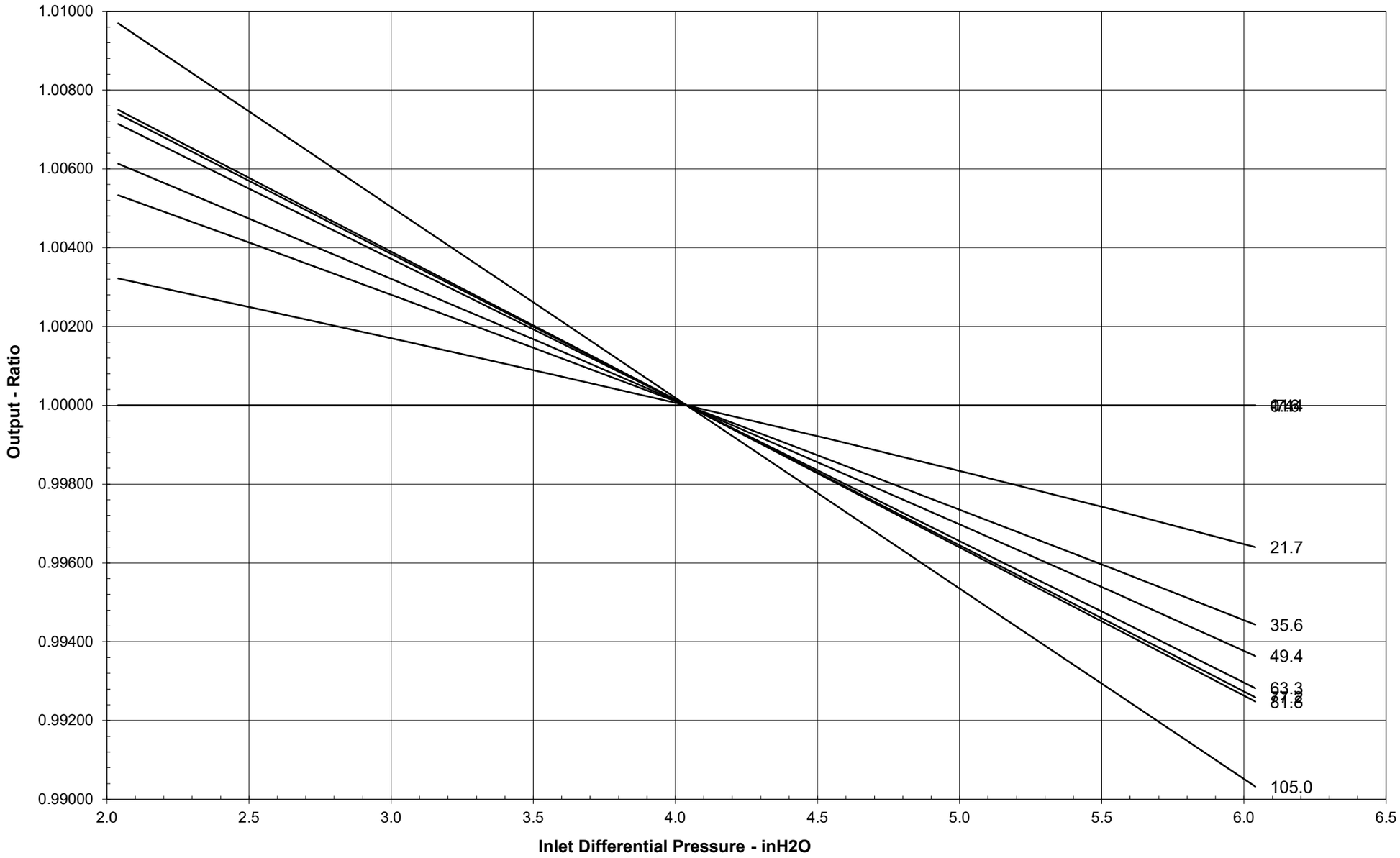
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Inlet Differential Pressure on Output at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Inlet dP (inH2O)	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
2.040	1.00000	1.00000	1.00000	1.00322	1.00533	1.00613	1.00714	1.00739	1.00750	1.00969
2.540	1.00000	1.00000	1.00000	1.00243	1.00402	1.00462	1.00536	1.00555	1.00562	1.00727
3.040	1.00000	1.00000	1.00000	1.00164	1.00270	1.00309	1.00358	1.00370	1.00375	1.00484
3.540	1.00000	1.00000	1.00000	1.00083	1.00136	1.00155	1.00179	1.00185	1.00188	1.00242
4.040	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
4.540	1.00000	1.00000	1.00000	0.99915	0.99863	0.99843	0.99821	0.99815	0.99812	0.99758
5.040	1.00000	1.00000	1.00000	0.99827	0.99724	0.99685	0.99641	0.99630	0.99624	0.99516
5.540	1.00000	1.00000	1.00000	0.99735	0.99584	0.99526	0.99462	0.99444	0.99436	0.99274
6.040	1.00000	1.00000	1.00000	0.99640	0.99443	0.99364	0.99282	0.99259	0.99248	0.99032

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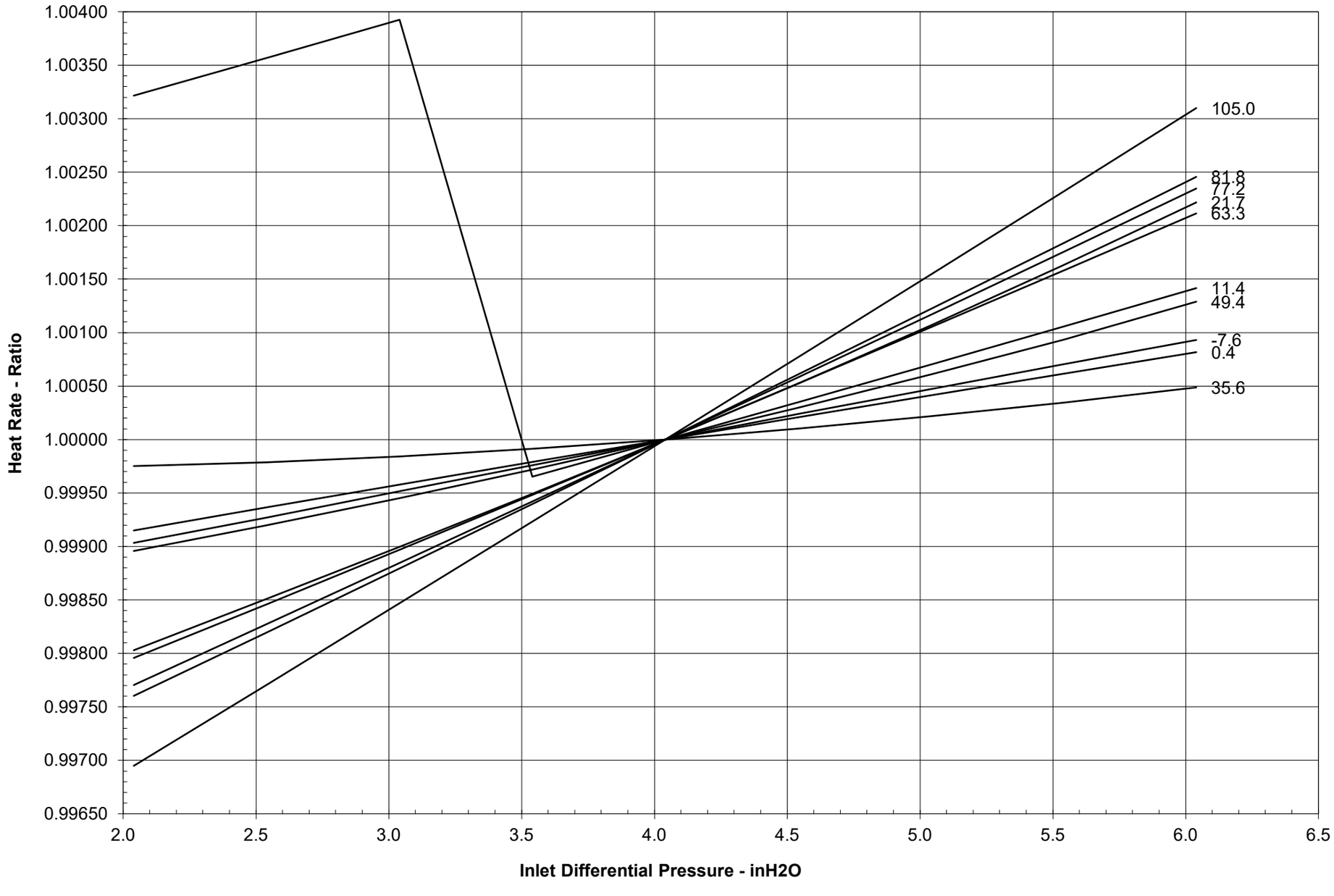
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Inlet Differential Pressure on Heat Rate at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Inlet dP (inH2O)

	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
2.040	0.99903	0.99915	1.00322	0.99803	0.99975	0.99896	0.99796	0.99770	0.99760	0.99695
2.540	0.99927	0.99936	1.00357	0.99851	0.99979	0.99920	0.99846	0.99827	0.99820	0.99771
3.040	0.99952	0.99958	1.00393	0.99900	0.99984	0.99945	0.99897	0.99885	0.99879	0.99847
3.540	0.99976	0.99979	0.99965	0.99949	0.99991	0.99972	0.99948	0.99942	0.99940	0.99923
4.040	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
4.540	1.00024	1.00021	1.00035	1.00052	1.00010	1.00030	1.00052	1.00058	1.00061	1.00077
5.040	1.00047	1.00041	1.00070	1.00107	1.00022	1.00061	1.00105	1.00117	1.00122	1.00154
5.540	1.00070	1.00062	1.00106	1.00163	1.00035	1.00093	1.00158	1.00176	1.00184	1.00232
6.040	1.00093	1.00082	1.00141	1.00222	1.00049	1.00129	1.00211	1.00235	1.00246	1.00310

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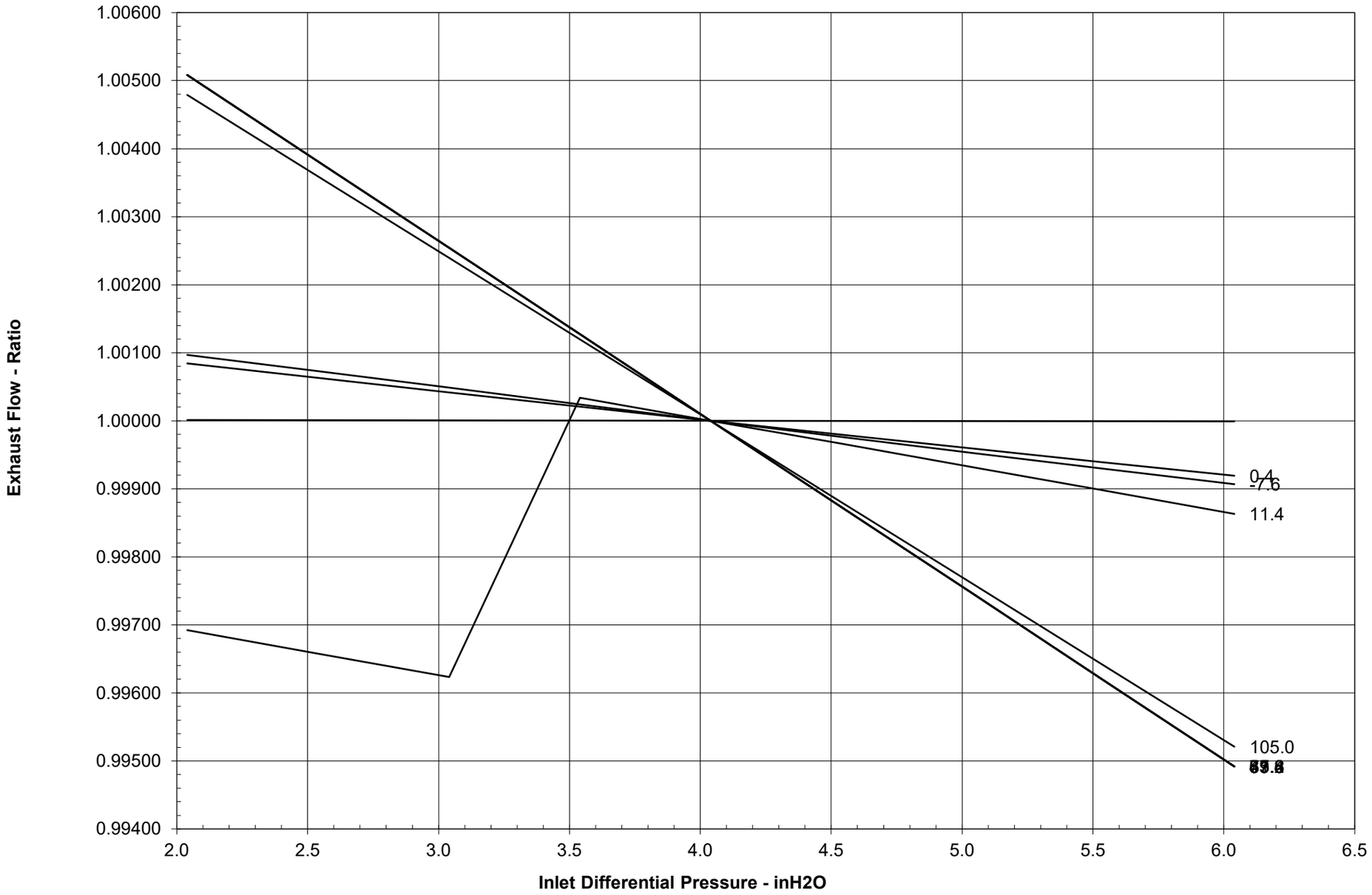
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Inlet Differential Pressure on Exhaust Flow at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Inlet dP (inH2O)	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
2.040	1.00097	1.00084	0.99692	1.00001	1.00508	1.00508	1.00508	1.00508	1.00508	1.00479
2.540	1.00073	1.00063	0.99658	1.00001	1.00381	1.00381	1.00381	1.00381	1.00381	1.00359
3.040	1.00048	1.00042	0.99623	1.00001	1.00254	1.00254	1.00254	1.00254	1.00254	1.00239
3.540	1.00024	1.00021	1.00034	1.00000	1.00127	1.00127	1.00127	1.00127	1.00127	1.00120
4.040	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
4.540	0.99976	0.99980	0.99966	1.00000	0.99873	0.99873	0.99873	0.99873	0.99873	0.99880
5.040	0.99953	0.99959	0.99932	0.99999	0.99746	0.99746	0.99746	0.99746	0.99746	0.99760
5.540	0.99930	0.99939	0.99897	0.99999	0.99619	0.99619	0.99619	0.99619	0.99619	0.99641
6.040	0.99907	0.99919	0.99863	0.99999	0.99492	0.99492	0.99492	0.99492	0.99492	0.99521

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24A-167 Rev A
Sheet 24

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GE Vernova Model 7F.04 Gas Turbine
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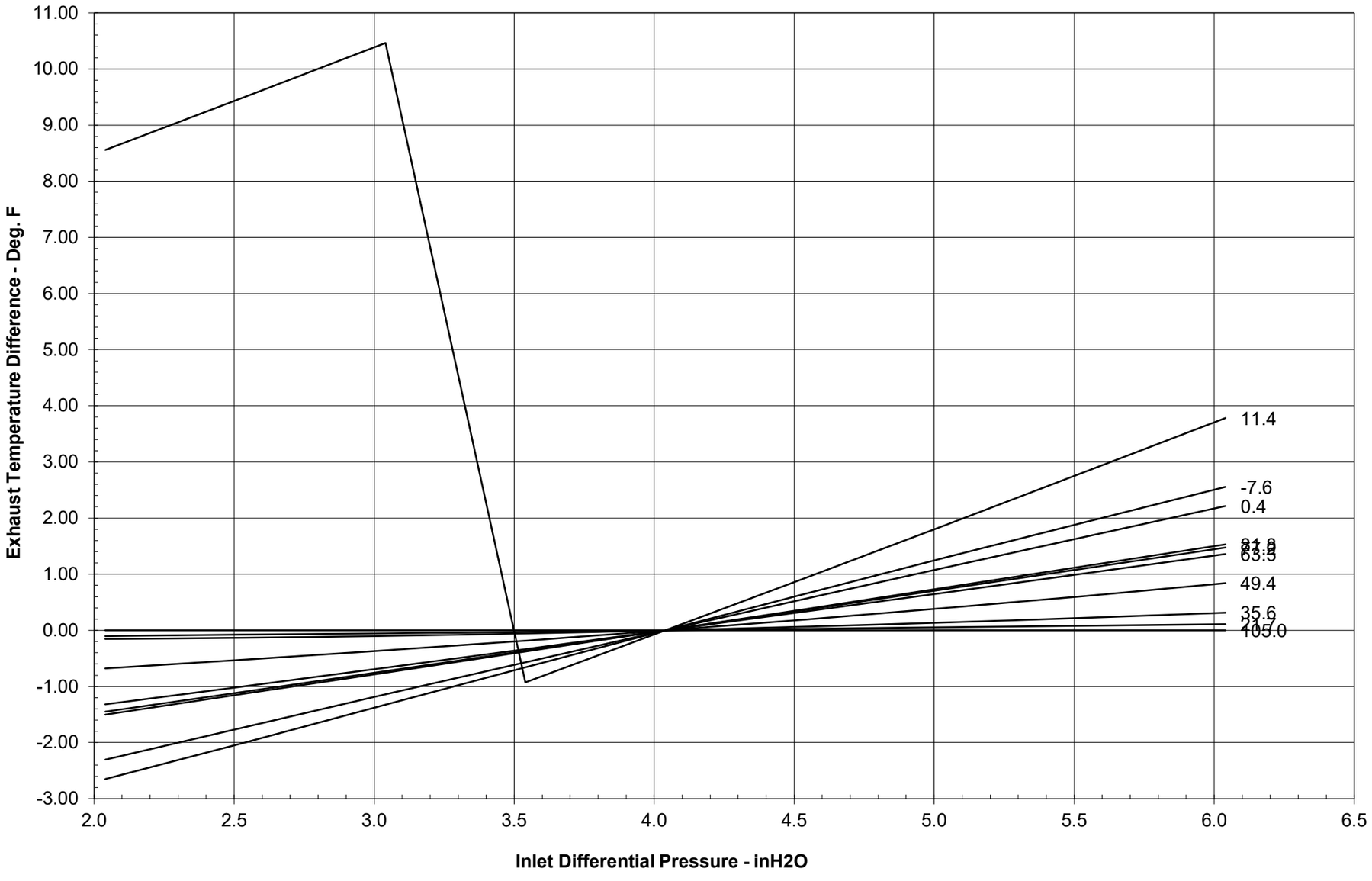
Estimated Performance

Effect of Inlet Differential Pressure on Exhaust Temperature at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Inlet dP (inH2O)

	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
2.040	-2.65	-2.30	8.56	-0.10	-0.15	-0.68	-1.32	-1.45	-1.50	0.00
2.540	-2.00	-1.72	9.51	-0.08	-0.13	-0.52	-0.99	-1.09	-1.13	0.00
3.040	-1.33	-1.14	10.46	-0.05	-0.10	-0.36	-0.66	-0.73	-0.75	0.00
3.540	-0.66	-0.57	-0.93	-0.03	-0.06	-0.18	-0.33	-0.36	-0.38	0.00
4.040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.540	0.65	0.56	0.93	0.03	0.07	0.19	0.34	0.37	0.38	0.00
5.040	1.30	1.12	1.88	0.05	0.14	0.40	0.67	0.73	0.76	0.00
5.540	1.93	1.67	2.82	0.08	0.22	0.61	1.02	1.10	1.15	0.00
6.040	2.55	2.21	3.78	0.11	0.31	0.84	1.36	1.47	1.53	0.00

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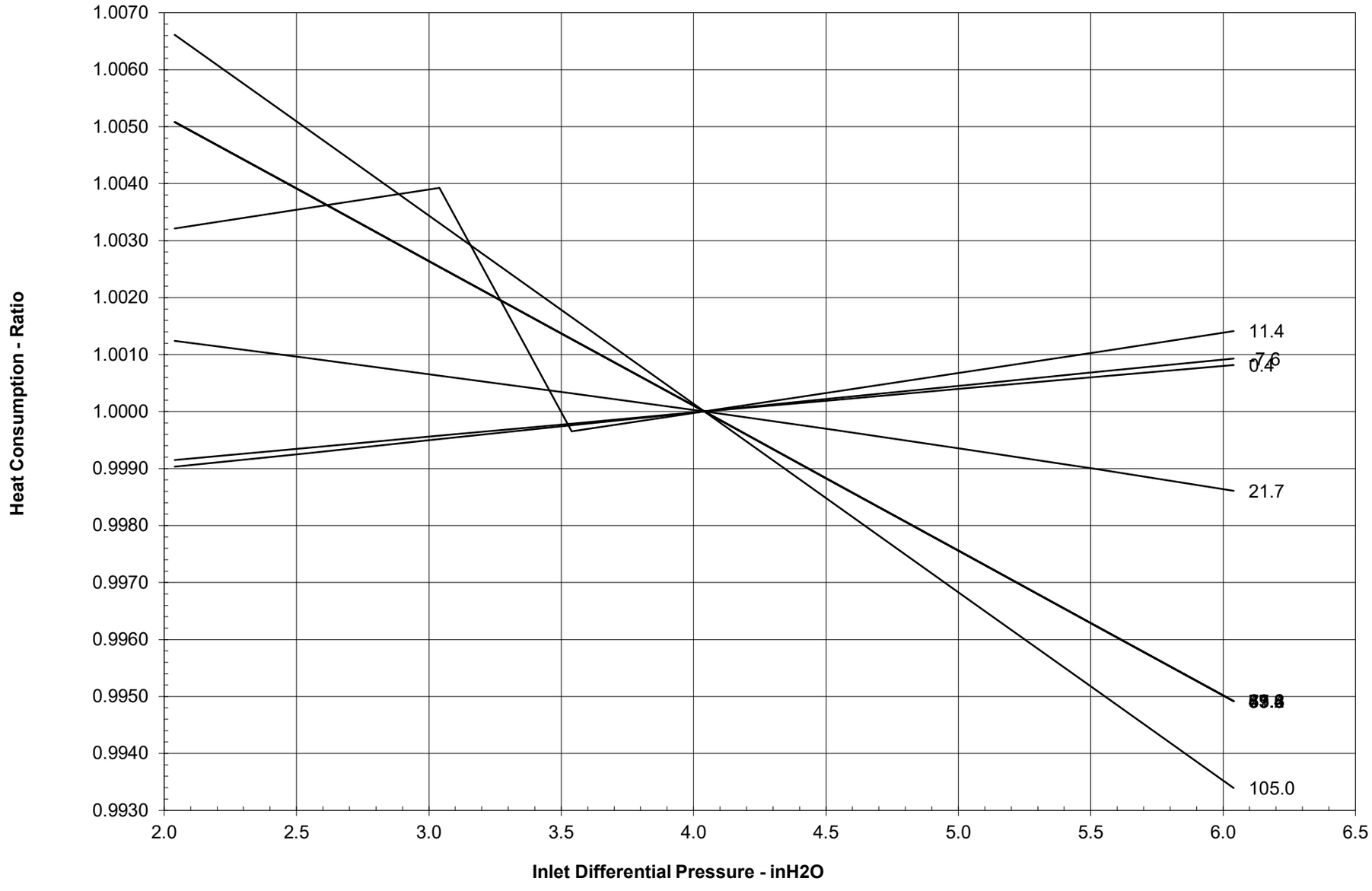
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Inlet Differential Pressure on Heat Consumption at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Inlet dP (inH2O)

	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
2.040	0.99903	0.99915	1.00322	1.00124	1.00508	1.00508	1.00508	1.00508	1.00508	1.00661
2.540	0.99927	0.99937	1.00357	1.00094	1.00381	1.00381	1.00381	1.00381	1.00381	1.00496
3.040	0.99952	0.99958	1.00393	1.00063	1.00254	1.00254	1.00254	1.00254	1.00254	1.00331
3.540	0.99976	0.99979	0.99965	1.00032	1.00127	1.00127	1.00127	1.00127	1.00127	1.00165
4.040	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
4.540	1.00024	1.00021	1.00035	0.99967	0.99873	0.99873	0.99873	0.99873	0.99873	0.99835
5.040	1.00047	1.00041	1.00070	0.99933	0.99746	0.99746	0.99746	0.99746	0.99746	0.99670
5.540	1.00070	1.00062	1.00106	0.99898	0.99619	0.99619	0.99619	0.99619	0.99619	0.99504
6.040	1.00093	1.00082	1.00142	0.99861	0.99492	0.99492	0.99492	0.99492	0.99492	0.99339

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24A-167 Rev A
Sheet 26

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GE Vernova Model 7F.04 Gas Turbine
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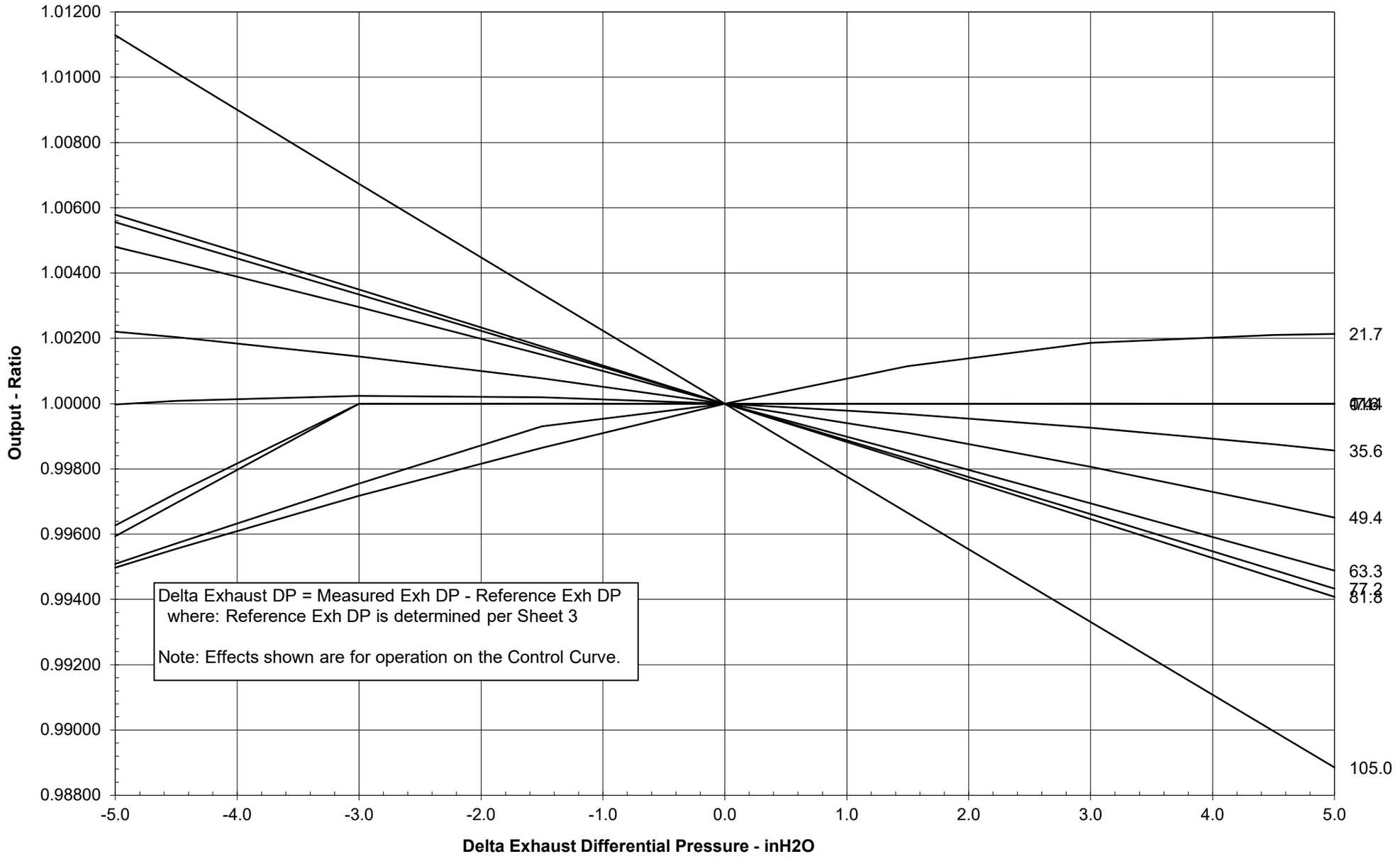
Estimated Performance

Effect of Exhaust Pressure on Output at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Delta Exhaust Differential Pressure - inH2O

	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
-5.00	0.99627	0.99594	0.99509	0.99497	0.99997	1.00220	1.00480	1.00556	1.00579	1.01129
-4.50	0.99725	0.99696	0.99572	0.99555	1.00008	1.00203	1.00435	1.00500	1.00522	1.01014
-3.00	1.00000	1.00000	0.99755	0.99717	1.00024	1.00145	1.00295	1.00335	1.00349	1.00673
-1.50	1.00000	1.00000	0.99931	0.99864	1.00020	1.00077	1.00149	1.00168	1.00175	1.00336
0.00	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
1.50	1.00000	1.00000	1.00000	1.00115	0.99968	0.99911	0.99848	0.99831	0.99824	0.99665
3.00	1.00000	1.00000	1.00000	1.00186	0.99926	0.99806	0.99695	0.99662	0.99646	0.99331
4.50	1.00000	1.00000	1.00000	1.00211	0.99876	0.99691	0.99540	0.99490	0.99468	0.98997
5.00	1.00000	1.00000	1.00000	1.00213	0.99856	0.99651	0.99488	0.99433	0.99408	0.98885

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24A-167 Rev A
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GE Vernova Model 7F.04 Gas Turbine
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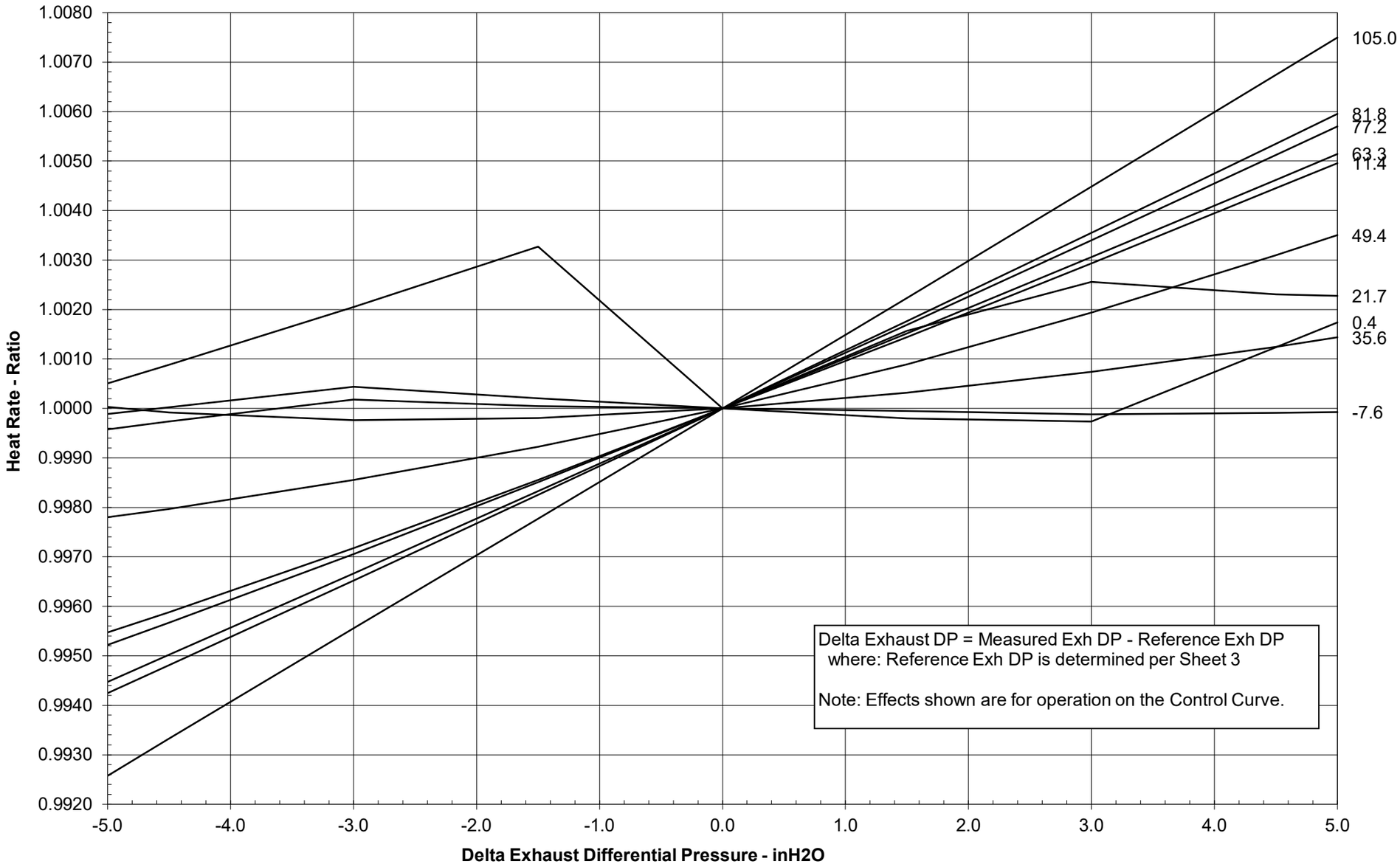
Estimated Performance

Effect of Exhaust Pressure on Heat Rate at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Delta Exhaust Differential Pressure - inH2O	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
-5.00	0.99958	0.99989	1.00050	0.99547	1.00003	0.99780	0.99522	0.99447	0.99425	0.99258
-4.50	0.99974	1.00003	1.00088	0.99588	0.99992	0.99797	0.99567	0.99502	0.99481	0.99332
-3.00	1.00018	1.00044	1.00205	0.99717	0.99976	0.99856	0.99705	0.99667	0.99652	0.99555
-1.50	1.00005	1.00021	1.00327	0.99855	0.99980	0.99923	0.99851	0.99833	0.99825	0.99777
0.00	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
1.50	0.99995	0.99980	1.00144	1.00157	1.00032	1.00089	1.00152	1.00169	1.00177	1.00223
3.00	0.99988	0.99974	1.00293	1.00256	1.00074	1.00194	1.00306	1.00340	1.00355	1.00448
4.50	0.99991	1.00124	1.00445	1.00231	1.00124	1.00310	1.00462	1.00512	1.00535	1.00674
5.00	0.99993	1.00174	1.00496	1.00228	1.00144	1.00350	1.00514	1.00570	1.00595	1.00750

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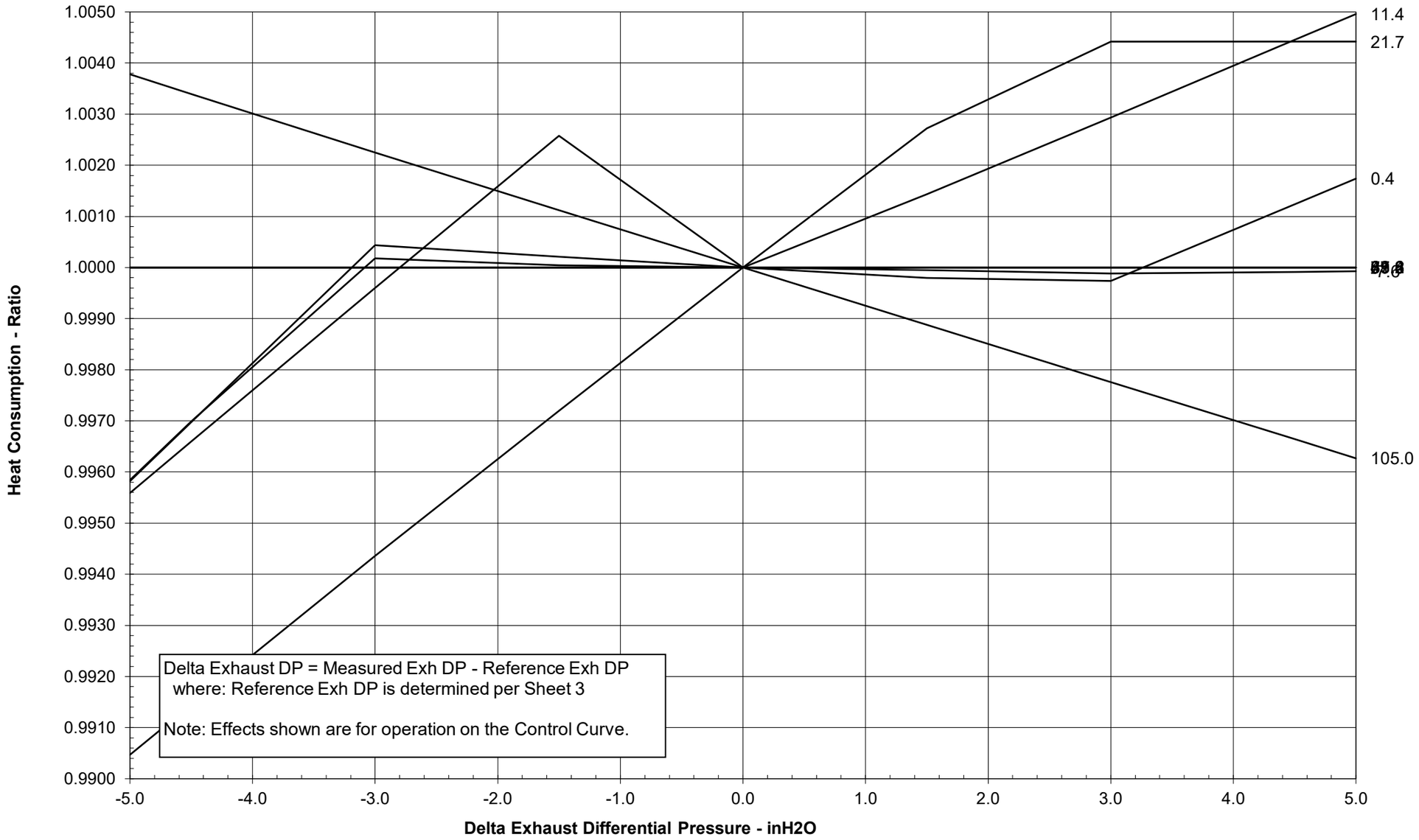
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Pressure on Heat Consumption at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Delta Exhaust Differential Pressure - inH2O	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
-5.00	0.99584	0.99582	0.99559	0.99047	1.00000	1.00000	1.00000	1.00000	1.00000	1.00378
-4.50	0.99699	0.99698	0.99660	0.99145	1.00000	1.00000	1.00000	1.00000	1.00000	1.00339
-3.00	1.00018	1.00044	0.99960	0.99436	1.00000	1.00000	1.00000	1.00000	1.00000	1.00225
-1.50	1.00005	1.00021	1.00257	0.99720	1.00000	1.00000	1.00000	1.00000	1.00000	1.00112
0.00	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
1.50	0.99995	0.99980	1.00144	1.00272	1.00000	1.00000	1.00000	1.00000	1.00000	0.99888
3.00	0.99988	0.99974	1.00293	1.00442	1.00000	1.00000	1.00000	1.00000	1.00000	0.99776
4.50	0.99991	1.00124	1.00445	1.00442	1.00000	1.00000	1.00000	1.00000	1.00000	0.99664
5.00	0.99993	1.00174	1.00496	1.00442	1.00000	1.00000	1.00000	1.00000	1.00000	0.99627

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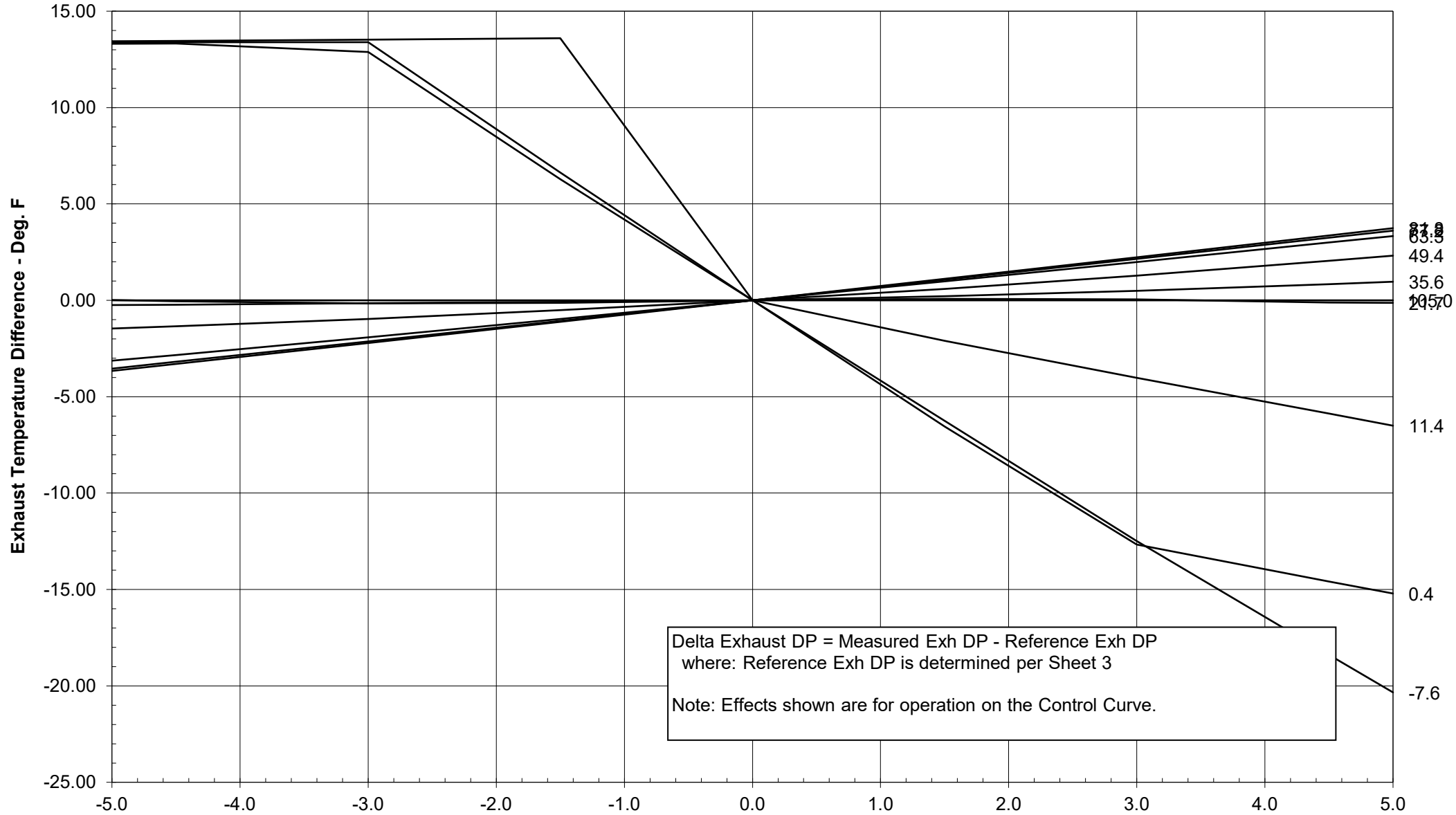
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Pressure on Exhaust Temperature at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Delta Exhaust Differential Pressure - inH2O

Compressor Inlet Temperature - Deg. F

Delta Exhaust Differential Pressure - inH2O	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
-5.00	13.31	13.38	13.44	-0.24	0.02	-1.46	-3.13	-3.54	-3.66	0.00
-4.50	13.32	13.39	13.46	-0.22	-0.05	-1.35	-2.84	-3.19	-3.30	0.00
-3.00	12.89	13.39	13.53	-0.15	-0.16	-0.96	-1.92	-2.13	-2.21	0.00
-1.50	6.29	6.63	13.60	-0.08	-0.13	-0.51	-0.97	-1.07	-1.11	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.50	-6.24	-6.55	-2.10	0.08	0.22	0.59	0.99	1.07	1.12	0.00
3.00	-12.48	-12.66	-4.03	0.05	0.50	1.29	1.99	2.16	2.24	0.00
4.50	-18.40	-14.58	-5.88	-0.12	0.84	2.05	3.00	3.25	3.37	0.00
5.00	-20.34	-15.21	-6.50	-0.14	0.97	2.32	3.33	3.61	3.74	0.00

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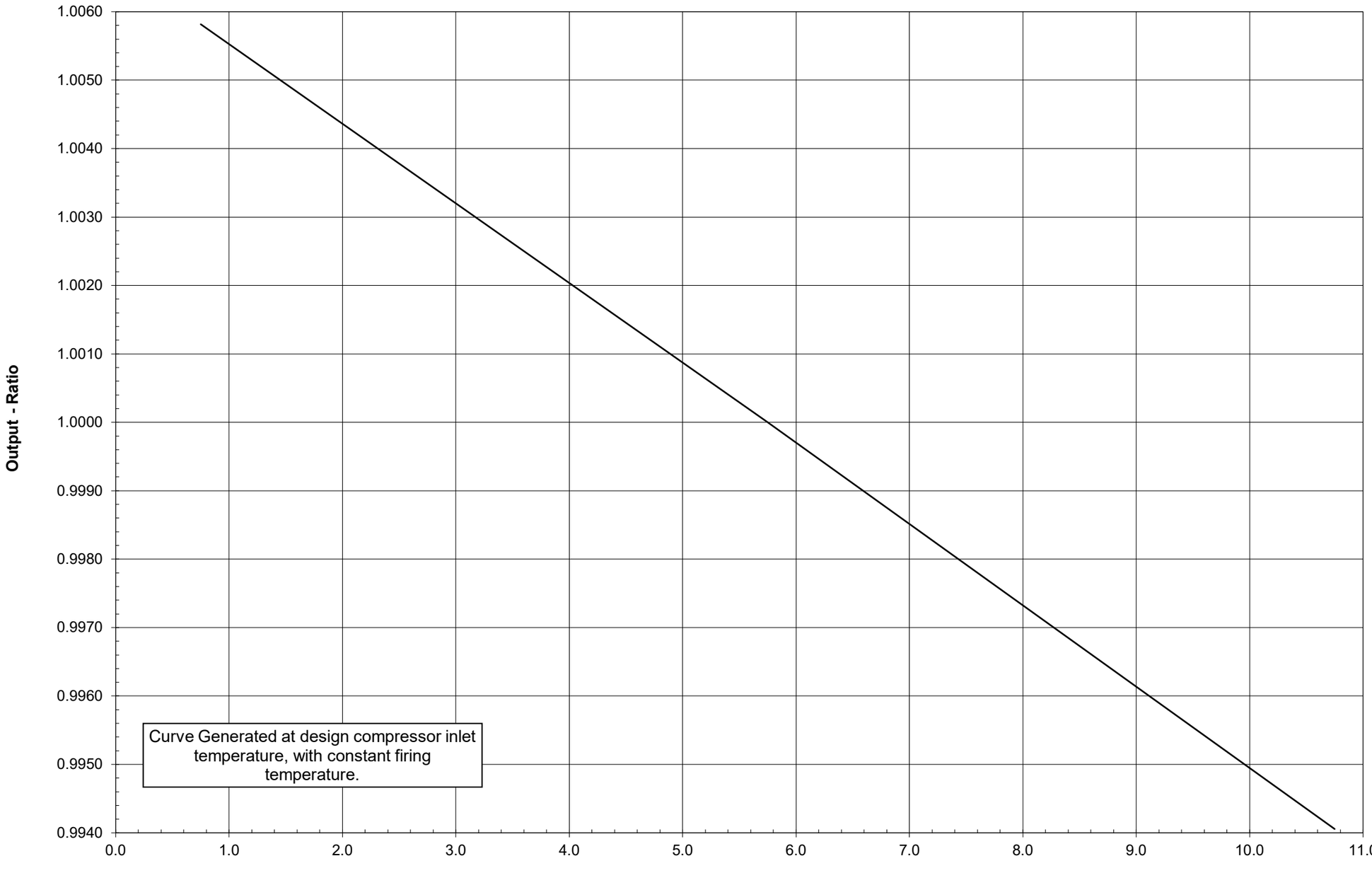
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Differential Pressure on Output

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units			
Exhaust DP	inH2O	0.75	5.75	10.75
Output Ratio		1.00582	1.00000	0.99406

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24A-167 Rev A
Sheet 31

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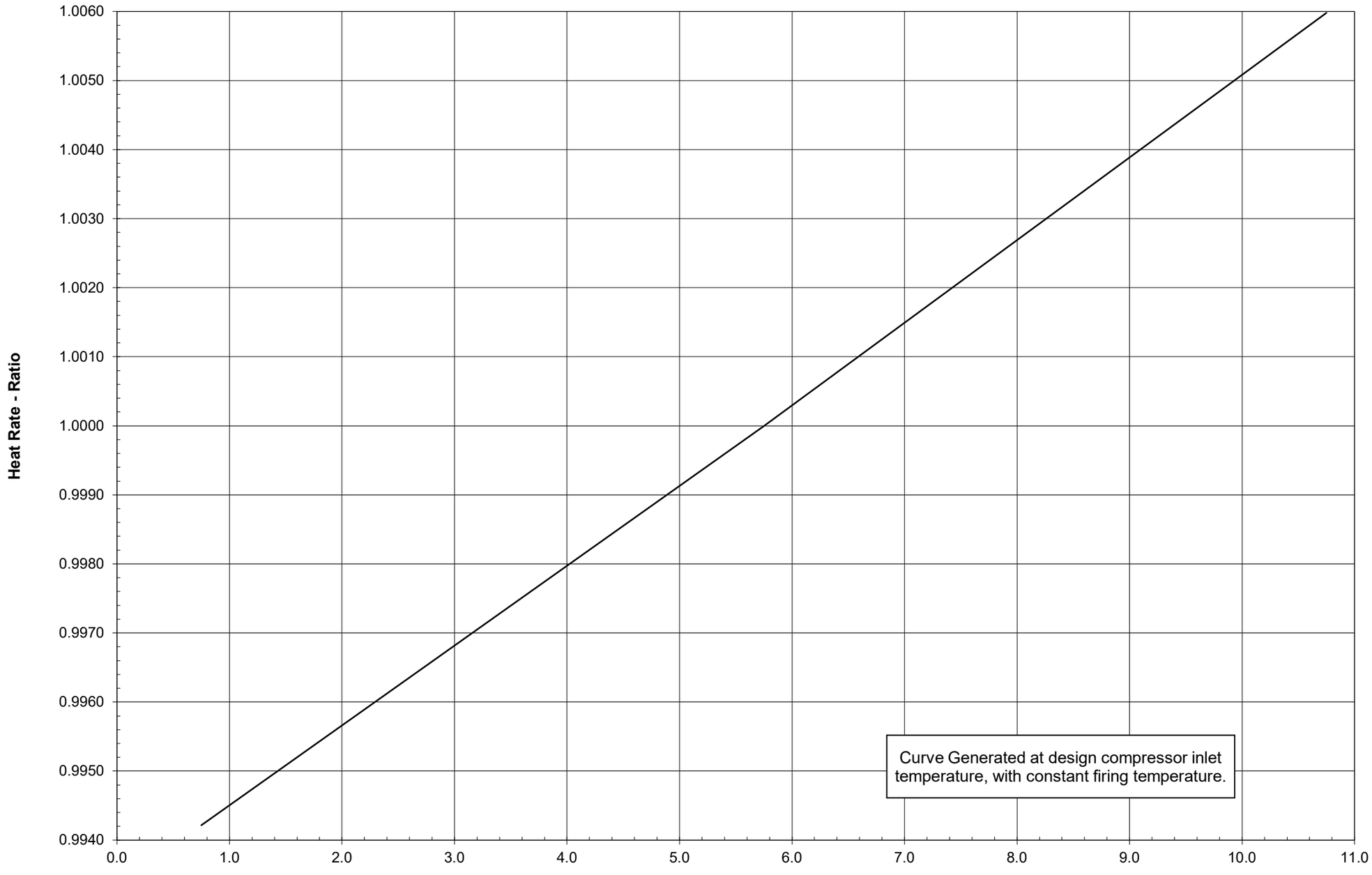
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Differential Pressure on Heat Rate

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units			
Exhaust DP	inH2O	0.75	5.75	10.75
Heat Rate Ratio		0.99422	1.00000	1.00598

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24A-167 Rev A
Sheet 32

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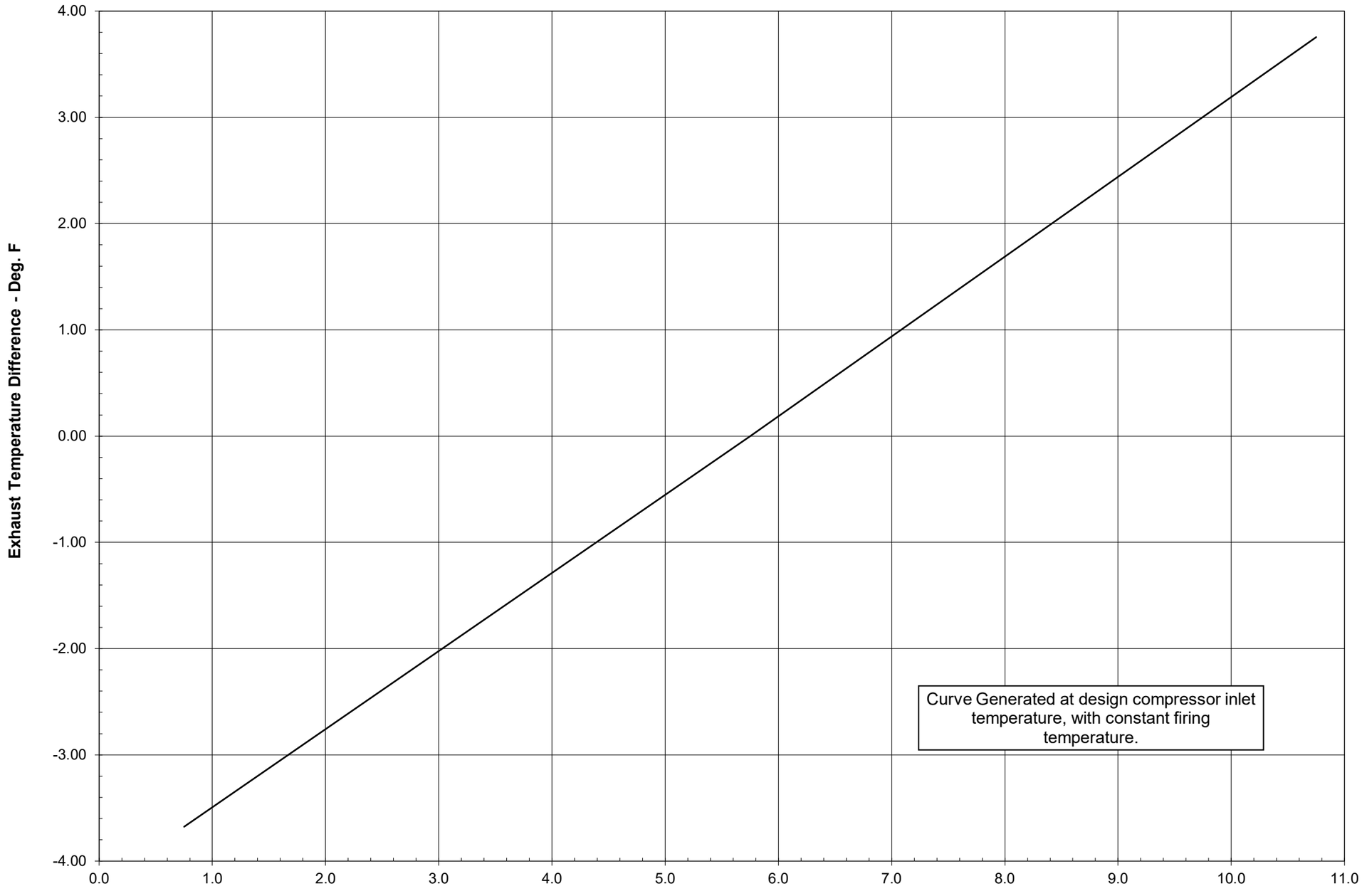
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Differential Pressure on Exhaust Temperature

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units			
Exhaust DP	inH2O	0.75	5.75	10.75
Tx Difference	F	-3.7	0.0	3.8

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24A-167 Rev A
Sheet 33

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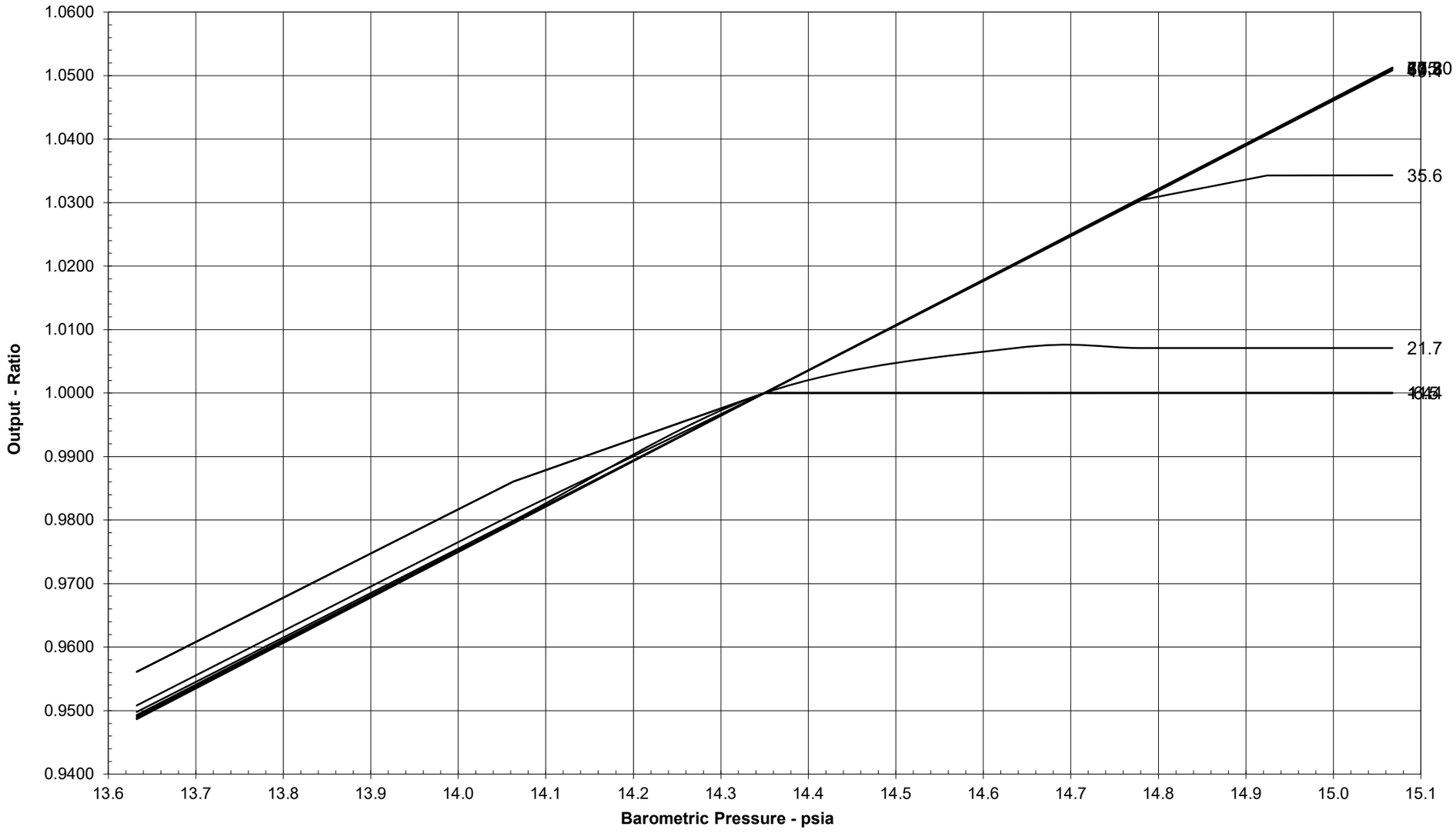
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Barometric Pressure on Output at Different Compressor Inlet Temps
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Barometric Pressure - psia	-6.5	1.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
13.633	0.95609	0.95612	0.95081	0.94978	0.94930	0.94914	0.94891	0.94881	0.94883	0.94865
13.776	0.96609	0.96611	0.96084	0.95983	0.95945	0.95932	0.95913	0.95905	0.95907	0.95893
13.920	0.97608	0.97610	0.97088	0.96988	0.96959	0.96949	0.96935	0.96929	0.96930	0.96920
14.063	0.98608	0.98608	0.98091	0.97992	0.97973	0.97966	0.97957	0.97953	0.97954	0.97947
14.350	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
14.637	1.00000	1.00000	1.00000	1.00710	1.02027	1.02033	1.02043	1.02047	1.02046	1.02051
14.781	1.00000	1.00000	1.00000	1.00710	1.03040	1.03050	1.03064	1.03070	1.03068	1.03077
14.924	1.00000	1.00000	1.00000	1.00710	1.03429	1.04066	1.04085	1.04093	1.04091	1.04101
15.068	1.00000	1.00000	1.00000	1.00710	1.03429	1.05082	1.05106	1.05116	1.05113	1.05126

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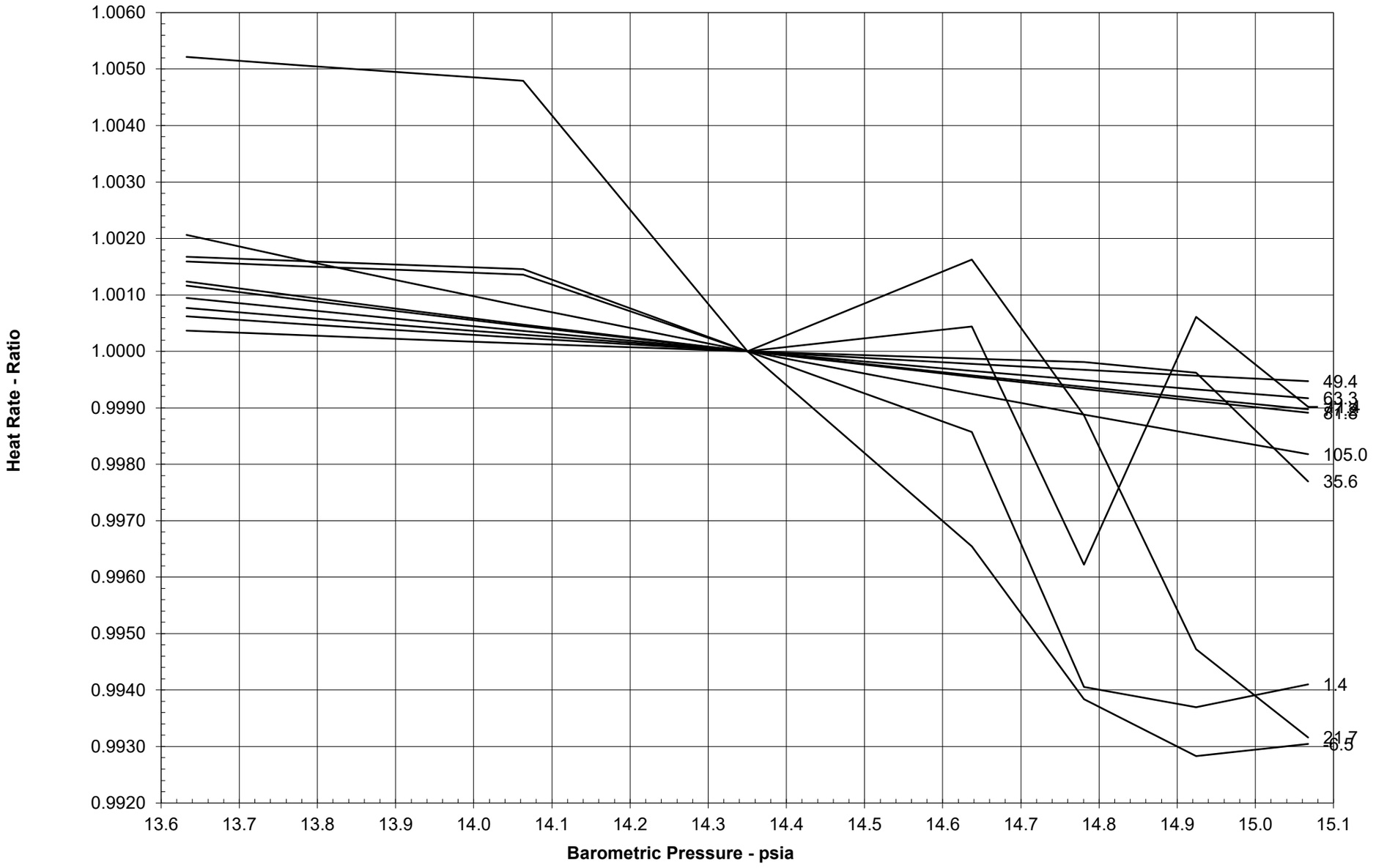
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Barometric Pressure on Heat Rate at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Barometric Pressure - psia	-6.5	1.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
13.633	1.00159	1.00168	1.00522	1.00077	1.00037	1.00062	1.00095	1.00116	1.00124	1.00206
13.776	1.00151	1.00160	1.00507	1.00061	1.00029	1.00049	1.00075	1.00092	1.00098	1.00163
13.920	1.00143	1.00153	1.00493	1.00045	1.00021	1.00036	1.00055	1.00068	1.00072	1.00121
14.063	1.00136	1.00146	1.00480	1.00029	1.00014	1.00024	1.00036	1.00045	1.00047	1.00079
14.350	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
14.637	0.99655	0.99857	1.00044	1.00163	0.99987	0.99978	0.99966	0.99957	0.99955	0.99924
14.781	0.99384	0.99405	0.99622	0.99887	0.99981	0.99967	0.99949	0.99937	0.99933	0.99888
14.924	0.99283	0.99370	1.00061	0.99472	0.99962	0.99957	0.99933	0.99917	0.99912	0.99853
15.068	0.99305	0.99410	0.99902	0.99316	0.99770	0.99947	0.99917	0.99897	0.99891	0.99818

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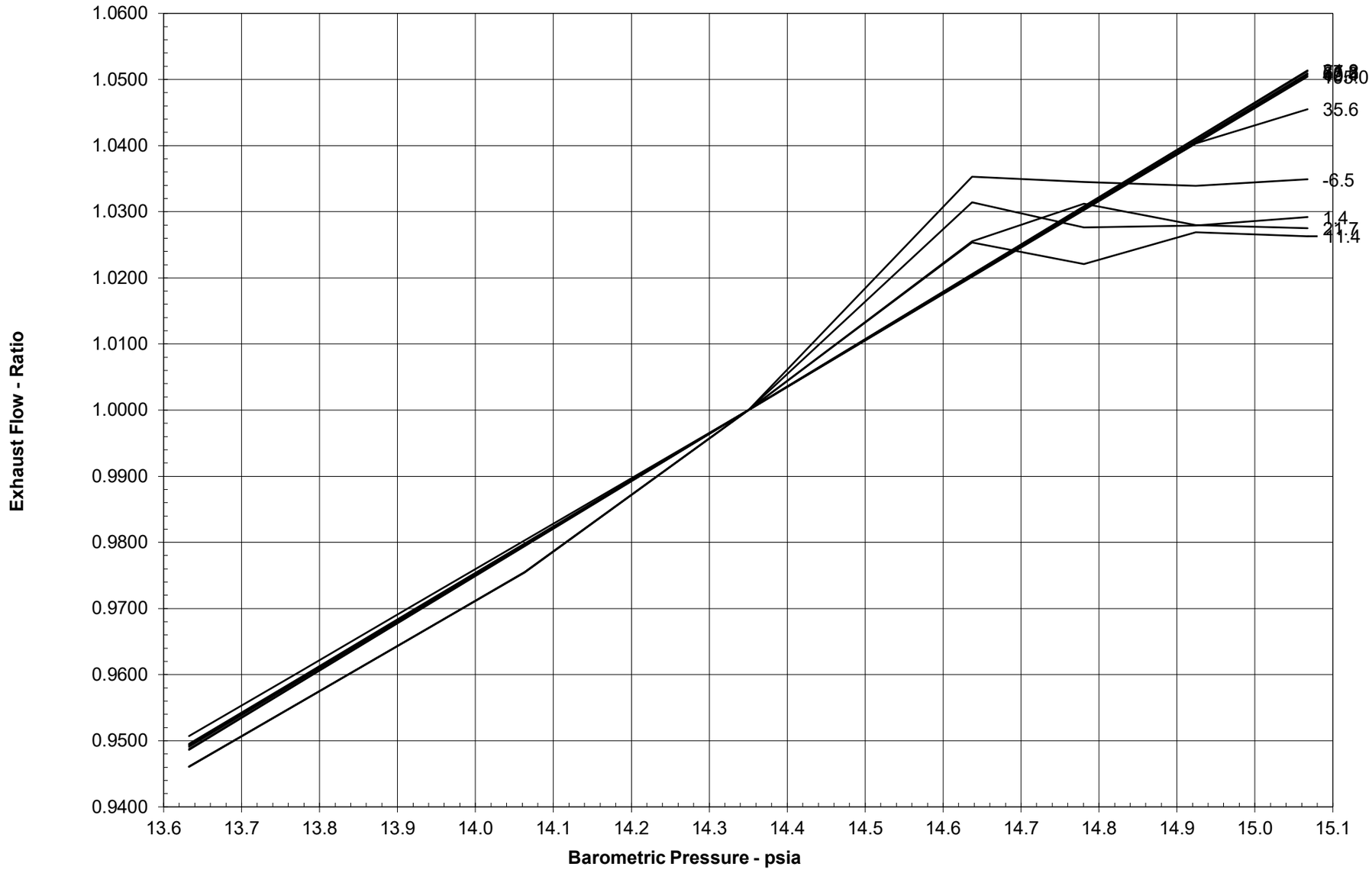
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Barometric Pressure on Exhaust Flow at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Barometric Pressure - psia	-6.5	1.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
13.633	0.94610	0.94608	0.94606	0.95071	0.94940	0.94931	0.94909	0.94874	0.94863	0.94953
13.776	0.95590	0.95588	0.95586	0.96057	0.95952	0.95945	0.95927	0.95899	0.95890	0.95963
13.920	0.96570	0.96568	0.96566	0.97042	0.96964	0.96958	0.96945	0.96925	0.96918	0.96972
14.063	0.97550	0.97548	0.97547	0.98028	0.97976	0.97972	0.97964	0.97950	0.97945	0.97982
14.350	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
14.637	1.03530	1.03143	1.02537	1.02550	1.02024	1.02028	1.02036	1.02050	1.02055	1.02018
14.781	1.03450	1.02760	1.02211	1.03122	1.03036	1.03042	1.03055	1.03075	1.03082	1.03026
14.924	1.03394	1.02794	1.02690	1.02795	1.04032	1.04055	1.04073	1.04101	1.04110	1.04035
15.068	1.03489	1.02919	1.02629	1.02751	1.04550	1.05069	1.05091	1.05126	1.05137	1.05043

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24A-167 Rev A
Sheet 36

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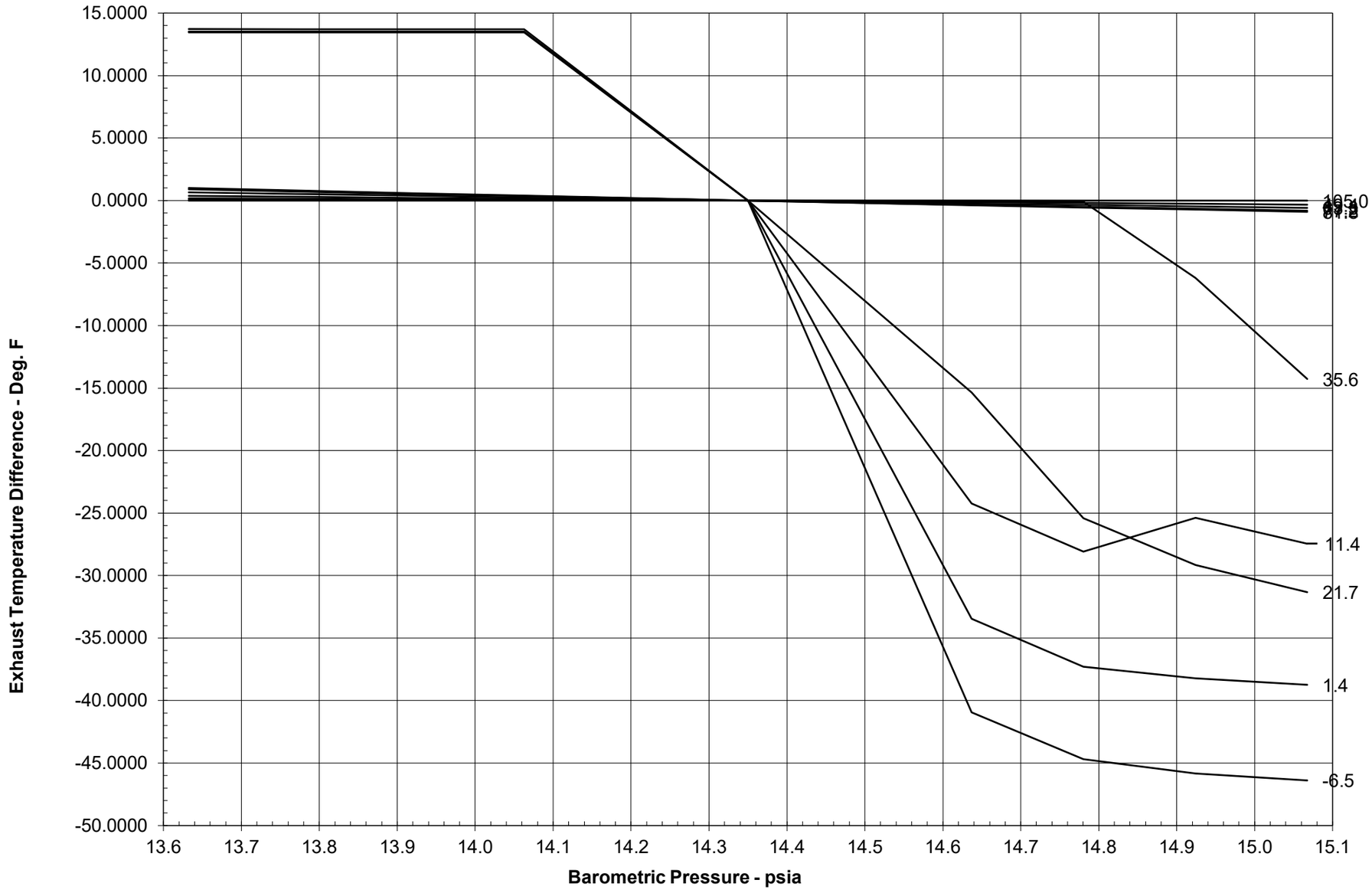
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Barometric Pressure on Exhaust Temperature at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Barometric Pressure - psia	-6.5	1.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
13.63	13.46	13.52	13.72	0.08	0.17	0.38	0.66	0.90	1.00	0.00
13.78	13.45	13.51	13.71	0.07	0.14	0.30	0.52	0.71	0.79	0.00
13.92	13.45	13.51	13.70	0.05	0.10	0.22	0.38	0.53	0.59	0.00
14.06	13.45	13.50	13.69	0.03	0.07	0.14	0.25	0.35	0.39	0.00
14.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14.64	-40.94	-33.46	-24.22	-15.35	-0.06	-0.14	-0.24	-0.34	-0.37	0.00
14.78	-44.69	-37.30	-28.09	-25.43	-0.09	-0.20	-0.36	-0.50	-0.55	0.00
14.92	-45.84	-38.22	-25.39	-29.17	-6.19	-0.27	-0.48	-0.66	-0.73	0.00
15.07	-46.39	-38.74	-27.44	-31.33	-14.27	-0.33	-0.59	-0.81	-0.90	0.00

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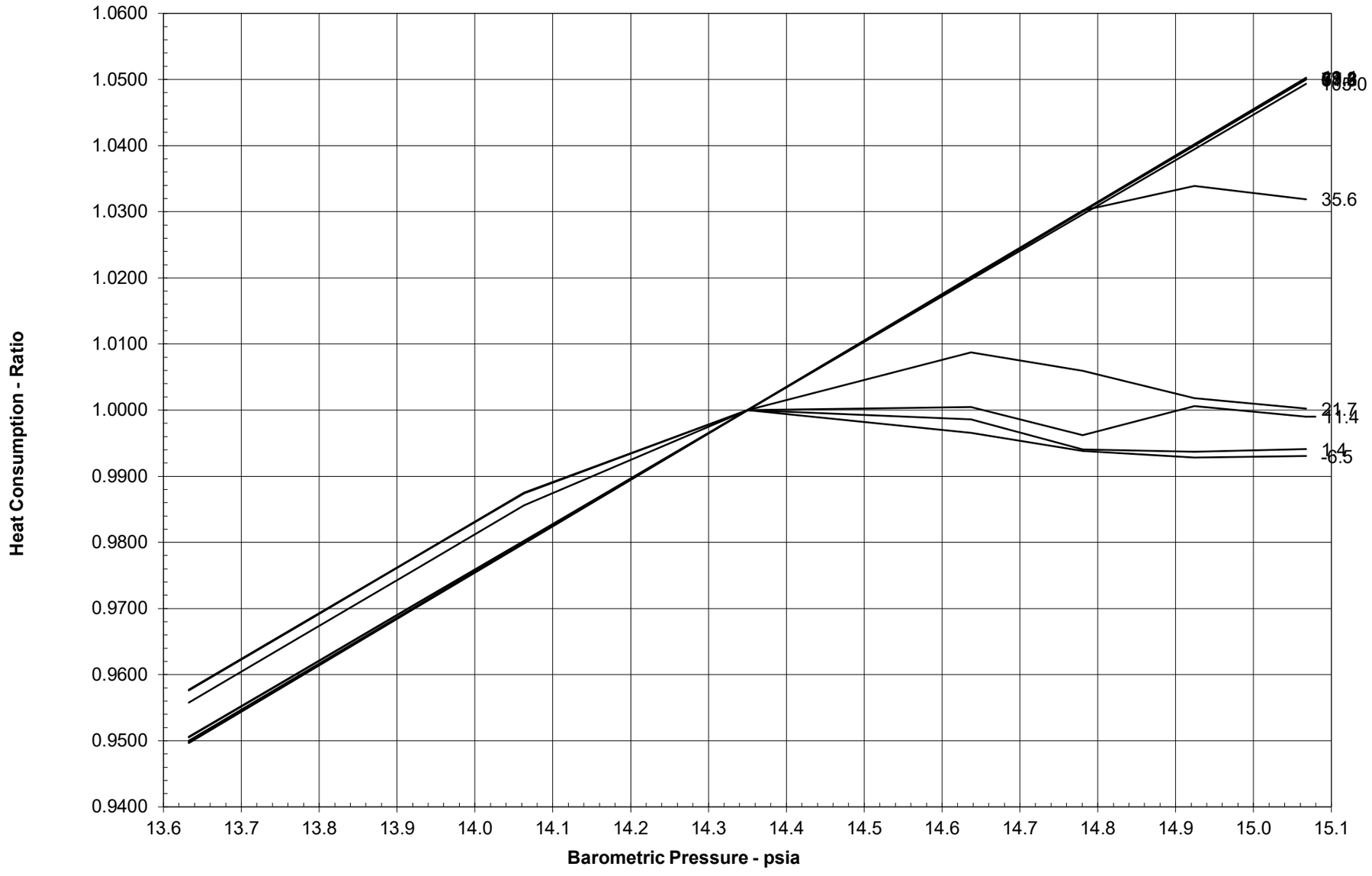
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Barometric Pressure on Heat Consumption at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Barometric Pressure - psia	-6.5	1.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
13.633	0.95761	0.95772	0.95577	0.95052	0.94965	0.94973	0.94981	0.94992	0.95000	0.95061
13.776	0.96755	0.96765	0.96572	0.96041	0.95972	0.95979	0.95985	0.95993	0.96000	0.96049
13.920	0.97748	0.97759	0.97566	0.97031	0.96979	0.96984	0.96989	0.96995	0.97000	0.97037
14.063	0.98742	0.98752	0.98561	0.98021	0.97986	0.97989	0.97992	0.97997	0.98000	0.98025
14.350	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
14.637	0.99655	0.99857	1.00044	1.00873	1.02014	1.02011	1.02008	1.02003	1.02000	1.01974
14.781	0.99384	0.99405	0.99622	1.00595	1.03021	1.03016	1.03011	1.03005	1.03000	1.02961
14.924	0.99283	0.99370	1.00061	1.00178	1.03390	1.04021	1.04015	1.04007	1.03999	1.03948
15.068	0.99305	0.99410	0.99902	1.00021	1.03191	1.05027	1.05019	1.05008	1.04999	1.04934

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24A-167 Rev A
Sheet 38

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GE Vernova Model 7F.04 Gas Turbine
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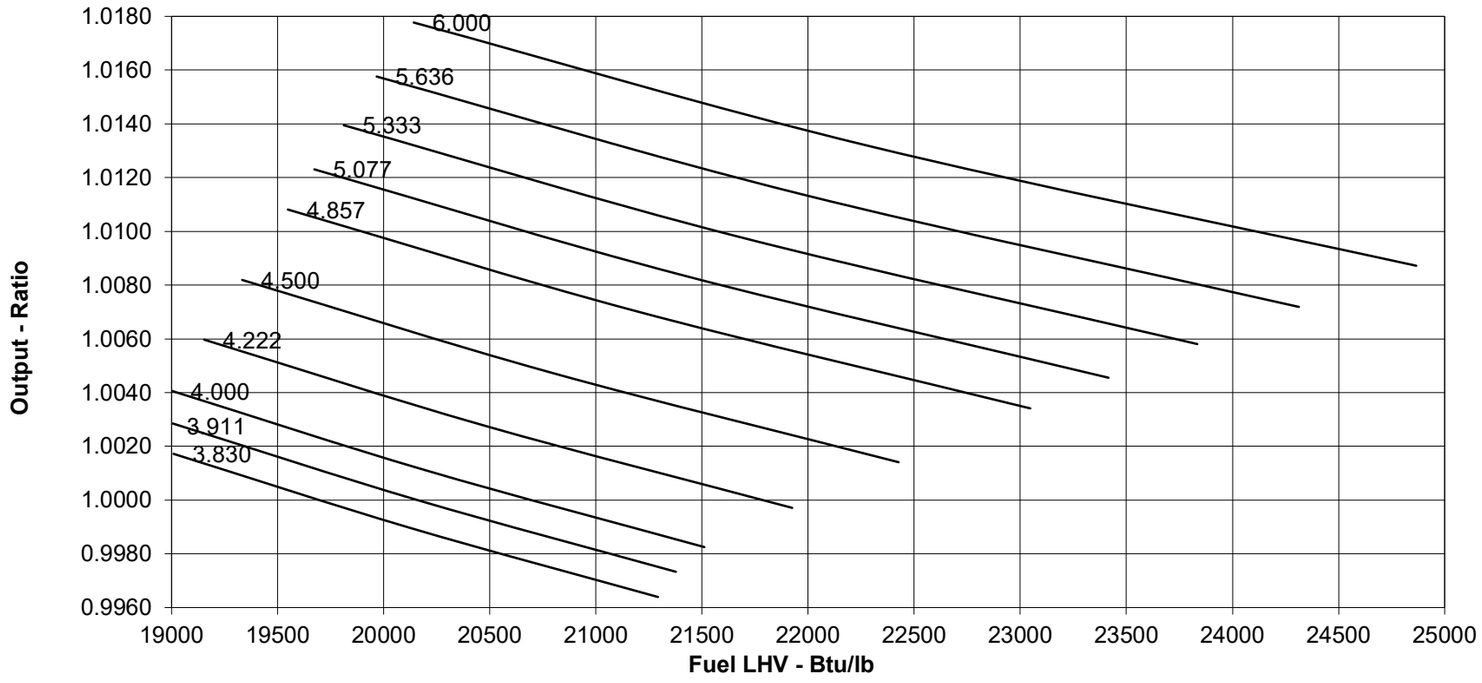
Estimated Performance

Effect of Gas Fuel Composition on Output

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Fuel LHV - Btu/lb	Fuel H/C 3.830
19010	1.00172
20122	0.99897
21292	0.99639

Fuel LHV - Btu/lb	Fuel H/C 3.911
19006	1.00285
20159	1.00000
21377	0.99733

Fuel LHV - Btu/lb	Fuel H/C 4.000
19002	1.00406
20199	1.00111
21511	0.99825

Fuel LHV - Btu/lb	Fuel H/C 4.222
19154	1.00597
20468	1.00279
21925	0.99971

Fuel LHV - Btu/lb	Fuel H/C 4.500
19333	1.00819
20790	1.00474
22426	1.00141

Fuel LHV - Btu/lb	Fuel H/C 4.857
19548	1.01081
21182	1.00705
23047	1.00341

Fuel LHV - Btu/lb	Fuel H/C 5.077
19673	1.01231
21412	1.00836
23416	1.00455

Fuel LHV - Btu/lb	Fuel H/C 5.333
19811	1.01395
21670	1.00980
23834	1.00581

Fuel LHV - Btu/lb	Fuel H/C 5.636
19966	1.01576
21961	1.01140
24313	1.00719

Fuel LHV - Btu/lb	Fuel H/C 6.000
20141	1.01777
22293	1.01316
24866	1.00872

NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

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24A-167 Rev A
Sheet 39

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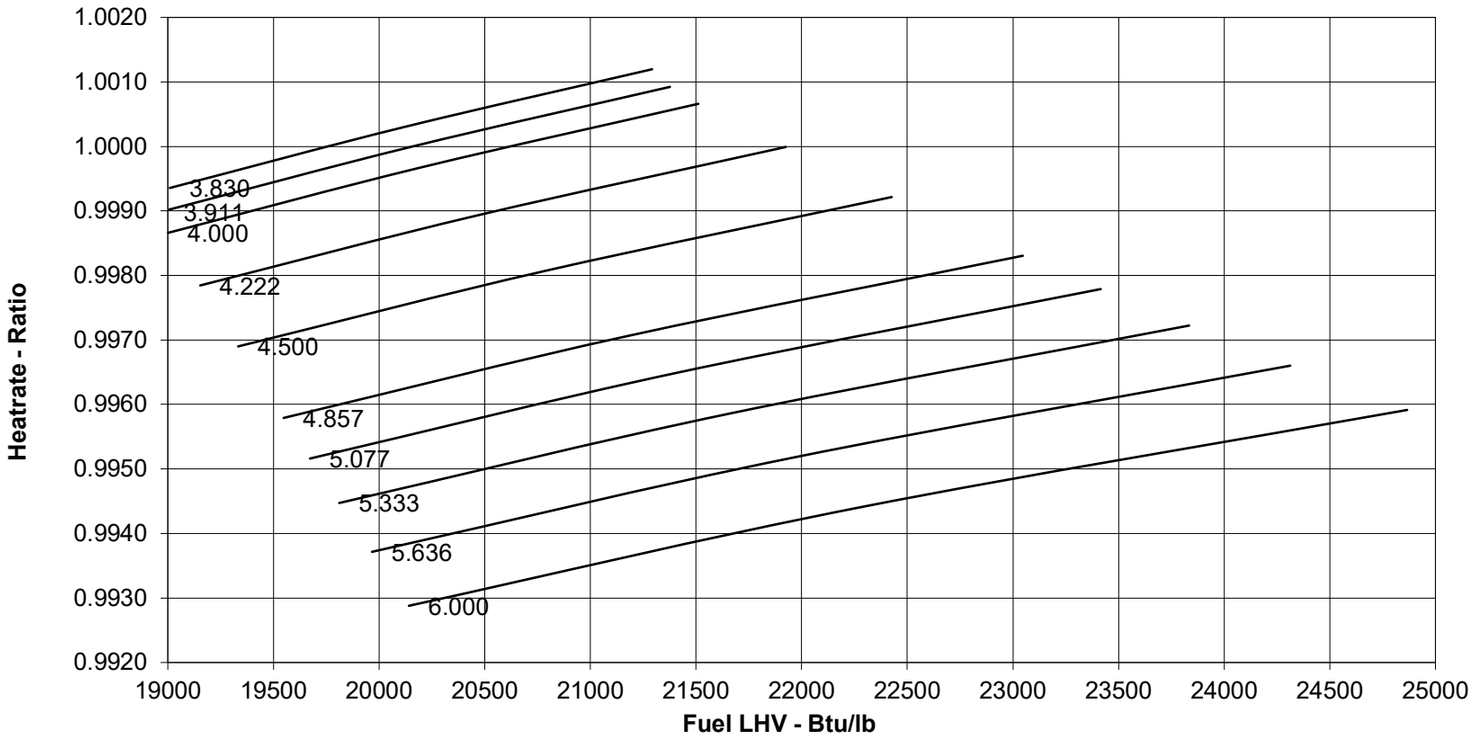
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Gas Fuel Composition on Heat Rate
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Fuel LHV - Btu/lb	Fuel H/C 3.830
19010	0.99936
20122	1.00030
21292	1.00120

Fuel LHV - Btu/lb	Fuel H/C 3.911
19006	0.99902
20159	1.00000
21377	1.00092

Fuel LHV - Btu/lb	Fuel H/C 4.000
19002	0.99866
20199	0.99967
21511	1.00066

Fuel LHV - Btu/lb	Fuel H/C 4.222
19154	0.99785
20468	0.99893
21925	0.99999

Fuel LHV - Btu/lb	Fuel H/C 4.500
19333	0.99690
20790	0.99807
22426	0.99922

Fuel LHV - Btu/lb	Fuel H/C 4.857
19548	0.99579
21182	0.99706
23047	0.99831

Fuel LHV - Btu/lb	Fuel H/C 5.077
19673	0.99516
21412	0.99649
23416	0.99779

Fuel LHV - Btu/lb	Fuel H/C 5.333
19811	0.99447
21670	0.99587
23834	0.99722

Fuel LHV - Btu/lb	Fuel H/C 5.636
19966	0.99372
21961	0.99518
24313	0.99660

Fuel LHV - Btu/lb	Fuel H/C 6.000
20141	0.99288
22293	0.99442
24866	0.99591

NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

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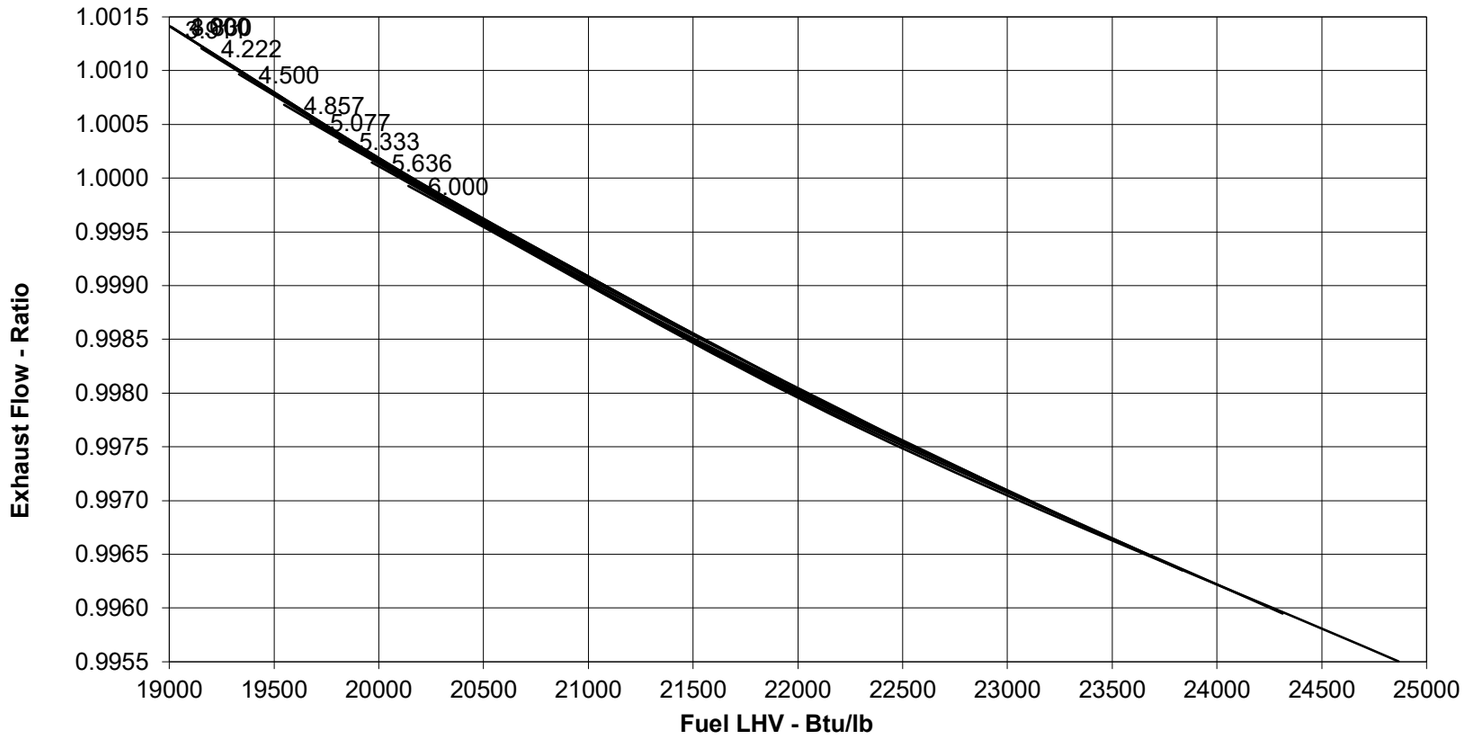
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Gas Fuel Composition on Exhaust Flow
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Fuel LHV - Btu/lb	Fuel H/C 3.830
19010	1.00141
20122	1.00004
21292	0.99877

Fuel LHV - Btu/lb	Fuel H/C 3.911
19006	1.00141
20159	1.00000
21377	0.99868

Fuel LHV - Btu/lb	Fuel H/C 4.000
19002	1.00141
20199	0.99995
21511	0.99854

Fuel LHV - Btu/lb	Fuel H/C 4.222
19154	1.00121
20468	0.99964
21925	0.99812

Fuel LHV - Btu/lb	Fuel H/C 4.500
19333	1.00097
20790	0.99927
22426	0.99763

Fuel LHV - Btu/lb	Fuel H/C 4.857
19548	1.00068
21182	0.99883
23047	0.99705

Fuel LHV - Btu/lb	Fuel H/C 5.077
19673	1.00052
21412	0.99858
23416	0.99671

Fuel LHV - Btu/lb	Fuel H/C 5.333
19811	1.00034
21670	0.99831
23834	0.99635

Fuel LHV - Btu/lb	Fuel H/C 5.636
19966	1.00015
21961	0.99801
24313	0.99595

Fuel LHV - Btu/lb	Fuel H/C 6.000
20141	0.99993
22293	0.99767
24866	0.99550

NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

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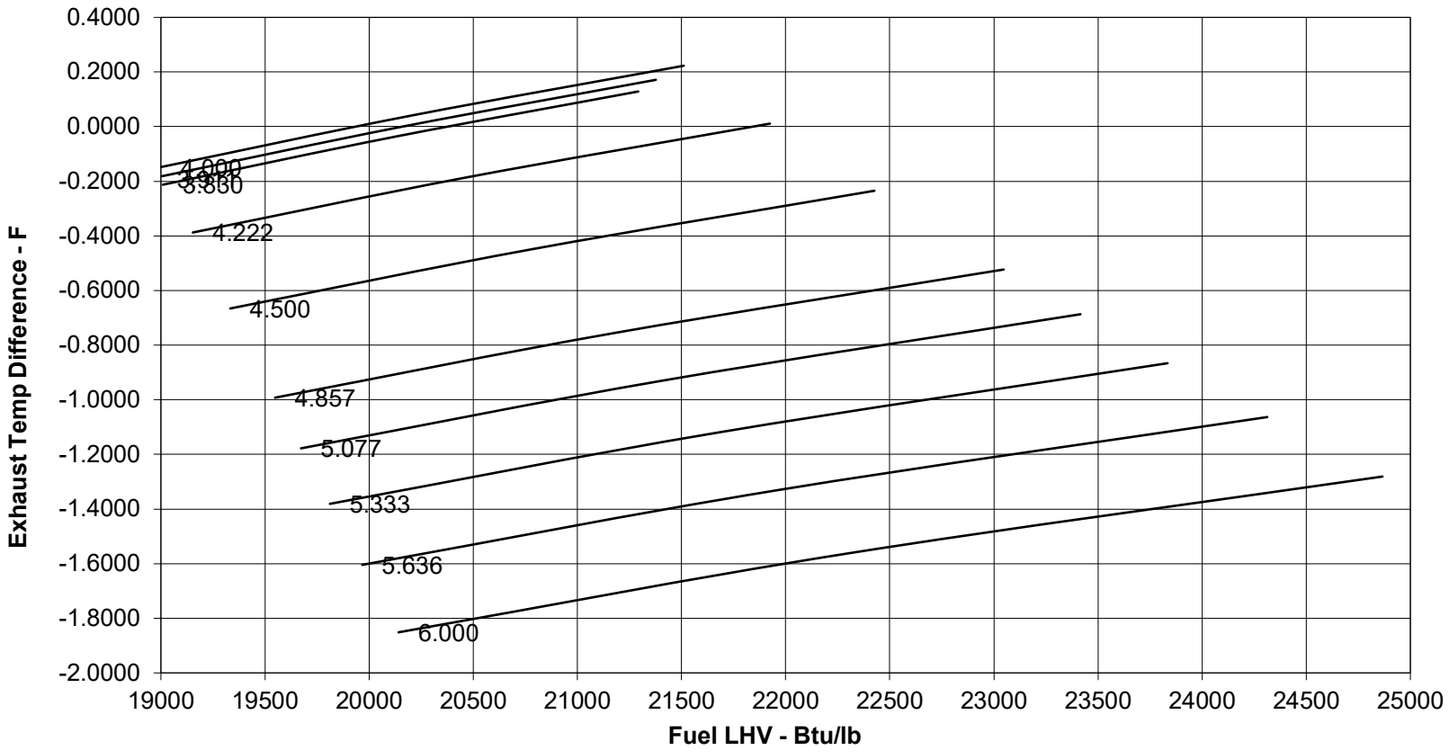
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Gas Fuel Composition on Exhaust Temperature
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Fuel LHV - Btu/lb	Fuel H/C 3.830
19010	-0.21257
20122	-0.03712
21292	0.12870

Fuel LHV - Btu/lb	Fuel H/C 3.911
19006	-0.18138
20159	0.00000
21377	0.17139

Fuel LHV - Btu/lb	Fuel H/C 4.000
19002	-0.14770
20199	0.03998
21511	0.22300

Fuel LHV - Btu/lb	Fuel H/C 4.222
19154	-0.38757
20468	-0.18583
21925	0.01102

Fuel LHV - Btu/lb	Fuel H/C 4.500
19333	-0.66578
20790	-0.44768
22426	-0.23478

Fuel LHV - Btu/lb	Fuel H/C 4.857
19548	-0.99235
21182	-0.75500
23047	-0.52313

Fuel LHV - Btu/lb	Fuel H/C 5.077
19673	-1.17787
21412	-0.92956
23416	-0.68689

Fuel LHV - Btu/lb	Fuel H/C 5.333
19811	-1.38103
21670	-1.12072
23834	-0.86619

Fuel LHV - Btu/lb	Fuel H/C 5.636
19966	-1.60445
21961	-1.33094
24313	-1.06333

Fuel LHV - Btu/lb	Fuel H/C 6.000
20141	-1.85141
22293	-1.56323
24866	-1.28112

NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

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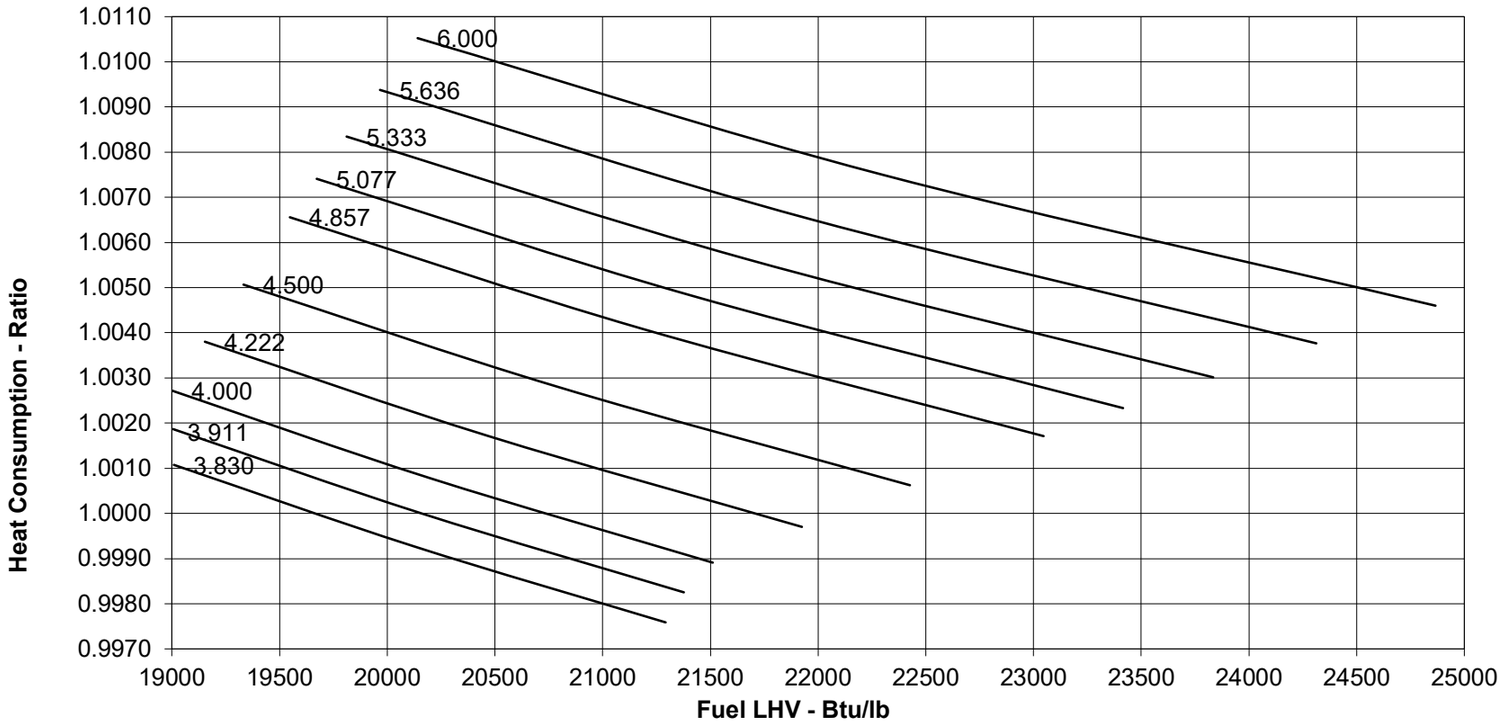
GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Gas Fuel Composition on Heat Consumption
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Fuel LHV - Btu/lb	Fuel H/C 3.830
19010	1.00108
20122	0.99927
21292	0.99759

Fuel LHV - Btu/lb	Fuel H/C 3.911
19006	1.00187
20159	1.00000
21377	0.99825

Fuel LHV - Btu/lb	Fuel H/C 4.000
19002	1.00272
20199	1.00078
21511	0.99891

Fuel LHV - Btu/lb	Fuel H/C 4.222
19154	1.00380
20468	1.00172
21925	0.99970

Fuel LHV - Btu/lb	Fuel H/C 4.500
19333	1.00507
20790	1.00281
22426	1.00062

Fuel LHV - Btu/lb	Fuel H/C 4.857
19548	1.00656
21182	1.00409
23047	1.00171

Fuel LHV - Btu/lb	Fuel H/C 5.077
19673	1.00741
21412	1.00482
23416	1.00233

Fuel LHV - Btu/lb	Fuel H/C 5.333
19811	1.00834
21670	1.00563
23834	1.00301

Fuel LHV - Btu/lb	Fuel H/C 5.636
19966	1.00938
21961	1.00652
24313	1.00377

Fuel LHV - Btu/lb	Fuel H/C 6.000
20141	1.01052
22293	1.00751
24866	1.00460

NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

David Walters
06/20/25

24A-167 Rev A
Sheet 43

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MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Generation O&M Expense
For the Years 2022 through September 2025
($000's)

Case No.: U-21870
Exhibit No.: A-201 (RTB-23)
Page: 1 of 4
Witness: RTBlumenstock
Date: October 2025

2022 Emergenent Reliability Expense

Description	Cost ('000's)	Details	Site	Month
JHC1 Boiler safety Programs FAC inspection	$ 120	broke fix	BESS	Jan
Hydro - Croton Shoreline Structure Compliance	$ 40	Funding needed to get property owners to sign easement, open house at township, real estate agents and potential for legal fees if easement isnt signed	Hydro	April
Hydros Update innundation maps	$ 42	Increase in scope of the AuSable Dam Breach Study and innudation maps. If we wait until 2023 it will be more expensive, consultants are avalable this year to complete the work, it is related to public safety. This funding will lower 2023 budget needed	Hydro	aug
Hydro - Croton Shoreline Structure Compliance	$ 25	Additional funds to cover real estate costs for getting easements signed. (122 of 206 signed)	Hydro	aug
Hydros Relief Well Piezometer Cleaning - WE	$ 64	Asking for funds to use for Waste Elimination	Hydro	Feb
Hydro - Hardy Chimney Repair	$ 175	Emergent request approved via email on 6/7/2022	Hydro	June
Hydros Annual FERC Dam Safety Requirements including Part 12 Inspections	$ 13	Moving funds from Tippy Powerhouse apron monitoring	Hydro	June
Hardy - new HQ building - IT costs - request from checkbook	$ 11	IT Costs ($6500 for phones/equipment; $4,100 for labor to move people in/close project)	Hydro	March
Hydro - Hardy - Replace U3 Penstock Expansion Joints	$ 13	Expansion bolts are rusted and cannot be adjusted, and the joint is leaking large amounts of water into the sump area, which is an environmental concern. Solution is to cut out old bolts and replace with new	Hydro	Nov
Hardy Hydro Embankment Stabilization	$ 47	Emergent CL approved on 9/14/2022 - Significant erosion on the embankment, there are drainage issues that need to be corrected to protect the integrity of the dam. The project will include various tasks to successfully execute the repairs.	Hydro	sept
Jackson - extra work/broke fix spring outage - emergent request	$ 197	Approved emergent via email on 4/15/2022	JGS	April
JGS Base Outage-Boiler Plant Equipment	$ 105	Broke/fix items discovered during plant outage. 7EA Duct Liner Plate&Diffuser Crack Repairs/LM6 turbine Exhaust Damper Repair/East Sky Vent Control Vavle Repairs	JGS	April
ST8 EHC Restoration-Major Maint	$ 215	The unit will continue to carry a minimum 15 MW derate without the clean & rinse flush, actuator rebuilds, and accumulator rebuilds. If the system and fluid are left in their current state, the gelling condition will have an increasing effect on other parts of the system. The effect will be a larger derate and possibly removing the unit from service (105 MW derate) until the clean & rinse flush, accumulator rebuilds, and actuator rebuilds are performed. JGS Spring Outage	JGS	Feb
JGS Cooling Tower Expansion Joints	$ 35	broke fix	JGS	Jan
JGS Base Outage-Boiler Plant Equipment	$ 190	Request for increased scope in Spring outage and contractor additional charges on POs for Fall 2021 outage work.Net with return from PP-10065	JGS	March
JGS - ST8/9 EHC Restoration	$ 175	The EHC fluid is highly degraded and beyond it's useful life. This EHC fluid and the varnish in the system could take off unit 9 causing up to a 105 MW derate. This issue needs to be addressed during the outage before it takes itself offline unexpectedly. This needs to be addressed in the spring 2022 outage.	JGS	March
JGS Non-LTSA Turbine and jet engine repairs	$ 150	Request of funding for write off to O&M. Fuel Nozzle work completed in 2018. GE provided parts. Install charges need to be moved to MM. Net request	jgs	Nov
JHC2 Turbine Valve Inspection	$ 62	Site approved CL to transfer funds between JHC U2 O&M projects.	JHC	April
JHC 3 Environmental SCR UBAS Nomnals, net of muni credit of $9k	$ 131	In need of 2 additional reactor cleanings at 70k each. Given the increase in dispatch on units 2 and 3, we are exhausting reactors faster than expected. The units remain at full load without dispatching down at night.	JHC	aug
JHC2 Turbine Valve Inspection	$ 68	True-up. Project received final acceptance. Net zero changelog for JHC Cap.	JHC	aug
JHC Site Plant Managed MM true ups, net of muni credit of $4k	$ 43	See note embedded in this cell/cleaning up ytd (over) under runs for site MM with internal cl and small request for balance.	JHC	aug
JHC 3 Forced Outage Funding	$ 93	Last request - needed 100k more than original request - pull from U3 Mill in November	jhc	Dec
JHC 3 Secondary Air Heater Cleaning, net of muni cr o $8k	$ 112	$150k approved in Jan BUG/New request Addl Env requirements	JHC	Feb
JHC2 Generator Overhaul and Rewedge	$ 310	Add'l GE and NB work associated with outage extension, SUT, and closeout.	JHC	Feb
JHC3 Outage Base-Boiler and Critical Maintenance, net of muni cr of $25k	$ 350	request as line item was pulled from ttfy 2022/2023 and this is a must have for break/fix/funded with JHC returns	JHC	Feb
JHC1 HEPS	$ 140	broke fix	JHC	jan
JHC1 NERC and Non-NERC PRC005 maintenance	$ 80	broke fix	JHC	Jan
JHC1 Transformer base maintenance	$ 100	broke fix	JHC	Jan
JHC2 Turbine Generator Inspection	$ 15	broke fix	JHC	Jan
JHC2 Turbine valve inspection	$ 15	broke fix	JHC	Jan
JHC3 BFP Turbine Inspection	$ 467	broke fix	JHC	Jan
JHC3 Secondary Air Heater Cleaning	$ 150	broke fix	JHC	Jan
JHC 3 - Fall Dive Inspection Intakes	$ 35	The 2022 dive inspection budget was wiped out due to the unexpected discharge nozzle replacements during the spring diving inspections. These inspections ensure the intake screens are clean for cooling water passage and intact, these reside in Lake Michigan.	JHC	July
JHC Deepwater Intake Screen Inspection	$ 75	During the spring dive inspections, numerous diffuser nozzles were found off of the dischaarge header and had to be replaced. This is public facing equipment that can affect Lake Michigan. Regulatory requirement per 316(a).	JHC	May
JHC3 Periodic Outage Major Maintenance	$ 109	Many issues identified during outage contributing to addl. spend. A few items include outage duration shortened and plant labor unable to complete priority 1 work requiring o/s. Multiple valves failed during shut down not previously part of outage scope. Scope growth of Eng inspections. Addl. work was identified to mitigate env. risk of bottom ash sediment entering water ways during online maint activities. All decisions based on reliability for summer months and Env issues.	JHC	May
JHC3 Forced Outage Funding	$ 154	Campbell unit 3 tripped offline 11/14. As a result of the trip, we lost steam supply to UBAS and as a result plugged up the crossover line requiring clearing. During the trip, steam from the turbine seals impacted the turbine turning gear motor and will require it to be sent off site to be inspected and baked out to dry. We need explosive deslagging at least around the burner opening to remove the eyebrows to support improved combustion once back online. There are a number of priority 1 balance of plant work orders that we need to utilize contracted support to complete. We learned we need to purchase additional turbine oil due to water intrusion and we had to pull parts out of stock for our opacity monitor.	jhc	Nov
JHC 2 Forced Outage - boiler leak	$ 100	Unit 2 has a suspected boiler leak in the south wall of the furnace. We need to access the ashpit, erect scaffolding and likely hang a sky climber to access the leak and contracted labor to deslag the boiler. $50k for tube leak repairs and $50k for boiler deslag.	jhc	Nov
JHC 3 Forced Outage - boiler leak	$ 280	Unit 3 There is a confirmed boiler leak. This will require contracted labor to erect scaffolding, hang a sky climber for access and make the repairs to the boiler leak(s). This will also require explosive deslagging to be performed to provide safe access into the furnace area. Additional costs include our own NDE resources for QA/QC and then balance of plant repairs while the unit is offline. This is unrelated to the most recent U3 forced outage. $200k for boiler repair, $55k for deslag, $10k for NDE, and $15k for BOP repairs & misc.	jhc	Nov
JHC FH Coal Pile Runoff Pond Cleaning, net of muni cr of $5k	$ 137	Coal Pile runoff minor issue turned into total pond cleaning using funds from chute liner repairs	jhc	Oct
JHC 3 2023 Periodic outage, net of muni c r of $1k	$ 19	Learned in 2022 Spring Per outage Linear amplifiers for communicatoin to sub station must be replaced in 2023 outage or sooner if forced outage. Had to order for lead time and to have at first available opportunity to install. Also needed ACI lances same scenario	JHC	sept
JHC 2 Periodic outage	$ 130	Due to downlever funds depleted and will not be able to do U2 priority 1 outage work in fall outage. Needs: fumace backpass cleaning 86k, priority 1 PA fan bearings, DA safety reliefs, APH bearings, 201A valve, scaffolding 34k/covered by forced outage return	JHC	sept
JHC1 Boiler Safety Programs FAC Inspection	$ 50	Changelog in August was entered in error as return of $25k. Should have been a request of $25k so September Changelog is request of $50k to true-up this project and adjust for error	jhc	sept
JHC 2 2021/20212 Periodic outage	$ 85	Invoice error for U2 2021 fall/2022 continued spring outage hit Aug, 2022 Project had been trued up in July and no way to cover. Mistake was thought this was covered in another project./using forced outage funds above	jhc	sept
JRW Ash Pond Post-Closure Care	$ 16	Net $0 transfer of $8K from PT-10990 Karn Lined Impoundment and $8K PT-10993 - JCW Landfill Inspections to cover Fees	jrw	Oct
Karn 1 Oil Spill	$ 200	New MM project PT-50108 for ICS Karn 1 Oil Spill. Funds transferred from BPS # 9585	Karn	April
Karn 2 Forced Outage	$ 230	New MM project PT-50107 for Karn 2 Forced Outage. Funds transferred from BPS # 9587	Karn	April
Emergent - Karn 2 Whip the Byproduct Silo MM for SDA functioning	$ 50	Approved via email on 8/12	Karn	aug
Karn 1 Screen Drive and Boiler Repairs.	$ 250	Superheat air distribution damper - screen drive and gunite in reheat boiler. Boiler repair, brick repair and screen drive repairs	Karn	aug
Karn 2 Wet Coal removal from Mill	$ 75	Wet coal was loaded into the mills and brought the unit offline. Estimated $75k required to remove.	Karn	aug
Karn 3 Periodic Outage	$ 298	Funding CL101 and CL104 from internal transfers 1. K 3&4 Periodic Outage BPS 6263 ($250k) 2. K3 Boiler Repairs BPS 6256 ($75k) 3. K4 Boiler Repairs BPS 6026 ($75k) 4.) Karn Site Tank Inspections BPS 6090 ($135k). Net Ask from checkbook $85k for both projects. Scope: Boiler Repair Dead Air Space; Combustion Air Heater Repairs; Reheat Pendant Cleaning; Condenser Cleaning; Traveling Scrn / Pit Cleaning; BOP Work	Karn	aug
Karn 4 Periodic Outage	$ 322	Funding CL101 and CL104 from internal transfers 1. K 3&4 Periodic Outage BPS 6263 ($250k) 2. K3 Boiler Repairs BPS 6256 ($75k) 3. K4 Boiler Repairs BPS 6026 ($75k) 4.) Karn Site Tank Inspections BPS 6090 ($135k). Net Ask from checkbook $85k for both projects. Scope: Combustion Air Heater Repairs; Reheater Pendant Cleaning; Cooling Tower Forebay Cleaning; Condenser Tube Cleaning; HP Turbine Brg #1 Inspection; BOP Work	Karn	aug
DEK 2 Mill Maintenance Materials	$ 152	Requesting funding for Karn 2F ($75k) and 2C ($77k) Mill repairs	Karn	Dec
DEK 2 Mill Maintenance Materials (3 mills)	$ 450	Repair of emergent grinding zone of Unit 2 Mills 07-09 through 07/16/2022.	Karn	July
Karn Conveyor Repairs (12A &18)	$ 67	To fund Karn Conveyor Repairs 12A and 18 using funds from JH Campbell U2 forced outage	Karn	June
Karn 1 Steam Leak Outage	$ 100	To fund Karn 1 Steam Leak Outage PT-60091 using funds from JH Campbell U2 forced outage	Karn	June
Karn 1 Online Steam Repair	$ 40	To fund Karn 1 Online Steam repair PT-60096 using funds from JH Campbell U2 forced outage	Karn	June
Karn 4 Cooling Tower Fore Bay Cleaning/CCWP Cavitation	$ 30	To fund Karn 4 Cooling Tower Fore Bay Cleaning/CCWP Cavitation using funds from JH Campbell U2 forced outage	Karn	June
Karn 3 Cooling Tower Fore Bay Cleaning/CCWP Cavitation	$ 30	To fund Karn 3 Cooling Tower Fore Bay Cleaning/CCWP Cavitation using funds from JH Campbell U2 forced outage	Karn	June
Karn 1 - Forced Outage - Boiler Repair	$ 130	To fund PT-60085, Karn 1 - Forced Outage - Boiler Repair using Forced outage funds BPS ID: 6071.	Karn	June
Karn 2 Hold (K2 Boiler Leak Repair Outage)	$ 199	Funding with cost underruns from PT-60084, PT-60083, PT-50108	Karn	May
Karn 3&4 Maintenance Outage	$ 30	Funding project with Karn forced outage funds 6071	Karn	May
K3&4 4B ID Fan Balance Repairs	$ 10	Funding project with Karn forced outage funds 6071	Karn	May
Karn 1 Forced Outage - Boiler Leak	$ 230	Funding project with Karn forced outage funds 6071	Karn	May
Karn 1 Maintenance Outage	$ 105	Net zero transfer of $52.5K from PT-60093 Karn 3 Periodic outage and $52.5K from PT-60094 Karn 4 Periodic outage	Karn	Nov
Karn 2 Boiler Tube Leak	$ 125	Funding request to repair boiler tube leak at Karn 2	Karn	Nov
Karn 1&2 Maintenance - Demand	$ 20	Net $0 transfer of $20K from PT-11134 to DEK1&2 Maintenance to help cover cost of Vacuum Exhauster.	Karn	Oct
Karn 2B Mill Classifier Shaft	$ 230	Contracted labor and B&W service representative and parts & materials to rebuild the 2-D mill grinding zone and 2-B mill classifier	Karn	Oct
Karn 2 Atomizer rebuild- bearings- key components	$ 35	Net zero budget transfer of $35,000 from BPS 6163 PT-10982 Karn 1 SDA Atomizer Rebuild to cover atomizer wheel rebuild costs per Tashia Walraven	Karn	sept
Karn 1 Maintenance Outage	$ 70	Net zero $ request to fund Karn 1 Maintenance Outage EHC System Flush (expanded scope); Funding coming from PT-60094 $14,493, PT-11059 $7,454, PT-10945 $10,000, PT-11112 $3,482, PT-60085 $31,721, PT-50108 $2,850	Karn	sept
Karn 2 Forced Outage August 2022 (Wet Coal in Mill) (CL103 $75,000 on August CL)	$ 37	Net zero $ request to fund Karn 2 Forced Outage (Expanded Scope) EHC System/Valve Replacement	Karn	sept
Karn 2 Maintenance Outage Oct 2022	$ 250	Net zero $ request to fund Karn 2 Maintenance Outage for Boiler Fouling / EHC Flush. Funding coming from Ops 1&2 Normals Labor/OT $75k, Ops 3&4 Normals Labor/OT $25k, PT-10984 $25k, PT-10945 $60k, PT-10944 $25k, PT-60095 $30k, PT-60091 $10k	Karn	sept
LPS U2 Penstock Study	$ 15	broke fix	LPS	Jan
LPS Operations, net of muni credit of $37	$ 38	Oil Water Separator cleaning and investigation of release to LPS tailrace Jan 14	LPS	March
LPS Unit 3 Lower and Upper Expansion Joint Repacking, net of muni cr of $6k	$ 6	Moving funds from LPSP FERC Dam Safety to extend monitoring	LPS	March
ZGS CO2 Isolation System Block/Bleed	$ 40	Install a better CO2 isolation system, double block and bleed for gas turbine CO2 systems making it safer and easier for Ops to tage out the gas turbines./fund internally with 4160 V Motor funds	ZGS	April
ZGS Deep well cleaning	$ 350	broke fix	ZGS	Jan
Emergent - Zeeland main steam bypass failure	$ 175	Emergent approved on 11/9/2022 - We discovered a steam leak on one of the large-bore piping systems. This is in the 20" main steam to cold reheat bypass line. We can see steam coming out from beneath the insulation and lagging. We had a similar failure in 2012.	ZGS	Nov
Zeeland 2C GSU	$ 120	Emergent CL approved on 9/14/2022 - GSU gassing trending towards failure - need to troubleshoot and inspect immediately	ZGS	sept
	$ 9,452			

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-201 (RTB-23)
Page: 2 of 4
Witness: RTBlumenstock
Date: October 2025

Consumers Energy Company
Generation O&M Expense
For the Years 2022 through September 2025
($000's)

2023 Emergenent Reliability Expense

Description	Cost ($000's)	Details	Site	Month
Battery Projects - O&M Costs	$ 6	Moving funds from #12797 to put all Battery funds in one area.	BESS	Mar
Covert Gas - 2B Circ water pump motor and the HRSG	$ 168	Emergent approval via email on 8/8/2023; HRSG is $100k; motor is $68k	CGS	Aug
Emergent - CGS HP Steam leak repair	$ 30	Repair HP Steam leak on unit 1	CGS	Oct
Emergent247 Covert Normal O&M	$ 200	Due to unforseen expenditures like Asset Mgmt Agreement with USPG, Software agreements and acquisition costs (not capital) we are in need of funds to support on-going day-to-day operations. Eartier this year, funding was returned for PSCR dollars and the $125M challenge.	CGS	Oct
Emergent246 Covert Fall Outage	$ 300	Need funding to cover the fall outage. Dollars were returned earlier this year for the $125M initiative under the assumptions that there would be enough funding under Normals to cover MM fall outage. Due to unforseen expenditures, those funds are no longer available.	CGS	Oct
5971 Hydros License Initiatives	$ 50	Increase in cost related to fixed payments forcing us to go over budget. This $50,000 puts us back to our original amount before the cut.	Hydro	April
Hydro - Hardy Units 2&3 Expansion Joint Leak Repairs	$ 112	The Hardy Generation Station Units 2&3 have expansion joints that have significant water leakage, causing our sump pits to fill up very rapidly <8 hours requiring pumping. However, due to the Mio oil spill, we cannot run the sumps in automatic. If we get a high sump alarm, we need to call in operators to manually pump down the sump. We have tightened up on the packing as far as we can, and did not solve the issue. Therefore, we need to repack the joints, we have contracted cost of $90,000, our internal team is just not skilled enough to complete this evolution.	Hydro	Feb
Hydro Tippy Headquarters Maint	$ 64	Headcount misaligned during budgeting transfering from Croton.	Hydro	Feb
Hydro - Croton - Hazardous Waste Removal	$ 20	Hazardous waste removal from Croton basement.	Hydro	Feb
Hydro - Croton Station Unit 4 Collector Ring Repairs	$ 24	Appr BUG	Hydro	Jan
9924 Hydro Croton Headquarters Maint	$ 21	Funding needed to cover oil sheen clean up at Croton	Hydro	July
9761 Hydro Croton Headquarters OPS	$ 11	The renewables safety action team has a human struggle elimination campaign ongoing. As a part of the campaign an ergonomic evaluation was completed at Hardy. It was noted that the penstock access covers and oil tank covers were a major safety concern due to the weight of the covers. This funding will be used to replace the covers to a more ergonomic friendly material that will still maintain their integrity	Hydro	July
5973 Hydros Annual FERC Dam Safety Requirements including Part 12 Inspections	$ 39	This is to replace the downstream dive that was determined to not be safe based on Diver Dan's past experiences. Also something we want to start utilizing more (ROV), with potential for CEC purchasing a better unit for in-house. However, we have limited time this year to complete the inspection because it's tied with our 2023 Part 12; hence, will need contractor support this year.	Hydro	July
5960 Hydros Concrete Repairs	$ 35	Fisher is currently working on Croton Bear Trap repairs. After removing vegetation from the bear trap, water was observed leaking from some of the joints. In order to seal the joints, they need to stop the leaks first with chemical injections. They also observed a few other old patch areas that are failing and would be beneficial to repair at the same time.	Hydro	June
Hydro - Croton Shoreline Structure Compliance	$ 20	Funding needed to cover additional cost of getting landowners to sign easements so that we will be in compliance.	Hydro	Mar
9928 Hydro Five Channels Headquarters Maint	$ 16	Charges from the Foote Auto Voltage Regulator capital project were deemed to be O&M, project was commissioned twice caused by a premature failure. Funding needed to cover the transfer in costs.	Hydro	Nov
Emergent279 Hydro - Loud unit 1 cracked shifting ring	$ 25	The loud unit 1 shifting ring was found to be cracked during the periodic inspection . The crack will eed to be stitched together in the field before the unit can be rewatered and returned to service. Costs are for machine shop to come to site, perform the stitching, as well as confined space rescue. If the work is not compeilted, the unit can not be rewatered or retruned to service due to risk of a ring failure and uncontrolled release of water into the plant.	Hydro	Oct
5917 JGS Base Outage-Boiler Plant Equipment	$ 170	Request of funding for Fall outage work scope. Duct Burner Ignitor Sleeving - $60k. CCW Heat Exchanger Cleaning - $64k. Glycol Heat Exchanger Washer Installation - $6.2k. LM1-6 MTGB Panel Access Mods - $22k. Lube Oil Cleaning - $10.5k. STG Bearing Inspect/Repair (TIL) - $25k	JGS	Aug
6046 Jackson Capacity Factor Used For Water and Chemicals	$ 200	Request of funding to cover projected water spend for August 2023. Current forecasted dollars is $75k. Total projected spend $275k	JGS	July
JGS Base Outage-Boiler Plant Equipment	$ 100	Request of funding.	JGS	Mar
JGS Plant Chiller Fouling - MM	$ 40	Request of funding.	JGS	Mar
Jackson Long Term Service Agreement - Running Maintenance Contract -MM	$ 100	Request of funding.	JGS	Mar
JGS 8 Condenser Cleaning and Eddy Current Testing	$ 26	Set funding back to zero. Funding was taken twice in January reductions.	JGS	Mar
JGS 9 Condenser Cleaning and Eddy Current Testing	$ 26	Set funding back to zero. Funding was taken twice in January reductions.	JGS	Mar
5918 JGS Non-LTSA Turbine and jet engine repairs	$ 100	Request of funding. GT7 S17, EGV 1, EGV 2, Stator Segment Damage Repair - Hook Fit Damage	JGS	Sept
JHC 2 Forced Outage Funding	$ 67	Requesting site keep returned funds from the completed Recycle Slurry Storage Tank to help maintain small forecast for future forced outages	JHC	Feb
JHC1 Forced Outage Funding	$ 67	Requesting site keep returned funds from the completed Recycle Slurry Storage Tank to help maintain small forecast for future forced outages	JHC	Feb
JHC3 Forced Outage Funding	$ 67	Requesting site keep returned funds from the completed Recycle Slurry Storage Tank to help maintain small forecast for future forced outages	JHC	Feb
JHC 3 Environmental SCR UBAS	$ 124	Due to budget cuts only 1 reactor cleaning was left in plan however known that two more are required. JHC has mitigated approximately 40k however request is to fund the balance of two reactor cleanings.	JHC	Mar
JHC - fund program shortfalls	$ 335	Various program shortfalls - funded via waste elimination returns	JHC	Mar
Emergent - JHC 3 Boiler Leak	$ 350	Approved emergent via email on 5/16	JHC	May
9645 JHC3 Forced Outage Funding	$ 481	**This is an emergent request** JHC 3 will need to take a forced outage to complete backpass cleaning in the reheater section to eliminate a 40MW derate and eliminate the potential for a reheat tube leak due to accelerated flyash erosion. Aside from the back pass cleaning, the furnace will be deslagged, 3 boiler safety valves will be repaired, and work to repeair multiple non-return check valves will be completed. There is other high priority balance of plant work that will be completed.	JHC	Nov
5460 JHC FH Dumper Outage Repairs	$ 50	From Dan Balt: Using quote from the last time that this cable was replaced as a preventative measure in 2018. Emergent repair - this particular component was on a 5 year replacement cycle to prevent this exact event from happening. These are the main reasons why we need to pursue getting a replacement and why the Positioner is important to the operation of the Unit 3 Dumper: -It allows for automated car unloading, nearly eliminating operator error and judgement, which has in the past caused significant car damage. oCar repairs can be greater than $100k oCan also cause additional damage to the Unit 3 Dumper Table and drive. -When the Positioner has been out of service, many times, Operators use the Retarders (Dumper table component) to stop train movement when moving cars across the table. oPositioner eliminates the manual use of the Retarders. oDamage to any of the 4 Retarders can cost up to $30k each if the whole assembly were in need of replacement.	JHC	Nov
5535 JHC FH Normal Maintenance	$ 43	Funding depleted in FH normal maint for track repairs. Emergent need to replace track switch heaters after fall inspection.	JHC	Nov
Emergent210 Campbell Battery Energy Storage (BESS)	$ 150	Funding is needed to complete engineering ($85k) and submit a MISO deposit ($65k) to install a 750MW/3000MWh BESS at the Campbell site.	JHC	Sept
Emegent242 JHC Misc MM over runs	$ 93	Request to use Dumper Outage MM funds to cover site MM over runs. Give back of Dumper outage would net this request to zero.	JHC	Sept
9210 Karn Results	$ 150	With the closure of Karn 1&2, D.I. Water Trailer will be required for Karn 3&4. Estimating $25K per month July - December. $150,000 total.	Karn	July
Emegent - Karn 3 Boiler Leak Repair	$ 20	Repair K3 Boiler leak to make unit available	Karn	Oct
13294 LPS Commons Gen Circuit Breaker Pumping Pole Maint	$ 87	Project True up transferring funds from Fish Barrier Net Installation project.	LPS	April
9822 LPS Maintenance Demand Break/Fix (67.7%)	$ 72	Requesting funds from MM project returns to cover over runs in Maint spending. The over runs are related to funding being pulled earlier in the year.	LPS	Aug
LPS National Compressor Hanwha Service DAC 3/4	$ 15	New compressors were installed and went into service late 2021. There was not major maintenance project setu p to account for their required service intervals to maintain the equipment. The changelog is to support alignment of MM funding to maintain the under warranty compressors while we work to create a MM project to account for this maintenance going forward.	LPS	Feb
13294 LPS - Commons Generator Circuit Breaker Pumping Pole Maintenance	$ 9	Funding needed to complete install of pumping poles. This will offset some of the return from the downlever earlier in the year.	LPS	June
LPS U4 Governor oil pump replacement	$ 36	We are seeing indication that the governor oil pump installed November 2022 is failing in the same fashion it was replaced in November. Gen Planning is working with the pump vendor on a root cause. This will be an O&M replacement / repair as the installed unit has not been in service over 24 months.	LPS	Mar
LPS County Road Commission repair	$ 13	Drain repair and cleanout on the lakeshore drive bridge that we must have the county road commission repair.	LPS	Mar
9822 LPS Maintenance Demand Break/Fix (67.7%)	$ 38	Oil Sheen clean up came in higher than planned.	LPS	Nov
13294 LPS Commons Generator Circuit Breaker Pumping Pole Maintenance	$ 86	This project had a reduction earlier in the year, part of the company challenge reductions. The parts for this project had already been pulled out of stock, causing this project to be over budget. We were unsuccessful in checking the parts back in stock. Funding will get the project back on budget.	LPS	Nov
Emergent - LPS oil sheen recovery	$ 79	Emergent email on 10/2: Due to the recent ICS at Ludington related to the oil sheen recovery plan, we have an emergent O&M changelog request for $79k in CE Major Maintenance (MM) for the clean-up and the baffle wall (not determined to be capital).	LPS	Oct
10547 ZGS 345kV Bkr 177 277 Maintenance	$ 15	Project pushed to 2024 however our ask is to keep $15K total in the 2023 budget for our agility to address/mitigate potential risks as these moving schedules may allow. We would like to perform the latch checks on the 299 in spring (using this funding) to mitigate risk of pumping on and potential damage to the 1B GSU prior to the 299 breaker replacement fall of 2024 (we performed similar on 199 when mobiles were landed in spring 2022). Note from Saroni Brahma	ZGS	April
6601 ZGS Base Outage Funding-Boiler Plant Equipment	$ 230	No funding for fall outage we have returns to offset all but 55k of this request. Please see Jason's note below regarding needs. We have several valves that need repaired in the facility. Both HRSG main steam attemperators, HRSG 2A hp steam dump and 2A CRH main iso valve that has a bad packing leak. There is also a need for some contingency money for discoverable items, line supervisor OT for outage support and operator OT for FIN evolutions. All items are high risk rated.	ZGS	Aug
Zeeland Generating Station - Operator Bonus	$ 66	Request to use changelog giveback for the HP Economizer Feed Reg Valve overhaul for the Zeeland bonus. Bonus was not accrued due to misunderstanding on timing of cancellation of bonus program.	ZGS	Feb
ZGS - Bus Suppt & Services Non Labor	$ 13	Use Zeeland give back of Economizer Feed Reg Valve overhaul to cover a portion of training needed to prepare newer staff to take on responsibilities of those close to retirement. Total need 35k however site to attempt to mitigate balance.	ZGS	Feb
6601 ZGS Base Outage Funding-Boiler Plant Equipment	$ 87	May downlever higher than balance of plant funds in project. Need to replenish site with overage.	ZGS	June
6601 ZGS Base Outage Funding-Boiler Plant Equipment	$ 30	Jason Ricketts - We have discovered a few MM outage items that have caused our base outage funding needs to grow to approximately $300K. Those items are the RO carbon filters have extreme bio fouling and need to have all of the media replaced. We also had 10 HRSG drain valves fall out and need to be chopped and swapped. At this time, I estimate that we will need a $30K change log to cover	ZGS	Nov
6601 ZGS Base Outage Funding-Boiler Plant Equipment	$ 90	Scope covered internally with itsa give back. Latest outage numbers due to inline drain valve repairs. Planning and inspections still underway and potential risk still unkown and will be disclosed with inspection outcomes.	ZGS	Oct
Totals =	$ 4,866			

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-201 (RTB-23)
Page: 3 of 4
Witness: RTBlumenstock
Date: October 2025

Consumers Energy Company
Generation O&M Expense
For the Years 2022 through September 2025
($000's)

2024 Emergenent Reliability Expense

Description	Cost (000's)	Details	Month	Site
Gen Ops - Covert Steam Sampling System Repair	$ 25	True-up of project costs	nov	COS
PP-10218 Covert U 3 HP Steam Leak Repair	$ 45	True-up of project with funds from the NERC Relay/DC Testing Compliance & Capacity Factor Projects.	sep	COS
Gen Ops - Covert 2B Circulating Water Pump O&M	$ 55	Additional cost of installation of modified pump.	nov	COS
Emergent35 Covert 1A Circulatine Water Pump	$ 60	Need funding for repair of 1A Circulating Water Pump	Feb	COS
12825 Covert - HEPS/FAC/DAST Inspections	$ 65	Need for developing plan and drawings.	Jan	COS
Emergent138 Covert ABT Discharge Line Repair	$ 65	The leak is below ground, and we are expecting to do the excavation. We discovered the leak when water started bubbling up. The biggest concern is that the temporary discharge line goes across the road where there is a potential for it to be damaged. We have to dig down several feet to find and repair the leak. This needs to be done prior to the fall outage.	June	COS
Emergent328 Overhaul 2A circ water pump	$ 70	Brokerfix	Jan	COS
Emergent36 Covert 1B Circulating Water Pump	$ 75	Need funding for repair of 1B Circulating Water Pump	Feb	COS
6263 DEK3-4 Periodic Outage Major Maintenance	$ 100	Request of funding to replace $100k of $250k down lever pulled in May 2024.	June	COS
Gen Ops - Covert Unit 1 Steam Turbine Valve Repair	$ 121	True-up of project costs.	nov	COS
Covert 1B Circulating Water Pump	$ 127	True-up of 1B Circulating Water Pump project with funding from LTSA	Oct	COS
Gen Ops - Covert Unit 3 HRSG Harp Repair	$ 130	True-up of project costs due to discovery of broke fix	nov	COS
Covert 1A Circulating Water Pump	$ 137	True-up of 1A Circulating Water Pump project with funding from LTSA	Oct	COS
Gen Ops - Covert Unit 3 HRSG Harp Repair	$ 140	Additional need for funding due to discovery of brokefix and extended crane rental fees	nov	COS
Gen Ops - Covert Fall Outage	$ 165	True-up of project costs due to discovery broke fix and valve purchase $20k.	nov	COS
PP-10219 Covert Fall Outage	$ 170	Additional funding needed to address issues at the Covert Generating Station during the fall outage.	sep	COS
Covert 2B Circulatine Water Pump Modifications	$ 187	Need to removal, modify and install the 2B circulating water pump.	Oct	COS
Covert - 12823 Covert - Base Outage Funding MM -Boiler Plant Equipment	$ 200	Need to write PO's for CMI to do inspections on all 3 units. No funding left for fall outage due to circ water pump repairs.	Aug	COS
Emergent67 Covert SCR Cleanings	$ 250	Asking for funding to complete necessary SCR cleanings in 2024 for all 3 units.(note we cut this funding in 2023 and DP data shows it is required now in order to mitigate summer derate)	Mar	COS
EMERGENT - Covert Unit 1 Steam Turbine Valve Repair	$ 250	A recent inspection at Covert identified a crack on a high-pressure control valve bushing. These can become a very serious or dangerous issue and definitely take the unit offline when it fails. We need to address this issue immediately at our earliest outage of opportunity which is this fall to avoid safety and forced outage issues.	sep	COS
Emergent121 Covert 2B Circulating Water Pump O&M	$ 270	Need this pump replaced to return Unit 2 to full operation. $150k for the replacement pump itself from Kennedy since Dubric can't get us one in time (not covered under warranty). $120k for install, removal and modifications.	June	COS
12823 Covert - Base Outage Funding MM -Boiler Plant Equipment	$ 300	Request funding for Spring Outage for Oil flushes and SCR Cleanings pushed from 2023.	Feb	COS
Emergent123 Covert Unit 3 Reheat Crossover Pipe Project	$ 480	Covert Unit 3 experienced a leak in the HRSG reheat crossover pipe at the top of the unit. The location of the leak is 4 or 5 feet downstream of the reheat attemperator. Cut the old attemperator assembly out and rigg it down, fly the new assembly up into place, fit, weld, heat treat, NDE, and reinsulation on Unit 3 plus crane support.	June	COS
Covert - Emergent151 Covert Unit 3 Dropped Reheat Header Repair	$ 500	Work required to remove broken harp supports, provide temporary lifting gear for rigging and support steel to lift the harp to the original design location, lifting the harp, and repair and reinstallation of the harp supports.	Aug	COS
Emergent46 Croton 3 head plate crack repair	$ 10	Croton 3 Head plate cracked can leak contaminants back into river (Emergent/Regulatory)	Jan	Hydro
Emergent52 Alcona road and parking lot repair	$ 19	There is a 100 year centennial celebration this year at Alcona, and we will be hosting a public event at the site and we need to fix these areas for public safety.	Mar	Hydro
Emergent141 Hydro - Hodenpyl Rental Air Compressor	$ 27	Hodenpyl air compressor has failed. We need funds to cover a one month rental for air compressor. Transferring funds from Croton to cover.	July	Hydro
5971 Hydros License Initiatives	$36	Bruak Fix The inner upweller at Croton was found on the trash rack Mobiety to retrive, inspect repair and return upweller to proper location.	July	Hydro
Emergent51 Webber Debris clean-up	$ 40	Athor the recent runoff event, there is a large accumulation of woody debris we have to remove from the intake side of the Webber Hydro Station.	Mar	Hydro
Emergent352 Loud Left Spillway Wall Sinkhole Remediation	$ 50	Left Wall Sinkhole discovered during inspection in 2023. Repair needed to keep dam in safe operating condition. We will have to notify FERC of ground disturbance activities. Planning on using concrete/cement type materials to fix the issue. Scope is a little more than typical concrete project which is why we split it out but transferring funds from concrete repairs to cover.	Jan	Hydro
Gen Ops- License Int	$ 50	Review of water Temp Control Tech at Hardy and Croton (15K) & During the Archaeological shoreline inspection a new site was discovered. It required extensive work above the original estimate (35K)	nov	Hydro
Emergent114 Rogers Unit 1 Resurface Bearings	$ 63	Rogers Unit 1 needs some bearings replaced. It requires us to pull the turbine shaft to complete.	May	Hydro
5971 Hydros License Initiatives	$ 80	Funds needed for a cultural resource site inspection for the Manistee, Muskegon and Au Sable Rivers.	Feb	Hydro
5971 Hydros License Initiatives	$ 88	Shoreline study increased in cost more than we planned. Transferring funding from Alcona Unit 1 Concrete Repairs to cover.	May	Hydro
Emergent60 JGS Chiller Condenser Cleaning	$ 40	Tube cleaning is a necessary maintenance activity to maintain efficient heat transfer in the heat exchanger of the chiller. Tube cleaning needs to be performed annually to remove deposits and scale left behind by water. Inefficient heat exchange causes loss of efficiency and performance of chillers. The 4-chiller arrangement at the plant is marginal during the hottest periods of the year. Fouled heat exchangers make their heat transfer capability that more of a challenge. Chillers expend up to 30 percent in additional energy due to inefficiencies and poor maintenance. The more a chiller becomes fouled, the more energy it will consume and increase O&M costs.	Mar	JGS
Gen Ops - JGS Drift Eliminators	$ 54	Drift Eliminators material purchase. The drift eliminators are used to minimize water droplets and moisture going to the inlet plenum and on to the gas turbine as part of the inlet air to the turbine. The existing drift eliminators in the LM6000 filter houses are the original ones and are brittle and falling apart. Recent cooling coil performance testing by EPTS identified an average cooling coil efficiency loss of 15.9% from expected which is a reduction of total plant output of 2.85 MW under summer GVTC conditions. $100K expense in 2025 for the removal/replacement of the drift eliminators and cooling coil cleaning.	nov	JGS
12813 Jackson 9 Generator Stator Corona Repair	$ 70	GE provided us with a schedule that supports the fall's planned outage window to accomplish the ST9 generator corona repair. However, the window for AGTS would be need to be three days versus the six days AGTS outlined in their proposal and their PO was based on. To not affect the outage, we've gotten an updated proposal from AGTS which would complete their work in three days by doing two shifts. This would require a $51,284 MoC to their current PO.	July	JGS
5917 JGS Base Outage-Boiler Plant Equipment	$ 70	Request of funding. STG Bearing Work. Both bearing metal temperature thermocouples for the Unit 9 high pressure steam turbine have failed (i.e., reading faulty values). These thermocouples are critical indications that are part of the unit's turbine supervisory instrumentation that protect the unit from a bearing failure related to bearing wear by detecting temperature increase associated with bearing babbitt degradation. They need to be replaced at the next unit outage when faulty. A compensatory measure (i.e., monitoring bearing oil drain temperatures) is in place until the instrumentation can be restored and is not intended to be a long term action. Associated with WO 41891935.	May	JGS
Emergent - JGS Heat Exchange Pate Repair	$ 75	The closed cooling water heat exchangers are fouled & have one or more failed plates. Approved email 3/5.	Mar	JGS
Emergent32 JGS-Install Grounding Cables- North Switchyard fence	$ 83	During recent walkdown with CE Substation group, it was identified that the North section of the switchyard fence lacked grounding. Due to the potential safety risks this poses, the plant needs to install permanent grounding straps to each section of fence in order to protect people and equipment should an electrical failure occur that energizes the fence and to safely discharge static electricity build up. Current conditions do not provide a safe path to ground for this section of fence.	Jan	JGS
12813 Jackson 9 Generator Stator Corona Repair	$ 90	Request of funding to cover project gap for execution of work. Quotes for work higher than originally anticipated.	May	JGS
JGS Base Outage PP-10097	$ 150	Full outage discovery items.	Oct	JGS
6046 Jackson Capacity Factor Used For Water and Chemicals	$ 200	Request of funding to lower gap in full year expected spend.	July	JGS
JGS - 5917 JGS Base Outage-Boiler Plant Equipment	$ 225	Request of funding. HRSG 5 Tube Leak. Economizer leak identified on HRSG5 requiring repair to return the unit to service and restore station back to full capacity – associated derate of 70MW for the duration of the outage.	Aug	JGS
6263 DEK3-4 Periodic Outage Major Maintenance	$ 45	Request of funding for outage work scopes/Karn 3&4 Reliability.	Mar	Karn
6232 Karn 3&4 Maintenance - Maintain-Roof Repairs	$ 45	Request of funding. During Emergency Roof Leak Response visit on Febnuary 13, 2024, we identified several roof	May	Karn
6230 Karn 3&4 Maintenance - Demand	$ 70	Request of funding. Water well leak repairs/chemical spill.	June	Karn
6230 Karn 3&4 Maintenance - Demand	$ 100	Move of Major Maint. Outage funding to Normals for forced outage work scopes including residual oil heater repair.	Mar	Karn
Karn 3&4 Louver Repairs	$ 100	This request only covers the scaffold costs. Anticipate utilizing plant resources to complete the work. There are approximately 10 to 12 louvers per unit that are inoperable, some stuck open allowing cold air to get into the plant during the winter. This caused freezing issues last winter affecting unit availability and even forced a must run condition when not necessarily economic for our customers. These issues occurred despite plant heating in service. Significant scaffolding over open areas (not accessible with lifts or JLGs) is required.	sep	Karn
10770 DEK3 DA and DA Storage Tank Inspection 2024	$ 115	Request for additional funding needed for outage.	Mar	Karn
10786 DEK4 DA & DA Storage Tank Inspection 2024	$ 115	Request for additional funding needed for outage.	Mar	Karn
8663 Karn FH Oil	$ 120	Karn Fuel Handling - Request for Fleet charges	July	Karn
Karn 4D Vac Pump Control Wiring	$ 160	Control wiring for K4D Vac Pump	Oct	Karn
6265 K34 Opacity Critical Equipment repairs	$ 180	Karn 3 – $80k MM (Refurbish 2 DA valves)	May	Karn
6230 Karn 3&4 Maintenance - Demand	$ 230	Karn Maintenance - Request for Fleet/Maint expenses due to forced outages/OT	July	Karn
Covert - Emergent153 Covert Emissions Testing	$ 250	Emission testing at Covert	Aug	Karn
Gen Ops- Ludington Unit 6 Trash Rack Repairs	$ 13	Repairs for Unit 6 trash rack repairs cost more than estimate.	nov	LPS
Ludington Unit 6 Trash Rack Repairs	$ 13	Funding needed because repairs needed for the trash rack were more extensive than originally anticipated.	Oct	LPS
Emergent99 LPS - NERC relay testing	$ 15	Additional funding needed to finish NERC relay testing. Transferring funds from Wicket Gate repair to cover.	May	LPS
Gen Ops- LPS Unit 3 south trash rack Dive and Repair	$ 20	Repairs to Unit 3 south trash rack cost more than estimate.	nov	LPS
PH-80089 LPS - Unit 4 & 6 Trash Rack Uplift Study	$ 26	Funding needed to complete the study	sep	LPS
B-PH-00168 LPS Unit 3 South Trash Rack Dive and Repair	$ 36	Based on an inspection of the LPS Unit 3 south trash rack on 8/29, additional funding is needed to perform emergent repairs and a dive to remove debris from the sill slot during the Unit 3 pumping outage this fall.	sep	LPS
Emergent28 Unifier Maintenance Fee - Ludington Plan	$ 37	Funding needed to cover Unifier Maint. Plan	Feb	LPS
LPS - 13520 LPS - Main transformers 6 & 12 year maintenance	$ 41	Outage scope includes two transformers for this year but we only have the budget for one transformer. By doing the second one this year it gets us caught up(should have done one last year 2023), it will also save us money with the contractor. Using funding from other MM projects coming in under budget.	Aug	LPS
Emergent80 LPS Repair damage to U1 Gate	$ 50	Emergent repair on Unit 1 wicket gate cavitation	Mar	LPS
Emergent31 LPS Station Drainage Sump and Oil/water Separator Cleaning	$ 54	Requesting funds be transferred from WE. Funds needed to clean the oil/water separator and station drainage sump at LPS during the all-unit outage in May 2024.	Feb	LPS
LPS Unit 1 High Speed Event	$ 75	Funding needed for parts to fix Unit 1 after high speed event		LPS
Emergent60 LPS Warranty Unit 5 Runner Blade Crack Repair	$ 132	We have discovered a crack in the pump discharge / turbine inlet side of runner blade 9 where it meets the runner band. The crack exceeds allowable criteria set by Toshiba for this area (which is about 3/8" in length) and occurred in a designated "No Weld Zone" per Toshiba design drawings. Due to the size and location of the crack, repair is necessary immediately. This repair will require specialized welding practices and skilled resources to perform.	Mar	LPS
LPS Turbine Oil	$ 332	The current turbine oil condition across the units shows a degraded additive package with respect to anti foaming performance. This degraded condition can lead to additional equipment wear and potential damage if continued degradation is observed. Per analysis a 50% oil replacement and mixing can return the additive package to specification and restore operating life of the turbine oil across the units to approx 20 years or more as advised by the manufacturer. The money being requested will cover the purchase of 40,000 gallons, which is enough for all 6 turbines plus 1000 gallons to mix with the extra oil in the clean oil tanks.	nov	LPS
6639 ZGS NERC Relay and DC Testing Compliance - missing from AS view	$ 40	Pulling 40k from #0227 Excitation and Isolation to cover NERC testing that was intended to be completed in 2023 however couldn't due to outage changes.	Feb	ZGS
Emergent - Zeeland - GT1B compressor blade crack	$ 425	Approved emergent on 10/9/2024	Oct	ZGS
2024 Totals =	$ 8,346			

Site	Spend '$000
Covert	3,987
Hydro	463
Jackson	1,057
Karn	1,530
Ludington	844
Zeeland	465
Total	8,346

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-201 (RTB-23)
Page: 4 of 4
Witness: RTBlumenstock
Date: October 2025

Consumers Energy Company
Generation O&M Expense
For the Years 2022 through September 2025
($000's)

January -September 2025 Emergenent Reilability Expense

Description	Cost (000's)	Details	Site	Month
BESS - Airpark - commissioning expenses	$ 200	Team has approached asset strategy needing approx $200k to commission and finalize airpark	BESS	Jan
Gen Ops - CGS HEPS/FAC Emergent Request #2	$ 535	This is a true up to the original request for Covert HEPS discovery/repairs and since this is a significant increase we would like BUG and VP approval to proceed. We are building an offsetting strategy of downlevers that we will bring to the April change log to offset these requests. This request is for $535k of additional O&M to finish the repairs.	CGS	April
Covert - auxiliary boiler leak repair	$ 46	EMERGENT approved email 8/11/2025	CGS	Aug
Gen Ops - Covert Software Maintenance	$ 78	Moving funds from Gen Ops Common to fund Covert SureService software maintenance agreement	CGS	Feb
CGS - 1. Cable Vault Tray Supports – Failed	$ 68	This has been entered as a threat to generation (cable tray failure could compromise conductors and result in unit trip) – seeking planning and funding in 2025	CGS	Jan
Covert - Site Diesel Generators– air inlet louver drive motors failed for both engines	$ 20	Louvers are supposed to open automatically upon engine start to ensure sufficient air for the engine and turbo chargers	CGS	Jan
Covert - Ammonia Fan Rebuilds	$ 93	moving 2025 funds to O&M for fan rebuild of the old design.	CGS	Jan
Covert HEPS & FAC - Emergent Changelog	$ 1,182	The team has evaluated whether these are "must do" vs potential deferral repairs. The plan includes the must do repairs. This project needs immediate approval to mitigate outage extensions.	CGS	Mar
EMERGENT - Covert Unit 1 Steam Turbine Valve Repair	$ 250	A recent inspection at Covert identified a crack on a high-pressure control valve bushing. These can become a very serious or dangerous issue and definitely take the unit offline when it fails. We need to address this issue immediately at our earliest outage of opportunity which is this fall to avoid safety and forced outage issues.	CGS	Sept
PP-10219 Covert Fall Outage	$ 170	Additional funding needed to address issues at the Covert Generating Station during the fall outage.	CGS	Sept
NEW - Covert HRSG Cycling Assessment	$ 33	Funding needed to complete a cycling assessment of the HRGSs at Covert. The study will look at current startup and shutdown procedures and practices to determine if any of these factors may induce cycling-related damage.	CGS	Sept
NEW - Covert Circ Pump Vibration Analysis	$ 62	The analysis being performed is highly technical and required to determine the root cause of our historical vibration issues with the pumps at Covert.	CGS	Sept
PP-10218 Covert U 3 HP Steam Leak Repair	$ 45	True-up of project with funds from the NERC Relay/DC Testing Compliance & Capacity Factor Projects.	CGS	Sept
Gen Ops- Ausable River Queen Clean up	$ 100	Cleanup costs related to the Ausable River Queen incident. USEPA holding us accountable on some of the invoices. Plan is to recoup money from owners but unsure of timeline and plan.	Hydro	April
Hardy spill tube aeration flow meters and lighting	$ 55	•Modify the lighting circuit that lights the caverns by spill tubes 2 &3 to keep it out of the water running down the wall that has faulted that circuit. This is more a safety issue, there is no light down there but your flashlight when trying to complete maintenance or daily operation duties in those areas.	Hydro	Aug
Emergent - Foote Downstream Concrete Repair	$ 205	Emergent - The hydro team requires $205k of O&M to finish this work. In our reviews we found out this project has been progressing and these are actual costs. We explored multiple options including stoppage of work. The decision to proceed now will save the customer approx. $30k on demob/mob of the crane. The majority of the work is completed.	Hydro	Jan
Webber voids were discovered	$ 400	voids were discovered under the left side of the spillway tumble bay slab	Hydro	Jan
Mio Spillway hollow chamber leakage sealing	$ 110	Leakage has been known, 2024 dive inspection found source. Need to repair to prevent sand ballast washout from the hollow chamber - dam stability	Hydro	Jan
Mio Spillway Hollow Chamber repair	$ 50	The divers discovered additional work needed. If work is completed now it would save remobilizing the contractor. Risk of not doing the work is loss of fill(washout) and destabilizing the powerhouse/spillway.	Hydro	May
Croton Unit 1 Generator	$ 80	There is a broken bus bar between the collector ring and the rotor poles on the Croton Unit 1 Generator.	Hydro	May
JGS MM Base Outage	$ 325	Funding request to execute Fall outage needs-includes emergent repair to fire protection header- safety issue.	JGS	Aug
JGS- Duct Burner Iso Valves	$ 160	JGS Duct Iso Valves. Request for install monies.	JGS	Aug
JGS - Cooling Tower Repairs	$ 271	This is 1st & 2nd quarter immediate issues identified during the ICT level 2 inspections in the fall 2024 outage. Materials is being purchased 4th quarter 2024 and fall outage work scope will be done thru levers/flex or change log processes	JGS	Jan
JGS - LM Filter House Drift Eliminator Repl and Cooling Coil Cleaning	$ 50	The existing drift eliminators in the LM6000 filter houses are the original ones and are brittle and falling apart. Recent cooling coil performance testing by EPTS identified an average cooling coil efficiency loss of 15.9% from expected which is a reduction of total plant output of 2.85 MW under summer GVTC conditions.	JGS	Jan
JGS - 480V WavePro Breaker Replacements	$ 75	Work was delayed in 2024 and a portion of the initial funding was utilized to address cubicle modifications due to an identified arc flash risk. These requested funds are to complete the rebuild and installation of the remaining half (quantity: 17) of the 480V breakers.	JGS	Jan
JGS Duct Burner Isolation Valves	$ 140	Funding to replace the duct burner isolation valves on the HRSGs during the Fall outage – ahead of the originally planned Spring 2026 execution. We are continuing to experience valve failures in the field resulting in significant losses in power production. Our recent GVTC testing had poor results which will have significant impact to our 2026 capabilities.	JGS	July
		We are requesting $140k of O&M (cost plus expediting) to purchase replacements for all the failed isolation valves along with remaining carbon steel valves that are at risk of failing	JGS	July
JGS Plant Normals	$ 315	Request for funding. Outside Services in Maint area has been higher than what was provided in budget. (Cooling tower and Chiller work)	JGS	July
JGS MM Base Outage	$ 100	Request for fall outage work scopes. Net with return from water/chemicals.	JGS	July
JGS HRSG 7 Perforated Plate Distribution Wall	$ 150	Request for fall outage work scopes. Net with return from water/chemicals.	JGS	July
Gen Ops-Karn 4 Burner Oil Pump Leak PT-11178	$ 180	Funding request. Net zero request with funding returns from K4 Main Transformer Bladder Replacement & Karn 3 Boiler Waterwall Tube Samples	Karn	April
K3 Station Power Relay (Non-NERC) Maintenance	$ 41	AET for testing of non-NERC relays on Karn 3- Fall outage. Funding was pulled in Feb as part of $50M challenge.	Karn	Aug
Karn B Aux Boiler FD Fan Shaft/Bearing Repair	$ 60	Karn B Aux Boiler FD Fan Shaft/Bearing Repair. Emergent Broke/Fix work.	Karn	Aug
Karn 3-4 Periodic Outage- Fall 2025 Outage	$ 250	Request for Fall outage funding as site does not currently have funding.	Karn	Aug
Gen Ops- Karn GSU Fire	$ 300	Initial ask to fund ICS at Karn for O&M	Karn	Feb
Karn 3 & 4 - FW Heater safety relief testing & setting	$ 40	Components need testing; not suspected to have been inspected before	Karn	Jan
Karn Forced Outage	$ 110	Request of funding. Site does not currently have funding for forced outages	Karn	July
Karn Fire & Transformer Move - Emergent Changelog	$ 2,000	HLI to Transport (1) Transformer by rail from West Olive, MI to Essexville, MI. -$1.2M	Karn	Mar
Karn ICS Additional Costs	$ 3,200	Estimated additional spending needed for Karn, POs written	Karn	Mar
Karn 3&4 Louver Repairs	$ 100	This request only covers the scaffold costs. Anticipate utilizing plant resources to complete the work. There are approximately 10 to 12 louvers per unit that are inoperable, some stuck open allowing cold air to get into the plant during the winter. This caused freezing issues last winter affecting unit availability and even forced a must run condition when not necessarily economic for our customers. These issues occurred despite plant heating in service. Significant scaffolding over open areas (not accessible with lifts or JLGs) is required.	Karn	Sept
Gen Ops - LPS - Unit 2 Penstock Intake Repair	$ 10	Error in calculation going from 100% to 51% in previous changelog, did not request enough funding.	LPS	April
Gen Ops - LPS intake gate slot bubbler orifices	$ 13	The intake gate slot bubbler orifices need to be replaced.	LPS	April
Ludington Fish Barrier Net-Installation, Cleaning, Repairs & Removal	$ 128	Part of it is HDR, looks like their costs are about $10k more per month with their new contract. Part of it is UCC being more attentive about staffing this project. UCC's contract ends November 30, no new contract yet for December's rates	LPS	Aug
LPS Turbine Oil	$ 28	Funding needed for testing and delivery of the oil	LPS	Aug
LPS environmental	$ 43	Environmental allocation came in higher than planned in 2025	LPS	Aug
Emergent - LPS - Unit 1 outage	$ 561	Emergent - Est. repair costs for the LPS Unit#1 Forced Outage due to a Runaway event on 12/4/24.	LPS	Jan
LPS - Unit 4 & 6 Trash rack uplift study	$ 70	Delays in developing the Statement of Work will more likely than not push the field work into January 2025	LPS	Jan
LPS Unit 1 South Trash Rack Repairs	$ 60	Funding, time, and resources for this trash rack repair were used to offset the emergent repair of the Unit 3 south trash rack. Having repaired the Unit 1 south and Unit 3 south trash rack in 2024, we have a better idea of the level of effort needed to effect these repairs.	LPS	Jan
Ludington Fish Barrier Net-Installation, Cleaning, Repairs & Removal	$ 36	Run rate for Barrier net install was higher than planned	LPS	July
LPS IPB Inspection and Maintenance	$ 46	The IPB on MTB1 needs to be cleaned. This was discovered from the MTB1 inspection.	LPS	Mar
LPS Turbine Oil	$ 38	Monthly storage fee required for turbine Oil purchased at the end of 2024. Moving money from normals since the storage fee is hitting the project	LPS	Mar
			LPS	Sept
B-PH-00168 LPS Unit 3 South Trash Rack Dive and Repair	$ 36	Based on an inspection of the LPS Unit 3 south trash rack on 8/29, additional funding is needed to perform emergent repairs and a dive to remove debris from the sill slot during the Unit 3 pumping outage this fall.	LPS	Sept
PH-80089 LPS - Unit 4 & 6 Trash Rack Uplift Study	$ 26	Funding needed to complete the study	LPS	Sept
2025 TOTALS =	$ 12,744			

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002195	**2025**	**3**	**Literal**

Investment Name	Scenario
JGS - Generator Step Up Transformer (GSU) Site Spare	**Draft**

Value Function	**Consumers Energy Value Function**

The Jackson Generating Station (JGS) relies on its main Generator Step-Up (GSU) transformers to transmit power from its generating units to the grid. These GSUs represent a single point of failure: a loss of any GSU would immediately force a significant derate and disrupt operations. Procurement of a replacement GSU requires custom engineering and specialized materials, resulting in lead times of approximately three years, which exposes JGS to prolonged operational and financial risk.
Existing spare transformers at other Consumers Energy sites (Campbell, Karn, Lake Winds, Crosswinds) are not compatible with JGS's voltage (138 kV–13.2 kV–13.2 kV) and winding configuration (WYE–DELTA). Previous efforts to secure a lease agreement with Midland Cogeneration Venture (MCV) failed in 2024, leaving JGS without a viable short-term backup solution. This reinforces the need for a dedicated on-site spare GSU to mitigate extended derate risk.

Why This Revision Was Necessary:
The original business case relied on Aurora modeling and assumptions that overstated capacity factor and understated derate risk. Specifically:
• Capacity Factor: Aurora projected 65–84%, while historical operation was 31–39%. This occurred because Aurora did not account for NOx emission limits, which constrain dispatch.
• Derate Magnitude: The prior low-end assumption of 37 MW was based on an incorrect failure-mode interpretation (isolating one LM). Engineering review confirmed that each LM GSU has one high-side and two low-side connections, meaning a GSU failure requires both LMs offline.
• Probability of Failure: The original analysis assumed failure at 100% certainty. Copperleaf now incorporates a risk-adjusted probability curve escalating from 5% in 2026 to 5 percentage points annually through 2039.

Updated Modeling Approach (Copperleaf):
• Derate Magnitude: 104 MW (planning basis), reflecting both LMs offline for an LM-tied GSU failure. Sensitivity ranges: ~90 MW (STG), 131–135 MW (LM), 136–145 MW (7EA).
• Restoration Window: ~1,080 days (≈3 years) for procurement and commissioning.
• Copperleaf Limitation: Lost Generation Risk module caps outage duration at 365 days, making energy-loss valuation conservative versus the true exposure. The Financial Risk leg still reflects full multi-year capacity impacts.
• Probability Curve: 5% in 2026, increasing by 5 percentage points annually through December 2039.
• Capacity Value: $28 million exposure for a 104 MW, 1,080-day derate based on MISO's rolling 3-year ZRC accreditation methodology and 75% CONE ($127,135).
• Energy Value: Uses historical and forecasted capacity factors from the current PSCR case, incorporating NOx/CO limits and the site's "adder" operating practice.

Copperleaf Risk and Investment Outputs (NPV in $000):
• Financial Risk (Capacity Revenue Loss): 9,599
• Lost Generation Risk (104 MW Derate): 6,774
• Total Investment Cost (Spare GSU): -4,423
• Total Value: 11,951

Recommended Alternative:
Purchase and store a spare GSU on-site at JGS
• Estimated cost: $5 million (includes transformer and storage pad).
• Benefits: Immediate access to a compatible spare, elimination of dependency on external agreements, mitigation of prolonged derate risk, and alignment with Copperleaf-based risk-adjusted valuation.

Other Alternative Considered:
Lease a Spare Transformer and Overhaul Failed GSU
• Estimated cost: $10.8 million plus ongoing rental fees.
• Limitation: No rental units meet JGS's voltage and winding specifications; prior MCV lease attempt failed.

Governance:
This Copperleaf-based model replaces the pre-Copperleaf Aurora valuation. Version anchor: October 2025 PSCR/Copperleaf parameters. All assumptions and limitations (including the 365-day cap in Lost Generation Risk) are documented for transparency.

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Unit - Plant
	Scope	Create bid specification for design of a spare Jackson Generating Station Main Generator Step Up Transformer (GSU) Create specification for the JGS spare GSU storage area (foundation and power if needed) Bid out and procure spare JGS GSU Provide onsite quality oversight of manufacturing at the facility. Bid out and install spare GSU storage area in time for receipt of the spare GSU.
	Objectives	This project provides JGS with a reliable spare GSU it currently does not have access to. In parallel with this project, CE is entering a shared spare lease agreement with Midland CoGeneration (MCV) in the 3rd or 4th quarter of 2023 via O&M funding to provide immediate short-term availability of a spare GSU for the site if needed. However, this agreement does have terms and conditions such that MCV can reject our request to use their spare GSU should they be in need of the spare or intend to use otherwise at their discretion, which is not a reliable plan for long term reliability for our customers. This will also mitigate the need to continue to carry the MCV lease agreement O&M expense ($60K/yr) once this spare GSU is close to delivery at site, saving future O&M spend on this agreement through the remaining life of the plant.

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002195	**2025**	**3**	**Literal**

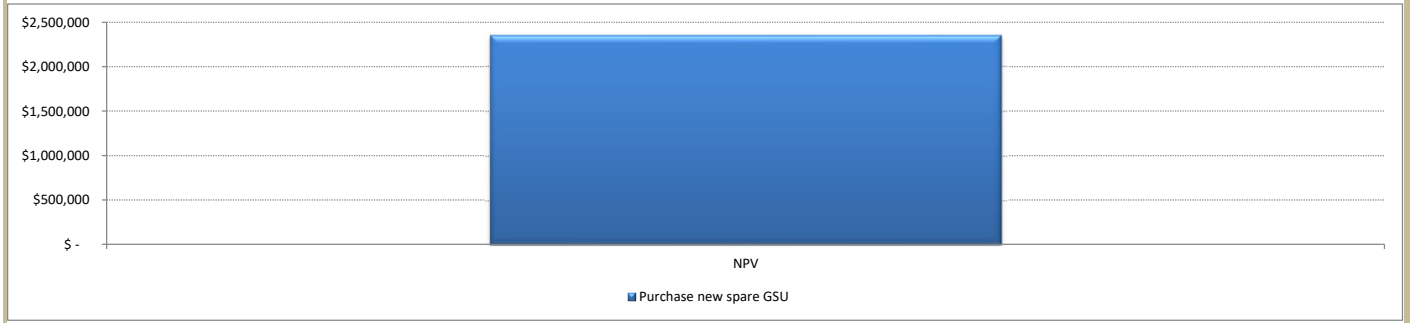
Investment Name	Scenario
JGS - Generator Step Up Transformer (GSU) Site Spare	**Draft**

Value Function	**Consumers Energy Value Function**

	Planner Recommended Alternative	Purchase new spare GSU transformer This option involves the procurement and long-term storage of a spare Generator Step-Up (GSU) transformer at the Jackson Generating Station (JGS). The estimated cost for this approach is $5 million, which includes the purchase of the spare GSU and the installation of a dedicated storage area or pad to ensure its safe preservation until needed. Rationale for Selection Purchasing and storing a spare GSU on-site at JGS is the most cost-effective, predictable, and reliable long-term strategy to mitigate potential losses and operational disruptions in the event of a GSU failure or overhaul. This solution provides JGS with a dedicated spare transformer that is immediately accessible when required, ensuring minimal downtime and avoiding costly delays associated with the procurement of a replacement unit. Other alternative considered: Lease a Spare Transformer, Overhaul the Failed GSU (If Repairable) This option examines the viability of leasing a GSU transformer. It entails obtaining and installing a rental GSU transformer if there is a failure, while the faulty GSU is dispatched for repairs, assuming it can be overhauled. This approach is estimated to cost approximately $10.8 million, based on similar scope projects, including the Zeeland Generating Station. The breakdown of costs includes $400,000 per month for the rental unit ($4.8 million per year), $3 million to overhaul the failed GSU if repairable within a one-year timeframe and an additional $3 million to remove, transport and install both the rental unit and the failed GSU. There are significant limitations to this option, primarily stemming from the unavailability of rental transformers with the specific voltage requirements (138kV-13.2kV-13.2kV) and winding configuration (WYE-DELTA) necessary for JGS. This means that leasing a spare GSU is not currently viable, as no rental units meet the unique specifications required for JGS operations.
	Model Assumptions	Technical failure mode: • Transformer configuration: Each LM GSU has one high-side connection and two low-side connections (one per LM). Practical isolation of a single LM on a failed GSU is not possible; both LMs tied to that GSU must be removed from service. • Planning basis: Maintain 104 MW derate for modeling consistency and technical accuracy (reflects both LMs offline for an LM-tied GSU failure). Sensitivity bands: ~90 MW (STG GSU), 131–135 MW (LM GSU), 136–145 MW (7EA GSU). • Restoration window: True economic exposure aligns with ~1,080 days (≈3 years) for procure/replace/commission. Copperleaf limitation (important conservatism): • Copperleaf Lost Generation Risk model allows a maximum outage duration of 365 days. We therefore enter 365 days in that module; this UNDERSTATES total energy loss vs. the true ~1,080-day exposure and is conservative. The Financial Risk (capacity) leg still reflects the full multi-year accreditation impact as described below. Probability of occurrence (annual schedule used in both risk legs): • 2026: 5%; 2027: 10%; 2028: 15%; then +5 percentage points per year through December 2039. Event treated as single-event loss applied in the year realized; probabilities apply only while no spare is in place. Capacity value methodology (Financial Risk leg): • Accreditation rule: MISO rolling 3-year average of ZRCs; any forced outage >30 days reduces accredited capacity for multiple subsequent years. • CONE basis: 75% of CONE = $127,135 (planning anchor). • Reference exposure: $28 million capacity value impact for a 104 MW, 1,080-day derate using the rolling ZRC methodology (used as the capacity consequence and then probability-weighted). • Market offer assumption: Unit not offered into the capacity market during extended derate; we quantify foregone capacity value only (no replacement capacity purchases). Energy (NEV) methodology (Lost Generation Risk leg): • Dispatch & capacity factor inputs: Use historical and forecast CF from the current PSCR case (not unconstrained Aurora). This corrects the earlier overstatement and aligns with portfolio standards. • Emissions constraints: Incorporate Jackson's NOx/CO limits and the site "adder" operating practice (weekly monitoring/offer adjustments) when shaping run-hours and margins. • Engine stall risk: Modeled as a separate operational risk (own probability and consequence) to avoid double counting. Lead time & alternatives:
Alternative Details	Purchase new spare GSU	Purchase new spare GSU

Alternative Spend Profile

Name	Status	NPV	Total Spend	Alternative Start Date
Purchase new spare GSU	Recommended	$ 2,351,432	$ 5,014,367	1/1/2025



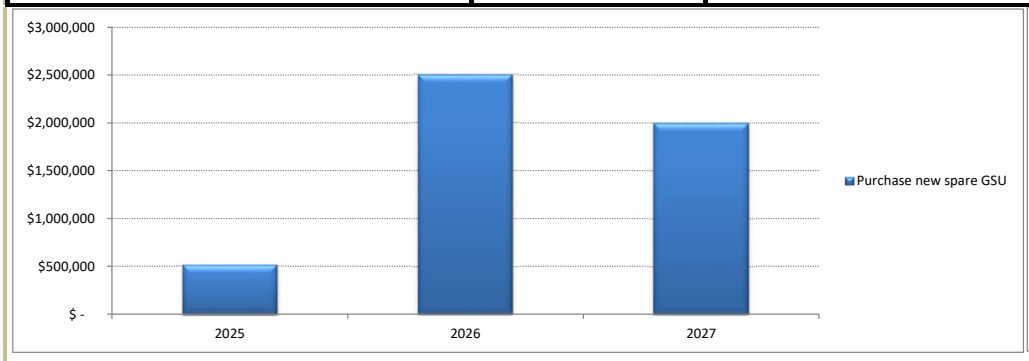
Name	Status	2025	2026	2027					
Purchase new spare GSU	Recommended	$ 514,367	$ 2,500,000	$ 2,000,000					

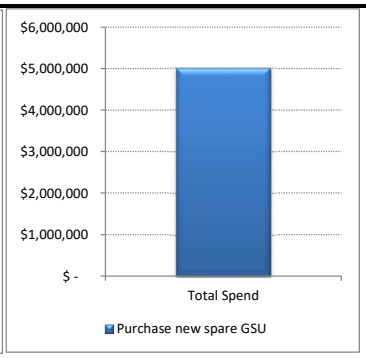
Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002195	**2025**	**3**	**Literal**

Investment Name	Scenario
JGS - Generator Step Up Transformer (GSU) Site Spare	**Draft**

Value Function	**Consumers Energy Value Function**





Forecasts - Draft (Purchase new spare GSU)

Account Type	2025	2026	2027
Capital	$ 514,367	$ 2,500,000	$ 2,000,000
Cost Of Removal	$ -	$ -	$ -
O&M	$ -	$ -	$ -

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Concept Approval Internal Report

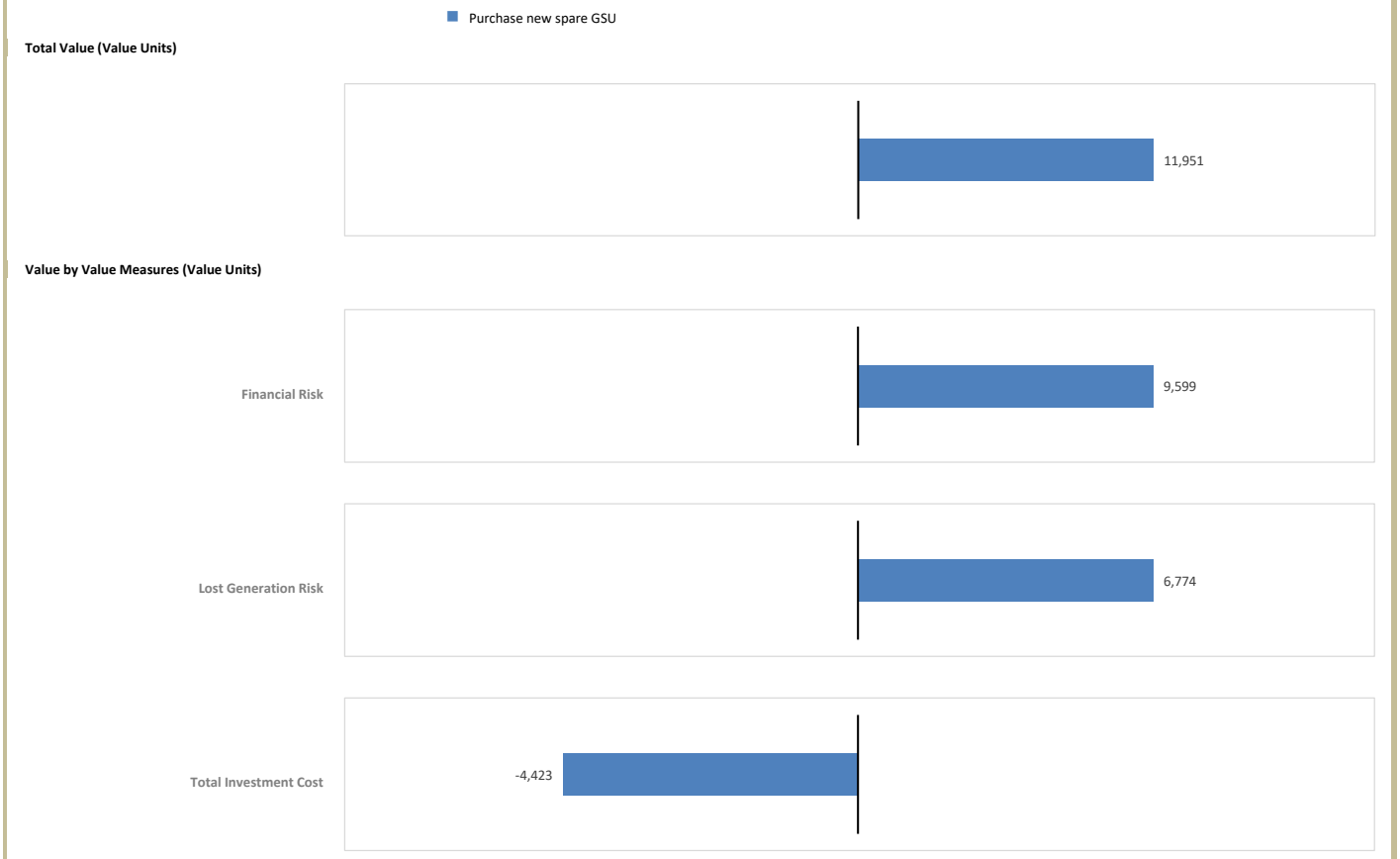
Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002195	**2025**	**3**	**Literal**

Investment Name	Scenario
JGS - Generator Step Up Transformer (GSU) Site Spare	**Draft**

Value Function	Consumers Energy Value Function

Alternative Value

Name	Status	Total Value	Cost Present Value	Value / $
Purchase new spare GSU	Recommended	$ 11,951	$ 4,422,551	0.0027



Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002195	**2025**	**3**	**Literal**

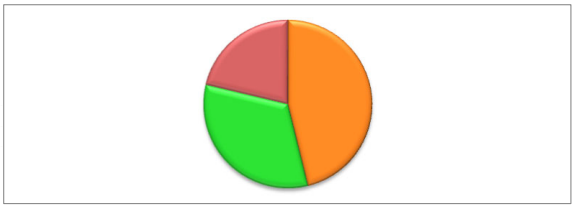
Investment Name	Scenario
JGS - Generator Step Up Transformer (GSU) Site Spare	**Draft**

Value Function	**Consumers Energy Value Function**

Purchase new spare GSU

Description	Purchase new spare GSU
Alternative Status	Recommended
Alternative Start Date	1/1/2025

Alternative Value



Value Function Measure	Value	Value in Percentage
Financial Risk	9,599	46%
Lost Generation Risk	6,774	33%
Total Investment Cost	(4,423)	21%
Total	**11,951**	**100%**

Alternative Value Details

Impacted Item					Value Model Name			Value Model			Value	
GEN002195 / JGS - Generator Step Up Transformer (GSU) Site Spare					Financial Risk Matrix			Financial Risk Matrix			9,599	
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**					
Financial Risk	Baseline		-	Value Unit	825	900	900					
Financial Risk	Outcome	2028	9,599	Value Unit	825	900	900					

Impacted Item					Value Model Name			Value Model			Value	
GEN002195 / JGS - Generator Step Up Transformer (GSU) Site Spare					Investment Cost			Investment Cost			(4,423)	
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**					
Total Investment Cost	Outcome	2025	(4,423)	Dollar	514,367	2,500,000	2,000,000					

Impacted Item					Value Model Name			Value Model			Value	
GEN002195 / JGS - Generator Step Up Transformer (GSU) Site Spare					Lost Generation Risk			Lost Generation Risk			6,774	
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**					
Lost Generation Risk	Baseline		-	Dollar	15,288	121,087	254,858					
Lost Generation Risk	Outcome	2028	6,774	Dollar	15,288	121,087	254,858					

Consumers Energy Count on Us®	Investment Code	Report Start Year	Number of Years	Currency Scale
	GEN002192	**2025**	**5**	**Literal**
Concept Approval Internal Report	Investment Name			Scenario
	JGS - LM1-6 VIGV(variable inlet guide vane) Project			**Draft**
	Value Function	**Consumers Energy Value Function**		

Background and Executive Summary:

The gas turbines at Jackson Generating Station currently use fixed Inlet Guide Vanes (IGVs) that limit their ability to adapt to varying operating conditions. This results in suboptimal performance, reduced efficiency, and increased risks to turbine reliability. The following are the key challenges associated with the current system:
•Inefficiency of Fixed IGVs: The fixed angle of the IGVs restricts airflow modulation, preventing the turbines from operating at peak efficiency across different ambient conditions and power settings. This leads to inefficient fuel use, particularly at part load, which is common in load-following operations at Jackson Generating Station.
•Fuel Consumption and Heat Rate: Due to the inability of the current system to adjust for optimal airflow, the heat rate of the turbines is higher than necessary, which increases fuel consumption. The inefficiency becomes more pronounced during partial load conditions, where fuel savings are critical for economic operation.
•Increased Risk of Engine Stall: Without dynamic control of the IGV angles, the turbines are more susceptible to engine stalls during rapid power reductions or operational fluctuations. An engine stall can cause significant damage to the turbines, resulting in costly repairs and extended downtime.
•Dependence on Duct Firing: To meet power demands, the station relies on duct firing, which is less efficient, consumes more fuel, and places additional stress on the system. This dependency results in higher operational costs and increased emissions.

Jackson Generating Station plans to upgrade six LM6000PC units (LM1–LM6) from fixed to Variable Inlet Guide Vanes (VIGV) to improve efficiency, reliability, and dispatch flexibility under NOx-constrained capacity factors. Fixed IGVs limit airflow modulation, driving inefficient fuel use at part load, elevated heat rate, higher stall risk during rapid load changes, and reliance on less efficient duct firing.
The VIGV system enables dynamic airflow control, increasing base-load capability and reducing duct firing without changing the site's ~560 MW (net) maximum output. Expected uplift is ~+12 MW at the gas turbines plus ~+15 MW at the steam turbine from increased exhaust energy, for a site-wide base-load increase of ~+27 MW. Heat rate improves by ~189 Btu/kWh at baseload (no duct); baseload HR improves from ~7,951 to ~7,762 Btu/kWh (LHV, no duct). Efficiency gains persist across the load range (≈2% at ~70% load). The upgrade increases stall margin, lowering the likelihood of damaging stall events during load-following and reducing unplanned downtime.

Generation Shift: +12 MW gas turbine base load plus +15 MW steam from increased exhaust energy → ~+27 MW site-wide base-load capability. Site maximum remains ~560 MW (net), but generation shifts from duct firing to efficient base load.
Fuel Efficiency: Heat rate improves by ~189 Btu/kWh at baseload (no duct). Baseload HR drops from ~7,951 to ~7,762 Btu/kWh (LHV, no duct). Efficiency gains persist across the load range (~2% at ~70% load).

Reliability: Increased stall margin reduces risk of catastrophic stalls and unplanned outages.

Model Assumptions

Six LM6000PC units; heat-rate values on LHV basis.
NOx-driven capacity factor limits incorporated using historical performance.
Stall risk: ~1 event every 5 years; repair cost up to $7.4M per turbine. Copperleaf planning uses 10% probability and $5–$15M consequence range → ~$22.2M cumulative risk avoided over 15 years.
Each stall causes ~90 MW derate for ~3 weeks (loaner engine install/remove included).

Economic Impact
Economic valuation has been revised from the initial Aurora run to a Copperleaf-based approach that (1) incorporates NOx-driven capacity factor limitations using historical performance and (2) explicitly prices stall risk and derate impacts. Value streams include fuel savings from lower heat rate, incremental base-load generation (with reduced duct firing), and avoided stall repairs and derate losses. A single stall can cost up to $7.4M per turbine (updated from $4M based on a recent LM306 engine stall event), with an underlying expectation of ~1 event every 5 years (~20% per five-year period). For planning within Copperleaf (tooling constraint), a conservative 10% probability with a $5–$15M consequence range is used, yielding an estimated cumulative consequence of ~$22.2M over 15 years that the VIGV upgrade helps mitigate. Each stall also drives an unplanned ~90 MW derate for ~3 weeks (≈1.5 weeks to install a loaner engine and ≈1.5 weeks to remove it post-repair).

Financial Analysis
Net Present Value (NPV) of $11,035 thousand (≈$11.0M) in total benefits from the VIGV upgrade, derived from:

Fuel Savings: $8,188K
Financial Risk (stall avoidance): $5,300K
Lost Generation Risk: $133K
Total Investment Cost: –$2,587K
Total NPV: $11,035K

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002192	**2025**	**5**	**Literal**

Investment Name	Scenario
JGS - LM1-6 VIGV(variable inlet guide vane) Project	**Draft**

Value Function	**Consumers Energy Value Function**

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Unit - Plant
	Scope	Install VIGV system on Engine Serial Number (ESN) 185-132 during its normally planned Major Overhaul interval April 2025 Install VIGV system on six other engines during their normally planned hot section interval: September 2025: ESN 191-312 April 2026: ESN 191-339 September 2026: ESN 191-307 April 2027: ESN 191-345 September 2027: ESN 191-306 April 2028: ESN 191-351
	Objectives	To address these issues, the Jackson LM1-6 Variable Inlet Guide Vane (VIGV) upgrade will replace the fixed IGVs with a variable system, enabling dynamic airflow modulation. This upgrade will: •Increase Base Load Output: The VIGV system will enhance the base load capacity of the gas turbines by 12 MW and contribute to a total site-wide increase of 27 MW when combined with steam turbine improvements. This increase will reduce the reliance on inefficient duct firing. •Improve Fuel Efficiency: The upgrade will improve the baseload heat rate by approximately 189 Btu/kWh (without duct firing) and 286 Btu/kWh (with duct firing). •Enhance Stall Margin: By allowing better airflow control, the VIGV system will improve the stall margin, reducing the risk of turbine failure during rapid load changes and ensuring more reliable operation. This project is critical for improving the overall performance and efficiency of the turbines, reducing operational costs, and minimizing the risk of unplanned outages due to engine stalls.
	Planner Recommended Alternative	Install VIGV upgrade.
	Model Assumptions	Revised economic modeling: The initial Aurora model did not account for the capacity factor limitation at the Jackson station from NOx emission limitations. Also, the engine stall risk was not included in this model. In order to accurately quantify the risk of the stalls and incorporate the accurate forecasted capacity factors based on historical performance, the approach to the value modeling was changed to a Copperleaf based approach. This will also align the business case with current practice post-adoption to the use of Copperleaf for business case generation. Fuel Efficiency Improvement Without the upgrade, the station will continue to operate with a heat rate of 7,951 Btu/kWh (LHV, assuming no duct burners used) for each LM6000PC turbine during base load operations. The VIGV upgrade would have reduced this heat rate to 7,7614 Btu/kWh (LHV, no duct burners used), leading to more efficient fuel usage and cost savings (heat rate improvement of 189 Btu/kWh across the entire load range). Refer to table in original concept approval for a summary of the increase in generation and heat rate impacts with and without VIGV. By not upgrading, the plant misses a significant MW improvement in output at lower heat rates without duct burners, and a considerable heat rate improvement of 189 Btu/kWh across the entire load range. This represents a significant loss in fuel savings and operational efficiency over time. Risk of stall event: $7.4M repair costs from stalls. expect to have a stall every 5 years. Three stalls over the next 15 years. $22.2M total risk. Stall Risk: The existing fixed IGV system increases the risk of engine stalls, particularly during rapid load reductions. An engine stall is a critical failure that can lead to catastrophic damage, requiring costly repairs. The estimated cost of an engine stall repair is up to $7.4 million per turbine (number updated from $4M based on recent 306 engine stall event updated costs), with an average stall probability of one occurrence every five years (20%). Due to Copperleaf software limitations a conservative probability of 10% with a consequence of $5M-$15M will be used for planning purposes. Over the next 15 years, the overall consequence is estimated at $22.2 million in repair costs that will be mitigated by the VIGV system. The stall events also result in a 90MW unplanned derate for a total of three weeks. It takes about 1.5 weeks for the loaner replacement engine to be delivered and installed and then another 1.5 weeks to uninstall once the repairs are completed on the failed engine. A 20% probability of realizing this risk every 5 years will be assumed for planning purposed.
Alternative Details	Add VIGV system to all LM6000 engines	Per Unit (x6): 2 MW output gain without duct firing, greater than 2% fuel efficiency gain at part load, exhaust energy increase of 3%, and greater protection from an engine stall condition. (Assumptions: $575K for 6 engines + $150K for 1 engine. Cost estimates include hardware, software, engineering, and labor for installation plus loadings.)

Concept Approval Internal Report

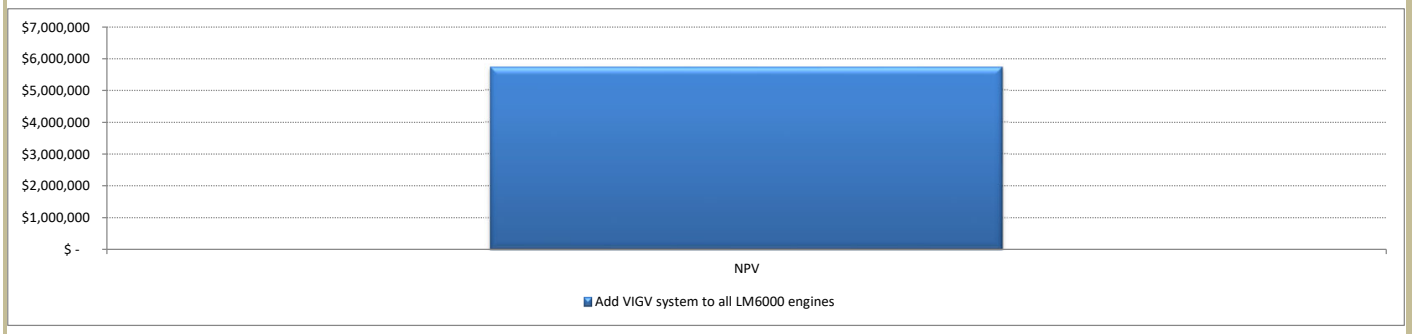
Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002192	2025	5	Literal

Investment Name	Scenario
JGS - LM1-6 VIGV(variable inlet guide vane) Project	Draft

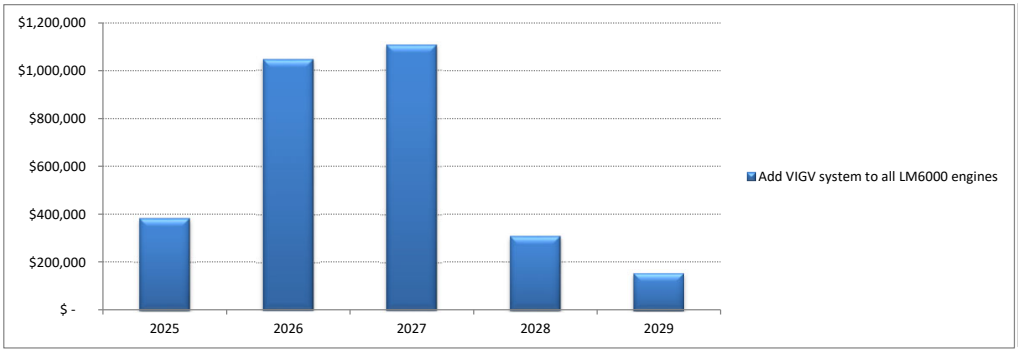
Value Function	Consumers Energy Value Function

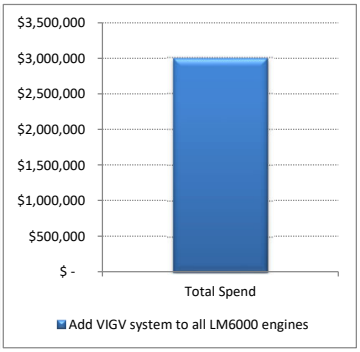
Alternative Spend Profile

Name	Status	NPV	Total Spend	Alternative Start Date
Add VIGV system to all LM6000 engines	Recommended	$ 5,734,649	$ 2,993,559	1/1/2025



Name	Status	2025	2026	2027	2028	2029			
Add VIGV system to all LM6000 engines	Recommended	$ 380,949	$ 1,046,370	$ 1,107,600	$ 305,760	$ 152,880			





Forecasts - Draft (Add VIGV system to all LM6000 engines)

Account Type	2025	2026	2027	2028	2029			
Capital	$ 341,149	$ 941,733	$ 996,840	$ 275,184	$ 137,592			
Cost Of Removal	$ 39,801	$ 104,637	$ 110,760	$ 30,576	$ 15,288			
O&M	$ -	$ -	$ -	$ -	$ -			

Consumers Energy
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Concept Approval Internal Report

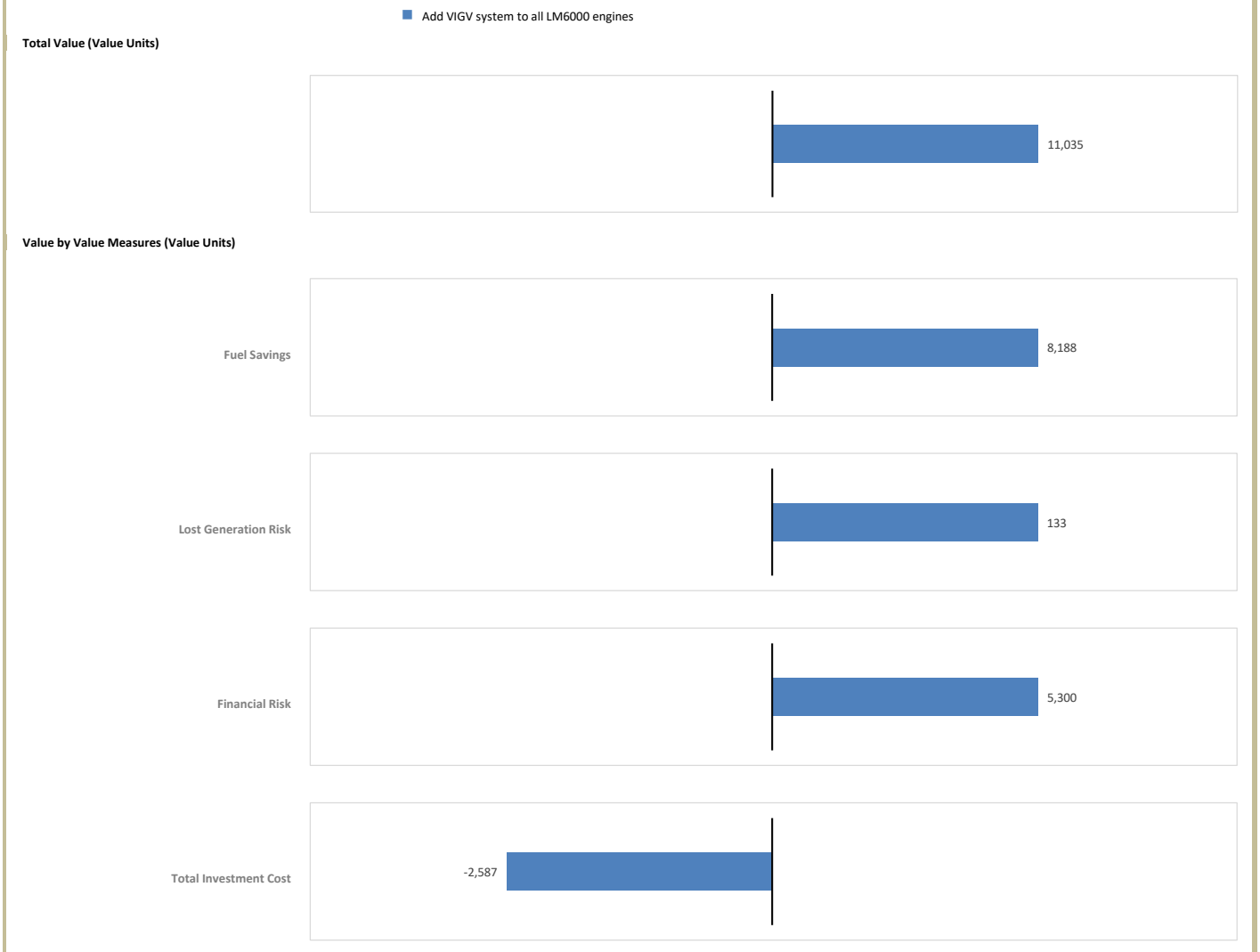
Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002192	**2025**	**5**	**Literal**

Investment Name	Scenario
JGS - LM1-6 VIGV(variable inlet guide vane) Project	**Draft**

Value Function	Consumers Energy Value Function

Alternative Value

Name	Status	Total Value	Cost Present Value	Value / $
Add VIGV system to all LM6000 engines	Recommended	$ 11,035	$ 2,586,759	0.0043



Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002192	**2025**	**5**	**Literal**

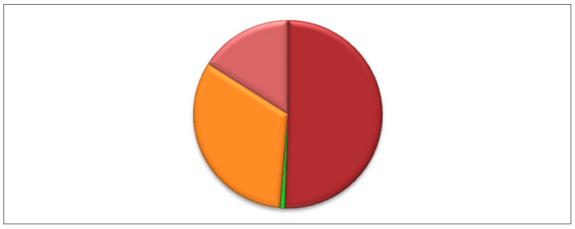
Investment Name	Scenario
JGS - LM1-6 VIGV(variable inlet guide vane) Project	**Draft**

Value Function	Consumers Energy Value Function

Add VIGV system to all LM6000 engines

Description	Per Unit (x6): 2 MW output gain without duct firing, greater than 2% fuel efficiency gain at part load, exhaust energy increase of 3%, and greater protection from an engine stall condition. (Assumptions: $575K for 6 engines + $150K for 1 engine. Cost estimates include hardware, software, engineering, and labor for installation plus loadings.)
Alternative Status	Recommended
Alternative Start Date	1/1/2025

Alternative Value



Value Function Measure	Value	Value in Percentage
Fuel Savings	8,188	51%
Lost Generation Risk	133	1%
Financial Risk	5,300	33%
Total Investment Cost	(2,587)	16%
Total	**11,035**	**100%**

Alternative Value Details

Impacted Item					Value Model Name			Value Model				Value
GEN002192 / JGS - LM1-6 VIGV(variable inlet guide vane) Project					Financial Risk Matrix			Financial Risk Matrix				5,300
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**	**2029**			
Financial Risk	Baseline		-	Value Unit	250	1,000	1,000	1,000	1,000			
Financial Risk	Outcome	2030	5,300	Value Unit	250	1,000	1,000	1,000	1,000			

Impacted Item					Value Model Name			Value Model				Value
GEN002192 / JGS - LM1-6 VIGV(variable inlet guide vane) Project					Heat Rate Impact			Heat Rate Impact				8,188
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**	**2029**			
Fuel Savings	Outcome	2030	8,188	Dollar	0	0	0	0	0			

Impacted Item					Value Model Name			Value Model				Value
GEN002192 / JGS - LM1-6 VIGV(variable inlet guide vane) Project					Investment Cost			Investment Cost				(2,587)
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**	**2029**			
Total Investment Cost	Outcome	2025	(2,587)	Dollar	380,949	1,046,370	1,107,600	305,760	152,880			

Impacted Item					Value Model Name			Value Model				Value
GEN002192 / JGS - LM1-6 VIGV(variable inlet guide vane) Project					Lost Generation Risk			Lost Generation Risk				133
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**	**2029**			
Lost Generation Risk	Baseline		-	Dollar	3,045	21,564	23,540	22,601	22,374			
Lost Generation Risk	Outcome	2030	133	Dollar	3,045	21,564	23,540	22,601	22,374			

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-204 (RTB-26)
Witness: RTBlumenstock
Date: October 2025

Consumers Energy Company
Generation O&M Expense
Year over Year O&M Expense
($000's)

		($/1000) Actuals 12 Months Ending 12/31/2017	($/1000) Actuals 12 Months Ending 12/31/2018	($/1000) Actuals 12 Months Ending 12/31/2019	($/1000) Actuals 12 Months Ending 12/31/2020	($/1000) Actuals 12 Months Ending 12/31/2021	($/1000) Actuals 12 Months Ending 12/31/2022	($/1000) Actuals 12 Months Ending 12/31/2023	($/1000) Actuals 12 Months Ending 12/31/2024	($/1000) Projected Bridge Period 16 Months Ending 4/30/2026	($/1000) Projected Test Year 12 Months Ending 4/30/2027
1	**BASE O&M**	**$ 114,090**	**$ 77,719**	**$ 96,814**	**$ 106,821**	**$ 106,195**	**$ 106,818**	**$ 93,864**	**$ 91,052**	**$ 105,324**	**$ 68,705**
	Admin/Generation Commons	$ 1	$ 1,407	$ (3,013)	$ (1,584)	$ (1,173)	$ 4,302	$ 873	$ 3,974	$ 12,121	$ 9,102
	Adjustment					$ -	$ -	$ -	$ -	$ -	$ -
	Alcona (Hydros)	$ 232	$ 215	$ 217	$ 713	$ 728	$ 231	$ 639	$ 980	$ 1,188	$ 990
	Allegan (Hydros)	$ 141	$ 240	$ 212	$ 758	$ 766	$ 183	$ 752	$ 664	$ 1,043	$ 826
	Battery					$ -	$ -	$ 30	$ 405	$ 622	$ 1,317
	Cadillac (Solar)	$ 47	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -
	Campbell	$ 27,873	$ 22,075	$ 39,179	$ 33,492	$ 37,751	$ 36,060	$ 34,858	$ 33,333	$ 16,896	$ -
	Circuit West (Solar)	$ 42	$ -	$ -	$ 18	$ -	$ -	$ -	$ -	$ -	$ -
	Cobb (Classic 7)	$ 61	$ 271	$ 58	$ 124	$ 49	$ 751	$ 34	$ 42	$ -	$ -
	Combustion Turbines	$ 775	$ 702	$ 298	$ 5	$ -	$ -	$ -	$ -	$ -	$ -
	Cooke (Hydros)	$ 191	$ 197	$ 211	$ 643	$ 754	$ 209	$ 683	$ 804	$ 731	$ 455
	Covert	$ 11,943	$ -	$ -	$ -	$ -	$ 4	$ 5,196	$ 6,813	$ 9,923	$ 6,934
	Croton (Hydros)	$ 1,743	$ 5,778	$ 2,026	$ 969	$ 1,055	$ 2,507	$ 1,431	$ 1,366	$ 1,368	$ 1,274
	Electric Grid Integration	$ 17,846	$ 9,725	$ 5,475	$ 13,873	$ 15,248	$ 16,780	$ 11,276	$ 10,118	$ 15,682	$ 12,111
	Five Channels (Hydros)	$ 1,314	$ 1,449	$ 1,354	$ 708	$ 790	$ 890	$ 717	$ 874	$ 920	$ 678
	Foote (Hydros)	$ 247	$ 285	$ 269	$ 644	$ 688	$ 246	$ 614	$ 702	$ 983	$ 29
	GVSU (Solar)	$ 118	$ 220	$ 141	$ 122	$ -	$ -	$ -	$ -	$ -	$ -
	Hardy (Hydros)	$ 283	$ 335	$ 375	$ 886	$ 910	$ 347	$ 836	$ 645	$ 2,268	$ 1,782
	Hodenpyl (Hydros)	$ 220	$ 223	$ 198	$ 647	$ 641	$ 266	$ 708	$ 822	$ 1,930	$ 1,698
	Hydro Commons	$ 1,505	$ 383	$ 199	$ (3,183)	$ (3,123)	$ 760	$ (2,698)	$ (3,494)	$ (6,040)	$ (4,498)
	Jackson	$ 4,725	$ 3,634	$ 5,890	$ 5,569	$ 6,219	$ 2,851	$ 5,860	$ 5,806	$ 7,746	$ 6,000
	Karn	$ 22,492	$ 19,183	$ 29,970	$ 36,913	$ 28,482	$ 27,039	$ 16,554	$ 11,139	$ 14,903	$ 11,589
	Loud (Hydros)	$ 205	$ 198	$ 190	$ 604	$ 690	$ 201	$ 509	$ 540	$ 826	$ 674
	Ludington	$ 4,909	$ 1,661	$ 4,929	$ 5,224	$ 4,827	$ 3,360	$ 5,433	$ 6,017	$ 8,382	$ 6,877
	Mio (Hydros)	$ 209	$ 247	$ 216	$ 559	$ 675	$ 197	$ 648	$ 736	$ 897	$ 780
	Muskegon (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68	$ -	$ -	$ -
	Mustang Mile (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68	$ -	$ -	$ -
	Renewables Development	$ 9,341	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Rogers (Hydros)	$ 190	$ 277	$ 265	$ 651	$ 854	$ 206	$ 734	$ 795	$ 1,303	$ 1,052
	Solar Commons	$ 159	$ -	$ -	$ -	$ -	$ 387	$ -	$ -	$ -	$ -
	Tippy (Hydros)	$ 750	$ 2,611	$ 640	$ 1,020	$ 1,100	$ 759	$ 1,003	$ 1,035	$ 1,645	$ 1,423
	Washtenaw (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Weadock (Classic 7)	$ (240)	$ (53)	$ 0	$ (0)	$ 6	$ 18	$ 3	$ 15	$ -	$ -
	Webber (Hydros)	$ 141	$ 237	$ 224	$ 759	$ 892	$ 195	$ 726	$ 810	$ 1,096	$ 735
	Whiting (Classic 7)	$ (131)	$ (144)	$ 2	$ (0)	$ 85	$ 95	$ 25	$ 45	$ -	$ -
	WMU (Solar)	$ 93	$ 43	$ 36	$ 41	$ -	$ -	$ -	$ -	$ -	$ -
	Zeeland	$ 6,668	$ 6,322	$ 7,253	$ 6,645	$ 7,282	$ 7,972	$ 6,284	$ 6,069	$ 8,889	$ 6,876
2	**Environmental Operations**	**$ 24,258**	**$ 26,133**	**$ 10,485**	**$ 8,595**	**$ 10,092**	**$ 10,802**	**$ 9,225**	**$ 8,539**	**$ 5,110**	**$ 2,045**
	Campbell	$ 12,322	$ 13,659	$ 5,361	$ 4,861	$ 6,364	$ 6,781	$ 6,421	$ 6,513	$ 2,398	$ -
	Covert	$ -	$ -	$ -	$ -	$ -	$ -	$ 72	$ 142	$ 197	$ 152
	Hydro					$ -	$ -	$ 13	$ 11	$ 29	$ 22
	Jackson	$ 371	$ 444	$ 68	$ -	$ 137	$ 146	$ 135	$ 141	$ 208	$ 156
	Karn	$ 10,780	$ 11,433	$ 4,811	$ 3,635	$ 3,389	$ 3,579	$ 2,254	$ 1,488	$ 1,883	$ 1,416
	Ludington					$ -	$ -	$ 116	$ 68	$ 100	$ 76
	Weadock (Classic 7)	$ 336	$ 81	$ 35	$ 44	$ 11	$ -	$ -	$ -	$ -	$ -
	Whiting (Classic 7)	$ 203	$ 196	$ 50	$ 56	$ -	$ -	$ -	$ -	$ -	$ -
	Zeeland	$ 245	$ 320	$ 161	$ -	$ 191	$ 296	$ 213	$ 176	$ 295	$ 223
3	**Major Maintenance**	**$ 17,750**	**$ 44,378**	**$ 19,804**	**$ 25,088**	**$ 31,958**	**$ 32,411**	**$ 15,759**	**$ 28,844**	**$ 40,012**	**$ 32,982**
	Admin/Generation Commons	$ -	$ -	$ -	$ 26	$ -	$ -	$ -	$ -	$ 150	$ 150
	Adjustment					$ -	$ -	$ -	$ -	$ -	$ -
	Alcona (Hydros)	$ 430	$ 916	$ 461	$ -	$ 108	$ 505	$ -	$ 132	$ 25	$ 82
	Allegan (Hydros)	$ 587	$ 669	$ 868	$ 131	$ -	$ 579	$ -	$ 53	$ 25	$ 50
	Battery					$ -	$ -	$ -	$ -	$ 412	$ 126
	Cadillac (Solar)					$ -	$ -	$ -	$ -	$ -	$ -
	Campbell	$ 1,285	$ 10,246	$ 4,558	$ 8,496	$ 14,893	$ 6,503	$ 2,049	$ 1,495	$ 1,192	$ 279
	Circuit West (Solar)					$ -	$ -	$ -	$ -	$ -	$ -
	Cobb (Classic 7)	$ 39	$ 130	$ 103	$ -	$ 38	$ (662)	$ -	$ -	$ 109	$ 82
	Combustion Turbines					$ -	$ -	$ -	$ -	$ -	$ -
	Cooke (Hydros)	$ 520	$ 655	$ 600	$ -	$ -	$ 535	$ -	$ -	$ 407	$ 578
	Covert	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,144	$ 6,553	$ 8,681	$ 7,771
	Croton (Hydros)	$ (777)	$ 697	$ (1,060)	$ 180	$ 122	$ (1,136)	$ 24	$ 69	$ 75	$ -
	Electric Grid Integration					$ -	$ -	$ -	$ -	$ -	$ -
	Five Channels (Hydros)	$ (668)	$ (517)	$ (625)	$ -	$ -	$ -	$ -	$ 52	$ 145	$ 240
	Foote (Hydros)	$ 397	$ 741	$ 386	$ 85	$ 1	$ 496	$ 18	$ 974	$ 165	$ 1,005
	GVSU (Solar)					$ -	$ -	$ -	$ -	$ -	$ -
	Hardy (Hydros)	$ 696	$ 830	$ 686	$ 460	$ 236	$ 873	$ -	$ -	$ 470	$ 873
	Hodenpyl (Hydros)	$ 504	$ 661	$ 421	$ 45	$ 5	$ 531	$ -	$ -	$ 51	$ 143
	Hydro Commons	$ (761)	$ (383)	$ (199)	$ 3,183	$ 3,123	$ (760)	$ 2,685	$ 3,483	$ 6,011	$ 4,476
	Jackson	$ 3,510	$ 6,219	$ 2,716	$ 4,284	$ 3,982	$ 7,546	$ 2,822	$ 5,669	$ 5,712	$ 4,112
	Karn	$ 3,032	$ 7,887	$ 2,953	$ 2,792	$ 3,271	$ 6,898	$ 283	$ 2,027	$ 2,732	$ 1,824
	Loud (Hydros)	$ 361	$ 492	$ 317	$ -	$ -	$ 478	$ -	$ 47	$ -	$ 33
	Ludington	$ 2,621	$ 5,255	$ 2,865	$ 2,962	$ 2,712	$ 4,921	$ 2,533	$ 3,314	$ 5,842	$ 4,708
	Mio (Hydros)	$ 468	$ 742	$ 405	$ 47	$ -	$ 623	$ -	$ -	$ -	$ -
	Muskegon (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mustang Mile (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Renewables Development	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Rogers (Hydros)	$ 519	$ 890	$ 632	$ 16	$ -	$ 518	$ 29	$ 22	$ 44	$ 108
	Solar Commons	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Tippy (Hydros)	$ 312	$ 213	$ 332	$ -	$ 41	$ 233	$ -	$ -	$ 511	$ 605
	Washtenaw (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Weadock (Classic 7)	$ 72	$ 12	$ 12	$ 15	$ 7	$ 13	$ 30	$ -	$ 108	$ 81
	Webber (Hydros)	$ 644	$ 457	$ 475	$ 57	$ -	$ 942			$ 8	$ 180
	Whiting (Classic 7)	$ 29	$ 46	$ 66	$ 10	$ -	$ 13	$ 22	$ -	$ 73	$ 55
	WMU (Solar)					$ -	$ -	$ -	$ -	$ -	$ -
	Zeeland	$ 3,930	$ 7,522	$ 2,831	$ 2,300	$ 3,419	$ 2,761	$ 3,121	$ 4,954	$ 7,063	$ 5,419
4	**Retention & Separation**	**$ -**	**$ -**	**$ 5,921**	**$ 12,028**	**$ 6,958**	**$ 2,339**	**$ 17,348**	**$ 8,626**	**$ 5,182**	**$ -**
	Campbell	$ -	$ -	$ -	$ -	$ -		$ 15,847	$ 8,626	$ 5,182	$ -
	Karn	$ -	$ -	$ 5,921	$ 12,028	$ 6,958	$ 2,339	$ 1,501	$ -	$ -	$ -
5	**TOTAL O&M**	**$ 156,097**	**$ 148,231**	**$ 133,024**	**$ 152,533**	**$ 155,204**	**$ 150,031**	**$ 118,848**	**$ 128,434**	**$ 150,445**	**$ 103,732**
	Admin/Generation Commons	$ 1	$ 1,407	$ (3,013)	$ (1,558)	$ (1,173)	$ 4,302	$ 873	$ 3,974	$ 12,271	$ 9,252
	Adjustment					$ -	$ -	$ -	$ -	$ -	$ -
	Alcona (Hydros)	$ 662	$ 1,131	$ 678	$ 713	$ 836	$ 736	$ 639	$ 1,112	$ 1,213	$ 1,072
	Allegan (Hydros)	$ 727	$ 908	$ 1,080	$ 889	$ 766	$ 762	$ 752	$ 717	$ 1,068	$ 876
	Battery					$ -	$ -	$ 30	$ 405	$ 1,033	$ 1,443
	Cadillac (Solar)	$ 47	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -
	Campbell	$ 41,480	$ 45,980	$ 49,098	$ 46,849	$ 59,008	$ 49,344	$ 43,327	$ 41,340	$ 20,487	$ 279
	Circuit West (Solar)	$ 42	$ -	$ -	$ 18	$ -	$ -	$ -	$ -	$ -	$ -
	Cobb (Classic 7)	$ 99	$ 402	$ 161	$ 124	$ 87	$ 89	$ 34	$ 42	$ 109	$ 82
	Combustion Turbines	$ 775	$ 702	$ 298	$ 5	$ -	$ -	$ -	$ -	$ -	$ -
	Cooke (Hydros)	$ 711	$ 853	$ 810	$ 643	$ 754	$ 744	$ 683	$ 804	$ 1,138	$ 1,034
	Covert	$ 11,943	$ -	$ -	$ -	$ -	$ 4	$ 7,413	$ 13,508	$ 18,800	$ 14,858
	Croton (Hydros)	$ 966	$ 6,475	$ 967	$ 1,149	$ 1,176	$ 1,371	$ 1,455	$ 1,434	$ 1,443	$ 1,274
	Electric Grid Integration(Energy Supply)	$ 17,846	$ 9,725	$ 5,475	$ 13,873	$ 15,248	$ 16,780	$ 11,276	$ 10,118	$ 15,682	$ 12,111
	Five Channels (Hydros)	$ 646	$ 932	$ 729	$ 708	$ 790	$ 890	$ 717	$ 926	$ 1,065	$ 918
	Foote (Hydros)	$ 643	$ 1,025	$ 655	$ 730	$ 688	$ 742	$ 632	$ 1,676	$ 1,148	$ 1,034
	GVSU (Solar)	$ 118	$ 220	$ 141	$ 122	$ -	$ -	$ -	$ -	$ -	$ -
	Hardy (Hydros)	$ 979	$ 1,165	$ 1,062	$ 1,346	$ 1,146	$ 1,220	$ 836	$ 645	$ 2,738	$ 2,656
	Hodenpyl (Hydros)	$ 724	$ 884	$ 619	$ 692	$ 646	$ 797	$ 708	$ 822	$ 1,981	$ 1,841
	Hydro Commons	$ 744	$ -	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ -
	Jackson	$ 8,606	$ 10,298	$ 8,674	$ 9,853	$ 10,338	$ 10,544	$ 8,817	$ 11,616	$ 13,666	$ 10,269
	Karn	$ 36,304	$ 38,503	$ 43,655	$ 55,367	$ 42,100	$ 37,516	$ 19,091	$ 14,653	$ 19,518	$ 14,829
	Loud (Hydros)	$ 565	$ 688	$ 507	$ 604	$ 690	$ 679	$ 509	$ 587	$ 826	$ 708
	Ludington	$ 7,530	$ 6,917	$ 7,794	$ 8,186	$ 7,539	$ 8,281	$ 8,083	$ 9,399	$ 14,324	$ 11,661
	Mio (Hydros)	$ 677	$ 988	$ 621	$ 606	$ 675	$ 820	$ 648	$ 736	$ 897	$ 780
	Muskegon (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68	$ -	$ -	$ -
	Mustang Mile (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68	$ -	$ -	$ -
	Renewables Development	$ 9,341	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Rogers (Hydros)	$ 708	$ 1,166	$ 897	$ 667	$ 854	$ 724	$ 763	$ 818	$ 1,347	$ 1,160
	Solar Commons	$ 159	$ -	$ -	$ -	$ -	$ 387	$ -	$ -	$ -	$ -
	Tippy (Hydros)	$ 1,062	$ 2,824	$ 972	$ 1,020	$ 1,141	$ 992	$ 1,003	$ 1,035	$ 2,156	$ 2,028
	Washtenaw (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Weadock (Classic 7)	$ 168	$ 41	$ 47	$ 59	$ 24	$ 31	$ 33	$ 15	$ 108	$ 81
	Webber (Hydros)	$ 785	$ 694	$ 699	$ 816	$ 892	$ 1,138	$ 726	$ 810	$ 1,104	$ 915
	Whiting (Classic 7)	$ 102	$ 98	$ 118	$ 66	$ 85	$ 108	$ 47	$ 45	$ 73	$ 55
	WMU (Solar)	$ 93	$ 43	$ 36	$ 41	$ -	$ -	$ -	$ -	$ -	$ -
	Zeeland	$ 10,843	$ 14,163	$ 10,244	$ 8,945	$ 10,893	$ 11,029	$ 9,618	$ 11,199	$ 16,248	$ 12,518

Methodology for Quantifying Capital Investment Risk with Copperleaf Value Models – Consumers Energy

Purpose and scope

This document explains how the Company converts engineering and operational risk into dollar-denominated values for investment evaluation. It is intended for the reader to understand the logic behind the results; it does not require access to internal tools or data libraries. The same expected-value reasoning is applied year by year and results are discounted to present value using the Company's approved discount rate.

Model overview

The Company employs multiple model families; this document illustrates three commonly used examples:

1. Financial Risk Matrix — converts the chance of an adverse event and its consequence into an expected annual cost; value equals the risk avoided by the investment.
2. Lost Generation Risk (Energy Only) — quantifies the dollar value of lost energy (MWh) from derates or outages; value equals the avoided energy loss.
3. Financial Benefits & Costs — prices direct financial effects (costs avoided, revenues, and ongoing costs).

Principal value drivers

In practice, the Financial Risk Matrix and Lost Generation Risk models are the most widely used and account for the majority of risk-mitigation value in the Company's Long-Term Financial Plan. Capacity value lost risk is handled within the Financial Risk Matrix to avoid overlap with energy-only valuation.

Common frame (applies to all models)

- Baseline vs With-Project ("Outcome"): Baseline represents conditions if we do nothing; Outcome represents conditions after the investment. Annual value is the difference: Annual Value ($) = Baseline Expected Impact ($) − Outcome Expected Impact ($).
- Expected value: Uncertain events are priced by multiplying their consequence (in $ if they occur) by how likely they are to occur that year. This yields a single expected $ figure for the year.
- Discounting: After computing annual values across the planning horizon, we calculate NPV using a constant discount rate specified by Company finance policy.
- Evidence base (examples): work orders and repair history; outage/derate logs and time-to-restore; unit operating profile and duty cycle; inspection findings and sensor trends; OEM notices; age/obsolescence; supply-chain lead times; peer and industry

experience (including EPRI guidance); and structured SME judgments recorded through Company procedures.

1) Financial Risk Matrix (general risk in dollars)

What it measures: the expected annual cost of a defined hazard (safety, environmental, compliance, or financial), and the amount of that cost the project removes.

How it works, step by step

- Define the hazard and pathway. We state what can go wrong, how it unfolds, and which impact categories it touches. This ensures the risk we price is specific and non-overlapping with other models.
- Monetize the consequence. For each year, we determine the dollar impact if the event occurs in that year. This can include response and repair cost, regulatory or contractual impacts, and business effects appropriate for that hazard. Values are drawn from Company-maintained sources that reflect current costs and obligations.
- Quantify how often it may occur. For each year, we express likelihood as either a frequency (events per year) or a probability for that year. Figures are derived from the evidence base above and recorded through our governance process.
- Convert uncertainty into dollars. Expected annual risk equals consequence × likelihood. This yields a single dollar amount for that year under Baseline.
- Reflect the project's effect. With the project in place, severity and/or frequency typically decline. We determine the with-project consequence and likelihood in the same manner and compute the Outcome expected risk.
- Value created. Annual value is the avoided risk (Baseline minus Outcome). We then discount and sum across years to get NPV.

Capacity value lost risk (handled here)

- Use Capacity Calculator outputs for each year to identify the magnitude and timing of potential capacity exposure relative to accreditation or obligations. These exposure drivers are not re-estimated here.
- Monetize the exposure by applying the Company's capacity valuation parameters for the relevant years (market/regulatory cost components for our jurisdiction and obligations). These parameters are maintained internally and updated on defined cycles as conditions change. The result is a dollar consequence if the exposure materializes in that year.
- Account for chance by assigning, for each year, the likelihood that the exposure will materialize as a dollar impact, consistent with the same evidence base and governance protocols used elsewhere.
- Compute expected annual capacity value loss under Baseline and re-compute under Outcome if the project reduces the exposure (magnitude, timing, or likelihood). The difference is the annual value attributable to mitigating capacity value risk.

2) Lost Generation Risk (energy only)

What it measures: the dollar value of lost energy production due to unit derates or full outages and the portion of that loss the project avoids. This model does not address capacity market value or capacity accreditation.

How it works, step by step

- Describe the operational shortfall for each year: either a derate (the unit can run but at reduced MW) or a complete outage (the unit cannot produce). Specify the MW affected and the expected duration to restore normal operation.
- Translate MW and time into energy. Lost MWh per event equals MW affected × 24 hours × number of days, adjusted for how the unit is expected to operate during that period (capacity factor for the affected window). Operating profiles come from Company-maintained sources that reflect expected duty cycles.
- Monetize the lost energy. Multiply lost MWh by the applicable energy value ($/MWh) for that year (net of costs as appropriate). Energy values are obtained from Company-maintained price/valuation sources refreshed on defined cycles.
- Account for chance. Express how often such a derate/outage is expected in that year (frequency or probability) based on history, condition, and SME protocols, and multiply by the dollar consequence to get the expected annual loss under Baseline.
- Project effect. The project may shorten the duration, reduce the MW affected, reduce the likelihood, or some combination. Recompute the Outcome expected loss with those changes.
- Value created. Annual value is the avoided energy loss; NPV aggregates those annual values.

3) Financial Benefits & Costs

Note: This model does not include capacity value lost risk; those impacts are valued within the Financial Risk Matrix using outputs from the Capacity Calculator.

What it measures: direct financial effects that show up as dollars—costs we avoid, revenues we gain, or ongoing costs attributable to the project.

How it works, step by step

- Identify the financial streams that the project influences (e.g., avoided corrective capex, avoided O&M, incremental revenue, or ongoing costs attributable to the project). Streams are kept distinct to prevent double-counting.
- Size the dollar amounts for each stream by year, using Company-maintained financial and operational sources (e.g., standard labor/material costs, contract terms, or tariff mechanisms).
- Represent uncertainty by assigning a likelihood (0–1) for each stream in each year, following the same governance used elsewhere.

- Compute expected value for each stream and year (amount × likelihood) and sum across streams to obtain the net annual financial effect.
- Value created is the net with-project improvement relative to Baseline, discounted to NPV.

Additional model families employed

- Safety Risk (personnel and public harm, medical/claim costs, and associated operational impacts)
- Regulatory Compliance Risk (violations, penalties, corrective actions, and programmatic impacts)
- Environmental Risk (releases, remediation/response, permitting, and stewardship commitments)
- Other specialized models are applied as warranted by the investment context. All follow the same expected-value logic and governance described in this document.

Relationship to prior business-case practice

- Alignment with prior business-case practice.
    - These value models formalize the same expected-value logic historically used in our narrative business cases (likelihood × impact by year, discounted to present value).
- Structured improvements introduced by Copperleaf.
    - The platform enforces a consistent, systematic structure across all investments: common Baseline vs Outcome framing; governed, Company-maintained input sources updated on defined cycles; a uniform year-by-year treatment of uncertainty; and a single NPV roll-up.
- Implications for portfolio decision-making.
    - This removes variability in author style and assumptions, places projects on a level playing field, enables like-for-like comparison across technologies and sites, and gives leadership a clear portfolio view of risk and value.
- Impact for customers and ratepayers.
    - A more objective, repeatable method for selecting the optimal risk-mitigation portfolio—supporting lower total cost and better reliability outcomes.

Governance, transparency, and QA

- Recorded reference values: For each plant, we keep the values that drive the calculations—Net Energy Value (NEV), Net Demonstrated Capacity (NDC), fuel cost, and capacity factor—and update them on defined cycles as those inputs change. Other supporting engineering context is maintained separately; we don't time-stamp every data point inside the value model.

- Consistency: The same rules are applied to Baseline and Outcome; differences in value come from the project's effect, not from changing the standard.
- Reasonableness checks: Unit consistency (e.g., MW→MWh, $/MWh→$), bounds on probabilities, and year-to-year continuity are verified.
- Change control: When inputs are updated, the prior set and the new set are retained; impacts of changes can be traced year by year.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Eugène M.J.A. Breuring and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as a Principal Sales Forecast Analyst in Sales Forecasting in the Financial Planning & Analysis Department.

Q. Are you the same Eugène M.J.A. Breuring who previously filed direct testimony in Case No. U-21870 on behalf of Consumers Energy?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal is to provide rebuttal to the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Paul R. Ausum.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

REBUTTAL OF STAFF WITNESS AUSUM

Q. In the direct testimony of Staff witness Ausum, page 5, lines 4 through 10, he recommends an increased deliveries adjustment of 204,656 MWh for bundled service and 16,308 MWh for choice service. This represents about 1.8% of the commercial forecast for the test year load. Do you agree with this adjustment?

A. No. I do not believe an increase in projected commercial test-year deliveries is warranted.

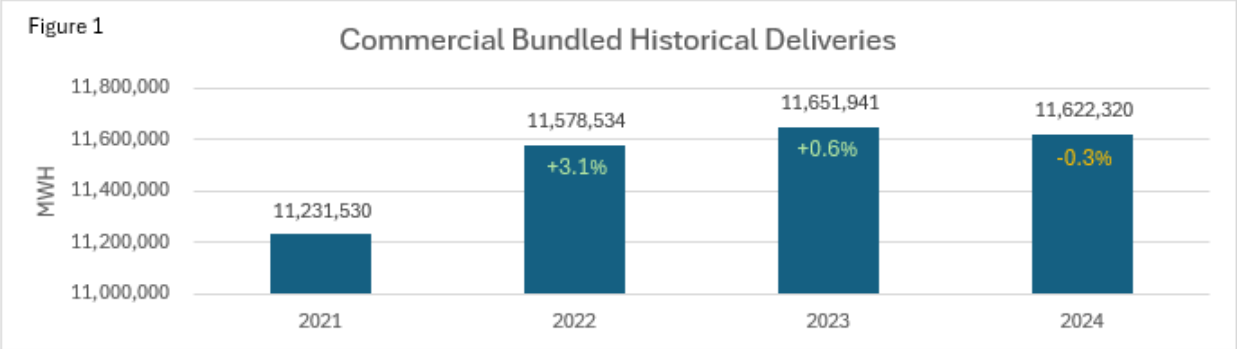
Q. Why don't you agree with Staff witness Ausum's suggested increase to the commercial forecast?

A. There are numerous reasons why I disagree with the suggested increase in the commercial load forecast, such as historical trends, limited analysis, and regression model limitations.

Q. Could you elaborate on the historical trends of the commercial bundled class and how they compare to those considered in Staff's forecasting process?

A. Since 2020, the commercial bundled class has been undergoing a recovery from the impacts of the COVID-19 pandemic. While electric consumption initially rebounded, growing by 3.1% in 2022, it began to stabilize in 2023 with a modest increase of 0.6%, and then declined slightly by 0.3% in 2024.[1] These figures reflect a return to more normalized consumption patterns, and this trend is illustrated in Figure 1.

Figure 1



Q. What is the cause of the normalizing trend, shown in Figure 1?

A. As previously noted, the initial surge in commercial electric deliveries following the pandemic has gradually normalized. This normalization is primarily driven by persistent downward pressure from Energy Waste Reduction ("EWR") initiatives, which reduce

[1] Part III, att 015, cycle-billed deliveries.

deliveries by approximately 1.8%[2] annually. While growth factors such as economic activity, increases in customer count, and electric vehicle ("EV") adoption provide some upward momentum, each of their impacts have been modest. Historical delivery growth remains marginal, reflected in a compound annual growth rate ("CAGR") of just +0.2%[3] from 2022 to 2024. In essence, the declining trend is the result of sustained EWR savings that are not sufficiently counterbalanced by other growth drivers to produce meaningful net growth.

Q. How does Staff's suggested increase in commercial bundled deliveries stack up against recent historical delivery trends?

A. Incorporating Staff's proposed increase in commercial bundled deliveries results in a projected two-year CAGR of 1.0% for the test year. In contrast, the Company's forecast reflects a more modest two-year CAGR of 0.1%, which is in line with the two-year historical CAGR of +0.2%. This disparity highlights a significant deviation from recent historical trends, as illustrated in the tables below and Figure 2.

Consumers Energy Projection (original)

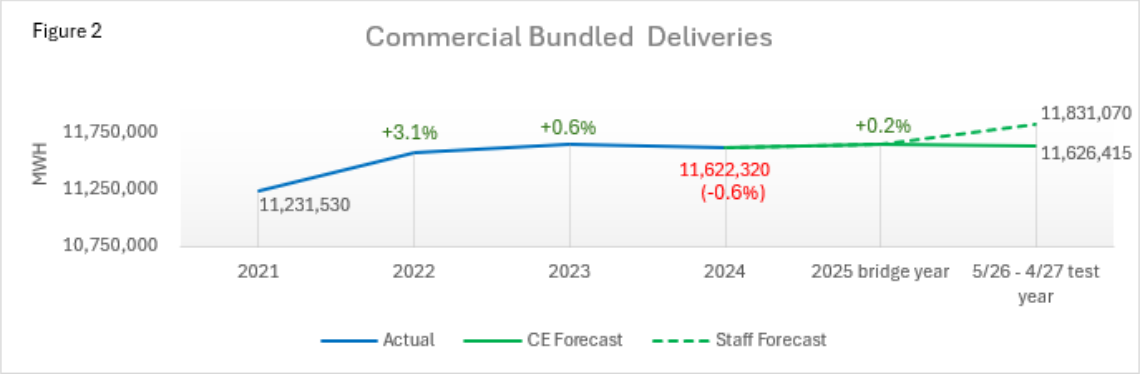
	Year	MWh	CAGR
act/fcst	2024/2025	11,597,766	
test yr.	2026/2027	**11,626,415**	**0.1%**

MPSC Staff Projection (suggested)

	Year	MWh	CAGR
act/fcst	2024/2025	11,597,766	
test yr.	2026/2027	**11,831,071**	**1.0%**

[2] Direct testimony, Company witness Breuring, page 18, lines 20-22 to page 19, lines 1-2.
[3] 2022: 11,578,534 MWh; 2024: 11,622,320 MWh. CAGR: (11,622,320/11,578,534) ^(1/2)-1 = 0.2%

Figure 2



Achieving a 1.0% annual growth rate by the test year, as Staff witness Ausum suggests, represents a significant departure from recent historical delivery trends, as shown in Figure 1. Such growth would only be plausible under conditions of substantial expansion in EV adoption, economic activity, commercial customer counts, or a combination thereof.

Q. Aren't we experiencing higher growth in EVs in the Commercial sector?

A. Yes, however, that growth (+0.47% CAGR)[4] has already been incorporated into the Company's test year forecast. Therefore, it is highly improbable that the EV projections—provided by Company witness Jeffrey A. Myrom—are understated by as much as 24%, or an incremental 152,000 vehicles.[5]

Q. If the EV count is not contributing to Staff's suggested incremental growth, can the economy in the Company's service territory facilitate the proposed growth in commercial deliveries?

A. Unlikely. As outlined in my direct testimony,[6] the primary growth drivers in the regression models are key economic indicators sourced from S&P Global, a reputable provider of industry-specific forecast data tailored to the Company's service territory.

[4] Based on EV count established in current forecast: 43,519 EVs (April 2025) to 122,989 EVs (end of test year).
[5] Based on my calculations, all else being equal, an additional 152,000 electric vehicles in Consumers Energy's service territory by the end of the test year would result in approximately 204,656 MWh of increased electric deliveries, the suggested increase by Staff witness Ausum.
[6] Direct testimony, Company witness Breuring, page 5, lines 3-7 and page 9, lines 14-17.

Upon reviewing the indicators used in both the Company's regression model (service employment) and Staff's model (non-manufacturing employment), the two-year CAGRs leading up to the end of the test year are just 0.1% and 0.17%, respectively.[7] These modest growth rates do not support the level of commercial delivery increase proposed by Staff.

Q. If not EV growth, nor economic expansion, how about growth in customer counts in the commercial sector? Can that support Staff's suggested commercial delivery growth?

A. No. The two-year CAGR for bundled commercial customer count leading up to the end of the test year shows a reduction of -0.22%.[8] Furthermore, Staff utilized the same customer count projections as the Company, indicating no material difference in assumptions.

Q. Are there any other concerns around Staff's sales increase suggestion?

A. Yes. Staff's proposed increase in commercial sales appears to be based solely on the output of their regression modeling, without incorporating additional context or expert judgment. This narrow approach overlooks the importance of integrating recent trends and forecaster experience, which are essential for producing accurate and responsive load projections.

Q. Why is it a concern that Staff's forecast focuses solely on its regression model results?

A. It's a concern because in the process of electric load projections, it is imperative that forecasters also utilize the human factor. In other words, the forecaster's experience, viewed through the lens of their expertise, can be very helpful in spotting certain trends, especially in the more recent history. Our models (both the Company and Staff use the

[7] Source data is the S&P Global for key economic indicators as used in both Consumers Energy and Staff regression models.
[8] Source: Part III att 015 and 016. 5/2024 – 4/2025 avg.: 230,281 custs. 5/2026 – 4/2027 avg.: 229,272 custs. CAGR: (229,272/230,281) ^(1/2)-1 = -0.22%.

same historical window) utilize historical data going back over 10 years (January 2014), so more recent trends and developments can be spotted by careful scrutiny in light of the forecaster's professional experience. As the authors of a recent study observed, "Comparative studies of quantitative methods and human judgement show that (1) neither method is universally superior, and (2) the better method varies…suggesting that (3) the two approaches can complement each other to yield more accurate and resilient models."[9] This hybrid approach is very common in the forecasting world as electric load forecasting (as well as customer counts and peak demands) demands both precision and adaptability. Electric load forecasting requires both analytical precision (using regression models) and adaptive insight (based on the forecaster's experience). As explained in my direct testimony, pages 4 and 5, multiple explanatory variables (such as economic indicators, temperature, etc.) are introduced into the regression models, which provides models that offer consistency and scalability, making them indispensable for baseline forecasts. Drawing on over 13 years of utility-specific forecasting experience, I've found that integrating human judgment with model outputs allows for timely adjustments that reflect current conditions more accurately. This hybrid approach, merging statistical models with expertise, results in forecasts that are not only more reliable but also more responsive to change.

Q. In utilizing this hybrid approach, what kind of adjustments did you make to the forecast?

A. Consumers Energy's commercial electric load forecast includes manual adjustments that improve accuracy by aligning recent growth trends with model outputs. These adjustments

[9] Zellner, M., Abbas, A. E., Budescu, D. V., & Galstyan, A. (2021). *A survey of human judgement and quantitative forecasting methods*. Royal Society Open Science, 8(201187). Abstract. https://doi.org/10.1098/rsos.201187.

reflect the latest data on EV adoption, economic activity, and customer growth in the Company's service territory. The final forecast, shown earlier in Figure 2, incorporates both regression modeling and expert judgment to ensure projections match current conditions.

Q. Did Staff's forecast process also use this hybrid approach?

A. No. Staff's forecast relies almost entirely on its regression model output. However, instead of developing its own manual adjustment to reflect recent trends, Staff adopted the Company's absolute adjustment value. While the Company used this adjustment in conjunction with its regression model to align with observed growth rates over the past 12-24 months, Staff applied the same fixed value directly to its own model without further refinement. This approach results in a growth rate that lacks proper justification. As shown in Figure 2, the projected growth appears overstated, especially when considering the downward pressure from EWR savings of -1.8%, annually. And, as mentioned earlier, Consumers Energy's service territory currently is not experiencing the kind of growth factors, in the commercial sector, that can offset the negative growth pressures of EWR and turn it into an annual growth rate of +1.0% by the end of the test year. There is simply no evidence to support this.

Q. Staff has introduced MetrixND regression modeling software for the first time this rate case to aid in assessing test year projections. Have you evaluated their regression model as it relates to the commercial deliveries projections?

A. Yes. With a few exceptions, Staff's regression models closely resemble those developed by Consumers Energy. However, Staff opted to use a different economic variable, non-manufacturing employment, in place of the Company's service employment metric to

drive model growth. Additionally, Staff introduced an extra explanatory variable, labeled "constant," in an effort to enhance the model's performance.

Q. Do you see an issue with Staff's commercial regression model?

A. Not entirely. While Staff's model utilizes a different economic driver (non-manufacturing employment), this variation does not materially affect the final delivery forecasts. Regression models are inherently flexible and can accommodate a broad range of valid explanatory variables. However, the inclusion of a "constant" variable raises concerns regarding the model's statistical robustness and explanatory relevance.

Q. Why is the "constant" variable deficient?

A. As outlined in my direct testimony,[10] the relevance of independent variables, like Staff's constant variable, in regression modeling is typically assessed using statistical indicators such as the t-statistic ("t-stat") and p-value. A t-stat greater than 2 and a p-value below 5% generally indicate that a variable contributes meaningfully to explaining the dependent variable. Variables that fall outside these thresholds should be excluded due to their limited explanatory power.

Staff's newly introduced "constant" variable does not meet these criteria, with a t-stat of 1.43 and a p-value of 15.54%,[11] suggesting it is statistically weak and unlikely to enhance the model's predictive accuracy.

[10] Company witness Breuring, direct testimony, pages 7 (lines 10-23) and 8 (lines 1-4).
[11] Staff witness Ausum, Exhibit S-15.9, "Staff Model Coefficients."

Q. Does the introduction of an independent variable that does not meet standard statistical criteria (e.g. t-stat > 2, p-value < 5%) hurt the model, and should such a variable be removed?

A. Not necessarily. Including a statistically weak variable does not inherently harm the model's performance; however, it also does not contribute meaningful explanatory power. Such a variable may simply add noise rather than insight. While it may not degrade the model's predictive accuracy, its inclusion offers limited value and should be carefully considered, especially when model parsimony and interpretability are priorities.

Q. Do you believe the Company's use of two separate commercial regression models, a 'use-per-customer' model and a 'total delivery' model, results in a less accurate forecast, as suggested by Staff witness Ausum in his direct testimony[12]?

A. I disagree with Staff witness Ausum's characterization of the Company's use of two separate commercial regression models, a "use-per-customer" model and a "total delivery" model, as delivering a less accurate forecast. This dual-model approach does not inherently reduce accuracy; rather, it introduces a valuable level of flexibility, as explained during discovery[13] and allows for cross-validation between different forecasting perspectives. While each model may have its own strengths and limitations, using both helps mitigate the risks associated with relying on a single methodology.

Although one model may appear statistically superior, particularly given that the models use different independent variables and therefore cannot produce identical results, the two-model framework, which is also employed in the Company's residential modeling,

[12] Staff witness Ausum, direct testimony, page 9 (lines 8-18).
[13] Discovery Response No. U21870-ST-CE-0086.

enhances the robustness of the projections. This methodology enables forecasters to balance the strengths and weaknesses of each model.

Since each model yields slightly different results, applying different weightings, in this case 60/40 (60% 'total delivery' and 40% 'use-per-customer'), can offer a more balanced analytical perspective. While it can be argued, as Staff witness Ausum did, that one model may be superior to another, it is important to recognize that no model is perfect. Forecasting methods are inherently subjective and often tailored to the individual forecaster's judgment and experience. Ultimately, accuracy should be evaluated based on the statistical performance of each model and the reasonableness of the final forecast, not solely on the number of models employed.

Q. Staff also suggests an increase in the sales projection of commercial choice of 16,308 MWh. Do you agree with this suggested increase?

A. No. Consumers Energy does not support any increase in its test year sales projections, whether for bundled or choice service, for the reasons outlined throughout this rebuttal testimony.

Q. Does Mr. Ausum suggest any other changes to the test year projections in this case?

A. No.

SUMMARY

Q. Would you please summarize why you disagree with Staff witness Ausum's proposed increase in commercial electric bundled and choice test year deliveries?

A. Consumers Energy disagrees with Staff witness Ausum's recommendation to increase the test year bundled and choice commercial deliveries by 204,656 MWh and 16,308 MWh,

respectively, for a total of 220,963 MWh. The following points summarize Consumers Energy's rebuttal testimony:

- **Historical Trends**: Commercial electric consumption has stabilized post-pandemic, with minimal growth from 2022 to 2024. The proposed increase contradicts this trend.
- **Forecasting Methodology**: Consumers Energy uses a hybrid approach combining regression modeling with expert judgment. This method accounts for recent trends and ensures more accurate projections.
- **Staff's Approach**: Staff relies solely on regression model outputs and applies a fixed adjustment without refinement, resulting in a projected growth rate that lacks empirical support.
- **Economic and Customer Growth Indicators**: Economic indicators and customer count growth are modest (CAGRs of 0.1%–0.17%), insufficient to justify the proposed increase.
- **EV Adoption**: Growth in EVs is already factored into the Company's forecast. Additional EVs required to support Staff's adjustment would imply a 24% underestimation, which is highly unlikely.
- **Regression Model Concerns**: Staff's use of a statistically weak "constant" variable (t-statistic of 1.43, p-value of 15.54%) raises concerns about model robustness and explanatory power.
- **Dual-Model Approach**: Consumers Energy's use of both "use-per-customer" and "total delivery" models enhances forecast reliability through cross-validation, contrary to Staff's critique.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

ANN E. BULKLEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

TABLE OF CONTENTS

I.	INTRODUCTION	1
II.	SUMMARY OF ANALYSES AND CONCLUSIONS	3
III.	RESULTS OF UPDATED COST OF EQUITY ANALYSES	6
IV.	AUTHORIZED ROES AND THE COMPARABLE RETURN STANDARD	8
V.	PROXY GROUP	24
VI.	DCF ANALYSIS	33
VII.	CAPM ANALYSIS	52
	A. Risk-Free Rate	55
	B. Market Risk Premium	57
	C. Beta Coefficients	69
	D. Response to Intervenor Positions	70
	E. Adjusted CAPM Results	79
VIII.	ECAPM ANALYSIS	81
IX.	BOND YIELD RISK PREMIUM ANALYSIS	91
X.	SUMMARY OF THE ADJUSTED RESULTS	115
XI.	BUSINESS RISK	120

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal at The Brattle Group ("Brattle"), a consulting firm that advises clients on regulatory finance and ratemaking issues.

Q. Are you the same Ann E. Bulkley that previously filed direct testimony in this proceeding?

A. Yes. I previously submitted direct testimony before the Michigan Public Service Commission ("MPSC" or the "Commission") in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the issues raised in the testimonies of Kirk D. Megginson on behalf of the Commission Staff ("Staff"),[1] Sebastian Coppola on behalf of the Attorney General,[2] Matthew J. Bandyk on behalf of Citizens Utility Board of Michigan ("CUB"),[3] Christopher C. Walters on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"),[4] and Matthew T. Lyon on behalf of Walmart Inc.,[5] regarding the just and reasonable return on equity ("ROE") for the Company in this

[1] Michigan Public Service Commission, Case No. U-21870, Testimony of Kirk D. Megginson, September 30, 2025 ("Megginson Direct").

[2] Michigan Public Service Commission, Case No. U-21870, Testimony of Sebastian Coppola, September 30, 2025 ("Coppola Direct").

[3] Michigan Public Service Commission, Case No. U-21870, Testimony of Matthew J. Bandyk, September 29, 2025 ("Bandyk Direct").

[4] Michigan Public Service Commission, Case No. U-21870, Testimony of Christopher W. Walters, September 30, 2025 ("Walters Direct").

[5] Michigan Public Service Commission, Case No. U-21870, Testimony of Matthew T. Lyon, September 30, 2025 ("Lyon Direct").

proceeding. To the extent that I do not address a particular issue raised by these witnesses in my rebuttal testimony, it should not be viewed as acceptance of that issue.

Q. Are you sponsoring any exhibits in support of your rebuttal testimony?

A. I am sponsoring the following exhibits:

Exhibit A-206 (AEB-2) Cost of Common Shareholder's Equity; and

Exhibit A-207 (AEB-3) Work Papers AG-37B, AG-39A, and AG-39B.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

Q. Have you updated the cost of equity analyses that you presented in your direct testimony to reflect current market conditions?

A. Yes. As discussed in more detail herein, I have updated my cost of equity analyses based on market data through September 30, 2025. These results continue to support the ROE range of 10.25% to 11.25% that I recommended in my direct testimony and the Company's requested ROE of 10.25%. While the analytical results of the cost of equity estimation models provide a starting point, I continue to base my recommendation on consideration of not only the results of multiple cost of equity models, but also other factors, including capital market conditions, the capital attraction and comparable return standards, and Company-specific risks.

Q. How is the remainder of your rebuttal testimony organized?

A. The remainder of my rebuttal testimony is organized as follows:

- Section II provides a summary and overview of my rebuttal testimony and the important factors to be considered in establishing the authorized ROE for the Company.
- Section III provides cost of equity analyses based on market data as of September 30, 2025.

- Section IV provides the expected market return as well as discusses authorized ROEs for comparable utilities nationwide relative to the witnesses' ROE recommendations in this proceeding.

- Section V provides my response to the issues raised by the parties regarding the proxy group.

- Section VI provides my response to the issues raised by the parties regarding the Discounted Cash Flow ("DCF") model.

- Section VII provides my response to the issues raised by the parties regarding the Capital Asset Pricing Model ("CAPM") analysis.

- Section VIII provides my response to the issues raised by the parties regarding the Empirical CAPM ("ECAPM") analysis.

- Section IX provides my response to the issues raised by the parties regarding the Bond Yield Plus Risk Premium ("BYRP") analysis.

- Section X provides the adjusted results of the cost of equity analyses of Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters based on the issues that I have identified with their respective analyses.

- Section XI provides my response to the issues raised by the parties regarding the Company's business risks.

II. SUMMARY OF ANALYSES AND CONCLUSIONS

Q. What factors should be considered in evaluating the results of the cost of equity analyses and establishing the authorized ROE?

A. The primary factors that should be considered are: (1) the importance of providing a return that is comparable to returns on alternative investments with commensurate risk; (2) the need for a return that supports a utility's ability to attract needed capital at reasonable terms; (3) the effect of current and expected capital market conditions; and (4) achieving a reasonable balance between the interests of investors and customers.

Q. What are the ROE recommendations of the parties in this proceeding?

A. Figure 1 summarizes the results of the analyses presented by Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters in this proceeding and each of their final ROE recommendations.

Figure 1: Summary of Cost of Equity Analyses Results and ROE Recommendations of Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters

Methods	Megginson	Coppola	Bandyk	Walters
DCF				
Constant DCF	9.76%	9.57%	-	8.85%-9.05% and 10.50%-11.05%[6]
Two-Stage DCF	-	-	8.96%	-
Multi-Stage DCF	-	-	-	8.21%-8.62%
CAPM	7.85%-10.05%	9.98%	8.11%	7.15%-10.88%
Risk Premium	10.23%-10.46%	9.81%	-	9.85%-9.93%
Current Authorized ROE	-	-	9.90%	-
Recommended ROE Range	9.25%-10.25%	-	-	9.00%-10.00%
Recommended ROE	**9.75%**	**9.80%**	**9.22%**	**9.50%**

Mr. Lyon does not estimate the cost of equity for the Company using any of the traditional estimation methodologies but rather evaluates average authorized ROEs for vertically integrated electric utilities nationally from 2023 through thus far in 2025.[7]

[6] Mr. Walters's results of 8.85% to 9.05% use a "sustainable growth" rate, and the results of 10.50% to 11.05% use analyst earnings growth projections.

[7] Lyon Direct, pages 13-17.

Q. What are your key conclusions and recommendations regarding the appropriate ROE for the Company?

A. Nothing in the direct testimonies of Mr. Megginson, Mr. Coppola, Mr. Bandyk, Mr. Walters or Mr. Lyon has caused me to change my conclusions or recommendations. My key conclusions regarding a reasonable ROE for the Company in this proceeding are as follows:

Cost of Equity

- Updated cost of equity analyses based on data through September 30, 2025 continue to support the reasonableness of the Company's proposed ROE of 10.25%.

- Mr. Bandyk recommends an ROE that is more than a *68-basis point decrease* relative to the Company's currently authorized ROE, which is primarily a function of his average CAPM estimate that is substantially below any authorized ROE for a natural gas or electric utility since at least 1980.

- When reasonable adjustments are reflected to the cost of equity analyses prepared by Mr. Megginson, Mr. Coppola, Mr. Bandyk, and Mr. Walters to update and correct their analyses, it demonstrates that the Company's proposed ROE is reasonable.

    - The adjusted results of Mr. Megginson's, Mr. Coppola's, Mr. Bandyk's, and Mr. Walters's analyses indicate a cost of equity in the range of 10.03% to 10.47%, which is supportive of the Company's proposed ROE of 10.25%.

- There is no basis to Mr. Bandyk's claim that regulators have incorrectly authorized ROEs substantially higher than the cost of equity for decades.

- No intervening witness has independently evaluated the comparative risk of the Company relative to their respective proxy groups. Therefore, there is no basis to conclude that the risk factors that I evaluated in my direct testimony should not be considered.

III. RESULTS OF UPDATED COST OF EQUITY ANALYSES

Q. Have you prepared cost of equity analyses to support your rebuttal testimony?

A. Yes. I updated the results of the cost of equity analyses conducted in my direct testimony based on market data through September 30, 2025. To develop my updated cost of equity analyses, I rely on the same methodologies used in my direct testimony.

Q. Have you adjusted the proxy group that was relied upon in your direct testimony?

A. Yes, I have. I have excluded Duke Energy Corporation ("DUK"), NorthWestern Corporation ("NWE"), and TXNM Energy, Inc. ("TXNM") from the proxy group that I relied on to conduct the updated cost of equity analyses for my rebuttal testimony. Since the filing of my direct testimony, DUK entered into two transactions: (1) on July 29, 2025, DUK agreed to sell Piedmont Natural Gas Co. Inc.'s natural gas operations in Tennessee to Spire Inc. for $2.48 billion; and (2) on August 5, 2025, DUK agreed to sell a 19.7% interest in Duke Energy Florida, LLC to Brookfield Corporation for $6 billion.[8] Similarly, on August 19, 2025, Black Hills Corporation agreed to acquire NWE for $6.8 billion.[9] Finally, on May 19, 2025, Blackstone Infrastructure Partners, L.P., a fund managed by Blackstone, Inc., agreed to acquire TXNM for $11.5 billion.[10] As a result, DUK, NWE, and TXNM no longer meet my merger and acquisition screen and are excluded from the proxy group that I relied on in my rebuttal testimony.

[8] *S&P Capital IQ.*
[9] *Id.*
[10] *Id.*

Q. What are the updated results of your cost of equity analyses?

A. Figure 2 summarizes the results of my updated analyses, which are also presented in Exhibit A-206 (AEB-2), pages 1-24.

Figure 2: Cost of Equity Model Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.26%	10.68%	11.77%
90-Day Avg. Stock Price	9.33%	10.76%	11.84%
180-Day Avg. Stock Price	9.40%	10.82%	11.91%
Average	9.33%	10.75%	11.84%
Median Results:			
30-Day Avg. Stock Price	9.65%	10.37%	11.19%
90-Day Avg. Stock Price	9.74%	10.42%	11.23%
180-Day Avg. Stock Price	9.85%	10.46%	11.20%
Average	9.75%	10.42%	11.21%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.28%	11.24%	11.19%
Current Bloomberg Beta	11.27%	11.23%	11.17%
Long-term Avg. *Value Line* Beta	11.51%	11.47%	11.42%
ECAPM:			
Current *Value Line* Beta	11.80%	11.77%	11.73%
Current Bloomberg Beta	11.79%	11.76%	11.72%
Long-term Avg. *Value Line* Beta	11.97%	11.94%	11.90%
Bond Yield Risk Premium	10.76%	10.66%	10.53%

Q. Do the updated results support the Company's requested ROE of 10.25% in this proceeding?

A. Yes. The results of each of the DCF analyses have increased since the filing of my direct testimony, while the results of my CAPM and ECAPM analyses are generally consistent

with those filed in my direct testimony (*i.e.*, the results of some scenarios have increased while others have decreased). The results of the Bond Yield Risk Premium have generally increased modestly since the filing of my direct testimony. Therefore, as shown, the results of the cost of equity analyses continue to support my direct testimony and exhibits and the Company's proposed ROE of 10.25% in this proceeding.

IV. AUTHORIZED ROES AND THE COMPARABLE RETURN STANDARD

Q. Are you aware of a requirement from the Administrative Law Judge ("ALJ") in this proceeding regarding parties that are submitting ROE testimony?

A. Yes. It is my understanding that as part of the scheduling memo in this proceeding, the ALJ indicated that:

> - Any party submitting testimony regarding the authorized return on equity (ROE) requested by the utility in this case shall submit direct or rebuttal testimony and any supporting exhibits which set forth a) the average expected long-term return on equity for the broader stock market, and b) the average ROE authorized for regulated utilities in the United States for the last five years.[11]

In addition, the ALJ issued an official notice of facts that:

> - A comparison of Wall Street asset managers' equity return forecasts for the United States stock market during the first half of 2023 indicates that the average expected long term (10+ years) aggregate United States equity market return forecast is 6.7%.[12]

Q. Have you estimated the expected market return on equity for the broader stock market?

A. Yes. As shown on Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21, based on an estimated market capitalization-weighted dividend yield of 1.36% and a weighted

[11] Michigan Office of Administrative Hearings and Rules, Interoffice Communication to the Michigan Public Service Commission regarding Case No. U-21870, July 8, 2025.

[12] Michigan Public Service Commission, Case No. U-21870, Official Notice of Facts, October 3, 2025.

long-term growth rate of 11.15%, the estimated required market return for the S&P 500 Index at the time of my direct testimony was 12.58%. As shown on Exhibit A-206 (AEB-2), pages 15-20, based on more recent data through September 2025, the estimated market return is 13.34%.

Q. Do you have any concerns with the ALJ's reference to a market return of 6.7% that is based on an average of the market return estimates of investment firms?

A. Yes, I have two concerns. First, while the returns published by investment firms represent a forecast of the return on U.S. equities over the next ten years or more depending on the source, studies have shown that investment firms have not accurately forecasted actual returns. For example, the investment firm Dimensional Fund Advisors LP compared the return forecasts of investment firms published in the capital market assumption reports (*i.e.,* the same reports used to calculate the 6.7% market return referenced by the ALJ[13]) for various asset classes for the ten-year period of 2014-2023 to the returns that were achieved over the same time-period. This comparison showed that the forecasted returns from investment firms for U.S. equities ranged from 5.5% to 7.7% for the period of 2014-2023; however, the actual return for U.S. equities over this period was 11.50%, or substantially greater than the range projected by the various investment firms. Given the inaccuracy of the forecasts, the recommendation was to not rely on the forecasts of investment firms when building investment portfolios:

> - Rather than relying on a crystal ball that does not exist, planning for the possible range of outcomes can better prepare investors for what's ahead. When setting expectations about potential outcomes, we believe a sensible starting point is to look at the long-term historical performance of asset classes, to incorporate information from real-time

[13] Mark Ellis, "Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities From Over-Charging the Public," *American Economic Liberties Project*, January 2025, at 7.

> market prices when relevant, and to consider a wide range of possible values.[14]

Second, while the article referenced by the ALJ classifies the returns included in the average as the expectations of the investment firms, the article fails to indicate that investment firms often also provide a range of return expectations, and that those ranges highlight the significant degree of uncertainty associated with their forecast estimates. For example, the article cites BlackRock, which currently provides annual return expectations for the next 10 years of 5.17% for U.S. equities. However, BlackRock also provided a range of annual return expectations for the next 10 years for U.S. equities from 0.45% to 10.09%.[15] Moreover, BlackRock specifically notes that their return expectations should not be used as an estimate of future performance:

> - This information is not intended as a recommendation to invest in any particular asset class or strategy or as a promise - or even estimate - of future performance.[16]

Given the inaccuracy of forecasting actual returns using the projected returns of investments firms and the large range of returns provided by such investment firms, I have significant concerns with concluding that the expected return on the market is 6.70% as represented in the article referenced by the ALJ.

Q. Are authorized returns in other jurisdictions a relevant benchmark that investors consider?

A. Yes, they can be when the corresponding market conditions are considered. Previously authorized ROEs provide a range of reasonableness and a benchmark that investors consider in assessing the authorized ROE of one utility against the returns available from

[14] Matt Wicker, "Reality Check: Capital Market Assumptions vs. Actual Returns," December 20, 2024.
[15] BlackRock Investment Institute, Capital Market Assumptions, August 26, 2025.
[16] *Id.*

other regulated utilities with comparable risk. However, it is important to screen this data to consider only the returns that have been authorized for risk-comparable companies. Further, it is important to consider the overall market conditions that existed at the time that the decisions were made to ensure that the conclusions drawn from the data are consistent with the comparable return standard. The *Hope* and *Bluefield* cases establish that authorized ROEs must be commensurate with other investments having corresponding risk.

Q. Have you evaluated the average ROE authorized for regulated utilities in the United States for the last five years?

A. Yes. Since the ROE that is being established in this proceeding is for the Company's electric operations, and the Company is a vertically-integrated electric utility, I have evaluated the annual average authorized ROEs for vertically-integrated electric utilities. Specifically, I have analyzed the recently authorized returns for vertically-integrated electric utilities and applied the following screening criteria:

- I have excluded limited-issue rider cases because these cases address only a specific issue or issues, such as the construction of generation assets and the associated incremental risk, and not a utility's entire operations.

- I have excluded jurisdictions that set ROEs using a formula as opposed to following an approach that is similar to what the Commission has typically considered in setting the ROE.

- I excluded returns awarded in Arizona, because the determinations in Arizona are based on fair value ratemaking adjustments. Therefore, the ROE that was established in the Arizona cases may have been set on a different basis.

- Lastly, I excluded authorized returns that reflect a utility-specific penalty, because an authorized ROE that includes a penalty is not indicative of a market-derived cost of equity.

As shown in Figure 3, over the past five years, authorized ROEs for vertically-integrated electric utilities have increased.

Figure 3: Range of Annual Authorized ROEs for Vertically-Integrated Electric Utilities, 2021-2025[17]

Year	Average	Maximum	Minimum
2021	9.57%	10.60%	8.90%
2022	9.75%	10.50%	9.30%
2023	9.72%	11.45%	9.25%
2024	9.79%	10.50%	9.26%
2025	9.72%	10.20%	9.25%

Q. Do you agree with the evaluations that Mr. Megginson, Mr. Coppola, and Mr. Walters have conducted of the annual average authorized ROEs?

A. No. These witnesses have each reviewed the average authorized ROEs for all electric utilities, which include both vertically-integrated electric utilities and transmission and distribution-only electric utilities.[18] However, the Company is a vertically-integrated utility, and electric generation ownership is recognized as being higher risk than a utility with only electric transmission and/or distribution operations.[19] Therefore, authorized ROEs for transmission and distribution-only electric utilities should be excluded when considering previously authorized ROEs for a vertically-integrated utility such as Consumers Energy because vertically-integrated electric utilities often have greater risk than transmission and distribution-only utilities due to the incremental risk of generation. In addition, it is unclear to what extent that these witnesses may have also included

[17] S&P Capital IQ Pro.

[18] Megginson Direct, at 29; Coppola Direct, at Exhibit AG-40; Walters Direct, at 5 (Table CCW-1). Note, Mr. Bandyk indicates that he does not have access to the individual authorized ROE data (see, Bandyk Direct, at 4).

[19] Moody's Investors Service. Rating Methodology: Regulated Electric and Gas Utilities, August 2024, at 14.

authorizations that are not appropriate (*e.g.*, authorizations subject to a penalty; authorizations in Arizona where fair value rate base is utilized).

Furthermore, Mr. Megginson references an average authorized ROE from 2021 through June 2025.[20] However, as discussed in more detail herein, the relationship between the cost of equity and interest rates is important to consider. In averaging data over 4.5 years, Mr. Megginson fails to consider the interest rate environment over this period. As shown in Figure 4, which provides the yield on the 30-year Treasury bond from 2021 through October 9, 2025, the yield was significantly lower throughout 2021 and most of 2022 than it is currently. Therefore, including an annual average for these years in a single average over the period fails to appropriately reflect the relevant market conditions.

Figure 4: 30-Year Treasury Yield – January 2021 through October 9, 2025[21]

[20] Megginson Direct, at 29.

[21] St. Louis Federal Reserve.

Q. What is Mr. Bandyk's position regarding previously authorized ROEs?

A. Mr. Bandyk claims that the Commission, as well as all other regulatory commissions across the United States, have incorrectly authorized ROEs for decades by awarding ROEs that are "above fair, market-based ROE estimates."[22] Based on this view, Mr. Bandyk suggests that previously authorized ROEs should not be considered for purposes of establishing the ROE for the Company in this proceeding.

Q. Is Mr. Bandyk's position consistent with Mr. Megginson's, Mr. Coppola's, or Mr. Walters' testimony?

A. No, Mr. Bandyk is alone in his position. Mr. Megginson specifically considers previously authorized ROEs in developing his recommended ROE in this proceeding, and Mr. Coppola and Mr. Walters also reference previously authorized ROEs as support for their recommended ROEs, with Mr. Walters also considering prior ROE authorizations as part of his Risk Premium analysis.[23]

Q. Based on his position that regulators have consistently incorrectly authorized ROEs in the past, what is Mr. Bandyk's ROE recommendation for the Company?

A. Mr. Bandyk states that the average of his cost of equity model results suggests a market-based cost of equity for Consumers Energy that is lower than his recommended ROE of 9.22%. However, Mr. Bandyk acknowledges that there is uncertainty in any financial model and there is a need "not to create unnecessary instability in the company's market value, which is based in part on the outcomes of regulatory proceedings like this one."[24] Therefore, Mr. Bandyk characterizes his ROE recommendation as "gradualism"

[22] Bandyk Direct, at 11.
[23] Megginson Direct, at 29; Coppola Direct, at Exhibit AG-40; Walters Direct, at 5 (Table CCW-1) and 42-50.
[24] Bandyk Direct, at 15-16.

in moving from the Company's currently authorized ROE to his recommended ROE, despite his claim that his recommendation is higher than the market-based cost of equity for Consumers Energy.[25]

Q. Does Mr. Bandyk indicate the point or range to which he believes the Company's ROE should transition to over time?

A. No. Mr. Bandyk has not defined where he believes the ultimate end point is of his proposed "gradualism."

Q. Do you agree with Mr. Bandyk's position?

A. No. Mr. Bandyk and I have a fundamental disagreement regarding his claim that regulators have incorrectly authorized ROEs substantially higher than the cost of equity for decades. I agree with him that: (1) there is a distinction between the cost of equity and the ROE authorized by regulatory commissions in setting just and reasonable rates; (2) the cost of equity cannot be definitively determined and therefore must be estimated by analysts; and (3) there is significant disagreement as to the way in which to estimate the cost of equity. However, he has provided no evidence that supports his position that regulatory commissions, including this Commission, have consistently erred for decades in establishing utilities' ROEs.

Q. Why is this disagreement with Mr. Bandyk so fundamental?

A. Regulatory commissions have an obligation to establish rates that balance the interests of customers and shareholders and that are just and reasonable. There is no evidence that Mr. Bandyk's estimate of the cost of equity, which includes the results of his CAPM analysis that is substantially lower than any ROE that has been authorized by a regulatory

[25] *Id.*

commission in the past, is in fact reasonable and that regulatory commissions have been consistently approving unjust and unreasonable rates.

Q. As a threshold matter, are you aware of any other regulatory jurisdiction in the United States that has adopted Mr. Bandyk's views?

A. No. I am not aware of any regulatory commission in the United States – state or federal – that has adopted Mr. Bandyk's position.

Q. Are you aware of any regulatory commissions that have specifically disagreed with Mr. Bandyk's notion that there is and has been a substantial difference between authorized ROEs and the cost of equity for utilities?

A. Yes. The Minnesota Public Utilities Commission has considered testimony offered by witnesses on behalf of the Minnesota Department of Commerce, Division of Energy Resources ("Department") and the Citizens Utility Board that contended authorized ROEs have historically exceeded the cost of equity. The Minnesota Public Utilities Commission has continued, however, to rely on its long-standing cost of equity estimation methodologies and other industry information to inform their decisions and has not specifically relied on the viewpoint that the cost of equity is lower than authorized ROEs. For example:

> - The Department's recommended cost of equity of 9.30% is informed by an underlying assumption that the cost of equity and the return on equity are distinct concepts in the sense that utility earnings exceed the cost of equity over time. This understanding, according to the Department, undermines the reliability of earnings' estimates in predicting long-term growth and instead justifies the use of a multi-stage DCF analysis that uses GDP to forecast the long-term cost of equity. ***The Commission does not share this concern***.[26]

[26] Minnesota Public Utilities Commission, Docket No. E-015/GR-21-335, Findings of Fact, Conclusions, and Order, February 28, 2023, at 45; emphasis added.

Q. Are you aware of examples where capital attraction and willingness to invest have been hampered when a regulatory jurisdiction is perceived as not being credit supportive?

A. Yes. Connecticut and Illinois are two recent examples. In Illinois, market reactions to regulatory decisions in December 2023 for Ameren Illinois Co. and Commonwealth Edison Co. were universally negative and both utilities considered shifting investment to their other utility operating subsidiaries outside of Illinois.

Connecticut, which is viewed by research analysts, equity analysts, and investors as among the least credit supportive jurisdictions in the United States for utilities, is the most recent example of where capital attraction and a willingness to invest have been hampered. For example:

- The two major utility holding companies operating in Connecticut (*i.e.,* Eversource Energy ("Eversource") and Avangrid Inc. ("Avangrid")) have announced their unwillingness to continue discretionary investment in the state until the regulatory environment and cost recovery outcomes change.
- Avangrid's utility operating subsidiaries in Connecticut (*i.e.,* Connecticut Natural Gas Corporation ("CNG") and Southern Connecticut Gas Company ("SCG")) have recently experienced difficulty fully subscribing bond issuances, and while able to do so, the premiums were higher than anticipated.

Specifically, in May 2024, Eversource, which owns Connecticut Light & Power and Aquarion Water in Connecticut, announced on its earnings call that it would be cutting investment by its utilities within the state due to "unreasonable, arbitrary decisions by the regulator," (*i.e.,* the Public Utilities Regulatory Authority), and that the company had

"grave concerns" regarding the Connecticut regulatory environment.[27] Eversource executives stated that the company is unwilling to place capital at risk within Connecticut given that the state's regulatory policy discourages investment.[28] Driving the cut in utility investment is Eversource's view that utility regulators have been slow to approve the recovery of $635 million in storm costs incurred from 2018 through 2021, $400 million in uncollected bills from ratepayers, a rate reduction imposed on Aquarion Water in its most recent rate proceeding, and elimination of a program supporting electric vehicles.[29] Consequently, Eversource stated that it is taking a "hard look" at its capital deployment priorities in Connecticut and plans to reduce its capital investment in Connecticut by $500 million over the next five years, which will likely come from reliability areas until "Connecticut's regulatory decisions come back into alignment with law and state policy."[30] Eversource indicated that it will not reduce safety spending, but that it has made significant investments in reliability over the past decade but is unwilling to continue doing so without a secure and predictable cost recovery path.[31]

Entering 2025, Eversource's subsidiary Connecticut Light & Power announced that it will spend approximately 15% less than previously planned on capital programs and reliability investments due to the state's adverse regulatory environment.[32] Connecticut Light & Power stated that its decision was made because the Connecticut utility regulator's

[27] Mark Pazniokas, "Eversource escalates CT fight, saying it will cut investments," CT Mirror, May 2, 2024.

[28] Jared Anderson, "Eversource cutting investment in Connecticut by up to $500 million over 5 years," S&P Capital IQ Pro, May 3, 2024.

[29] Mark Pazniokas, "Eversource escalates CT fight, saying it will cut investments," CT Mirror, May 2, 2024.

[30] Jared Anderson, "Eversource cutting investment in Connecticut by up to $500 million over 5 years," S&P Capital IQ Pro, May 3, 2024.

[31] *Id*.

[32] Noah Schwartz, "Eversource pares back Connecticut investment plan, risking grid reliability," S&P Capital IQ Pro, December 31, 2024.

decisions have failed to adhere to utility finance principles, economics, or law and were politically motivated solely to reduce rates. Due to the reduction in reliability spending, Connecticut Light & Power projects a decrease in service reliability over the next five years, although reliability will remain above baseline levels set by law.[33] In addition, Eversource and its subsidiaries, including its Connecticut-based subsidiaries Connecticut Light & Power, Yankee Gas and Aquarion Water, were downgraded by S&P in December 2024. Eversource and Connecticut Light & Power were downgraded one notch while Yankee Gas and Aquarion Water were downgraded two notches. S&P highlighted "a recent pattern of adverse regulatory developments for investor-owned utilities operating in Connecticut, which we believe has increased business risk for Eversource Energy and its Connecticut-based subsidiaries."[34] Moreover, Eversource recently entered into an agreement to sell Aquarion Water.[35]

Similarly, United Illuminating, which is owned by Avangrid, noted in its ongoing rate proceeding in Connecticut that it has recently limited capital investments to only those that are considered "most critical" to maintaining safe and reliable service because any incremental capital investment over this level "will cause continuing degradation of the Company's financial integrity."[36] In addition, on December 6, 2024, S&P downgraded the credit ratings of both CNG and SCG, which are owned by Avangrid, to BBB+ which was a two notch downgrade for CNG (*i.e.,* A to BBB+) and one notch downgrade for SCG

[33] *Id*.

[34] S&P Global Ratings, "Eversource Energy Issuer Credit Rating Lowered To 'BBB+' From 'A-'; Subsidiaries Ratings Also Lowered; Outlooks Stable," December 9, 2024.

[35] "Eversource Energy Announces Sale of Aquarion Water Company," Business Wire, January 27, 2025.

[36] Public Utilities Regulatory Authority, Docket No. 24-10-04, Direct Testimony of Charles J. Eves, Jr. November 12, 2024, at 7.

(*i.e.*, A to BBB+) based primarily on the downward assessment of the Connecticut regulatory environment.[37]

Finally, Avangrid has indicated that it experienced difficulties in attracting adequate subscription levels for debt issuances by its Connecticut utilities that closed in December 2023, and the bonds priced at a higher coupon rate than anticipated.[38] Specifically, as stated in its currently pending rate proceeding:

> - The debt issuance was a private offering in which four banks served as lead placement agents and worked with the Company to market the transaction to investors in advance of pricing. On the day of pricing, November 15th, the subscriptions sought for CNG and SCG were only 65% and 50% fulfilled, respectively. This compares to the offering for one of the other Avangrid utilities which was more than two-times subscribed. After some additional negotiation, the banks were able to get one investor to fill the remaining portions of the issuance sought for CNG and SCG and the full transaction priced on the following day; however, the credit spreads were wider than anticipated across the Avangrid Connecticut utilities, raising the financing cost by approximately 10-15 basis points. *The bankers informed Avangrid that the difficulty in fulfilling the necessary subscription levels and the wider credit spreads attracted were caused in part by the limited interest to invest in Connecticut utilities due to concerns over the regulatory environment and potential impacts to current ratings*.[39]

Q. Have utilities shifted investment outside of a jurisdiction that is viewed as unsupportive?

A. Yes. After Eversource's announcement to curtail investment in Connecticut, Guggenheim Partners analyst Shahriar Pourreza noted that the threats to reduce investment should be taken seriously and that it has happened in other states, most recently in Illinois. Because utilities are capital intensive and inherently cash-flow negative, Mr. Pourreza stated that he

[37] S&P Global Ratings, Research Update: Connecticut Natural Gas Corp. And Southern Connecticut Gas Co. Downgraded to 'BBB+' on Final Rate Order, Outlook Stable, December 6, 2024.

[38] Public Utilities Regulatory Authority, Docket No. 23-11-02, Response of Connecticut Natural Gas Corporation to data request RRU-402, February 27, 2024.

[39] *Id*., emphasis added.

has seen utilities that operate in multiple jurisdictions shift capital to where the return is more predictable.[40]

Q. What sources does Mr. Bandyk cite to claim that awarded ROEs are too high and why are they not credible sources to support his conclusions?

A. The three sources that Mr. Bandyk cites are: (1) a paper published by Rode and Fischbeck (2019) on the growing market risk premium; (2) an Energy Institute *working paper* that Mr. Bandyk claims is published to presumably lend it more credibility; and (3) an op-ed article from *Fortnightly Magazine* from 2016 by a lawyer.[41] None of these sources credibly support Mr. Bandyk's claim that "public regulatory commissions have tended to accept estimates for ROE that are above fair, market-based ROE estimates."[42]

Q. Do you agree with how Mr. Bandyk has presented the results of Rode and Fischbeck (2019)?

A. No. I do not. Rode and Fischbeck (2019) is the only peer-reviewed published academic article, and it studies the spread between *electric* ROEs and risk-free rates. The paper does not use causal empirical techniques to support a conclusion that ROEs are too high. The paper only considers the CAPM model, and it does not evaluate the DCF and other considerations that may impact ROEs such as capital market conditions. Most strikingly, the authors conclude that "[o]ur research does not necessarily imply that the rates of return authorized by regulators are too high, or otherwise necessarily inappropriate for utilities."[43]

[40] Mark Pazniokas, "Eversource escalates CT fight, saying it will cut investments," CT Mirror, May 2, 2024.
[41] Bandyk Direct, at 8-10.
[42] *Id*., at 11.
[43] David Rode and Paul Fischbeck, "Regulated equity returns: A puzzle," *Energy Policy*, October 2019.

Therefore the paper does not support Mr. Bandyk's conclusion that a "market-based ROE" should be lower than recently authorized ROEs.

Q. What is your response to Mr. Bandyk's reliance on the Werner and Jarvis study to support his conclusion that authorized ROEs historically have consistently exceeded the cost of equity for utilities?

A. The working paper by Werner and Jarvis which appears to have been updated most recently in March 2025 suffers from several limitations.[44] First, the Werner and Jarvis (2025) study, which benchmarks authorized returns to corporate bond yields and Treasury bond yields, as well as each utility's approved cost of debt, incorrectly assumes that a 1.00 percentage point change in the bond yields will result in a 1.00 percentage point change in the authorized returns. However, the authors provide no references to studies or other information to support their assumption. Further, when the authors calculated an alternative scenario that assumed the authorized return would change at only half the rate of change in the Treasury yield (*i.e.,* a 100 basis point increase in the Treasury yield would result in a 50 basis point increase in the authorized ROE), the spread between the estimated benchmark returns and the authorized returns decreased significantly and was only 11 basis points as of 2022, which indicates that their initial 1-to-1 relationship between the change in the yield on Treasury bonds and the change in authorized ROEs is flawed.[45]

Second, the authors acknowledged that their analysis, which compares authorized returns to the cost of equity estimates resulting from the CAPM, is highly dependent on the assumptions used to calculate the CAPM. Further, their analyses demonstrated the

[44] Mr. Bandyk appears to reference the Werner and Jarvis study from September 2024; however, since the study has been updated in March 2025, I will discuss the most recent version of the report.

[45] Karl Dunkle Werner and Stephen Jarvis, "Rate of Return Regulation Revisited," Working Paper, Energy Institute, University of California at Berkeley, 2025, Appendix, at 14.

sensitivity of their results to the assumptions relied on in the CAPM. The authors used three CAPM analyses, with significantly different assumptions for beta and the market risk premium and demonstrated that the spread between the cost of equity results of these models and authorized returns were dramatically different. For example, the low CAPM analysis resulted in a spread between the estimated cost of equity and the authorized return of 3.99 percentage points in 2022, the central CAPM produced a spread of 2.31 percentage points, while the high CAPM analysis produced a spread of only 1.24 percentage points.[46] Therefore, this test demonstrated that their analysis was highly dependent on the assumptions used in the CAPM and did not support a conclusion that authorized ROEs were systematically higher than the cost of equity.

The authors acknowledge that:

> Of course there's no particular reason to think the UK regulator is setting the correct RoE, and there are good reasons to think that US state PUCs should not simply adopt UK rates of return – there are many differences between the utility sector and investor environment in the US and UK.[47]

In addition, while the authors acknowledge the differences in the risk factors between utility operations in the United States and the United Kingdom, they are not addressed in the study. Given that the authors acknowledge there are differences in the regulatory environments, yet have not considered the effect of those differences on the cost of equity for the electric and natural gas utilities in either the UK or US, it is not reasonable to conclude that the authorized ROEs in the US are too high based on a comparison to the returns authorized for utilities in the UK. As a result, the Werner and Jarvis (2025) study does not support Mr. Bandyk's contention that US state regulatory commissions have

[46] *Id.*

[47] *Id.,* Appendix, at 8.

consistently authorized ROEs in excess of the cost of equity in light of the study's limitations and unsupported assumptions.

Q. Do you have any concerns with Mr. Bandyk's reference to a 2016 op-ed from *Public Utilities Fortnightly* by Steve Huntoon?

A. Yes. In the article, Steve Huntoon, a utility attorney, claims that commissions set authorized ROEs at rates that are higher and not consistent to utilities' risk level.[48] As a threshold matter, Mr. Huntoon has a background in energy, he is not a cost of capital expert, and this article is merely his opinion. Mr. Huntoon recommends individuals invest in Vanguard's utility Exchange-Traded Fund, VPU, because there have been periods where regulated utilities have outperformed the broader market. However, since the article's publication in August 2016, the VPU has significantly lagged the S&P 500 Index through September 30, 2025, with the VPU returning approximately 118% over this period, while the S&P 500 has returned approximately 261%.[49] Clearly, this refutes Mr. Bandyk's claims that utilities violate "the economic reality that lower risk means lower return."[50]

V. PROXY GROUP

Q. How have Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk specified their respective proxy groups?

A. To estimate the cost of equity for Consumers Energy, Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk develop their respective proxy groups as follows:

- Mr. Megginson relies on a proxy group of eight electric companies by requiring that the companies in his proxy group: (1) have net plant greater than $10.0 billion but less than $37.0 billion; (2) derive no less

[48] Steve Huntoon, "Nice Work If You Can Get It," *Fortnightly*, August 2016; Mr. Bandyk did not provide the article as the article is behind a paywall, and only two pages of the article is accessible.

[49] *S&P Capital IQ* from August 1, 2016 – September 30, 2025.

[50] Bandyk Direct, at 10.

than approximately 50% or more of revenues from regulated electric service; (3) have an investment grade credit rating within three to four notches from that of the Company; (4) pay dividends; (5) be followed by two or more International Business Estimating System (I/B/E/S) analysts; and (6) not be a party to a merger or acquisition.[51]

- Mr. Coppola develops a proxy group of 11 electric companies by requiring that the companies in his proxy group: (1) have revenue greater than $1 billion but less than $20 billion; (2) have dividend growth; (3) have no foreign investment; (4) no reorganization or merger and acquisition activity; (5) no low/no growth in earnings; (6) no excessive earnings growth; (7) not have higher risk considerations such as off-shore wind generation construction or wildfire risk; and (8) no large non-utility operations.[52]

- Mr. Walters starts with the same proxy group that I utilized in my direct testimony but excludes NorthWestern Corporation and TXNM Energy due to merger and acquisition activity for each company that was announced after the filing of my direct testimony.[53]

- Mr. Bandyk relies on the same proxy group for his cost of equity analyses as I utilized in my direct testimony.[54]

Q. What is your primary concern with the screening criteria relied upon by Mr. Megginson?

A. While I have various disagreements with the screening criteria relied on by Mr. Megginson,[55] my primary concern is with Mr. Megginson's requirement that a company have net plant greater than $10.0 billion but less than $37.0 billion. As shown below in Figure 5, Mr. Megginson's net plant screening criterion results in the exclusion

[51] Megginson Direct, at 20-21.

[52] Coppola Direct, at 131 and Exhibit AG-42.

[53] Walter Direct, at 29.

[54] Bandyk Direct, at 14.

[55] For example, Mr. Megginson's requirement that a company derive at least 50.00% of revenues from regulated electric operations because the required percentage is too low and could result in a company being included in the proxy group that derives 50.00% of total revenue from unregulated operations.

of eight companies that were included in my proxy group. In fact, while we apply a different set of screening criteria, Mr. Megginson's net plant screening criterion appears to be the sole driver of the differences in our respective proxy groups. I disagree with Mr. Megginson's net plant screening criterion because he has provided no support for his requirement that a company have net plant in the range of $10.0 to $37.0 billion. While he claims it results in a group of companies that are similar in size to Consumers Energy, it is not clear that is the case. For example, as shown in Figure 5, IDACORP, Inc. ("IDA") had net plant of $6.51 billion in 2024 and appears to be relatively close in size to Consumers Energy, which had net utility plant of $13.3 billion in 2024. However, IDA was excluded from Mr. Megginson's proxy group because IDA's net plant was less than $10 billion. Conversely, Ameren Corporation, which had net plant of $36.38 billion and would appear less comparable in size to Consumers Energy than IDA, was nonetheless included in Mr. Megginson's proxy group. Therefore, Mr. Megginson's arbitrary selection of a range of net plant as a screening criterion appears to exclude companies that investors would otherwise consider comparable to Consumers Energy.

Figure 5: Bulkley Proxy Group Companies Eliminated Due to Mr. Megginson's Net Plant Screening Criterion[56]

Company	Ticker	2024 Net Plant ($millions)[57]
Alliant Energy Corporation	LNT	$18,701
Ameren Corporation	AEE	$36,376
American Electric Power Company, Inc.	AEP	$82,416
Avista Corporation	AVA	$6,020
Dominion Resources, Inc.	D	$68,862
DTE Energy Company	DTE	$31,081
Entergy Corporation	ETR	$47,423
Evergy, Inc.	EVRG	$24,200
IDACORP, Inc.	IDA	$6,517
NextEra Energy, Inc.	NEE	$138,852
OGE Energy Corporation	OGE	$11,538
Pinnacle West Capital Corporation	PNW	$19,198
Portland General Electric Company	POR	$10,345
PPL Corporation	PPL	$33,149
Southern Company	SO	$100,028
Xcel Energy Inc.	XEL	$57,198

Q. Is Mr. Megginson's net plant screen consistent with the net plant screen that he applied in the Company's last electric rate proceeding to develop his proxy group?

A. No. As just discussed, in the current proceeding Mr. Megginson requires companies to have net plant that is greater than $10.0 billion but less than $37.0 billion. However, in the Company's last electric rate proceeding, Case No. U-21585, Mr. Megginson required companies included in his proxy group have net plant greater than $4.0 billion but less than $35.0 billion.[58] Therefore, not only has Mr. Megginson provided no explanation or support for the arbitrary range of his net plant criterion selected in this proceeding, it is also contrary to his prior testimony, further highlighting that his criterion is arbitrary.

[56] Gray shading indicates the company was excluded from Mr. Megginson's proxy group.

[57] Value Line Reports dated May 9, 2025, June 6, 2025, and July 18, 2025.

[58] Michigan Public Service Commission, Case No. U-21585, Direct Testimony of Kirk D. Megginson, September 27, 2024, at 26.

Q. Is the net plant screening criterion applied by Mr. Megginson overly restrictive?

A. Yes. The development of the screening criteria is intended to establish a proxy group that is reasonably comparable to the subject company, yet not unnecessarily restrictive such that one individual estimated result can bias the analysis. As shown by the gray shading in Figure 5, Mr. Megginson's net plant screen excludes eight companies included in my proxy group. Given that Mr. Megginson's proxy group includes only eight companies, this means that his proxy group is more susceptible to producing results that are overly influenced by the results of an individual company.

Q. Is there a more appropriate approach that Mr. Megginson could have applied to consider the risk associated with the size of a company?

A. Yes. Mr. Megginson's use of a net plant screen appears to be due to his conclusion that smaller firms have different business risk than larger firms. In fact, I agree that both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." However, it is not appropriate to apply an arbitrary net plant screening criterion as Mr. Megginson has done to account for the risk associated with the size of a company. Instead, Mr. Megginson should have relied on my proxy group and considered the small size premium study conducted by *Kroll.* As shown in Figure 6, *Kroll* estimates a stock risk premia based on the size of a company's market capitalization. Smaller companies have greater risk than larger companies and therefore, have a higher cost of equity. Mr. Megginson could have determined the implied market capitalization for Consumers Energy's electric operation in Michigan and compared it to the median market capitalization for the proxy group to determine the premium needed to account for the additional risk of the size of Consumers Energy's electric operations

relative to the proxy group. Further, while I did not consider a size premium for Consumers Energy's electric operations in Michigan, because Mr. Megginson is concerned that my proxy group consists of companies that are larger than Consumers Energy's electric operations in Michigan, this would mean the results of my DCF and CAPM may understate the cost of equity for Consumers Energy.

Figure 6: *Kroll* – CRSP Deciles Size Study[59]

Breakdown of Deciles 1-10	Market Capitalization of Largest Company ($ millions)	Size Premium
1-Largest	3,522,211.14	-0.01%
2	46,949.06	0.33%
3	20,178.36	0.49%
4	9,937.35	0.50%
5	6,181.27	0.74%
6	3,946.15	1.00%
7	2,464.50	1.19%
8	1,417.45	0.88%
9	729.92	1.73%
10-Smallest	304.48	4.47%

Q. Do you have any concerns with Mr. Coppola's proxy group screening criteria?

A. Yes. I have two primary concerns with the screening criteria applied by Mr. Coppola to develop his proxy group. First, Mr. Coppola requires companies to have revenue between $1 and $20 billion to account for the risk associated with the size of a company. However, Mr. Coppola has provided no support for his revenue range. As I just discussed regarding Mr. Megginson's proxy group, instead of relying on an arbitrary screen to account for company size, it is more appropriate to account for the relative size risk of the subject

[59] *Kroll*, Cost of Capital Navigator, CRSP Deciles Size Study; data as of December 31, 2024.

company to the proxy group using the size premium study conducted by *Kroll*. Second, Mr. Coppola has inconsistently applied the screens he has selected, which incorrectly results in the exclusion of PPL Corporation ("PPL") from his proxy group and the inclusion of Consolidated Edison, Inc. ("Consolidated Edison") in his proxy group.

Q. Why should Consolidated Edison be excluded from the proxy group that Mr. Coppola relies on to estimate the cost of equity for Consumers Energy?

A. Mr. Coppola applies a screening criterion to exclude companies that have exposure to "high risk" from offshore wind generation construction.[60] Given that Mr. Coppola identifies offshore wind generation construction as high risk, he appears to acknowledge the increased risk associated with developing and owning generation assets. However, Mr. Coppola has included Consolidated Edison in his proxy group which engages primarily in the transmission and distribution of electricity and the distribution of natural gas. In fact, Consolidated Edison owns only a de minimis amount of generation while Consumers Energy is a vertically-integrated electric utility. The generation function is generally regarded by investors as being higher risk than electric transmission or distribution. As stated by Moody's in its 2024 ratings methodology for regulated electric and gas utilities:

> Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and

[60] Coppola Direct, at 131.

> operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.[61]

Given that investors view vertically-integrated electric utilities as having higher risk than transmission and distribution only electric utilities, which Mr. Coppola appears to acknowledge given the application of his "high risk from offshore wind development" screen, Mr. Coppola should have excluded Consolidated Edison from the proxy group he uses to estimate the cost of equity for Consumers Energy.

Q. Do you agree with Mr. Coppola's decision to exclude PPL from his proxy group?

A. No. Mr. Coppola appears to exclude PPL because the company has "low/no growth in earnings." It is not entirely clear how Mr. Coppola determined if a company should be excluded from the group due to "low/no growth in earnings." Based on Exhibit AG-42, for PPL, Mr. Coppola appears to base his decision on: (1) a decline in earnings per share ("EPS") from 2020 to 2021; and (2) an ambiguous note that says "future growth is unclear." However, Mr. Coppola does not explain how a decline in historical EPS is a reasonable basis to exclude a company from the proxy group. Further, in the *Value Line* report that Mr. Coppola references, *Value Line* noted the following regarding PPL's future growth:

> Our 2026 top- and bottom-line estimates anticipate continued momentum. We look for earnings of $1.95 per share on revenues of $8.7 billion. This growth is supported by ongoing rate base expansion and execution of the company's multiyear investment strategy. The utility is targeting rate base growth of 9.8% annually from 2024 to 2028, up from 6.3% in the previous plan. ***PPL is looking for EPS growth in the top half of its 6%-8% range, and we believe that's achievable given the company's consistency and improving regulatory***.[62]

[61] Moody's Investors Service. Rating Methodology: Regulated Electric and Gas Utilities, August 2024, at 14.

[62] PPL, Value Line report dated May 9, 2025. (emphasis added).

Therefore, according to *Value Line*, future growth is positive, not negative, and certainly not "unclear" as Mr. Coppola suggests. While I agree that a negative growth rate cannot be used in the constant growth DCF model, PPL has a positive projected EPS growth rate from *Value Line* and, therefore, Mr. Coppola should have included PPL in his proxy group.

Q. Does Mr. Coppola's exclusion of PPL highlight a broader concern with the arbitrary screening criteria applied by Mr. Coppola?

A. Yes, it does. In addition to the "low/no growth in earnings" criteria, Mr. Coppola applies several other screens that require substantial subjective judgment, including: no excessive earnings growth, not having higher risk considerations such as offshore wind generation construction, wildfire risk, and having no large non-utility operations. Given the subjective judgment required to apply these screens, Mr. Coppola could apply these screens to include or exclude companies in order to bias the results of his cost of equity models. As a result, I recommend that the Commission disregard the results of Mr. Coppola's DCF and CAPM analyses that rely on his proxy group.

Q. Do you have any concerns with the proxy groups relied on by Mr. Walters and Mr. Bandyk?

A. Yes. As noted above, I updated the proxy group used in the analysis I conducted in my rebuttal testimony to reflect changes that occurred since my direct testimony was filed. Specifically, I am now excluding DUK, NWE and TXNM due to each company being involved in mergers and acquisition activity that was announced after the filing of my direct testimony. While Mr. Walters relied on the proxy group presented in my direct testimony excluding both NWE and TXNM, he should have also excluded Duke Energy Corporation.

Similarly, Mr. Bandyk relied on the proxy group presented in my direct testimony; however, he should have excluded DUK, NWE and TXNM.

Q. What is your conclusion regarding the appropriate proxy group for Consumers Energy?

A. I continue to support the screening criteria outlined in my direct testimony to develop the proxy group for Consumers Energy.

VI. DCF ANALYSIS

Q. Please summarize the DCF analyses of these witnesses.

A. Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk have each conducted a form of the DCF analysis. Specifically:

- Mr. Megginson conducts a constant growth DCF, and for each of his proxy group companies relies on: (1) an average of closing monthly stock prices as of June 1, July 1, and August 1, 2025; (2) annualized dividends that reflect one-half of the estimated growth rate; and (3) projected EPS growth rates from *Value Line* and *Zacks Investment Research* ("*Zacks*"). The average cost of equity resulting from Mr. Megginson's constant growth DCF analysis is 9.76%.[63]

- Mr. Coppola conducts a constant growth DCF, and for each of his proxy group companies relies on: (1) an average of the 30-day high and low stock prices from June 18 to July 31, 2025; (2) projected dividends as reported by *Value Line*; and (3) averages growth rates from analysts' long-term projected EPS growth rates as published by *Value Line* and two-year forecasted EPS growth rates as published by *Yahoo! Finance*.[64] The average cost of equity from Mr. Coppola's constant growth DCF analysis is 9.57%.

[63] Megginson Direct, at 24 and Exhibit S-4, Schedule D-5, at 5. Note, Mr. Megginson inexplicably includes Eversource Utilities as part of the proxy group when calculating a dividend yield but excludes them for purposes of estimating the cost of equity using the DCF. The inclusion of Eversource Utilities on Exhibit S-4, Schedule D-5, at 5 is assumed to be in error and does not affect his results.

[64] Coppola Direct, Exhibit AG-37.

- Mr. Walters conducts three DCF analyses: two constant growth DCF models (*i.e.*, one version that relies on analysts' projected EPS growth rates and the other that relies on estimated sustainable growth rates), and a multi-stage DCF model. Mr. Walters's multi-stage DCF model relies on analysts' projected EPS growth rates in Stage 1 (years 1-5) and a growth rate of 4.09% in Stage 3 (year 11 onward) to represent projected long-term gross domestic product ("GDP") growth, while the growth rate in Stage 2 (years 6-10) transitions between the Stage 1 and Stage 3 growth rates.[65] The results of these analyses range from 8.21% to 11.05%.[66]

- Mr. Bandyk conducts two versions of a two-step DCF analysis. His first version uses: (1) an average of the 30-day high and low stock prices; (2) annualized dividends as reflected in my direct testimony; (3) projected EPS growth rates reflected in my direct testimony for the initial stage growth rate; and (4) a growth rate that applies a weighting of 80% to the average of the analysts' projected EPS growth rates and a weighting of 20% to his estimate of a long-term nominal GDP growth rate of 3.80%.[67] Mr. Bandyk's second version of his two-step DCF is the same as his first except he replaces the projected EPS growth rates with *Value Line* forecasted dividend growth rates for the initial stage growth rate. The resulting cost of equity of Mr. Bandyk's constant growth DCF analyses are 9.65% and 8.26%, respectively, with an average of 8.96%.[68]

Q. What is your primary area of disagreement with the constant growth DCF analyses conducted by Mr. Megginson?

A. In addition to the arbitrary nature by which Mr. Megginson develops his proxy group that I have previously discussed, I have two primary concerns with Mr. Megginson's constant growth DCF model.

[65] Walters Direct, at 30-41.

[66] *Id.,* at 42.

[67] Bandyk Direct, at 27 and Exhibit CUB-7.

[68] Exhibit CUB-7 and Exhibit CUB-8.

First, Mr. Megginson relies on an average of only three stock prices (*i.e.*, the last day of June, July, and August 2025) for purposes of calculating the dividend yield in his DCF analysis. It is more appropriate to utilize an average of all of the stock prices over this period for each of the proxy group companies in order to mitigate any anomalous activity that may occur by only relying on the stock price on three specific days.

Second, as shown on Exhibit S-4, Schedule D-5, page 5, Mr. Megginson's DCF result of 9.76% is the average of the cost of equity estimates of the eight companies in his proxy group. However, as shown therein, the result for one of those companies – Pinnacle West, with a cost of equity estimate of 7.59% – is far below the rest of the DCF results and, in fact, is far below any ROE that has been authorized for either an electric or natural gas utility since at least 1980 (*i.e.*, the period back to which data is readily available). Therefore, at a minimum, given the limited size of Mr. Megginson's proxy group and the anomalous result of one of those proxy group companies, Mr. Megginson should have at least relied on the median result of his DCF analysis.

Q. Have you adjusted Mr. Megginson's constant growth DCF analysis to reflect the issues you have identified?

A. Yes. Specifically, I have adjusted Mr. Megginson's constant growth DCF analysis to: (1) utilize the average closing stock prices for each trading day over the period June through August 2025 for each of the proxy group companies; (2) rely on the median DCF result. As shown on Exhibit A-206 (AEB-2), page 26, applying these reasonable adjustments to Mr. Megginson's constant growth DCF analysis results in a median cost of equity estimate of 10.21%, or 45 basis points higher than the average result relied on by Mr. Megginson. In addition, as shown on Exhibit A-206 (AEB-2), page 25, even if the

median of Mr. Megginson's as-filed DCF results is utilized and no other changes are made, the estimated cost of equity is 10.14%, or 38 basis points higher than the average result relied on by Mr. Megginson.

Q. What are your primary disagreements with Mr. Coppola's application of the constant growth DCF model?

A. I disagree with two aspects of Mr. Coppola's DCF – his use of two-year growth rates published by *Yahoo! Finance* and his arbitrary exclusions of certain growth rates in the DCF analysis.

First, for purposes of his DCF analysis, Mr. Coppola relies on an average of three- to five-year projected EPS growth rates published by *Value Line* for his proxy group companies and two-year projected EPS growth rates published by *Yahoo! Finance*. Mr. Coppola provides no explanation as to the basis for using these projected EPS growth rates, but as discussed in my direct testimony, *Yahoo! Finance* no longer publishes three- to five-year projected EPS growth rates that are over a similar duration as the projected EPS growth rates published by *Value Line*. However, given this data limitation with the *Yahoo! Finance* data, Mr. Coppola relied on the Company's most recent natural gas rate proceeding (*i.e.*, Case No. U-21806) on projected EPS growth rates published by not only *Value Line* but also *Zacks Investment Research* ("*Zacks*"), both of which are projected over a similar three- to five-year period.[69] It is unclear why Mr. Coppola switched from using the *Zacks* growth rates that he used recently to a shorter-term *Yahoo! Finance* growth rate in this proceeding; however, he should have relied on the *Zacks* data that is consistent with the duration of the *Value Line* projections that he also relies on in this proceeding.

[69] Michigan Public Service Commission, Case No. U-21806, Direct Testimony and Exhibits of Sebastian Coppola, April 23, 2025, Exhibit AG-43.

Second, Mr. Coppola arbitrarily excludes certain growth rates from his DCF analysis. As shown on Exhibit AG-37 and Work Paper AG-37B, (see Exhibit No. A-207, (AEB-3), page 1) Mr. Coppola excludes the growth rates for Evergy published by *Value Line*, and for CenterPoint Energy and IDACORP published by *Yahoo! Finance*. Mr. Coppola provides no explanation for why he excludes these growth rates or the methodology he applies for such exclusion. While it appears that Mr. Coppola excludes the growth rates for these companies because they are on the higher end of the growth rates published for his other proxy group companies, his exclusion of these growth rates is not only arbitrary but also inconsistently and asymmetrically applied. Specifically, there are also companies in his proxy group that have growth rates on the lower end of the growth rates published for his other proxy group companies, but he does not exclude these companies. As shown on Work Paper AG-37B (see Exhibit No.: A-207 (AEB-3), page 1), the average growth rate for Mr. Coppola's proxy group is 6.23%, and he excludes growth rates of 7.50%, 7.64%, and 8.17%; however, he does not exclude any growth rates that are well below his average growth rate. For example, Mr. Coppola includes a growth rate of 4.00% for Portland General Electric and 4.50% for DTE Energy even though those growth rates are further from the average than growth rates he excludes that are above his average. There is no basis for Mr. Coppola's arbitrary and one-sided treatment of the published growth rates in his DCF analysis.

Q. Have you adjusted Mr. Coppola's constant growth DCF analyses to address the issues you just discussed?

A. Yes. I have modified Mr. Coppola's constant growth DCF analysis to: (1) rely on the three- to five-year projected EPS growth rates published by *Zacks* instead of his shorter-

term growth rates from *Yahoo! Finance*; and (2) included all of the growth rates for the proxy group companies published by these sources rather than arbitrarily and asymmetrically excluding certain growth rates. In addition, since Mr. Coppola also relies on data through July 31, 2025,[70] even though data through the end of August 2025 was available at the time of the filing of his testimony, I have also updated the market data for the DCF (*i.e.*, share prices, dividends, and growth rates) through August 31, 2025. As shown in Exhibit A-206 (AEB-2), page 29, when these reasonable adjustments are made to Mr. Coppola's constant growth DCF analysis, the result is 9.86%, or approximately 30 basis points higher than Mr. Coppola's stated cost of equity estimate from his DCF analysis.

Q. Mr. Megginson states that the results your DCF analyses of 10.30% using three different stock price averages is "not entirely out of bounds but some of the growth rates are unreasonable."[71] Mr. Coppola also suggests that the growth rates for certain of your proxy group companies are inappropriately high.[72] What is your response?

A. I agree with Mr. Megginson's characterization that the results of my DCF analyses are reasonable; however, I disagree with his and Mr. Coppola's conclusion regarding certain growth rates. Mr. Megginson relies on two sources of projected EPS growth rates (*i.e.*, *Value Line* and *Zacks*), which I have also relied on (along with EPS growth rates reported by *S&P Capital IQ Pro*), and the only differences between our DCF analyses are the proxy group relied on and the timing of the data. Further, as I previously discussed, while

[70] Coppola Direct, at Exhibit AG-37.
[71] Megginson Direct, at 32.
[72] Coppola Direct, at 135.

Mr. Coppola arbitrarily excludes certain growth rates he deems too high, he has not similarly excluded any growth rates that are relatively low and thus has made a one-sided arbitrary adjustment to his DCF analysis.

Q. Mr. Walters has conducted three versions of a DCF model. How does he use the results of these models to establish his ROE recommendation in this proceeding?

A. In this proceeding, Mr. Walters states that he places primary weight on the results of two of his DCF analyses – his constant growth DCF analysis that relies on sustainable growth rates, and his multi-stage DCF analysis.[73]

Q. Is Mr. Walters's reliance on the results of these two DCF models for his ROE recommendation consistent with his approach in past proceedings?

A. No. While Mr. Walters has used the same three DCF models in past proceedings and his specification of these analyses has not changed, his reliance on the results of each of the models to establish his ROE range has changed over time. Specifically, Mr. Walters has gone from primarily weighting his constant growth DCF using projected EPS growth rates, to generally weighting all three of his DCF analyses equally, to now giving primary weight to his constant growth DCF using sustainable growth rates and his multi-stage DCF and giving minimal weight to his constant growth DCF that relies on projected EPS growth rates.[74]

[73] Walters Direct, at 41-42.

[74] *See, e.g.*, Oklahoma Corporation Commission, Case No. 2021-00164, Responsive Testimony of Christopher C. Walters, April 22, 2022, at 35, 38 and Exhibit CCW-3; Oklahoma Corporation Commission, Case No. 2022-000093, Responsive Testimony of Christopher C. Walters, March 7, 2023, at 35, 38 and Exhibit CCW-3; Wyoming Public Service Commission, Docket No. 20000-633-ER-23, Direct Testimony of Christopher C. Walters, August 14, 2023 at 41, 43 and WOCA Exhibit No. 602.5; Michigan Public Service Commission, Case No. U-21389, Direct Testimony of Christopher C. Walters, August 29, 2023, at 39, 42 and Exhibit AB-14; Walters Direct, at 41-42.

Q. Why does Mr. Walters contend that primary weight should be placed on the results of his constant growth DCF model that relies on sustainable growth rates and his multi-stage DCF analysis?

A. Mr. Walters places primary weight on the results of these two models because he contends that the average projected EPS growth rate for the proxy group is unsustainable because it exceeds his projected GDP growth rate.[75]

Q. Is Mr. Walters's rationale for the change in his approach as to which results should receive greater weight credible?

A. No. While Mr. Walters offers this as his current rationale for limiting the weight on his DCF models that rely on projected EPS growth rates, the fact is that the average projected EPS growth rate that he has relied on in his constant growth DCF analysis in prior proceedings, and which he has previously used to inform his recommended ROE, also exceeded his projected GDP growth rate in each of those proceedings.[76]

Furthermore, by Mr. Walters's own logic, he should have given minimal weight in this proceeding to his DCF using a sustainable growth rate given that the average sustainable growth rate he relies on is 5.29%, which also materially exceeds his assumed GDP growth rate of 4.09%.[77]

[75] Walters Direct, at 41-42.

[76] For example, see Wyoming Public Service Commission, Docket No. 20000-633-ER-23, Direct Testimony of Christopher C. Walters, August 14, 2023, WOCA, Exhibit No. 602.4, Page 1, WOCA, Exhibit No. 602.7 page 1 and WOCA, Exhibit No. 602.9, Page 1.

[77] *Id*., at Exhibit AB-11 and Exhibit AB-12.

Q. Setting aside the inconsistency in the weighting that Mr. Walters assigns to his DCF results to establish his ROE recommendation, do you agree with Mr. Walters's specification of the DCF models?

A. No, I do not agree with Mr. Walters's constant growth DCF model using sustainable growth rates or his multi-stage DCF model.

Q. Why do you disagree with Mr. Walters's constant growth DCF analysis that relies on sustainable growth rates?

A. The premise of Mr. Walters's reliance on sustainable growth rates for one of his DCF scenarios is that the sustainable growth rate is "determined by the proportion of the utility's earnings that is retained and reinvested in utility plant and equipment," and thus the "internal growth approach is linked to the percentage of earnings retained within the company, as opposed to being paid out as dividends."[78] Accordingly, Mr. Walters's sustainable growth rate calculation assumes that future earnings will increase as the retention ratio *(i.e.,* the portion of earnings not paid out in dividends) increases. However, this assumption that future earnings growth is inversely related to the dividend payout ratio does not necessarily hold in practice. For example, management may decide to: (1) conserve cash for capital investments; (2) manage the dividend payout for the purpose of minimizing future dividend reductions; (3) manage its capital structure; or (4) signal future earnings prospects. These decisions can and do influence the amount of earnings retained versus paid out as dividends, and such decisions have been seen recently in the market. For example, due to the economic effects of COVID-19, more than 40 companies

[78] Walters Direct, at 34.

in the S&P 500 Index temporarily suspended their dividends.[79] Counter to Mr. Walters's assumption, a company's management will alter dividend policy to respond to changes in earnings, and therefore dividend growth will not always reflect earnings growth (and vice versa).

Q. Is there academic research that supports the conclusion that future earnings growth is not inversely related to the dividend payout ratio?

A. Yes. Academic research has found the opposite to be true (*i.e.*, low retention ratios are associated with relatively higher earnings growth and vice versa). Zhou and Ruland (2006), Gwilym, *et al*. (2006) and Vivian (2006) discussed the theory that high dividend payouts (*i.e.*, low retention ratios) are associated with low future earnings growth.[80] Each of these studies also cited Arnott and Asness (2003) that found, over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[81] Specifically, Arnott and Asness (2003) concluded:

> Unlike optimistic new-paradigm advocates, we found that low payout ratios (high retention rates) historically precede low earnings growth. This relationship is statistically strong and robust. We found that the empirical facts conform to a world in which managers possess private information that causes them to pay out a large share of earnings when they are optimistic that dividend cuts will not be necessary and to pay out a small share when they are pessimistic, perhaps so that they can be confident of maintaining the dividend payouts. Alternatively, the facts also fit a world in which low payout ratios lead to, or come with, inefficient empire

[79] Karen Langley, "U.S. Companies Slashed Dividends at Fastest Pace in More Than a Decade," *Wall Street Journal*, July 8, 2020.

[80] Ping Zhou and William Ruland, "Dividend Payout and Future Earnings Growth," *Financial Analysts Journal*, Vol. 62, No. 3, 2006; Owain Gwilym, James Seaton, Karina Suddason, and Stephen Thomas, "International Evidence on the Payout Ratio, Earnings, Dividends and Returns," *Financial Analysts Journa*l, Vol. 62, No. 1, 2006; Andrew Vivian, "The Payout Ratio, Earnings Growth Returns: UK Industry Evidence," Working Paper, School of Economics, Finance and Business, University of Durham, 2006.

[81] Robert Arnott and Clifford Asness, "Surprise: Higher Dividends = Higher Earnings Growth," *Financial Analysts Journal*, Vol. 59, No. 1, January/February 2003. Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

> building and the funding of less than-ideal projects and investments, leading to poor subsequent growth, whereas high payout ratios lead to more carefully chosen projects. The empire-building story also fits the initial macroeconomic evidence quite well. At this point, these explanations are conjectures; more work on discriminating among competing stories is appropriate.[82]

All four studies found that there is a negative, not a positive, relationship between earnings growth rates and retention ratios. As such, Mr. Walters's reliance on retention growth rates in the constant growth DCF model is not appropriate.

Q. Are there any other reasons why sustainable growth rates should not be used in the DCF model?

A. Yes, there are two additional reasons beyond the empirical evidence and academic research demonstrating that projected EPS growth rates are the most relevant for stock price valuation. First, the use of the sustainable or retention growth rates involves estimating investor expectations for four separate variables over the near-term: (1) the retention ratio, reflected as the "b" variable; (2) the expected return on book equity, reflected as the "r" variable; (3) the growth in the number of share of common equity, reflected as the "s" variable; and (4) the portion of the market-to-book ratio that exceeds unity, reflected as the "v" variable. This means that the growth estimate includes the forecasting error of the four separate variables.

Second, Mr. Walters relies on two growth rates that he suggests represent the long-term growth of the proxy group (*i.e.*, the sustainable growth rate assumed in his constant growth DCF analysis and the long-term growth rate assumed in his multi-stage DCF analysis); however, as noted, these assumed growth rates are significantly different

[82] *Id.*

from one another and affect the results of his DCF analyses. The average long-term "sustainable" growth rate that Mr. Walters relies on in a constant growth DCF model is 5.29%.[83] Mr. Walters states that the sustainable growth rate is limited by the projected long-term GDP growth rate as that reflects the projected long-term growth in the economy as a whole, yet this growth rate is inconsistent with the long-term growth rate that he assumes in his multi-stage DCF model (*i.e.*, 4.09%).[84]

Q. Are projected EPS growth rates, such as Mr. Walters has relied on in one version of his constant growth DCF analysis, the most appropriate growth rates for use in the DCF model?

A. Yes. There are several reasons why the use of analysts' projected EPS growth rates in the DCF model is the most appropriate assumption:

- Earnings are the fundamental determinant of a company's ability to pay dividends, and over the long-term, dividend growth can only be sustained by earnings growth.[85] Therefore, EPS growth rates should be relied on in the DCF analysis.

- There is significant academic research demonstrating that EPS growth rates are most relevant in stock price valuation.[86] For example, Liu, *et al*. (2002) examined "the valuation performance of a comprehensive list of value drivers" and found that "forward earnings explain stock prices remarkably well" and were generally superior to other value drivers analyzed. Gleason, *et al*. (2012) found that the sell-side analysts with the most accurate stock price targets were those whom the researchers found to have more accurate earnings forecasts.

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[83] Walters Direct, at Exhibit AB-11.

[84] *Id*., at 33.

[85] As noted by Brigham and Houston: "Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE)." Eugene F. Brigham and Joel F. Houston, *Fundamentals of Financial Management*, at 317 (Concise Fourth Edition, Thomson South-Western, 2004).

[86] *See, e.g.*, Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66; James H. Vander Weide and Willard T. Carleton, "Investor growth expectations: Analysts vs. history," *The Journal of Portfolio Management*, Spring, 1988; Robert S. Harris

Continued on next page

- Investment analysts report predominant reliance on EPS growth projections. In a survey completed by 297 members of the Association for Investment Management and Research, the majority of respondents ranked earnings as the most important variable in valuing a security (more important than cash flow, dividends, or book value).[87]

- Projected EPS growth rates such as those available from *S&P* and *Zacks* are based on consensus estimates available from multiple sources. In other words, projected EPS growth rates include the contributions of more than one analyst and thus the results are less likely to be biased in one direction or another. Moreover, the fact that projected EPS growth estimates are available from multiple sources on a consensus basis attests to the importance of projected EPS growth rates to investors when developing long-term growth expectations.

Therefore, the use of sustainable growth rates by Mr. Walters ignores all these factors that demonstrate EPS growth rates are most relevant in stock price valuation.

Q. Before discussing the merits of Mr. Walters's multi-stage DCF analysis and Mr. Bandyk's two-step DCF analyses, as a threshold matter, are the results of those analyses reasonable?

A. No. Neither the results from Mr. Walters's multi-stage DCF, which range from 8.21% (median) to 8.62% (average), nor Mr. Bandyk's two-step DCF using a projected dividend per share ("DPS") growth rate as the first step growth rate, which is 8.26%, are reasonable. The results of these analyses are well below the low-end of the range of comparable authorized returns for electric utilities in at least the last 45 years, including during periods

and Felicia C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management*, Summer, 1992; Advanced Research Center, "Investor Growth Expectations," Summer 2004; Eugene F. Brigham, Dilip K. Shome and Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management*, Vol. 14, No. 1, Spring, 1985; Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 299-303; Jing Liu, *et al*., "Equity Valuation Using Multiples," *Journal of Accounting Research*, Vol. 40 No. 1, March 2002; C. A. Gleason, *et al*., "Valuation Model Use and the Price Target Performance of Sell-Side Equity Analysts," *Contemporary Accounting Research*, September 2011; Bochun Jung, *et al*., "Do financial analysts' long-term growth forecasts matter? Evidence from stock recommendations and career outcomes," *Journal of Accounting and Economics*, Vol. 53 Issues 1-2, February-April 2012.

[87] Stanley B. Block, "A Study of Financial Analysts: Practice and Theory," *Financial Analysts Journal*, July/August 1999.

with extremely low long-term interest rates. The *Hope* and *Bluefield* decisions,[88] which both Mr. Walters and Mr. Bandyk acknowledge are standards to be followed in setting a just and reasonable utility return,[89] require the authorized return to be comparable to other returns available to investors in companies with similar risk. As a result, it is reasonable to conclude that neither the results from Mr. Walters's multi-stage DCF nor Mr. Bandyk's two-step DCF using a projected DPS growth rate as the first step growth rate are reasonable and meet the comparable return standard of *Hope* and *Bluefield*.

Q. Do you agree with Mr. Walters's and Mr. Bandyk's use of multi-stage DCF analyses to estimate the ROE for the Company?

A. No. The utility industry is considered a mature industry due to its regulated status and relatively stable demand. Thus, financial projections such as earnings growth rate projections are also likely to be relatively stable over the long-term. The relative stability of the financial forecasts for utilities supports the use of a constant growth DCF model to estimate the cost of equity for a mature industry like utilities. As noted, both Mr. Megginson and Mr. Coppola also conduct constant growth DCF analyses and do not rely on a multi-stage DCF model. For these reasons, the constant growth DCF model is the more appropriate model to estimate the cost of equity for the Company rather than the multi-stage analyses conducted by Mr. Walters and Mr. Bandyk.

[88] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

[89] Walters Direct, at 24; Bandyk Direct, at 6.

Q. Do the multi-stage forms of the DCF model relied on by Mr. Walters and Mr. Bandyk increase the number of subjective inputs required to estimate the DCF model?

A. Yes. The multi-stage DCF model introduces additional assumptions and potential analyst bias. Specifically, the multi-stage DCF models presented by Mr. Walters and Mr. Bandyk in this proceeding resulted in the following additional assumptions that require subjective judgment:

- Specification of the Model: In this case, Mr. Walters and Mr. Bandyk present two different specifications of a multi-stage model (*i.e.,* a three-stage DCF and a two-step DCF, respectively).

- Selection of the Growth Rates: Mr. Bandyk's DCF that relies on a blended growth rate requires selecting a short-term and long-term growth rate, while Mr. Walters's multi-stage DCF with three stages of growth requires the additional selection of an intermediate growth rate.

- Weighting Factors for the Blended Growth Rate: Consistent with the Federal Energy Regulatory Commission's ("FERC") two-step DCF approach, Mr. Bandyk places 80.00% weight on the short-term growth rate and 20.00% on the long-term growth rate when calculating his blended growth rate.[90] The selection of the weighting factor has a direct effect on the result produced by Mr. Bandyk's two-step DCF model.

- Duration of Each Stage of the Multi-Stage DCF Model: For his multi-stage DCF model with three stages of growth, Mr. Walters assumes Stage 1 growth is years 1-5, Stage 2 growth is years 6-10, and Stage 3 growth is year 11 and after.[91]

Given the number of additional subjective assumptions required, it is reasonable to conclude that a multi-stage DCF analysis creates greater opportunity for an analyst to influence the results of the DCF model.

[90] Bandyk Direct, at 28.
[91] Walters Direct, at 36-37.

Q. How do Mr. Walters and Mr. Bandyk develop their projected GDP growth rates?

A. Mr. Walters relies on a projected nominal GDP of 4.09% as reported by *Blue Chip Financial Forecasts*.[92] Mr. Bandyk relies on the projected nominal GDP growth rate over the period of 2028-2035 from the Congressional Budget Office ("CBO") of 3.80%.[93]

Q. Do you agree with Mr. Bandyk's and Mr. Walters's projected GDP growth rate?

A. No. Mr. Walters relies on a projected nominal GDP growth rate that is only for the next five to ten years (*i.e.*, 2027-2036), while his multi-stage DCF analysis relies on a long-term growth rate for Stage 3 that starts in year 11 (*i.e.*, 2036) and continues into perpetuity. Therefore, his assumed long-term growth rate only covers the first year of the long-term period to which it is being applied in his DCF analyses. Similarly, Mr. Bandyk's two-step DCF analysis relies on a blended growth rate that also continues into perpetuity; however, the projected nominal GDP growth rate that he relies on reflects growth only for the seven-year period 2028-2035, meaning his assumed long term growth rate only covers a small portion of the period to which it is being applied in his two-step DCF analyses. As a result, the projected GDP growth rates relied on by Mr. Walters and Mr. Bandyk may not be indicative of the expected growth in GDP over the longer term, and therefore, cannot be used as the basis to conclude that the projected EPS growth rate for my proxy group will not be sustained in perpetuity.

Q. Is there academic research that challenges the use of GDP growth as the long-term estimate of growth in the DCF model?

A. Yes. For example, *Modern Regulatory Finance* notes the following:

[92] *Id.*, at 39 and Exhibit AB-12.
[93] Bandyk Direct, at Exhibit CUB-6 and CUB-7.

- One central assumption in Multi-Stage DCF models, and a potential Achilles' heel, in my view, is that utility growth rates will eventually match the growth of the macroeconomy usually measured by the growth of the Gross Domestic Product (GDP). I am not aware of any financial literature supporting the notion that utility earnings per share are expected to grow at the average growth of the economy, or GDP.

- As discussed in Chapter 10, based upon the wealth of empirical and academic literature that supports the superiority of analyst's forecasts as a measure of investor expectations for the use of such forecasts in the DCF model, current earnings growth forecasts are the appropriate growth rates to use in a DCF analysis. Besides, to the extent that economic trends influence growth, it is reasonable to assume that they are already captured in analysts' growth estimates for utilities.

- Multi-stage DCF applications appear somewhat disconnected from the assumptions of the method and the consensus expectations of investors. The investment community does not look to GDP growth over the next several decades when evaluating an investment in utility stocks, nor does it anticipate a series of discrete muti-stage decennial stages. *I am not aware of any evidence that investors evaluate the future based on the assumptions and data sources required to apply the two-stage or three-stage DCF model*.[94]

Q. Do you agree with Mr. Walters and Mr. Bandyk that the use of projected EPS growth rates are "unstainable" and "unrealistic", respectively, in the DCF analysis and thus inconsistent with the infinite time horizon in the DCF model?[95]

A. No. There are multiple reasons why there is no basis to Mr. Walters's and Mr. Bandyk's claims.

First, their contention is inconsistent with the source that Mr. Walters relies on to conclude that projected EPS growth rates cannot exceed the growth rate of GDP. Specifically, Mr. Walters includes the following quote from Fundamentals of Financial Management by Eugene Brigham and Joel F. Houston:

[94] Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, at 486; emphasis added.
[95] Walters Direct, at 64-65; Bandyk Direct, at 26.

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[96]

However, Mr. Walters cites only a portion of the quote from Brigham and Houston and omits the remainder of the discussion, which indicates the growth rate range that would be considered reasonable:

> On this basis, one might expect the dividends of an average, or "normal," company to grow at a rate of 5 to 8 percent a year.[97]

As shown on Exhibit A-14 (AEB-1), Schedule D-5, pages 3-5, the average projected EPS growth rate in my constant growth DCF analysis that Mr. Walters and Mr. Bandyk criticize is 6.48%, which is well within the range referenced by the source relied on by Mr. Walters and is not excessive.

Second, both Mr. Walters[98] and Mr. Bandyk[99] support their conclusion by comparing the projected EPS growth rates to their respective projected GDP growth rates, noting that it is not reasonable to assume that utilities can grow at a rate that is greater than the economy over the long term. However, this comparison relies entirely on the accuracy of their respective estimates of a long-term GDP growth rate.

Third, considering the empirical studies comparing the total factor productivity ("TFP") growth of the utility industry relative to the economy, it is not unreasonable to assume that earnings growth for utilities could exceed GDP growth over the long term. In

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96 Eugene F. Brigham & Joel F. Houston, *Fundamentals of Financial Management*, Eleventh Edition, 2007, at 298.

97 *Id.*

98 *Id*., at 65.

99 Bandyk Direct, at 27.

a study filed as part of the Rate Regulation Initiative of the Alberta Utilities Commission, the authors calculated TFP growth[100] for 72 U.S. electric and combination electric and natural gas utilities and for the U.S. economy for the period of 1972 through 2009. For the U.S. utility group, TFP growth averaged 0.96% over the period of 1972 to 2009,[101] while TFP growth for the U.S. economy was 0.91%,[102] indicating that electric and combination electric and natural gas utilities were approximately 5.00% more productive than the U.S. economy over the study period. Therefore, the authors demonstrated that utility growth exceeded growth for the U.S. economy for approximately 40 years.

Q. Mr. Bandyk also conducts an alternative two-step DCF analysis in which he replaces projected EPS growth rates with projected DPS growth rates as the growth rate in the initial stage of his analysis. Do you agree with the use of projected DPS growth rates in the DCF analysis?

A. No. As I previously discussed, there are multiple reasons why the use of DPS growth is not appropriate and that projected EPS growth rates should be utilized in the DCF analysis. Mr. Bandyk's use of DPS growth rates ignores all these factors that demonstrate EPS growth rates are most relevant in stock price valuation.

[100] TFP growth is a measure of productivity calculated as the difference between output growth and input growth. Higher TFP growth indicates that a company is converting inputs into higher levels of output growth (*i.e.*, increased productivity).

[101] Alberta Utilities Commission, Jeff Makholm and Agustin Ros, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative", February 22, 2012, at 5.

[102] Alberta Utilities Commission, Jeff Makholm, and Agustin Ros, "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative," December 30, 2010, at 19.

Q. Have you adjusted Mr. Walters's and Mr. Bandyk's DCF analyses for the issues that you have addressed?

A. Yes. I have updated Mr. Walters's constant growth DCF using projected EPS growth rates but have removed DUK from the proxy group as a result of its recent merger and acquisition activity. As shown on Exhibit A-206 (AEB-2), page 31, if Mr. Walters had appropriately placed primary weight on the results of this DCF model consistent with the approach he has supported in prior proceedings, the cost of equity estimate from his DCF analyses would be 11.09% (average) and 10.72% (median), which fully supports the Company's proposed ROE in this proceeding.

Further, I have also modified Mr. Bandyk's DCF analysis to: (1) rely on the constant growth DCF model as opposed to the two-step DCF model; and (2) reflect my updated proxy group that removes companies that since my direct testimony have engaged in meaningful transactions. As shown on Exhibit A-206 (AEB-2), page 33, the average DCF result is 10.39% when applying these reasonable adjustments to his DCF analysis.

VII. CAPM ANALYSIS

Q. Please summarize the CAPM analyses prepared by Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk.

A. Mr. Megginson conducts three CAPM analyses, one using a historical market risk premium, and two additional scenarios using different implied projected market risk premia, one based on the trailing 12-month cash yield and the other based on the average cash yield over the past 10 years.[103] For all three of his CAPM analyses, Mr. Megginson relies on: (1) a risk-free rate of 4.58%, which is based on a weighted average of projected

[103] Megginson Direct, Exhibit S-4, Schedule D-5, at 7-9.

30-year Treasury bond yields for 2025, 2026 and 2027 as reported by S&P Global Market and *econforecasting.com*; and (2) current betas for each of the proxy group companies as published by *Value Line*. Mr. Megginson calculates his historical market risk premium, which is 6.94%, as the arithmetic mean realized return on large company stocks over the period 1928-2024 minus the income-only total return on long-term government bonds over that same period. For each of his CAPM scenarios relying on a projected market risk premium, Mr. Megginson relies on data reported by Professor Damodaran. The average cost of equity result of Mr. Megginson's CAPM analyses are 10.05% (historical market risk premium), 7.85% (12-month trailing projected market risk premium), and 9.04% (10-year cash yield smoothed projected market risk premium).[104]

Mr. Coppola conducts a CAPM analysis that relies on: (1) a risk-free rate of 4.40% based on the near-term projected 30-year Treasury bond yield as reported by *Blue Chip Financial Forecasts* as of May 1, 2025; (2) current betas for each of the proxy group companies as published by *Value Line*; and (3) a market risk premium of 7.35%, which is the historical market return of large company stocks minus the income-only return on long-term government bonds from 1926 through 2024.[105] The cost of equity resulting from Mr. Coppola's CAPM analysis is 9.98%.

Mr. Walters produces 12 different cost of equity estimates from his CAPM analysis, relying on different estimates of the risk-free rate, beta, and market risk premium. Specifically, for the risk-free rate, Mr. Walters relies on a projected 30-year Treasury yield in eight scenarios, and a *Kroll* "normalized" risk-free rate in the remaining four

[104] Megginson Direct, at 25-27 and Exhibit S-4, Schedule D-5, at 7-9.
[105] Coppola Direct, at 136-138 and Exhibit AG-38.

scenarios.[106] For beta, Mr. Walters relies on four estimates for the proxy group companies: (1) current five-year betas published by *Value Line*; (2) historical average betas published by *Value Line*; (3) current beta estimates from S&P Market Intelligence's Beta Generator ("Market Intelligence"); and (4) current three-year raw betas published by Market Intelligence to which he applies the Blume adjustment similar to *Value Line's* adjustment.[107] For the market risk premium, Mr. Walters also relies on three estimates: (1) the long-term historical arithmetic average real return on the S&P 500 plus an expected inflation rate, less the risk-free rate; (2) a constant growth DCF-derived return on the S&P 500, averaging the method prescribed by FERC in Order No. 569-A with an alternative where all the companies in the S&P 500 are used rather than just the dividend-paying companies, less the risk-free rate; and (3) a "normalized" market risk premium published by *Kroll*.[108] Mr. Walters's CAPM results produce a cost of equity range from 7.15% to 10.88%.[109]

Mr. Bandyk produces four different cost of equity estimates from his CAPM analysis, relying on different estimates of the risk-free rate, beta, and market risk premium. Specifically, for the risk-free rate, Mr. Bandyk relies on the current yield on long-term Treasury bonds reported by Dr. Damodaran and a *Kroll* "normalized" risk-free rate.[110] For beta, Mr. Bandyk relies on current betas for each of the proxy group companies as published by *Value Line* and *Bloomberg*, but adjusted to remove the Blume adjustment

[106] Walters Direct, Exhibit AB-19.
[107] *Id.*
[108] *Id.*
[109] *Id.*, at 51-60 and Exhibit AB-19.
[110] Bandyk Direct, Exhibit CUB-3.

reflected in those betas, thus relying on the raw betas.[111] For the market risk premium, Mr. Bandyk relies on: (1) an average of the five projected market risk premia reported by Dr. Damodaran; and (2) the "normalized" market risk premium published by *Kroll*.[112] Mr. Bandyk's CAPM analysis produces a cost of equity range from 6.96% to 9.37%, with an average of 8.11%.[113]

A. Risk-Free Rate

Q. Is the risk-free rate that Mr. Coppola relies on in his CAPM analysis reasonable?

A. No. Mr. Coppola's risk-free rate is outdated and does not reflect current expectations and therefore should not be relied upon. Specifically, Mr. Coppola relies on a risk-free rate of 4.40% based on the *Blue Chip Financial Forecasts* as of May 1, 2025 from my direct testimony, and states that his 4.40% risk-free rate is forecasted for the "second and third quarters of 2026 sourced from economic projections provided by the Company."[114] However, the *Blue Chip Financial Forecast* is a monthly publication, and thus Mr. Coppola's analysis should have been based on the most recent data available. It is unclear why Mr. Coppola relies on an outdated risk-free rate that is more than five months old, given that more current data was available prior to the submission of his testimony on September 30, 2025.

[111] *Id.,* at Exhibit CUB-4.
[112] *Id.,* at Exhibit CUB-3.
[113] *Id.*, at Exhibit CUB-5.
[114] Coppola Direct, at 137.

Q. Is the current consensus estimate of the 30-year Treasury bond yield higher than assumed in Mr. Coppola's CAPM analysis?

A. Yes. As reported in the most recent publication of the *Blue Chip Financial Forecasts*, the consensus estimate of the 30-year Treasury bond yield for the second and third quarters of 2026 as relied on by Mr. Coppola is 4.60%.[115]

Q. Do you have any concerns with the risk-free rate that Mr. Bandyk relies on in his CAPM analyses?

A. Yes. I disagree with Mr. Bandyk's use of the current yield on long-term Treasury bonds reported by Dr. Damodaran in two of his four CAPM analyses, which appears to be the current yield on the 10-year Treasury bond. In determining the security most relevant to the application of the CAPM, it is important to select the term (or maturity) that best matches the life of the underlying investment. As noted by *Morningstar*:

> The horizon of the chosen Treasury security should match the horizon of whatever is being valued… If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[116]

Because utility companies represent long-duration investments, the 30-year Treasury yield, not the 10-year Treasury bond, is the appropriate measure of the risk-free rate for the purpose of the CAPM. In addition, based on principles of prudent financial management, the term of the debt financing should match the useful life of the asset being financed. Utility plant assets generally have useful lives between 25 and 40 years, meaning

[115] *Blue Chip Financial Forecasts*, Vol. 44, No. 10, October 1, 2025, at 2.

[116] *Morningstar, Inc.*, 2010 Ibbotson Stocks, Bonds, Bills and Inflation, Valuation Yearbook, at 44.

that, under prudent financial management, those assets should be financed with bonds of longer duration than 10-years.

B. Market Risk Premium

Q. What is the primary criticism that you have of the development of the market risk premium used by each of the witnesses recommending an ROE for the Company in this proceeding?

A. Each witness develops their market risk premium independent from the risk-free rate that they are using in their CAPM analyses. This ignores the academic research that there is an inverse relationship between the risk-free rate and the market risk premium.[117] As I will discuss, this misalignment of the risk-free rate and market risk premium in their respective CAPM analyses serves to underestimate the cost of equity.

Q. Please explain why you disagree with Mr. Megginson's and Mr. Coppola's use of a historical market risk premium for estimating the CAPM.

A. Fundamentally, the market return and market risk premium should be forward-looking. Neither Mr. Megginson nor Mr. Coppola have provided any evidence that the historical averages that they calculate for the market return or the market risk premium reflect the expected market conditions during the period in which the Company's proposed rates will be in effect. As *Morningstar* has observed, the market risk premium is a forward-looking concept, not a historical analysis:

> It is important to note that the expected equity risk premium, as it is used in discount rates and the cost of capital analysis, is a forward-looking concept. That is, the equity risk premium that is used in the discount rate should be reflective

[117] *See e.g.*, S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March, 1998. *See also*, Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

> of what investors think the risk premium will be going forward.[118]

Interest rates have increased significantly since historical lows and are expected to remain elevated over at least the next year. Inflation remains above the Federal Reserve's target level, and uncertainty (*i.e.*, higher overall risk) in the market has increased because of the effect of the current administration's policies with respect to tariffs, immigration, and taxes on the economy. All of these conditions affect the current and projected equity risk premium and should be considered in establishing the ROE in this proceeding.

Q. Are there other reasons why using a historical market risk premium for estimating the forward-looking cost of equity is not appropriate in the calculation of the CAPM based on current market conditions?

A. Yes. As noted previously, Mr. Megginson's and Mr. Coppola's use of the historical market risk premium disregards the demonstrated relationship between interest rates and the market risk premium. Both Mr. Megginson and Mr. Coppola calculate the cost of equity using the CAPM by relying on a long-term historical average market risk premia and a near-term projected risk-free rate. However, in Mr. Megginson's and Mr. Coppola's specification of the CAPM, their respective near-term projected risk-free rates bear no relationship to the historical average interest rates underlying the historical average market risk premia on which they rely. Therefore, the use of assumptions from different time periods fails to account for the inverse relationship that exists between the risk-free rate and the equity risk premium. Both academic literature and market evidence indicate that the equity risk premium is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa), and given that current

[118] *Morningstar Inc*., 2010 Ibbotson SBBI Valuation Yearbook, at 55.

interest rates on long-term government bonds are below the historical average interest rate of those same bonds, the market risk premium should be *greater than* the long-term historical average market risk premium – which is not the case for either Mr. Megginson's or Mr. Coppola's CAPM analyses.

Q. Can you illustrate the inconsistency between Mr. Megginson's and Mr. Coppola's risk-free rate and equity risk premium?

A. Yes. Mr. Megginson's estimate of the historical market risk premium, relies on the arithmetic average market risk premium of 6.94% for the period of 1928-2024, which is based on the difference between the historical average return on large company stocks (*i.e.*, 11.79%) and the historical average income-only return on long-term government bonds (*i.e.*, 4.85%) over this period.[119] However, Mr. Megginson relies on a near-term projected risk-free rate on long-term government bonds of 4.58% to estimate the cost of equity in the CAPM, which is *lower than* the historical average return on long-term government bonds (*i.e.*, 4.85%) that he relies on to estimate the market risk premium. Considering the academic research demonstrating the inverse relationship between interest rates and the market risk premium, since Mr. Megginson's current return on long-term government bonds is *less than* the historical average return on those same bonds, the current market risk premium should be *greater than* the long-term historical average of 6.94% that Mr. Megginson assumes. Consequently, Mr. Megginson's use of a historical market risk premium understates the market risk premium in the current market environment when interest rates are below the long-term average.

[119] Megginson Direct, Exhibit S-4, Schedule D-5, at 6.

Similarly, Mr. Coppola's market risk premium of 7.35% is also understated. He uses approximately the same historical average return on long-term government bonds that Mr. Megginson relies on (*i.e.*, 4.84%[120]) to estimate his equity risk premium, but relies on an even lower forward-looking risk-free rate of 4.40% as compared to Mr. Megginson.[121] Because his risk-free rate is lower than the historical risk-free rate that was used to derive his risk premium, Mr. Coppola's CAPM analysis also understates the cost of equity.

Q. Has *Kroll*, the publisher of the historical data on which Mr. Megginson and Mr. Coppola rely to estimate the historical market risk premium, highlighted a potential inconsistency with relying on historical data for a forward-looking analysis such as the CAPM?

A. Yes. *Kroll* has stated that, "[i]n using a historical measure of the equity risk premium, one assumes that what has happened in the past is representative of what might be expected in the future."[122] However, because the near-term projected long-term government bond yields are currently below those that Mr. Megginson and Mr. Coppola have relied on in their historical average market risk premium estimates, the market risk premium based on long-term historical average data is certainly not representative of what is expected in the future. Given the inverse relationship between the market risk premium and interest rates, since the projected interest rate is lower than the historical average, it is reasonable to expect that the market risk premium would be higher than the historical average.

[120] Coppola Direct, Work Paper AG-38A (see Exhibit A-207 (AEB-3), page 6).
[121] Coppola Direct, Exhibit AG-38.
[122] *Kroll*, 2022 SBBI Yearbook, at 198.

Q. Is there also evidence that the use of a historical market premium can produce counter-intuitive results?

A. Yes. Figure 7 illustrates the problem with relying on the historical market risk premium such as Mr. Megginson and Mr. Coppola have done. Specifically, the figure shows that from 2007-2009, the historical market risk premium decreased even as market volatility (*i.e.*, the primary statistical measure of risk) significantly increased. Further, this figure demonstrates the significant swings in the annual equity risk premium that are averaged into the long-term historical average calculations. As shown, in 2008, the annual equity "premium" was actually negative, which implies a discount for equity holders relative to the cost of debt. It is incomprehensible that the perceived risk for equity was negative (implying a lower required return) in the height of the financial market collapse when the overall market return was a negative 37.00%. As shown, this individual observation alone, which runs counter to the theory of the equity risk premium, reduces the historical average market risk premium for the prior 80 years by 60 basis points.

Figure 7: Historical Market Risk Premium and Market Volatility

	Market Volatility	Market Return	Annual Equity Premium	Long-term Average Historical Market Risk Premium[123]
2007	17.54	5.49%	0.63%	7.10%
2008	32.69	-37.00%	-41.45%	6.50%
2009	31.48	26.46%	3.47%	6.70%

The assumption that investors would expect or require a lower equity risk premium during periods of increased volatility is counter-intuitive and leads to unreliable analytical results. As noted earlier, the relevant objective in the application of the CAPM is to ensure

[123] Ibbotson SBBI Yearbook. *Morningstar Inc*. 2008, at 28. *Ibbotson SBBI Yearbook. Morningstar Inc*. 2009, at 23; Ibbotson SBBI Yearbook. *Morningstar Inc*. 2010, at 23. The historical market risk premium equals the total return on large company stocks less the income-only return on long-term government securities.

that all three components of the model (*i.e.*, the risk-free rate, the beta, and the market risk premium) are consistent with market conditions and investor perceptions. The forecasted market risk premium estimates used in my original and rebuttal CAPM analyses specifically address that concern.

Q. Is the method that Mr. Megginson relies on for purposes of estimating his historical market risk premium consistent with Staff's prior methodology?

A. No. The calculation of the historical average market risk premium that Mr. Megginson relies on is inconsistent with the method that Staff utilized previously in another recent proceeding. As noted, Mr. Megginson relies on a historical average market risk premium of 6.94%, which is based on historical data reported by Professor Damodaran from 1928 through 2024. However, in Case No. U-21461, the Staff witness relied on a historical market risk premium based on the data published by *Kroll*, which published the data from 1926 through the current year.[124] By relying on a different source, Mr. Megginson has arbitrarily shortened the historical period used to calculate the long-term average market risk premium.

Q. What is the effect of relying on a shorter historical data set than what Staff has relied on in prior cases?

A. Relying on data starting in 1928 rather than the full data set understates the long-term market return and market risk premium. Mr. Megginson calculates a market return of 11.79% and a market risk premium of 6.94% using the truncated data set. However, on their online Cost of Capital Navigator, *Kroll* reports that the historical long-term market return for 1926 through 2024 is 12.17%, and that the long-term income-only return on

[124] Michigan Public Service Commission, Case No. U-21461, Qualifications and Direct Testimony of Joseph E. Ufolla, January 18, 2024, at 13.

long-term government bonds over the same period is 4.86%, meaning the long-term historical average equity risk premium over this period is 7.31%.[125] This historical calculation is higher than Mr. Megginson's market risk premium and is consistent with the historical market risk premium on which Mr. Coppola relies for this CAPM analysis.[126] Therefore, while Mr. Megginson's and Mr. Coppola's use of a historical average market risk premium in their CAPM analyses understates the market risk premium and thus understates the cost of equity by failing to account for current market conditions and the inverse relationship between interest rates and the market risk premium, Mr. Megginson has further understated the historical average market risk premium, and thus cost of equity, by relying on a source (*i.e.*, Professor Damodaran) that reports data for a shorter time period than the historical data set published by *Kroll*.

Q. Mr. Megginson also calculates two CAPM analyses using projected market risk premia. Are these analyses reasonable?

A. No. First, as a threshold matter, Mr. Megginson's CAPM analysis that relies on the 12-month trailing market risk premium of 4.15% results in a cost of equity of 7.85%,[127] which is unreasonable given that such a result is well below the low end of any authorized ROE in a comparable regulatory jurisdiction for either an electric or natural gas utility since at least 1980.

Second, Mr. Megginson's CAPM scenarios that rely on projected market risk premia are also inconsistent with the inverse relationship between the risk-free rate and the market risk premium, and, as a result, significantly understate the cost of equity.

[125] *Kroll*, Cost of Capital Navigator, Historical Long-Term (1926-2024) equity risk premium.

[126] Coppola Direct, Exhibit AG-44; see "Sources, column (d)" and Work Paper AG-38A, (see Exhibit No.: A-207 (AEB-3), page 5).

[127] Megginson Direct, at 27 and Exhibit S-4, Schedule D-5, at 8.

Specifically, Mr. Megginson relies on a risk-free rate of 4.58%, which is well below the historical average return on long-term government bonds (*i.e.*, 4.86%), which means that one would expect Mr. Megginson's projected market risk premia to be greater than the long-term historical average market risk premium of 7.31%; however, Mr. Megginson's projected market risk premia of 4.15% and 5.66% are substantially below the long-term historical average (*i.e*., by 316 basis points and 165 basis points, respectively.)[128]

Q. Is Mr. Megginson's projected market risk premium consistent with his prior testimony?

A. No. In the recent Michigan Gas Utilities proceeding in Case No. U-21540, Mr. Megginson relied on a projected market risk premium as calculated in the same manner as I have done in my direct testimony (*i.e.,* the projected return on the S&P 500 less the assumed risk-free rate).[129] In addition, in the Company's last electric rate proceeding in Case No. U-21585, Mr. Megginson also relied on a similar approach, although he used an outdated market risk premium based on data filed more than 16 months prior in another rate proceeding.[130] Mr. Megginson has provided no basis for changing his methodology.

[128] *Id*., at 8-9.

[129] Qualifications and Direct Testimony of Kirk D. Megginson, Case No. U-21540, July 1, 2024, Exhibit S-4, Schedule D-5, at 6 of 11. Note, the heading in column (e) of this exhibit mistakenly refers to the market risk premium as a "historical market risk premium;" however, the exhibit is clear that the market risk premium assumed by Mr. Megginson is a projected market risk premium consistent with the method relied on by the company in that proceeding.

[130] Direct Testimony of Kirk D. Megginson, Case No. U-21585, September 27, 2024, Exhibit S-4, Schedule D-5, at 8, whereby Mr. Megginson referenced and relied on the market risk premium in the Direct Testimony of Todd A. Wehner, Case No. U-21389, May 1, 2023, Exhibit A-14, Schedule D-5, page 10 of 12.

Q. Does this change in Mr. Megginson's approach when using a projected market risk premium produce a significantly different result for his projected market risk premium?

A. Yes. If Mr. Megginson had calculated the market risk premium in a manner consistent with his prior testimony in Case No. U-21540, his projected market risk premium would be 8.00% (*i.e.,* the market return of 12.58% as shown in my direct testimony in Exhibit A-14, Schedule D-5, page 16, minus Mr. Megginson's assumed risk-free rate in this proceeding of 4.58%), or *234 basis points and 385 basis points higher* than the 5.66% and 4.15% estimates that he assumes for his projected market risk premium in the current proceeding.

Q. Do the market risk premia relied on by Mr. Walters and Mr. Bandyk suffer from the same failure to appropriately reflect the inverse relationship between interest rates and the market risk premium as you previously discussed in your response to Mr. Megginson and Mr. Coppola?

A. Yes. As shown in Figure 8, 4 out of 12 of Mr. Walters's CAPM analyses that rely on his *Kroll* "normalized" market risk premium, as well as the projected market risk premia from *Kroll* and Professor Damodaran relied on by Mr. Bandyk in his CAPM analysis, are also inconsistent with the inverse relationship between interest rates and the market risk premium and thus understates the cost of equity. Specifically, the risk-free rate assumptions used in their CAPM analyses are either below or consistent with the long-term average risk-free rate, and yet contrary to the inverse relationship between interest rates and the market risk premium, their respective market risk premia are well below the long-term term average market risk premium.

Figure 8: Misalignment of Market Risk Premia Relied on by Mr. Walters and Mr. Bandyk[131]

Witness	Source	Market Risk Premium	Amount Below Long-Term Avg.	Risk-Free Rate	Amount Below Long-Term Avg.
	Long-Term Historical Avg.	**7.31%**		**4.86%**	
Walters	*Kroll* - Normalized	5.50%	-1.81%	4.85%	-0.01%
Bandyk	Damodaran (TTM sustainable payout)	3.68%	-3.63%	4.23%	-0.63%
Bandyk	Damodaran (TTM)	3.94%	-3.37%	4.23%	-0.63%
Bandyk	Damodaran (smoothed)	5.37%	-1.94%	4.23%	-0.63%
Bandyk	Damodaran (normalized)	3.57%	-3.74%	4.23%	-0.63%
Bandyk	Damodaran (net cash yield)	3.68%	-3.63%	4.23%	-0.63%
Bandyk	*Kroll* - Normalized	5.00%	-2.31%	4.76%	-0.10%

Q. Are the results of either Mr. Walters's CAPM analyses that rely on the *Kroll* "normalized" market risk premium or Mr. Bandyk's CAPM reasonable?

A. No. The cost of equity results from their CAPM analyses are unreasonable. Specifically, the results of Mr. Walters's *Kroll* "normalized" market risk premium CAPM scenarios are 7.15%, 8.35%, 8.99%, and 9.16%,[132] while the results of Mr. Bandyk's CAPM analysis are 6.96%, 7.97%, 8.13%, and 9.37%.[133] Due to their misspecification of the market risk premium in these scenarios, all of these results are either at or well below the low end of any authorized ROE in a comparable regulatory jurisdiction for a vertically integrated electric utility in nearly half a century. I recognize that Mr. Bandyk believes it is not appropriate to compare his CAPM result to previously authorized ROEs given that he claims that regulatory commissions have consistently authorized ROEs well in excess of

[131] Note, Mr. Walters relies on the equity risk premium reported by *Kroll* prior to September 1, 2025, which was 5.50%, while Mr. Bandyk relies on the current equity risk premium of 5.00%.

[132] Walters Direct, at 60 and Exhibit AB-19, at 1.

[133] Bandyk Direct, at Exhibit CUB-5.

the cost of equity for decades; however, as I have discussed, his position is unsupported and unfounded.

Q. What are your concerns with Mr. Walters's "forward-looking" risk premium-derived market return and thus market risk premium?

A. I disagree with what Mr. Walters considers a "forward-looking" estimate of the market return. Mr. Walters calculates what he terms a "forward-looking" estimate of the market return, which reflects the long-term historical arithmetic average real return of the S&P 500 from 1926 through 2023 of 9.02% plus a projected inflation rate based on the Consumer Price Index of 2.40% as reported by *Blue Chip Financial Forecasts* as of August 29, 2025.[134] From this market return of 11.64%, Mr. Walters then subtracts his projected risk-free rate of 4.60% to estimate a market risk premium that he then uses in four of his 12 CAPM scenarios.[135]

Q. Why do you disagree with Mr. Walter's "forward-looking" risk premium-based estimate of the market return?

A. Mr. Walters's risk premium-derived estimate of the market return is neither "forward-looking" nor does it reflect the current and expected market conditions during which the Company's rates will be in effect. First, while Mr. Walters characterizes his market return as "forward-looking," which presumably is to recognize that the market return estimate of the CAPM should be forward-looking, simply applying a projected inflation rate to a long-term historical average market return does not produce a "forward-looking" market return. Second, while Mr. Walters' use of the average real return of the S&P 500 from 1926 through 2023 is reflective of the returns realized by

[134] Walters Direct, at 55.
[135] *Id*.

investors under different market and economic conditions, it is not necessarily reflective of the market return required by investors in the current and expected market environment. Mr. Walters provides no evidence that the historical average market return is reflective of the expected market conditions during the period in which the Company's proposed rates will be in effect.

Q. Have you identified inconsistencies in the analyses prepared by Mr. Bandyk?

A. Yes. The assumptions used in Mr. Bandyk's CAPM are inconsistent with the results of his DCF analyses. As shown in Figure 9, the market risk premia estimates from Professor Damodaran on which Mr. Bandyk relies reflect an implied market return that ranges from 7.80% to 9.60%, which are all lower than his average DCF result using projected EPS growth rates of 9.65%.[136] Further, the *Kroll* "normalized" market risk premium reflects an implied market return of 9.76%, which is only 11 basis points greater than Mr. Bandyk's average DCF result that relies on projected EPS growth rates. This result is counterintuitive, as it is reasonable to expect that the return on the overall market, with a presumed beta of 1.0, would be higher than the return on Mr. Bandyk's proxy group of electric utilities, which he assumes have an average beta coefficient of 0.92 (*Value Line*) and 0.68 (*Bloomberg*) in his CAPM analysis. However, as shown in Figure 9, the results of Mr. Bandyk's analyses indicate the exact opposite of the expected risk/return trade off. As shown, Mr. Bandyk's overall market return is either consistent with or lower than the DCF return he estimates for the electric gas utility proxy group using projected EPS growth rates, despite the expectation that this proxy group has lower overall risk than the market.

[136] Bandyk Direct, at 15 and Exhibit CUB-7. As discussed above, projected EPS and not projected DPS growth rates are the appropriate estimate of growth to use in the DCF model; therefore, Mr. Bandyk's implied estimates of the market return were compared to the results of his DCF analysis that rely on projected EPS growth rates.

Figure 9: Mr. Bandyk's Implied Market Return in the CAPM Analysis as Compared to His DCF Results

	Mr. Bandyk CAPM Assumptions				Mr. Bandyk DCF Analysis	
Source	Market Risk Premium	Risk-Free Rate	Implied Return for the *Market*		Proj. EPS Growth	Proj. DPS Growth
Damodaran (TTM sust. payout)	3.68%	4.23%	7.91%		9.65%	8.26%
Damodaran (TTM)	3.94%	4.23%	8.17%		9.65%	8.26%
Damodaran (smoothed)	5.37%	4.23%	9.60%		9.65%	8.26%
Damodaran (normalized)	3.57%	4.23%	7.80%	v.	9.65%	8.26%
Damodaran (net cash yield)	3.68%	4.23%	7.91%		9.65%	8.26%
Kroll - Normalized	5.00%	4.76%	9.76%		9.65%	8.26%

C. Beta Coefficients

Q. What are the primary areas where you disagree with the betas used by the witnesses in this case?

A. I disagree with Mr. Bandyk's reliance on raw betas, and Mr. Walters's reliance on betas from S&P Market Intelligence that reflect what is known as a Vasicek adjustment, whereby the raw beta is adjusted to assume that a company's beta coefficient will trend toward the *industry* average as opposed to the *market* average of 1.0.

Q. Why you do you disagree with these betas relied on by Mr. Bandyk and Mr. Walters?

A. The use of either raw betas as Mr. Bandyk has utilized or the Vasicek-adjusted betas that Mr. Walters has utilized is not appropriate for regulated utilities because these beta coefficients likely understate the true beta of utility stocks given that the utility sector is not only correlated to the broader market, but is also sensitive to changes in interest rates, which are *not* factored into either the raw beta or Vasicek-adjusted beta calculations. Therefore, neither of Mr. Bandyk's raw beta coefficients nor Mr. Walters's Vasicek-adjusted betas consider interest rate risk and likely understate the actual risk, which in turn understates the result of the CAPM analysis. Conversely, the Blume adjustment applied by *Value Line* and *Bloomberg* adjusts the raw beta coefficients toward the market average

of 1.0, thus likely better reflecting the true beta of the utility sector inclusive of interest rate risk.

Q. Do any of the other witnesses in this proceeding rely on either raw betas or Vasicek-adjusted betas?

A. No. Mr. Megginson, Mr. Coppola, and I have all relied on beta coefficients that have been adjusted using the Blume adjustment for purposes of our CAPM analyses. Furthermore, even Mr. Walters relies on Blume-adjusted betas in 9 out of 12 of his CAPM analyses.

D. Response to Intervenor Positions

Q. What are the positions of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk regarding your CAPM analysis?

A. These witnesses offer the following positions regarding my CAPM analyses:

- Mr. Coppola alleges that my use of multiple risk-free rates "seems to be a hunt for an approach that will result in a higher ROE rate."[137]
- Mr. Walters contends that the *Value Line* betas that I relied on in my direct testimony are overstated because my analysis date was March 31, 2025, and thus the *Value Line* betas that I relied on were affected by the market volatility in 2020 due to COVID-19.[138]
- Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk contend that my market risk premium is excessive, with Mr. Walters suggesting that I should have considered multiple methodologies to estimate the expected market return and market risk premium.[139]
- Mr. Coppola also contends that a problem with my calculation of the market return is that there are many companies with dividend yields and long-term growth estimates that are omitted.[140]

[137] Coppola Direct, at 139.
[138] Walters Direct, at 66.
[139] Megginson Direct, at 33; Coppola Direct, at 140-141; Bandyk Direct, at 21-22; Walters Direct, at 67-68.
[140] Coppola Direct, at 140.

Q. Is your use of three different risk-free rates an intentional attempt to achieve a higher CAPM result as Mr. Coppola alleges?

A. No. There is no basis to Mr. Coppola's claim that I have intentionally selected three risk-free rates in an attempt to increase the resulting cost of equity from the CAPM. The Company's authorized ROE should be a forward-looking estimate of the cost of equity, and, as stated in my direct testimony, I have relied on a current risk-free rate, a near-projected risk-free rate, and a longer-term risk-free rate consistent with estimating a forward-looking cost of equity. While Mr. Coppola suggests my use of a longer-term projected risk-free rate is used to achieve a specific result, it is important to note that the long-term risk-free rate is the lowest of the three risk-free rates that I have relied upon in my analyses. Therefore, I cannot have relied on this projection to increase the results of my analyses.

Q. Mr. Walters contends that the *Value Line* betas that you relied on in your direct testimony are "overstated" because they are affected by the market volatility that occurred in 2020 due to COVID-19?[141] How do you respond?

A. At the time I filed my direct testimony, the analyses were timely and appropriate for the filing date. However, as previously discussed, I have updated my cost of equity analyses, including my CAPM analysis that relies on current *Value Line* betas, to reflect market data through September 30, 2025. Specifically, my CAPM analysis relies on the *Value Line* reports for the electric utilities included in my proxy group as of July 18, 2025, August 8, 2025, and September 5, 2025, which are the most recent reports available. Therefore, the current *Value Line* betas relied on in my updated CAPM analyses, which rely on five years

[141] Walters Direct, at 68.

of returns, exclude the market volatility that Mr. Walters references. In fact, Mr. Walters also relies on current *Value Line* betas in his CAPM analyses and does not contend that the *Value Line* betas that he relies on were affected by the market volatility due to COVID-19.

Q. Is there any basis to the claims by Mr. Megginson, Mr. Coppola, Mr. Walters, or Mr. Bandyk regarding your market return and thus market risk premium?

A. No. There are multiple reasons why there is no basis to their contention regarding the market return and thus market risk premia used in my CAPM analyses.

Q. Is it reasonable to rely on forecasted EPS growth rates in the calculation of the return on the market that exceed U.S. GDP growth?

A. Yes. It reasonable to rely on growth rates, such as forecasted EPS growth rates, in the market return calculation that exceed projected U.S. GDP growth. Companies in the S&P 500 Index operate in the modern global economy and not just in the United States. As a result, these companies' future earnings growth is not necessarily constrained by or representative of future growth in the U.S. such as reflected by projected U.S. GDP growth. The U.S. GDP does not account for companies' revenue achieved in international markets.

As stated by *Seeking Alpha*, "the most obvious difference between GDP growth and S&P 500 earnings growth is international earnings growth." Additionally, it has been noted that between 1950-2014, the median S&P 500 return was 13.00%, while GDP grew less than 3.00%.[142] Similarly, as recently noted by Morgan Stanley: "U.S. companies now get more of their sales from outside the U.S. than they did in the past. GDP does not include those sales."[143] Wellington Management also provides an intuitive example of

[142] Matt Comer, "How Do We Have 18.4% Earnings Growth In A 2.58% GDP Economy?" *Seeking Alpha*, April 19, 2018.

[143] Burt White and Jeff Buchbinder, "The S&P and GDP are not the Same Thing," *LPL Financial*, November 4, 2014.

how the disconnect between GDP and EPS growth can be observed between the U.S. and China:

> China EPS growth has stagnated while U.S. EPS growth has been exceptional, despite China's economy growing at twice the speed of the U.S.… When EPS is diluted by additional company share issuance, it can further exacerbate this misalignment with GDP growth.[144]

Furthermore, it is reasonable to assume that the average growth of the S&P 500 Index could be sustainable in the long run. The calculation of the market risk premium is based on the return on the broader stock market, as measured by the S&P 500 Index, less the return on a risk-free instrument (which in my case, is the yield on the 30-year Treasury bond). The S&P 500 Index is composed of the largest top-performing companies. Over time, the specific companies that are included in the S&P 500 Index will vary; however, because the index is composed of the largest top performing companies, it is reasonable to assume the index will always contain individual companies with projected earnings growth rates that will be considered high. Therefore, investor expectations of growth and return for the index as a whole may not change over time.

Q. Have other regulatory commissions supported the use of a constant growth DCF model to estimate the market return in the CAPM such as you have done?

A. Yes. Various state utility regulatory commissions have supported the use of a constant growth DCF model to estimate the market return in the CAPM. As shown in Figure 10, the Staff of the Illinois Commerce Commission ("ICC"), the Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Pennsylvania PUC"), and the Staff of the Maine Public Utilities Commission ("Maine PUC") have each

[144] N. Samouihan and A. King, "Chart in focus: The need to differentiate market growth from macro growth," Wellington Management, September 2024.

supported the forward-looking market risk premium, and the market return estimates using the constant growth DCF model. In each of these cases, the respective regulatory commission relied on the estimated CAPM results by these parties to determine the authorized ROE and did not dispute the use of the constant growth DCF model to calculate the market return.

Figure 10: Examples of Jurisdictions Where Market Return Estimated Using the Constant Growth DCF Model

Intervening Party	Applicant	Docket No.	Approach of Intervening Party to Calculating the Market Return	Date of Order	Did the Commission Rely on the Intervening Party's CAPM?
Staff of the ICC	North Shore Gas Company	20-0810	Constant growth DCF of the dividend-paying companies in the S&P 500 (11.95%)[145]	9/8/21	Yes[146]
I&E	Aqua Pennsylvania, Inc.	R-2021-3027385	CGDCF of the Value Line Universe and S&P 500 (12.14%)[147]	5/12/22	Yes, the regulator placed primary weight on I&E's CAPM[148]
Staff of the Maine PUC	Northern Utilities, Inc.	2019-00092	CGDCF of the dividend-paying companies in the S&P 500 (11.33%-13.49%)[149]	4/1/20	Yes[150]

In addition, in a recent cost of capital proceeding for the electric utilities in California, the California Public Utilities Commission noted that all parties recognized that historical market returns and economically logical projections fall within the range of 12.00%.[151] This recognition is generally consistent with the market return utilized in my

[145] Illinois Commerce Commission, Docket No. 20-0810, Order, September 8, 2021, at 71.

[146] *Id*., at 86-87.

[147] Pennsylvania Public Utility Commission, Docket No. R-2021-3027385, Opinion and Order, May 16, 2022, at 147.

[148] *Id*. at 178.

[149] Maine Public Utilities Commission, Docket No. 2019-00092, Bench Analysis, October 29, 2019, at 21.

[150] *Id*., Order Part II, April 1, 2020, at 58.

[151] California Public Utilities Commission, Application 22-04-008, *et al*., Decision 22-12-031, December 15, 2022, at 23.

initial CAPM analyses in my direct testimony and herein in my updated CAPM analyses in my rebuttal testimony.

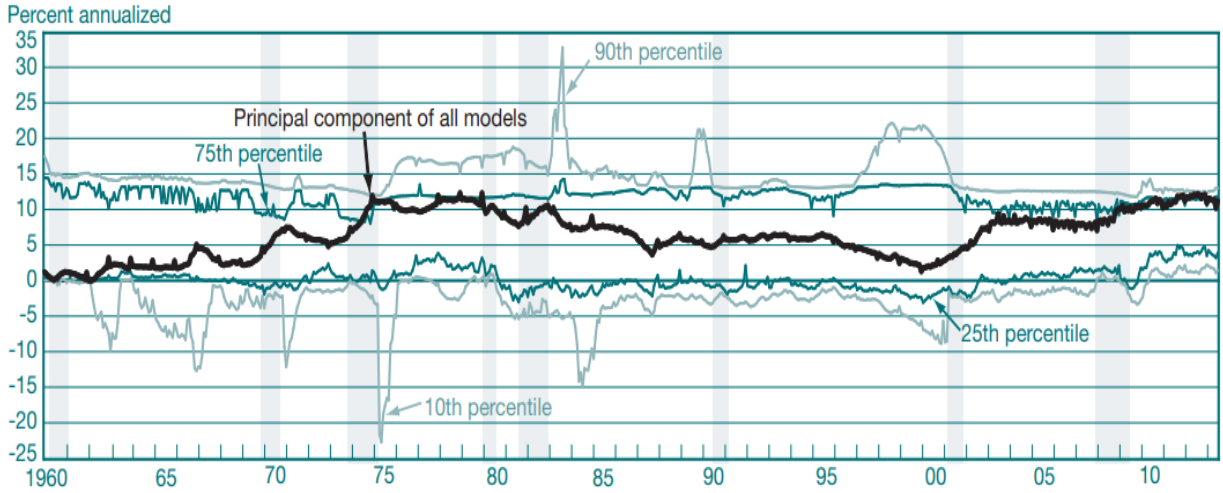
Q. Do studies demonstrate that the market return used in your CAPM, and thus the market risk premium, is reasonable?

A. Yes. The Federal Reserve Bank of New York published an analysis in 2015 that reviewed 20 methodologies (including the methodology relied on by Dr. Damodaran, which Mr. Megginson and Mr. Bandyk rely on in their respective CAPM analyses) over the period 1960 through 2013 for estimating the market risk premium.[152] The result of this study demonstrates that my market risk premium estimates, which, as shown on Exhibit A-206 (AEB-2), pages 5-13, of my rebuttal cost of equity analyses, are in the range of 8.55% to 8.94%, are reasonable. Specifically, the key conclusions from this study are:

- The 20 methodologies reviewed reflected a range for the market risk premium of between -1.00% to 14.50%.
- As shown in Figure 11, the principal component analysis of the 20 models (*i.e.,* the bold black line) produced a range for the market risk premium of approximately 0.00% to over 10.00% from 1960 through 2013.
- The one-year-ahead market risk premium was consistently greater than 10.00% following the financial crisis of 2008/09.

[152] Fernando Duarte and Carla Rosa, "The Equity Risk Premium: A Review of Models," Federal Reserve Bank of New York (2015).

Figure 11: The Federal Reserve Bank of New York, One-Year-Ahead Market Risk Premium[153]



Further, the Federal Reserve Bank of New York also noted the following:

> Chart 2 shows the first principal component of all twenty models in black (the black line is the same principal component shown in black in each of the panels of Chart 1). ***As expected, the principal component tends to peak during financial turmoil, recessions, and periods of low real GDP growth or high inflation***. It tends to bottom out after periods of sustained bullish stock markets and high real GDP growth. Evaluated by the first principal component, the one-year ahead ERP [*equity risk premium*] reaches a local peak in June 2012 at 12.2 percent. The surrounding months have ERP estimates of similar magnitude, with the most recent estimate in June 2013 at 11.2 percent. This behavior is not so clearly seen by simply looking at the collection of individual models in Chart 1, a finding that highlights the usefulness of principal component analysis. Similarly high levels were observed in the mid- and late 1970s, during a period of stagflation, while the recent financial crisis had slightly lower ERP estimates, closer to 10 percent.[154]

Thus, the Federal Reserve Bank of New York noted that the market risk premium is higher during periods of increased inflation. While inflation has declined significantly

[153] *Id.*, at 50.

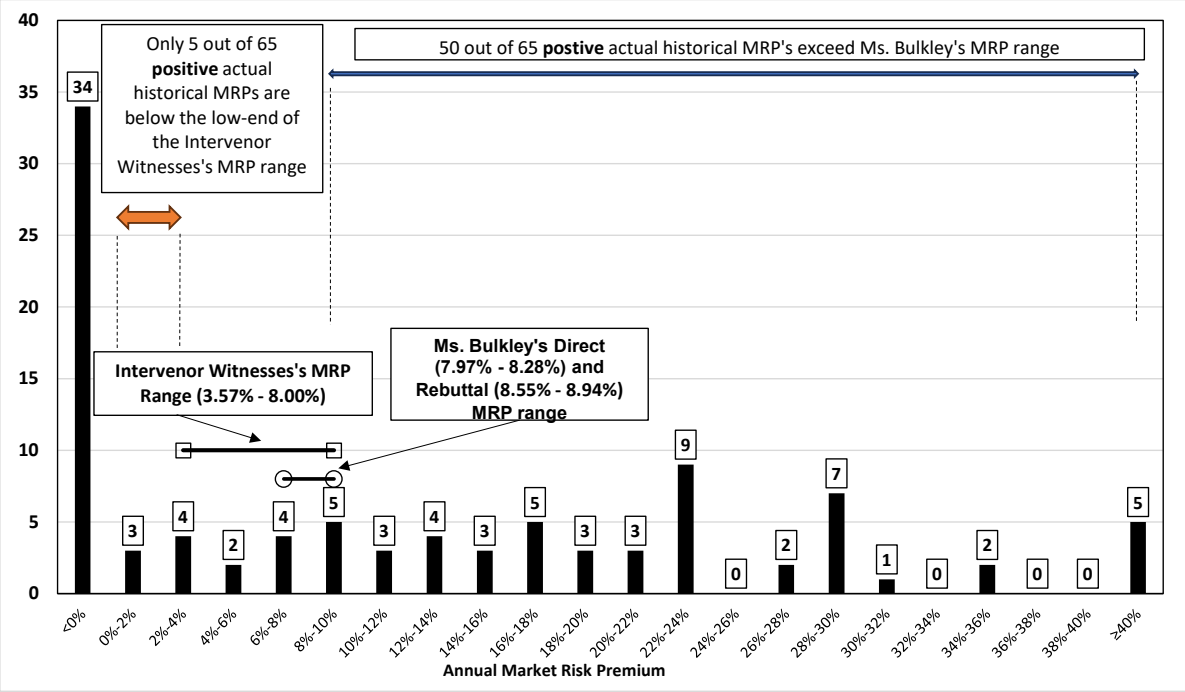
[154] *Id.*; emphasis and clarification added.

in the past two years, it remains above the Federal Reserve's target of 2% and core inflation has recently increased as expected by Federal Reserve officials and economists due to the Trump administration's tariffs.[155]

Q. How do the market risk premia in your CAPM compare with the observed historical market risk premia?

A. As shown in Figure 12 below, the vast majority of the positive historical market risk premia observations (50 out of 65) are at or above the market risk premia range used in my direct (7.97% to 8.28%) and rebuttal testimonies (8.55% to 8.94%), whereas there are very few positive historical market risk premia observations (5 out of 65) that are below the low-end of the marker risk premium range (3.57% to 8.00%) relied on by the Intervenor witnesses.

Figure 12: Distribution of Historical Market Risk Premia (1926-2024)[156]



[155] *See, e.g.,* Greg Iacurci, "Here's the inflation breakdown for August 2025 — in one chart," *CNBC*, September 11, 2025.

[156] Depicts the risk premia as calculated as the difference between total annual returns on large company stocks and income only returns on long-term government bonds, as reported in the 2023 Kroll SBBI Yearbook for 1926-2022 and from S&P Capital IQ Pro (market returns) and Kroll (long-term government bond yields) for 2023-2024.

Q. Do any of the witnesses rely on a market risk premium that is similar to the market risk premium that you have relied on in your CAPM analysis?

A. Yes. Mr. Walters calculates a market risk premium using a forward-looking single stage DCF analysis in this proceeding (which are consistent with the market risk premium range in my direct testimony).[157] Furthermore, as discussed previously, Mr. Megginson has conducted a CAPM scenario using a forward-looking single stage DCF analysis in prior cases and offers no discussion as to why he has changed his methodology.

Q. What is your overall conclusion regarding the market return in your CAPM analysis?

A. For all of the reasons just discussed, the market return, and thus market risk premium, in my CAPM analyses are reasonable and consistent with the findings of the Federal Reserve and other utility regulatory commissions. Therefore, there is no basis to conclude that the market return, and thus market risk premium, in my CAPM analyses is excessive.

Q. Have courts addressed these witnesses' assertion that your forward-looking market return is inflated?

A. Yes. In its review of FERC Opinion No. 569-B, the U.S. State Court of Appeals for the District of Columbia addressed the concern regarding the use of projected EPS growth rates in a constant growth DCF model to estimate the market return. In the Court's decision, it acknowledged that FERC has relied on the use of projected EPS growth rates in the calculation of the market return on the S&P 500 because the S&P 500 is regularly updated to include companies with high market capitalization and it includes companies at all stages of growth, including lower and higher growth potential. The Court determined that

[157] As shown in Exhibit AB-19, the market returns in his analysis are 12.58% and 12.57% and the market risk premia are 8.00%, which are consistent with the range I relied on in my direct testimony.

FERC's rationale for using projected EPS growth rates was sufficient and did not accept the challenge to this assumption.[158]

Q. Mr. Coppola also suggests that there is a concern with your market return in that certain companies have been omitted. Is there any merit to Mr. Coppola's contention?

A. No. Mr. Coppola's suggestion that my calculation of the market return on the S&P 500 Index results in a modified population of companies that is inconsistent with the S&P 500 Index or the equity markets is incorrect. As shown on Exhibit A-14, Schedule D-5, pages 16-21, of my direct testimony, companies in the S&P 500 Index are only excluded from my constant growth DCF analysis if their projected EPS growth rate was either negative or greater than 20.00%. While I believe that the calculation of the weighted projected earnings growth rate for the S&P 500 Index should include all of the companies in the index, my calculation of the market return for the CAPM and ECAPM excludes companies in the S&P 500 Index that have a long-term earnings growth rate that is negative or greater than 20.00% to address previously raised concerns by parties regarding the use of a constant growth DCF model relying on projected EPS growth rates.

E. <u>Adjusted CAPM Results</u>

Q. Have you recalculated the CAPM analyses of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk to address the issues you have identified with their analyses?

A. Yes, I have adjusted their respective CAPM analyses to address the issues that I have discussed as follows:

[158] United States Court of Appeals, District of Columbia Circuit, Opinion, Docket No. 16-1325, August 9, 2022, at 19.

- As noted, Mr. Megginson relies on both a historical market risk premium and projected market risk premia for his CAPM analysis.

  - First, rather than relying on the historical market risk premium for the reasons discussed, I have adjusted Mr. Megginson's CAPM analysis to calculate the market risk premium as the historical arithmetic average market return from 1926 through 2024 minus his estimate of the risk-free rate. While I do not agree with the use of the historical market return as the estimate of the forward-looking market return for the reasons discussed, a calculation that at least derives the market risk premium from the risk-free rate that is being used in the CAPM to estimate the cost of equity is more appropriate than the calculation performed by Mr. Megginson. This is because the derived market risk premium will reflect an inverse relationship between interest rates and the market risk premium that is established in the CAPM equation (*i.e.*, because near-term interest rates are lower than the long-term historical average, the market risk premium should be greater than the historical average risk premium). As shown on Exhibit A-206 (AEB-2), page 35, when the market risk premium is adjusted as just discussed, the average cost of equity for Mr. Megginson's CAPM analysis is 10.56%, which is an increase of 51 basis points from his as-filed position.

  - Second, given that Mr. Megginson's approach for his projected market risk premia is inconsistent with his prior testimony, I have updated his CAPM analysis to rely on a projected market risk premium consistent with his prior approach. As shown on Exhibit A-206 (AEB-2), page 36, this results in a cost of equity of 10.88%.

  - Therefore, whether using Mr. Megginson's historical market risk premium or his prior approach of a projected market risk premium, the cost of equity results support the reasonableness of the Company's proposed ROE in this proceeding.

- I have also adjusted the market risk premium for Mr. Coppola's CAPM analysis in the same manner as I just discussed regarding Mr. Megginson's CAPM analysis, and I have also updated Mr. Coppola's risk-free rate through September 30, 2025. As shown on Exhibit A-206 (AEB-2), page 38, this results in a cost of equity of 10.35%, which fully supports the reasonableness of the Company's proposed ROE in this proceeding.

- As discussed, six of Mr. Walters's 12 CAPM scenarios either rely on a *Kroll* "normalized" market risk premium that does not properly reflect the inverse relationship between interest rates and the market risk premium or rely on betas from S&P Market Intelligence that reflect a Vasicek adjustment that does not consider interest rate risk and thus likely understates the beta coefficients of the utility sector. When those scenarios of Mr. Walters's CAPM analyses are excluded, the average result of his remaining eight CAPM scenarios is 10.04%, which at a minimum supports the reasonableness of an increase in the Company's ROE for this proceeding.

- Mr. Bandyk incorrectly relies on the yield on the 10-year Treasury bond yield as the risk-free rate in two of his four CAPM analyses as well as projected market risk premia that are inconsistent with the inverse relationship between interest rates and the market risk premium. As a result, I have adjusted Mr. Bandyk's CAPM analysis to: (1) consider only the *Kroll* "normalized" risk-free rate; and (2) rely on the projected market return of 12.58% that I relied on in my direct testimony, which is a more reasonable estimate of the market return than the implied market return based on the market risk premia in his CAPM analysis. As shown on Exhibit A-206 (AEB-2), page 40, making these adjustments produces a cost of equity range of 10.05% to 11.98%, which is significantly higher than Mr. Bandyk's as-filed range of 6.97% to 9.38%, and fully supports the reasonableness of the Company's proposed ROE in this proceeding. I also do not agree with Mr. Bandyk's use of raw betas for the reasons discussed; however, I have not adjusted his betas for purposes of the analysis shown on Exhibit A-206 (AEB-2), page 40.

VIII. ECAPM ANALYSIS

Q. Please summarize the positions of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk regarding your ECAPM analyses.

A. Mr. Megginson, Mr. Coppola, and Mr. Walters suggest that the use of an adjusted beta in the ECAPM analysis is duplicative, as the weighting adjustments applied in the ECAPM are mathematically the same as adjusting beta, and thus the ECAPM produces a result that

is overstated.[159] In addition, Mr. Megginson and Mr. Coppola also claim that the use of long-term interest rates as the risk-free rate is inconsistent with the ECAPM.[160] Mr. Bandyk states that he has not conducted an ECAPM since the Staff has historically declined using an ECAPM and the Commission has not previously recognized the ECAPM as a valid methodology.[161]

Q. Is it appropriate to use adjusted betas in the ECAPM?

A. Yes, it is entirely appropriate to use adjusted betas in the ECAPM, and doing so is consistent with academic literature and the estimation of the ECAPM in this manner has been accepted by various regulatory commissions. There is no merit to any of these witnesses' contentions regarding the ECAPM.

Q. What is the purpose of using adjusted betas in the ECAPM?

A. The purpose of adjusting beta in the CAPM is to account for the tendency of beta to trend back over time to the market beta of 1.00. As noted by Mr. Megginson, the betas published by *Value Line* include this adjustment,[162] which was first proposed by Marshall E. Blume in 1975.[163] The use of adjusted betas in the CAPM is important because if beta trends towards 1.00, as Blume noted, then the adjusted beta will be more reflective of the beta that can be expected over the near-term. This is equally important in the specification of the CAPM in this case since the cost of equity for the Company is being estimated over the near term.

[159] Megginson Direct, at 34-35; Coppola Direct, at 141-143; Walters Direct, at 68-72.
[160] Megginson Direct, at 34-35; Coppola Direct, at 142.
[161] Bandyk Direct, at 26.
[162] Megginson Direct, at 34.
[163] Marshall E. Blume, "Betas And Their Regression Tendencies," *The Journal of Finance*, Vol. 30, No. 3, 1975, at 785-795.

The ECAPM does not account for the tendency of beta to trend toward 1.00. The purpose of the ECAPM is to account for the fact that the risk-return relationship is flatter than what is estimated by the CAPM, ***even when using adjusted betas***. While beta is not observable and must be estimated, the theory behind the ECAPM is that even if the true value of a stock's beta were observable, the CAPM would understate the results for stocks with betas less than 1.00 and overstate the results for stocks with betas greater than 1.00. Therefore, contrary to the assertions of Mr. Megginson, Mr. Coppola, and Mr. Walters, the purpose of each adjustment is different and thus applying both adjustments in the ECAPM is not duplicative.

Q. Mr. Coppola cites a chapter in Dr. Morin's text *New Regulatory Finance* to support his view that there is academic disagreement with the studies that led to the use of the ECAPM.[164] Do you agree with Mr. Coppola's conclusion from this text?

A. No. In reviewing the excerpt provided by Mr. Coppola, it is clear that, while Dr. Morin identifies some who have argued that the use of ECAPM is inconsistent with the use of adjusted betas, Dr. Morin further explains that the argument that has been used to support this concern is erroneous. Importantly, Dr. Morin's text fully supports the use of adjusted betas in the ECAPM and explains why it is appropriate:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such a trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate.

[164] Coppola Direct, at 142-143.

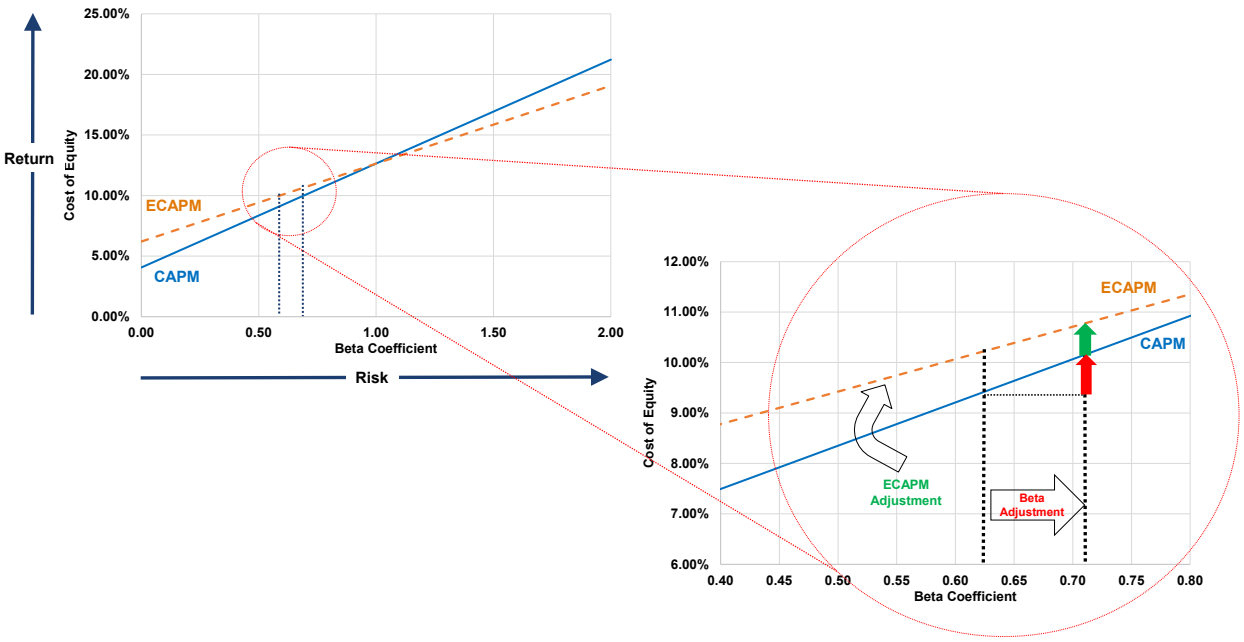
> The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated…***Both adjustments are necessary. Moreover, recall from Chapter 3 that the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas***.[165]

Q. Can you demonstrate that using adjusted betas in the CAPM and relying on the ECAPM are two distinct adjustments to the CAPM?

A. Yes. Figure 13 demonstrates the point that adjusting betas and adjusting the slope of the risk/return relationship through the ECAPM are two distinct adjustments and are not duplicative as alleged by Mr. Megginson, Mr. Coppola, and Mr. Walters. As shown in Figure 13, when beta is adjusted to recognize that betas revert to the market mean of 1.0 over time and used in the CAPM, the resulting adjustment is shown by the red arrow in the lower right-hand corner. Separately, when the ECAPM is employed to recognize that the risk/return relationship is flatter than predicted by the CAPM, the resulting adjustment is shown by the green arrow in the lower right-hand corner. To the extent that a company with a beta greater than 1.0 is being evaluated, the same process of two separate adjustments would apply, albeit in the opposite direction from what is shown in Figure 13 and would result in a decrease in the cost of equity otherwise predicted by the CAPM.

[165] Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 191 (emphasis added).

Figure 13: Risk/Return Relationship between CAPM and ECAPM



Q. Are you aware of academic studies that have used adjusted betas to estimate the ECAPM?

A. Yes. For example, a study conducted by Litzenberger, Ramaswamy, Sosin (1980) found that the CAPM tends to understate the return for stocks such as utilities that have a beta less than 1.00.[166] To develop their analysis, the authors used historical (*i.e.,* "raw") betas to estimate the "alpha" factor in the ECAPM. However, the authors also showed that an "alpha" factor can be derived for Blume-adjusted betas using the results of their analysis for raw betas. The Blume adjustment is shown in the following equation:

$$\beta_i = \omega\beta_{i(historical)} + (1 - \omega) \qquad [1]$$

Where:

β_i = adjusted beta

β_i [historical] = raw beta

ω = Blume Adjustment factor (*i.e.*, 0.67)

[166] Robert Litzenberger, *et al*., "On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital," *The Journal of Finance*, Vol. 35, No. 2, 1980, at 369-383.

The estimate of "alpha" using Blume-adjusted betas can be derived using the results presented in the "Raw Beta" section of Table 1 on page 380 and the equations on page 376:

$$a = a' - b' \left(\frac{1-\omega}{\omega}\right) = 0.326 - 0.330 \left(\frac{0.33}{0.67}\right) = 0.163 \qquad [2]$$

Where:

a = estimated alpha factor for Blume adjusted betas

a' = estimated alpha factor using raw betas

b' = estimated excess return over the risk-free rate using raw betas

Because the authors relied on monthly returns for stocks in the New York Stock Exchange, the estimated "alpha" factor using adjusted betas of 0.163% must be annualized.[167] When annualized, the estimated "alpha" factor is 1.97% using Blume-adjusted betas, which is consistent with the "alpha" factor relied on by Dr. Morin of 1.0 to 2.0% to develop the 0.25 and 0.75 factors included in the ECAPM that I rely on in the ECAPM analyses presented in my direct and rebuttal testimony. Therefore, the Litzenberger, *et al.* (1980) study shows that the adjustment to beta and the use of the ECAPM are not duplicative, but rather account for two different factors in the CAPM.

In addition, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry in particular subgroups of utilities for a data set that included market data through the end of 2006.[168] Chrétien and Coggins considered the CAPM, the Fama-French three-factor model, and a model similar to the ECAPM. The study shows that the ECAPM significantly outperformed the traditional CAPM at predicting the observed risk premium for the various utility subgroups.

[167] (1.00163)^12-1 = 1.97%

[168] Stéphane Chrétien and Frank Coggins, "Cost Of Equity For Energy Utilities: Beyond The CAPM," *Energy Studies Review*, Vol. 18, November 2, 2011.

Finally, Dr. Morin directly addresses the issue in his 2021 text *Modern Regulatory Finance* as follows:

> Because of this adjustment, some critics of the ECAPM argue that the use of Value Line adjusted betas in the traditional CAPM amounts to using an ECAPM. This is incorrect. The use of adjusted betas in a CAPM analysis is not equivalent to the ECAPM. Betas are adjusted because of the regression tendency of betas to converge towards 1.0 over time. We have seen that numerous empirical studies have determined that the SML [Security Market Line] described by the CAPM formula at *any given moment* in time is not as steeply sloped as the predicted SML. The slope of the SML should not be confused with Beta. On the point, Eugene F. Brigham, finance professor and the author of many financial textbooks states:
>
> > The Slope of the SML (5% in Figure 6-16) reflects the degree of risk aversion in the economy. The greater the average investor's aversion to risk, then (a) the steeper the slope of the line, (b) the greater the risk premium for all stocks, and (c) the higher required rate of return on all stocks. Students sometimes confuse beta with the slope of the SML. This is a mistake.
>
> The use of an adjusted beta by Value Line is correcting for a different problem than the ECAPM. The adjusted beta captures the fact that betas regress towards one over time. The ECAPM corrects for the fact that the CAPM under-predicts observed returns when beta is less than one and over-predicts observed returns when beta is greater than one.[169]

[169] Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 223-224 (emphasis added).

Q. Do you agree with Mr. Megginson and Mr. Coppola that your ECAPM is flawed because of the use of a long-term risk-free rate as opposed to a short-term risk-free rate?

A. No. While Mr. Megginson does not explain his disagreement on this issue, Mr. Coppola contends that Dr. Morin concluded in New Regulatory Finance that the use of the ECAPM was not required if long-term interest rates were used as the risk-free rate as opposed to short-term interest rates.[170] However, Mr. Coppola misquotes Dr. Morin and, thus, misrepresents Dr. Morin's conclusion regarding the ECAPM. Specifically, Dr. Morin states the following:

> An alpha range of 1%-2% is somewhat lower than estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. That is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free rate version which has been tested. Thus, it is reasonable to apply a conservative alpha adjustment. Moreover, the lowering of the tax burden on capital gains and dividend income enacted in 2002 may have decreased the required return for taxable investors, steepening the slope of the ECAPM risk-return trade-off and bring it closer to the CAPM predicted returns.[171]

Thus, Dr. Morin developed the ECAPM based on a conservative estimate of alpha (*i.e.,* 1.00% to 2.00%) relative to the range of alphas estimated empirically to account for the effect of using a long-term risk-free rate as opposed to a short-term risk-free rate. Figure 14 provides the list of studies summarized by Dr. Morin. As shown, six of the eight studies estimated positive values of the constant term, and among the six studies that

[170] Coppola Direct, at 142-143.

[171] Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 191; emphasis added.

estimate only positive values of the constant term, the range of the constant term was 1.63% to 13.56%. It is evident that Dr. Morin's use of an alpha in the range of 1.00% to 2.00% to develop the 0.25 and 0.75 factors included in the ECAPM is conservative. The ECAPM was developed to be used with a long-term risk-free rate, and thus the use of a long-term risk-free rate is not a substitute for the ECAPM as suggested by Mr. Megginson and Mr. Coppola.

Figure 14: Empirical Evidence on the Alpha Factor (Constant Term)[172]

Author	Range of Alpha
Black (1993)	-3.6% to 3.6%
Black, Jensen and Scholes (1972)	-9.61% to 12.24%
Fama and McBeth (1972)	4.08% to 9.36%
Fama and French (1992)	10.08% to 13.56%
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%
Pettengill, Sundaram and Mathur (1995)	4.6%
Morin (1989)	2.0%

[172] Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, at 222.

Q. While Mr. Megginson and Mr. Bandyk state that the Commission has not previously considered the merits of the ECAPM,[173] and Mr. Coppola and Mr. Walters state that the ECAPM is not widely accepted by state regulatory commissions,[174] are you aware of state regulatory commissions that have accepted the use of the ECAPM in the manner as you have conducted?

A. Yes. While Mr. Coppola references a Company data response from a proceeding filed in 2017 as support for his position,[175] there are various regulatory commissions that have supported the use of the ECAPM in establishing an authorized ROE and have done so when adjusted betas are used in the ECAPM analysis. For example, the New York Public Service Commission ("NYPSC") and the North Carolina Utilities Commission ("NCUC") have accepted the ECAPM analysis with the use of adjusted beta coefficients in establishing the authorized ROE for regulated utilities. Specifically, the NYPSC gives equal weight to the CAPM and ECAPM (which it refers to as the "Zero Beta" CAPM) results,[176] and the NCUC has recently found that both the adjustment to beta in the CAPM and the adjustment in the ECAPM were needed because they correct for different things.[177]

In fact, while Mr. Walters contends that in his experience regulatory commissions generally disregard the results of the ECAPM, he was the witness on behalf of the Public Staff of the NCUC in this recent case in which the NCUC considered the ECAPM in authorizing the ROE. Specifically, in that case, while the NCUC agreed with Mr. Walters's contention that mathematically the Blume adjusted betas provided by *Value Line* achieve

[173] Megginson Direct, at 35; Bandyk Direct, at 26.

[174] Coppola Direct, at 142-143; Walters Direct, at 71-72.

[175] *Id*., at 143.

[176] New York Public Service Commission Case No. 20-G-0101, Order, May 19, 2021, at 44-46.

[177] North Carolina Utilities Commission, Docket No. E-2, SUB 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, August 18, 2023, at 162-63.

the same result as using the ECAPM model with unadjusted betas, the NCUC nonetheless concluded that both adjusting betas and using the ECAPM were needed because they correct for different things.[178]

IX. BOND YIELD RISK PREMIUM ANALYSIS

Q. Do any of the witnesses conduct a Risk Premium analysis?

A. Yes. Mr. Megginson, Mr. Coppola, and Mr. Walters each conduct a Risk Premium analysis. Specifically:

- Mr. Megginson conducts two forms of a Risk Premium analysis: one reflecting the historical equity risk premium of electric utility stock returns less utility bond yields over the period 1932 to 2024 plus a projected utility bond yield on A-rated rated utility bonds ("Utility Bond Approach"); and another reflecting the historical equity risk premium of electric utility stock returns less 30-year Treasury bond yields over the period 1932 to 2024 plus a projected 30-year Treasury bond yield ("Treasury Bond Approach"). The result of Mr. Megginson's Utility Bond Approach is 10.23%, while the result of his Treasury Bond Approach is 10.46%.[179]

- Mr. Coppola's Risk Premium analysis is similar to Mr. Megginson's Utility Bond Approach. Mr. Coppola's analysis reflects the historical equity risk premium of electric utility stock returns less A-rated utility bond yields over the period 1932 to present plus a projected A-rated utility bond yield. The result of Mr. Coppola's risk premium model is 9.81%.[180]

- Mr. Walters develops three forms of a Risk Premium analysis. The first approach subtracts the average 30-year Treasury yield from the average authorized electric ROE over the period 1986-2025 and adds a projected 30-year Treasury yield ("Treasury Bond Approach"), which produces an ROE of 9.88%. Mr. Walters's second approach is similar to his first but measures the risk premium relative to yields on Moody's A-rated utility bonds both using three-month average yield data and six-month

[178] *Id.*

[179] Megginson Direct, at 28-30 and Exhibit S-4, Schedule D-5, at 12.

[180] Coppola Direct, at 144 and Exhibit AG-39.

yield data ("Utility Bond Approach"), which produce ROEs of 9.92% and 9.93%, respectively. In his last approach, Mr. Walters develops an ROE estimate based on a weighted least squares ("WLS") regression, which produces an ROE of 9.85%.[181]

Q. Do you agree with the Risk Premium analyses conducted by Mr. Megginson and Mr. Coppola?

A. No. Mr. Megginson's and Mr. Coppola's use of an historical risk premium and applying that to a projected interest rate fails to consider the inverse relationship between interest rates and the market risk premium based where their projected interest rates are below their long-term average. Specifically, the Risk Premium methods relied on by Mr. Megginson and Mr. Coppola sum a projected interest rate (*i.e.,* a utility bond yield or a Treasury bond yield) that is different than the historical average interest rate over the time-period each witness uses to estimate their respective risk premium. Therefore, this calculation fails to appropriately account for the dynamic and inverse relationship between risk premia and interest rates. As discussed, the error in this calculation is that it relies on interest rates from two different time periods, which would represent different equity risk premiums.

The failure to account for the inverse relationship between interest rates and the equity risk premium effects all of the Risk Premium analyses that Mr. Megginson and Mr. Coppola conduct. As shown in Figure 15, the long-term historical average bond yields (*i.e*., either a utility bond yield or a 30-year Treasury bond yield) over the period analyzed by Mr. Megginson and Mr. Coppola are higher than their assumed projected yields for those same bonds. For example, in his Utility Bond Approach, Mr. Megginson adds a projected Treasury bond yield of 5.67% to his historical average utility bond risk premium

[181] Walters Direct, at 42-50, Exhibit AB-14 through Exhibit AB-17.

of 4.56%, resulting in his estimated cost of equity of 10.23%. However, the historical average utility bond yield relied on by Mr. Megginson to calculate his risk premium was 6.27%,[182] *or 60 basis points higher* than the projected utility bond yield of 5.67% that he relies on to calculate the cost of equity for this version of his Risk Premium analysis.

Therefore, given the inverse relationship between interest rates and the risk premium previously discussed, and that their projected bond yields are lower than the historical average that they rely on to calculate their risk premia, the risk premia that Mr. Megginson and Mr. Coppola rely on should be *greater than* the long-term historical average risk premia – however, they rely on the long-term historical average risk premium.

Figure 15: Failure of Mr. Megginson's and Mr. Coppola's Risk Premium Analyses to Properly Account for the Inverse Relationship Between Interest Rates and the Equity Risk Premium

	Long-Term Historical Avg. Bond Yield	Assumed Projected Bond Yield	Difference In Bond Yields (Hist. - Proj.)	Long-Term Historical Avg. ERP	Current ERP Higher/ Lower Than Historical ERP	ROE Higher/Lower than Witness Calculation
	(a)	(b)	(c)=(a)-(b)	(d)	(e)	ROE= (b) + (e)
Mr. Megginson						
Utility Bond Approach	6.27%	5.67%	0.60%	4.56%	Current Bond Yield < LT Average = **Higher Current ERP**	Current ROE > Megginson calculation
Treasury Bond Approach	4.96%	4.58%	0.38%	5.88%		
Mr. Coppola						
Utility Bond Approach	6.26%	5.56%	0.70%	4.25%	Current Bond Yield < LT Average = **Higher Current ERP**	Current ROE > Coppola calculation

Q. Can you illustrate the extent to which Mr. Megginson and Mr. Coppola have understated the equity risk premium in their respective analyses?

A. Yes. Exhibit A-206 (AEB-2), pages 41-42 demonstrates that Mr. Megginson's analysis understates the risk premium. Exhibit A-206 (AEB-2), pages 41-42 calculate an average risk premium for the years where the yields on the Treasury bonds and utility bonds were less than the long-term average yield on those bonds respectively. As shown on Exhibit

[182] Megginson Direct, at Exhibit S-4, Schedule D-5, at 12.

A-206 (AEB-2), pages 41-42, the historical average risk premia on which Mr. Megginson relies of 4.56% for utility bonds and 5.89% for Treasury bonds is well below the risk premia that more closely corresponds with the projected interest rate that he adds to his historical risk premium. This demonstrates that as interest rates decline, the risk premium increases.

I performed a similar analysis in Exhibit A-206 (AEB-2), pages 43-44. The conclusions using Mr. Coppola's data is consistent with the findings summarized above. The average risk premium during periods where interest rates were below the long-term average is significantly higher than the long-term historical average risk premium that Mr. Coppola relied upon.

Q. Do you have any other concerns with Mr. Coppola's Risk Premium analysis?

A. Yes. There are three additional issues with Mr. Coppola's Risk Premium analysis that should be corrected.

First, Mr. Coppola relies on a near-term projected 30-year Treasury bond yield of 4.40% in his Risk Premium analysis, which is the risk-free rate that he relies on in his CAPM analysis. However, as previously noted in my discussion of Mr. Coppola's CAPM analysis, his near-term projected risk-free rate is outdated based on when he filed his testimony in this proceeding, and the consensus estimate of the 30-year Treasury bond yield for the second and third quarters of 2026 as relied on by Mr. Coppola is 4.60%.[183]

Second, on Work Paper AG-39A, page 1, (see Exhibit No.: A-207 (AEB-3), page 2) Mr. Coppola calculates the spread between utility bond yields and 30-year Treasury bond yields that he uses in his Risk Premium analysis, which he states is 1.16%. However, Mr. Coppola has incorrectly calculated the average of the spread that he presents on Work

[183] *Blue Chip Financial Forecasts*, Vol. 44, No. 10, October 1, 2025, at 2.

Paper AG-39A, page 1 (see Exhibit No.: A-207 (AEB-3), page 2) because he has only included 23 of the 24 observations that he presents, but divides the sum of those observations by 24. When calculated correctly, the spread between utility bond yields and 30-year Treasury bond yields that he uses in his Risk Premium analysis should be 1.19%.

Lastly, as shown on Work Paper AG-39B, page 1, (see Exhibit No.: A-207 (AEB-3), page 4) the average historical risk premium based on the data Mr. Coppola relies on is 4.27%; however, he uses 4.25% in his Risk Premium analysis.

Q. What would the result of Mr. Coppola's Risk Premium analysis be when these three issues are corrected?

A. As shown on Exhibit A-206 (AEB-2), page 45, when these three issues are corrected, the result of Mr. Coppola's Risk Premium analysis is 10.06%, not 9.81%. It is important to note that these three corrections do not account for the fact that, as I have discussed, the risk premium in Mr. Coppola's analysis is understated because it fails to account for the inverse relationship between risk premia and interest rates.

Q. Do you agree with Mr. Walters's Risk Premium analyses?

A. No. I disagree with the methodologies relied upon by Mr. Walters in this proceeding.

Q. Are the methodologies that he relies on in this proceeding consistent with the methodology that he has applied for his Risk Premium analyses in other recent proceedings?

A. No. Just as with the arbitrary and inconsistent changes in his DCF analyses previously discussed, Mr. Walters has also arbitrarily changed the inputs for his Risk Premium analyses multiple times over the past year. For example, as shown in Figure 16, over time, Mr. Walters has changed how he calculates the risk premium using his historical data set:

- 2024- April 2025: Mr. Walters initially relied on a long-term historical average;
- July 2025: Risk premium was calculated using an average of a long-term historical average and a short-term average since 2023; and
- Current Case: Mr. Walters relies only on a short-term average since 2023.

Figure 16: Changes in Mr. Walters's Risk Premium Methodology in Recent Proceedings[184]

Applicant	Case	Testimony Date	Treasury Bond Approach	Utility Bond Approach		Credit Spreads (Utility - Treasury)
				Method 1	Method 2	
Southwest Gas	Dkt No. G-01551A-23-0341	9/19/2024	Historical avg. risk premium	Historical avg. risk premium	n/a	Current: 1.18% (A rated) 1.40% (Baa rated)
			5.63%	4.27%	n/a	Long-term Avg: 1.48% (A-rated) 1.90% (Baa-rated)
Consumers Energy Company	Case No. U-21806	4/23/2025	Historical avg. risk premium	Historical avg. risk premium	n/a	Current: 1.01% (A rated) 1.21% (Baa rated)
			5.63%	4.27%	n/a	Long-term Avg: 1.48% (A-rated) 1.90% (Baa-rated)
UNS Gas	Dkt No. G-04204A-24-0237	7/7/2025	Avg. of (1) historical avg. risk premium; and (2) avg. risk premium since 2023	Avg. of (1) historical avg. risk premium; and (2) avg. risk premium since 2023	Historical avg. risk premium	Current: 1.15% (A rated) 1.34% (Baa rated)
			Avg. of 5.63% & 5.40% = 5.52%	Avg. of 4.27% & 4.11% = 4.19%	4.27%	Long-term Avg: 1.47% (A-rated) 1.88% (Baa-rated)
Consumers Energy Company	Case No. U-21870	9/30/2025	Avg. risk premium since 2023	Avg. risk premium since 2023	Avg. risk premium since 2023	Current: 0.97% (A rated) 1.17% (Baa rated)
			5.28%	4.06%	4.06%	Long-term Avg: 1.47% (A-rated) 1.88% (Baa-rated)

Q. Is Mr. Walters's explanation for the changes in his methodologies reasonable?

A. No. Mr. Walters has attempted to justify the changes in his estimate of the risk premium in the current proceeding by stating that a risk premium below the longer-term historical

[184] Arizona Corporation Commission, Docket No. G-01551A-23-0341, Direct Testimony of Christopher C. Walters, September 19, 2024, at 41-42; Michigan Public Service Commission, Case No. U-21806, Direct Testimony of Christopher C. Walters, April 23, 2025, 45-47; Walters Direct, at 47-50.

average is warranted because the current spread between utility bond yields and Treasury bond yields is below the historical average, which he states indicates that "investors presently view utilities as less risky than in the past.."[185] However as shown in Figure 16, Mr. Walters's explanation is flawed for the following reasons:

- The current spread between utility bond yields and Treasury bond yields has consistently been below the long-term historical average in each of these proceedings in which Mr. Walters has testified. Therefore, the spread between utility bond yields and Treasury bond yields would not warrant a change in methodology.
- The spread between utility bond yields and Treasury bond yields is currently the same as where that spread was when Mr. Walters testified in the Company's natural gas rate proceeding in April 2025. At that time, he relied on the historical average risk premium for his Risk Premium analysis in that proceeding. There is no principled basis for Mr. Walters's consistent change in methodology and can only be viewed as being done to arbitrarily derive a specific result, which in this case is to reduce the risk premium and the resulting ROE estimate.

Q. Setting aside the averaging period relied upon, do you agree with how Mr. Walters reflects the changing relationship between bond yields and authorized utility returns in the analyses presented in Exhibits AB-14 and AB-15?

A. No. I disagree with *how* Mr. Walters reflects the changing relationship between bond yields and authorized utility returns in the calculation and estimate of the ROE in the referenced exhibits. Mr. Walters attempts to estimate a forward-looking equity risk premium by an arbitrary weighting of the annual historical risk premia that he calculates, and, as a result, he understates the risk premium, and thus the resulting ROE estimate.

[185] Walters Direct, at 44.

Q. How does Mr. Walters calculate the risk premium in these Exhibits?

A. Mr. Walters calculates the difference between annual average authorized ROEs and annual average Treasury bond yields and utility bond yields to estimate his treasury and utility bond yield risk premiums. In the referenced exhibits, he presents a long-term historical average of his indicated risk premiums for the period from 1986 through June 2025 and five-year and ten-year rolling averages of the annual historical risk premium over the same time periods. However, Mr. Walters does not rely on these averages in his estimate of the ROE. Rather, Mr. Walters relies on a risk premium calculated as the average equity risk premium from 2023 through June 2025 to a *projected* bond yield (*i.e.,* his Treasury Bond Approach) and a *current* bond yield (*i.e.,* his Utility Bond Approach).[186]

Q. Is the time-period that Mr. Walters relies on to estimate the risk premium used in his estimation of the ROE consistent with his testimony describing this analysis?

A. No. In his testimony, Mr. Walters states that the time period from 1986 to the present is appropriate to be used to estimate the risk premium:

> The period from 1986 to the present is long enough to capture a variety of economic conditions while smoothing out temporary market distortions. It represents a sustained era during which utilities traded above book value, demonstrating that authorized ROEs were sufficient to meet investor expectations and to allow utilities to raise equity capital on reasonable terms.[187]

While Mr. Walters suggests that it is appropriate to consider the entirety of this time period in his analysis, he selected a risk premium that is entirely based on his judgment. Further, Mr. Walters invalidates the results of this form of his Risk Premium analyses by failing to appropriately account for the dynamic and highly correlated inverse relationship

[186] Walters Direct at 44.
[187] Walters Direct at 43.

between risk premia and interest rates that is clearly present in the historical data that he considers.

Q. What is the appropriate approach to recognize the relationship between historical ROEs and bond yields?

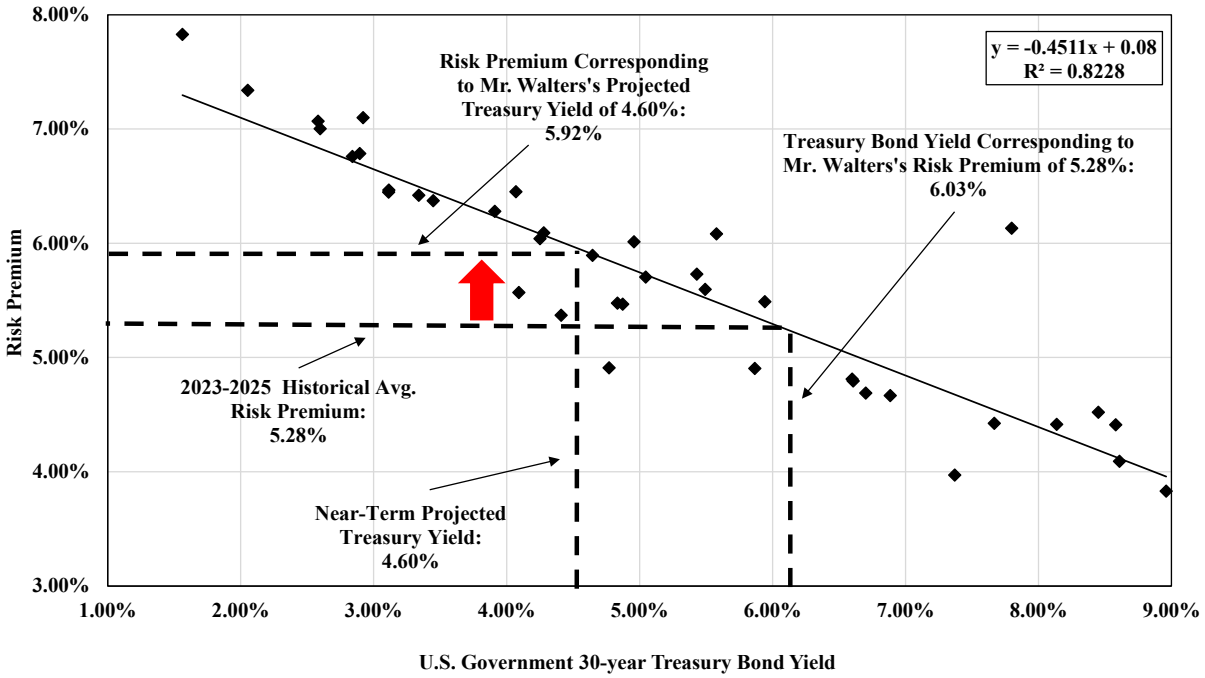
A. To recognize the relationship between the historical authorized ROEs and the yield on bonds over time, Mr. Walters should have developed a regression equation such as I have done in both my direct and rebuttal testimonies, and similarly such as he has also done for his alternative Risk Premium analysis (albeit incorrectly as I explain later herein). My regression appropriately reflects the dynamic relationship between authorized returns and Treasury bond yields over an extended period of time that can be used to project the required return using current or projected bond yield and the regression equation. The benefit of conducting an appropriate regression equation is that it can be used to estimate a forward-looking equity risk premium that corresponds to the interest rates expected over the near-term or the period that the Company's rates will be in effect. Moreover, an appropriate regression equation eliminates the need for arbitrary and inconsistent "adjustments" to the historical risk premium such as Mr. Walters has applied to both his Treasury Bond and Utility Bond approaches. By specifying the interest rate projected for the period that the Company's rates from this proceeding will be in effect, one can estimate an equity risk premium (and thus ROE) for the corresponding forward-looking period.

Q. Can you illustrate the extent to which Mr. Walters has understated the cost of equity resulting from this form of his Risk Premium analyses?

A. Yes. Figure 17 graphs the relationship between Mr. Walters's historical average Treasury bond risk premium and the historical average Treasury bond yield over the period 1986

through 2025 that he presents on Exhibit AB-14 for his Treasury Bond Approach. As shown, there is a strong negative relationship between the risk premia and interest rates (*i.e.,* as interest rates increase the risk premium declines and vice versa). In his Treasury Bond Approach, Mr. Walters uses a risk premium that reflects the average implied equity risk premium from 2023 through 2025 of 5.28% and adds a near-term projected 30-year Treasury bond yield of 4.60%, the sum of which produces his estimated ROE of 9.88%. However, as shown in Figure 17, Mr. Walters's arbitrary use of a risk premium of 5.28% corresponds to a historical average 30-year Treasury bond yield of 6.03% – or substantially higher than the Treasury bond yield of 4.60% on which he relies for his Treasury Bond Approach. Looking at it a different way, as shown in Figure 17, a Treasury bond yield of 4.60% corresponds to a risk premium of 5.92% – or meaningfully higher than the 5.28% that Mr. Walters arbitrarily selects. The amount of Mr. Walters's understatement of the risk premium in his Treasury Bond Approach is depicted by the red arrow in Figure 17. Because Mr. Walters has significantly understated his risk premium, he in turn also significantly understates the ROE produced by his Treasury Bond Approach.

Figure 17: Mr. Walters's Treasury Bond Approach

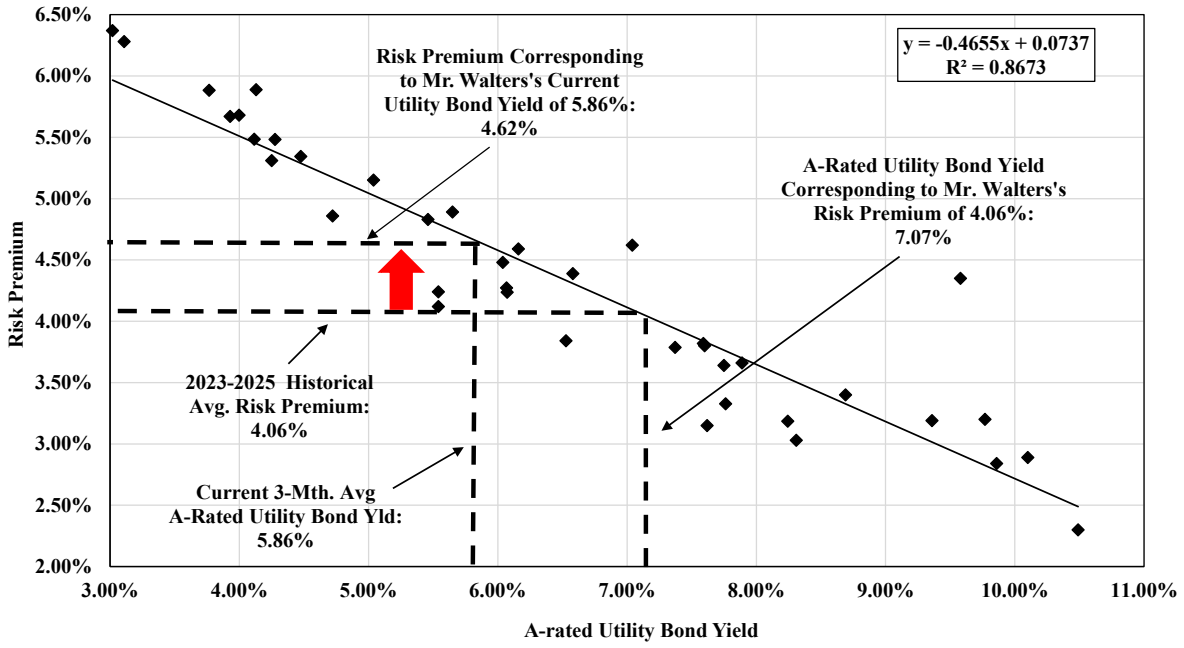


Q. Does Mr. Walters's Utility Bond Risk Premium Approach also understate the cost of equity?

A. Yes. In the same manner as just discussed regarding Mr. Walters's Treasury Bond Approach, his Utility Bond Approach also understates the estimated ROE. Mr. Walters develops two versions of his Utility Bond Risk Premium Approach. In his first scenario, Mr. Walters uses a risk premium that reflects the average implied equity risk premium from 2023 through 2025 of 4.06% and adds a current three-month average utility bond yield of 5.86%, the sum of which produces his estimated ROE of 9.92%. In his second scenario, Mr. Walters uses the same risk premium that reflects the average implied equity risk premium from 2023 through 2025 of 4.06% and adds a current six-month average utility bond yield of 5.88%, the sum of which produces his estimated ROE of 9.94%.

To demonstrate that Mr. Walters has not reflected the inverse relationship between the risk premia and utility bond yields, I have relied on his first Utility Bond scenario where he uses a three-month average A-rated utility bond yield as an example.[188] As shown in Figure 18, if the market risk premium was 4.06% such as he suggests, the corresponding utility bond yield would have been 7.07% – or substantially higher than the three-month average A-rated utility bond yield of 5.86% that he assumes. Alternatively, as shown in Figure 18, an A-rated utility bond yield of 5.86% corresponds to a risk premium of 4.62%, or meaningfully higher than the 4.06% that Mr. Walters arbitrarily selects. The amount of Mr. Walters's understatement of the risk premium in his Utility Bond Approach is depicted by the red arrow in Figure 18, meaning he in turn also significantly understates the ROE produced by his Utility Bond Approach.

Figure 18: Mr. Walters's Utility Bond Approach



[188] While I do not discuss Mr. Walters's second Utility Bond Approach, it is evident from Figure 18 that a 6-month average utility bond yield of 5.88 percent such as he has assumed would correspond to a risk premium that is significantly greater than the risk premium of 4.06 percent such as he has assumed.

Q. Have you adjusted this form of Mr. Walters Risk Premium Analysis?

A. Yes. I have adjusted both Mr. Walters's Treasury Bond Approach and his Utility Bond Approach so that the results of the analyses account for the inverse relationship between interest rates and the risk premium. For his Treasury Bond Approach, I have developed a regression analysis using the following equation that is similar to the equation I relied on for my risk premium analysis:

$$RP = a + b(T) \qquad [4]$$

Where:

RP = average Treasury bond risk premia
a = intercept term
b = slope term
T = average Treasury bond yield

As shown on Exhibit A-206 (AEB-2), page 47, the regression equation has an R^2 of approximately 0.82 and the coefficients are statistically significant at the 99.00% level. Using the estimated coefficients, a Treasury bond yield can be input to determine the resulting risk premium and cost of equity. Using Mr. Walters's near-term projected Treasury bond yield of 4.60%, the risk premium would be 5.92%, and thus the resulting ROE is 10.52%. In other words, when the inverse relationship between interest rates and the risk premium are appropriately considered, the result of Mr. Walters's Treasury Bond Approach increases by 64 basis points from 9.88% to 10.52%.

Similarly, I have adjusted Mr. Walters's Utility Bond Approach using equation [4] above, substituting the annual average Treasury bond risk premia for the annual average utility bond risk premia. As also shown on Exhibit A-206 (AEB-2), page 49, using Mr. Walters's current three-month average and six-month average A-rated bond yields results in a risk premium of 4.62% and 4.61%, respectively, and an ROE of 10.48% and

10.49%, respectively. Thus, adjusting Mr. Walters's Utility Bond Approach increases the cost of equity from 9.92% to 10.48% (using his three-month average utility bond yield) and from 9.94% to 10.49% (using his six-month average utility bond yield).

Q. Mr. Walters also conducts an additional Risk Premium analysis that is based on a Weighted Least Squares regression. Is Mr. Walters's approach valid?

A. No. There are several issues with the WLS regression that Mr. Walters develops:

- Mr. Walters uses a lambda ("λ") value, which is a decay factor that controls how quickly the influence of older data declines, of 0.20 to weight the variables in his regression, which is a significant driver in the analysis that is unsupported

- As Mr. Walters notes, the use of a 0.20 value for lambda places more weight on the more recent period of his analysis. In fact, the lambda he utilizes gives nearly all weight to the most recent 10 years (*i.e.,* 86%) and 70% weight in the regression to the most recent six-year period from 2020 to 2025.

- When discussing the CAPM analysis, Mr. Walters states that the 2020 pandemic period is not reasonable to use in estimating beta coefficients for the proxy group due to the unprecedented conditions at that time.[189] However, as noted, Mr. Walters's lambda value places more weight on the recent period of his analysis, placing approximately 15% of the weight on the 2020 and 2021 period – a period characterized as the lowest interest rate period over the last forty years. As such, Mr. Walters's use of this data for his Risk Premium analysis is inconsistent with his testimony on estimating beta in his CAPM analysis.

Q. Have you evaluated Mr. Walters's WLS regression analysis?

A. Yes. Specifically, I have reviewed the range of the historical equity risk premium data relied on by Mr. Walters and compared that to the equity risk premium range that is predicted by Mr. Walters's WLS regression that relies on a lambda value of 0.20. The data

[189] Walters Direct, at 66.

set relied on by Mr. Walters from 1986 through 2025 reflects Treasury bond yields that range from 1.56% to 8.96%, and equity risk premia that range from 3.83% to 7.83%. Using the Treasury bond yields across this range and the coefficients produced by Mr. Walters's WLS regression, I have calculated the range of equity risk premia predicted by his regression and compared that to the actual historical equity risk premia.

Q. What does your analysis show?

A. As shown in Figure 19, using the range of actual Treasury bond yields from Mr. Walters's data set, his WLS model predicts an equity risk premium ranging from 1.52% to 7.87%. While the high end of the range of his predicted equity risk premium (7.87%) is consistent with the high-end of the range of the historical actual risk premium (7.83%) experienced from 1986 through 2025 in his data set, the low-end of the range of his predicted equity risk premium (1.52%) is substantially different than the low-end of the range of the historical actual equity risk premium (3.83%) experienced from 1986 through 2025 in his data set.

Figure 19: Predicted Equity Risk Premium and ROE Using Mr. Walters's WLS Regression

30 Year Treasury Bond Yield	Equity Risk Premium	ROE
1.50%	7.87%	9.37%
2.00%	7.44%	9.44%
2.50%	7.02%	9.52%
3.00%	6.60%	9.60%
3.50%	6.18%	9.68%
4.00%	5.75%	9.75%
4.50%	5.33%	9.83%
5.00%	4.91%	9.91%
5.50%	4.48%	9.98%
6.00%	4.06%	10.06%
6.50%	3.64%	10.14%
7.00%	3.22%	10.22%
7.50%	2.79%	10.29%
8.00%	2.37%	10.37%
8.50%	1.95%	10.45%
9.00%	1.52%	10.52%

As shown on Mr. Walters's workpapers, when the yield on the 30-year Treasury bond was 1.56%, the risk premium was 7.83%, and when the yield on the 30-year Treasury bond was on the high end of the range at 8.96%, the actual risk premium was 3.83%. Comparing the actual data to the predictions using Mr. Walters's WLS regression demonstrates that his WLS regression substantially underestimates the risk premium in higher interest rate scenarios.

Q. What is causing Mr. Walters's WLS regression to understate the risk premium at higher interest rates?

A. The selected lambda, which is unsupported, causes the underprediction discussed previously. This is because Mr. Walters's lambda value of 0.20 places substantial weight on the last ten years when Treasury bond yields were at historical lows and little weight on

prior periods when interest rates were higher. By essentially excluding economic periods with higher interest rates, Mr. Walters's WLS regression is unable to accurately predict observed risk premiums in higher interest rate environments. If Mr. Walters had correctly specified lambda, his model might better predict the equity risk premium in both low- and high-interest-rate environments instead of only performing well for low-interest-rate environments, particularly the extremely low-interest-rate environment observed during the COVID-19 pandemic.

Q. Does the ROE produced by Mr. Walters's WLS regression change with relatively small changes in the lambda value selected?

A. Yes. For example, the use of a lambda of 0.10 instead of 0.20 would place approximately 40% of the weight on the most recent period 2020-2025 (instead of 63%), thus reducing the effect of the COVID period and increasing the weighting on ROE authorizations prior to 2020. Based on Mr. Walters's WLS regression, when the lambda value is changed to 0.10, the resulting ROE is 10.26% – which is consistent with the Company's request in this proceeding.

Q. Is Mr. Walters's emphasis on such a short historical time period consistent with his views on the long-term historical data set that he relies on?

A. No. As noted previously, Mr. Walters states that the benefit of considering the historical period from 1986 to the present is reasonable because it is "long enough to capture a variety of economic conditions while smoothing out temporary market distortions," yet, the lambda that he selects does not adequately reflect that full time period.[190] Ultimately, specifying a lambda value that relies on a longer historical time-period than five years

[190] Walters Direct at 43.

would more reasonably account for and weight a broader sample than what Mr. Walters has done and encompasses a period in which both low and high interest rates were experienced.

Q. Does Mr. Walters WLS regression produce results that are consistent with the results that would be produced by his Risk Premium analysis had he relied on his five-and ten-year average risk premiums using the historical data from 1986 through June 2025?

A. No. As noted previously, Mr. Walters calculates five- and ten-year average risk premiums using the historical data from 1986 through June 2025. The most recent five- and ten-year average risk premiums shown in his Treasury bond yield risk premium exhibit are 5.93% and 6.48% respectively. In his WLS methodology, the lamba that Mr. Walters uses weights most heavily the most recent five years of data. Adding the five-year rolling average risk premium he calculated of 5.93%, to his projected Treasury bond yield of 4.60% results in an ROE of 10.53%. Using the five-year rolling average utility bond yield risk premium of 4.66% and adding that to his projected utility bond yield of 5.86% results in an ROE of 10.52%. These estimates exceed his estimate ROE using the WLS regression by approximately 68 basis points. Further, these estimates exceed the results of his other bond yield risk premium analyses by 60-65 basis points.[191]

Q. What are the positions offered by Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk regarding your Risk Premium analyses?

A. The following summarizes the reasons offered by each of these witnesses to suggest that my Risk Premium approach should be given little weight or not be relied upon:

[191] Utility bond yield risk premium analysis: 10.52%- 9.92%= 0.60%. Treasury bond yield risk premium: 10.53%- 9.88%= 0.65%.

- Mr. Megginson, Mr. Coppola, and Mr. Bandyk suggest that my Risk Premium analysis is not a reflection of investor behavior since it relies on authorized ROEs instead of actual utility returns and is thus circular.

- Mr. Megginson also claims that I have used an additional adder for the Risk Premium analysis (*i.e.*, not using the historical average risk premium but rather an inflated result instead) without providing any support for doing so.[192]

- Mr. Coppola also contends that my Risk Premium analysis: (1) is biased because it covers a period when interest rates were declining from 1980 to 2024; and (2) assumes a direct relationship between interest rates and ROE decisions when this relationship can be influenced by many factors.[193]

- Mr. Walters states that the regression framework in my Risk Premium analysis is not dynamic enough to capture how the relationship between interest rates and the equity risk premium has evolved over time. Mr. Walters contends that his WLS regression approach adequately addresses this issue.[194]

- Mr. Bandyk also states that the results of my Risk Premium analyses should be disregarded because it relies on the ROEs authorized by regulatory commissions, which he argues is not objective data because regulatory commissions have historically and consistently authorized excessive ROEs for utilities.[195]

Q. Is there any validity to the claims regarding your Risk Premium analyses not reflecting investor behavior?

A. No. While authorized ROEs are not "market data," it is unreasonable to suggest that investors are not aware of authorized ROEs and do not consider them in their assessment of the value of a utility stock. It is unquestionable that both credit rating agencies and investors consider the authorized ROE data in their determination of the valuation of utility

[192] Megginson Direct, at 36.
[193] Coppola Direct, at 145-146.
[194] Walters Direct, at 72-74.
[195] Bandyk Direct, at 30-31.

stocks, and both have responded negatively to authorized ROEs deemed to be too low. Recent market data demonstrates that unconstructive ROEs have resulted in sharp declines in utility stock prices, as well as commentary from equity analysts and rating agencies. In addition, while I disagree with his approach, Mr. Walters also relies on a risk premium-based methodology using previously authorized ROEs as one of the methodologies he uses for purposes of determining his recommended ROE in this proceeding. Therefore, the relationship between recently authorized ROEs and the prevailing interest rates at the time that the ROE was authorized is reasonable to consider when establishing the ROE in a rate proceeding, and it is appropriate for the Commission to accept and consider the results of my Risk Premium analyses in this proceeding.

Moreover, it is also important to recognize the inconsistency in both Mr. Megginson's and Mr. Coppola's position regarding the reliance of authorized ROEs in the Risk Premium analysis. They each suggest that my Risk Premium approach cannot be relied upon because the authorized ROEs do not reflect investor behavior; however, despite that claim, both Mr. Megginson and Mr. Coppola evaluate previously authorized ROEs as support for their recommended ROEs for the Company in this proceeding.[196] Therefore, Mr. Megginson and Mr. Coppola are inconsistent in their positions on the use of this information, seeking only to rely on it in establishing their own ROE recommendations, while disregarding the historical relationship developed in my Risk Premium approach.

[196] Megginson Direct, at 34-35; Coppola Direct, at 146, Exhibit AG-45, and Exhibit AG-48.

Q. Do you agree with Mr. Megginson's contention that you have incorrectly applied an upward adjustment to the historical average risk premium in your Risk Premium analysis?

A. No. As discussed in my direct testimony, it is important to recognize that both academic literature and market evidence have identified a relationship between the equity risk premium and the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Accordingly, I have developed such an analysis based on a regression of the risk premium as a function of 30-year Treasury bond yields. As shown on Exhibit A-14, Schedule D-5, pages 22-25, the risk premium that I have used in my analyses that is a result of my regression is consistent with the inverse relationship between the equity risk premium and interest rates and is specifically the reason why I have not used the average historical equity risk premium such as Mr. Megginson suggests is appropriate. As shown on Exhibit A-14 (AEB-1), Schedule D-5, the long-term historical average risk premium is 5.44%, which corresponds to an average 30-year Treasury bond yield of 6.04%. However, the current and projected interest rates are lower than the historical average, and thus, consistent with the inverse relationship between interest rates and the equity risk premium, the regression appropriately estimates an equity risk premium that is higher than the historical average. However, as I have demonstrated herein, the Risk Premium analyses conducted by Mr. Megginson (both his Treasury Bond Approach and Utility Bond Approach); Mr. Coppola (Utility Bond Approach), and Mr. Walters (both his Treasury Bond Approach

and Utility Bond Approach) fail to appropriately account for this inverse relationship. Therefore, there is no basis to Mr. Megginson's contention that the results of my Risk Premium analysis use a risk premium adder that is not supported.

Q. Do you agree with Mr. Coppola that your Risk Premium results are invalid because you have not considered other factors in addition to interest rates in your regression analyses?

A. No. Mr. Coppola fails to recognize the large body of research that supports the inverse relationship between equity risk premia and interest rates and have failed to present any research to support his position. For example, Berry (1998) came to similar conclusions regarding the inverse relationship between interest rates and the risk premia.[197] Also, as summarized in *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates—rising when rates fell and declining when interest rates rose. The reason for this relationship is that when interest rates rise, bondholders suffer a capital loss. This is referred to as interest rate risk…. Conversely in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earning power dominate, the risk differential will widen and hence the risk premium will increase.[198]

In his more recent textbook, *Modern Regulatory Finance*, Dr. Morin outlines the issues and academic research and concludes the following with respect to the relationship between interest rates and the equity risk premium:

[197] S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March, 1998.

[198] Dr. Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 128.

> This is particularly true in a high inflation environment. Interest rates rise as a result of accelerating inflation, and the interest rate risk of bonds intensifies more than the earnings of common stocks, which are partially hedged from the ravages of inflation. This phenomenon has been termed as a "lock-in" premium. Conversely, in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earnings power dominate, the risk differential will widen and hence the risk premium will increase.
>
> Published empirical studies demonstrate that risk premiums vary inversely with the level of interest rates, rising when rates fell and declining when interest rates rose. Studies by Brigham, Shone, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), and Morin 2020), and others ***demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose***.[199]

These studies demonstrate that my Risk Premium analysis is consistent with academic and scholarly research. Mr. Coppola does not present any academic studies that refute the bases and methodology that I have used in my Risk Premium analyses.

Q. Does the regression analysis that you have conducted for your Risk Premium analysis demonstrate a strong inverse relationship between interest rates and the equity risk premium?

A. Yes. As shown on Exhibit A-14, Schedule D-5, pages 22-25, the regression equation for my Risk Premium analysis has an R^2 of approximately 0.84, which means that 84.00% of the variation in historical implied utility equity risk premia can be explained by changes in interest rates. The regression indicates that there indeed exists a strong negative correlation between utility equity risk premia and interest rates, and that the regression equation is an

[199] Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, at 146; graphic referenced in cite and shown in text has been omitted.

effective tool for predicting authorized ROEs at specified interest rate levels, whether current or projected interest rates. Mr. Coppola fails to address this strong relationship demonstrated by the data in my Risk Premium analysis, which invalidates his critique of the importance of many factors in the relationship between interest rates and authorized ROEs.

Q. Please respond to Mr. Coppola's concern that interest rates of the 1980s are not comparable to today's interest rates.

A. Mr. Coppola's own methods undermine his critique given that he relies on the same type of data he dismisses related to my Risk Premium analyses. While Mr. Coppola critiques my use of data from the 1980s, he nonetheless also relies on historical equity and bond yield data, not only from the same period, but going as far back as 1932 in his Risk Premium approach.[200]

Q. Do you agree with Mr. Walters's critique that the regression framework in your Risk Premium analysis is not sufficiently dynamic to capture how the relationship between interest rates and the equity risk premium has evolved over time?

A. No. As I have discussed, unlike both Mr. Walters's Treasury Bond Approach and his Utility Bond Approach, my Risk Premium reasonably reflects the inverse relationship between interest rates and the equity risk premium. While Mr. Walters has also conducted an alternative Risk Premium analysis using a WLS regression, I have also demonstrated the problems with that analysis.

[200] Coppola Direct, at Exhibit AG-39 and Work Paper AG-39B (see Exhibit No.: A-207 (AEB-3), page 2).

Q. Is there any merit to Mr. Bandyk's position regarding the use of authorized ROEs that are "excessive" in your Risk Premium analyses?

A. No. As I discussed previously, there is no merit to Mr. Bandyk's claim that regulatory commissions have consistently authorized "excessive" ROEs.

X. SUMMARY OF THE ADJUSTED RESULTS

Q. Have you considered how the ROE recommendations of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk would change if their cost of equity analyses were corrected for the issues you have identified with each of their analyses?

A. Yes, I evaluate how each of these witnesses' ROE recommendations would change once their analyses are updated and corrected.

Q. How do the results of Mr. Megginson's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?

A. Figure 20 presents the results of Mr. Megginson's cost of equity analyses based on the updates and corrections to those analyses that I have discussed. As shown, when the results of Mr. Megginson's cost of equity analyses based on the updates and corrections to those analyses that I have discussed are considered, the average cost of equity resulting from his analyses is 10.43%, which is greater than the Company's requested ROE of 10.25% in this proceeding.

Figure 20: Results of Mr. Megginson's as Filed and Adjusted Cost of Equity Analyses

		Mr. Megginson As Filed	Mr. Megginson As Adjusted
Constant Growth DCF	[1]	9.76%	10.21%
CAPM			
Historical MRP		10.05%	10.56%
Projected Market Risk Premium			
Proj. Return on S&P 500 Less Risk-free Rate		n/a	10.88%
Damodaran (4.15%)		7.85%	n/a
Damodaran (5.66%)		9.04%	n/a
Average	[2]	8.98%	10.72%
Risk Premium			
Utility Bond Risk Premium (A-rated)		10.23%	10.23%
Treasury Bond Risk Premium		10.46%	10.46%
Average	[3]	10.35%	10.35%
Average of [1], [2], [3]		**9.70%**	**10.43%**
Recommended ROE		9.75%	
Company's Proposed ROE			10.25%

Q. How do the results of Mr. Coppola's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?

A. Figure 21 presents the results of Mr. Coppola's cost of equity analyses based on the updates and corrections to his analyses that I have discussed. As shown, Mr. Coppola applies a 50.00% weighting to the result of his constant growth DCF and a 25.00% weighting each to the results of his CAPM and Risk Premium analyses. As shown in Figure 21, applying these same weightings to the updates and corrections to Mr. Coppola's analyses produces a cost of equity of 10.03%, which at a minimum supports the reasonableness of an increase in the Company's ROE for this proceeding. Further, it is important to note that the cost of equity of 10.03% is still likely understated as I did not adjust the risk premium in

Mr. Coppola's Risk Premium analysis to account for the inverse relationship between the risk premia and interest rates.

Figure 21: Results of Mr. Coppola's as Filed and Adjusted Cost of Equity Analyses

	Model Weighting	As Filed	As Adjusted
Constant Growth DCF	50.00%	9.57%	9.86%
CAPM	25.00%	9.98%	10.35%
Risk Premium	25.00%	9.81%	10.06%
Wgtd. Avg. Cost of Equity		**9.73%**	**10.03%**
Recommended ROE		9.80%	
Company's Proposed ROE			10.25%

Q. How do the results of Mr. Walters's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?

A. Figure 22 summarizes the results of Mr. Walters' cost of equity models based on the adjustments to his analyses that I have discussed. Based on these changes, the average results of each of Mr. Walters' three analyses range from 10.04% to 10.91%, with a midpoint of 10.47%, which supports the Company's proposed ROE of 10.25%, and is significantly greater than Mr. Walters' recommended ROE of 9.50%.

Figure 22: Results of Mr. Walters's As-Filed and Adjusted Cost of Equity Analyses

	Mr. Walters As Filed		Mr. Walters As Adjusted	
	Mean	**Median**	**Mean**	**Median**
DCF				
Constant Growth (analyst growth rates)	11.05%	10.50%	11.09%	10.72%
Constant Growth (sustainable growth rates)	9.05%	8.85%	n/a	n/a
Multi-Stage	8.62%	8.21%	n/a	n/a
Average	**9.38%**		**10.91%**	
Risk Premium				
Near-Term Projected Treasury Bond Yield	9.88%		10.52%	
3-Month Avg. A-rated Utility Bond Yield	9.92%		10.48%	
6-Month Avg. A-rated Utility Bond Yield	9.93%		10.49%	
WLS Regression	9.85%		n/a	
Average	**9.90%**		**10.50%**	
CAPM				
Kroll Normalized Method:	8.41%		n/a	
Risk Premium Method:	9.14%		9.67%	
FERC DCF Method:	9.79%		10.40%	
Average	**9.11%**		**10.04%**	
Midpoint	**9.50%**		**10.47%**	
Recommended ROE	9.50%			
Company's Proposed ROE			10.25%	

Q. Lastly, how do the results of Mr. Bandyk's cost of equity analyses change if the issues that you have identified are addressed with each of his analyses?

A. Figure 23 presents the results of Mr. Bandyk's cost of equity analyses based on the updates and corrections to his analyses that I have discussed. As shown, Mr. Bandyk calculates his recommended ROE by taking the average of the results of his DCF and CAPM analyses, and then average that result with the Company's currently authorized ROE. I disagree with this approach for determining the ROE in this proceeding given that the existing authorized

ROE is not representative of the current or projected capital market conditions during the period in which the rates established in this proceeding will be in effect. Therefore, a more appropriate ROE recommendation for the Company based on Mr. Bandyk's corrected cost of equity analyses would be the average of the results of his DCF and CAPM analyses, which is 10.70% and is greater than the Company's requested ROE of 10.25% in this proceeding. Nonetheless, even if the same approach that Mr. Bandyk applies for determining his recommended ROE is applied, the recommended ROE is still 10.30%, or substantially higher than the 9.22% that he reflects in his testimony.

Figure 23: Results of Mr. Bandyk's As-Filed and Adjusted Cost of Equity Analyses

	As Filed	**As Adjusted**
DCF		
Constant Growth DCF (EPS growth rates)	n/a	10.39%
Two-Stage DCF (EPS growth rates)	9.65%	n/a
Two-Stage DCF (DPS growth rates)	8.26%	n/a
Average	**8.96%**	**10.39%**
CAPM		
Proj. Return on S&P 500 Less Risk-free Rate and *Value Line* Beta	n/a	11.98%
Proj. Return on S&P 500 Less Risk-free Rate and *Bloomberg* Beta	n/a	10.05%
Damodaran ERP and *Value Line* Beta	7.97%	n/a
Damodaran ERP and *Bloomberg* Beta	6.96%	n/a
Kroll ERP and *Value Line* Beta	9.37%	n/a
Kroll ERP and *Bloomberg* Beta	8.13%	n/a
Average	**8.11%**	**11.02%**
Average	**8.53%**	**10.70%**
Consumers Current Authorized ROE	9.90%	9.90%
Recommended ROE	**9.22%**	**10.30%**

XI. BUSINESS RISK

Q. What are the positions of Mr. Megginson, Mr. Coppola, Mr. Walters, and Mr. Bandyk regarding the business and financial risks of the Company relative to the ROE that should be authorized for the Company in this proceeding?

A. The witnesses have the following positions:

- Mr. Megginson testifies that Consumers Energy operates in Michigan, which Regulator Research Associates ("RRA") ranks as Average/1, or in "the upper tier of the national average."[201] Further, Mr. Megginson contends that the Company has experienced several years with positive net income growth and also has several cost recovery mechanisms, including an Investment Recovery Mechanism to recover certain capital expenditures and which the Company is proposing to expand in this case.[202] According to Mr. Megginson, the Company's "preferred enhancement programs" or cost recovery mechanisms "reduce the Company's overall business and financial risk"[203] and that Consumers Energy's filing every 12-months "borders on a 100% risk-free investment."[204]

- Mr. Coppola does not comment on or develop an assessment of the business risk of the Company relative to the poxy group.

- Mr. Walters suggests that Consumers Energy is less risky than the proxy group on the basis of the relative credit ratings and common equity ratios.[205]

- Mr. Bandyk disagrees with my conclusion regarding the business and regulatory risks of the Company, and claims that the business and regulatory risks of Consumers Energy relative to the proxy group are already reflected in the credit ratings of the Company, which are higher than the proxy group average.[206]

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[201] Megginson Direct, at 7.
[202] *Id.,* at 7-9
[203] *Id*., at 37
[204] *Id*., at 38
[205] Walters Direct, at 29-30.
[206] Bandyk Direct, at 31-33.

Q. Has Mr. Megginson conducted any analysis to support his position that Consumers Energy has less risk as a result of rate mechanisms?

A. No. Simply because the Company has certain cost recovery mechanisms does not mean that it is rational or appropriate to otherwise reduce its authorized ROE as Mr. Megginson contends. To determine whether or not the risk mitigation should be considered in setting the ROE, it is necessary to review what types of mechanisms have been implemented by the proxy group companies and therefore are reflected in the market data that is used to estimate the ROE. Mr. Megginson has not conducted such an analysis. As discussed in my direct testimony, I evaluate Consumers Energy's business and regulatory risk relative to the operating utilities of the proxy group and, based on that analysis, demonstrate that Consumers Energy has moderately greater regulatory risk as compared to the operating subsidiaries of the proxy group companies given the more-timely cost recovery of the proxy group companies.

Q. Please respond to Mr. Megginson's analysis of the Company's steady earnings.

A. Mr. Megginson's analysis is incomplete and inconclusive. As discussed in the rebuttal testimony of Company witness Marc R. Bleckman, Mr. Megginson reviews the Company's annual change in net income in isolation without considering the changes in investment over time, as net income would be expected to increase if the Company has invested in the system over the period from 2010 through 2024.[207] Accordingly, Mr. Megginson's review of such information cannot be used to conclude anything meaningful about the Company's earnings or its financial integrity, and thus should be disregarded.

[207] Bleckman Rebuttal, at 13.

Q. Do you agree with Mr. Megginson's claim that the frequency of Consumers Energy's rate filings "borders on a 100% risk-free investment for the Company"?[208]

A. No, filing a rate case is not akin to a risk-free investment. If Mr. Megginson's claim was correct, investors would flood Consumers Energy with capital and bid up its bond prices. The Company's bond yields would converge to risk-free government Treasury yields. Mr. Megginson's claim ignores principles of finance, including the risk-reward tradeoff, opportunity cost, and regulatory risk, and he has provided no support for his claim.

Q. Do you agree with either Mr. Walters's or Mr. Bandyk's assessment of the relative risk of the Company as compared to the proxy group?

A. No, I do not. Mr. Walters suggests that Consumers Energy is less risky than the proxy group on the basis of the relative credit ratings and common equity ratios, while Mr. Bandyk concludes that Consumers Energy is less risky than the proxy group based on only the relative credit ratings.

First, I disagree with a comparison of credit ratings because credit ratings are assessments of the likelihood a company could default on its debt, whereas a topic of the current proceeding is to determine the riskiness and cost of the Company's equity. In addition, while credit rating agencies consider the business risks of an individual company, when establishing its debt credit rating, they do not conduct a comparative analysis of business risks relative to the proxy group. The development of the investor-required ROE is based on a proxy group of risk-comparable companies. In developing the proxy group, it is essential to balance the relative risk of the companies included in the proxy group with the overall size of the group. Therefore, it is always the case that the proxy companies do

[208] Megginson Direct, at 37.

not have exactly the same risk profile as the subject company. As such, it is reasonable to review the relative risks of the proxy group companies and the subject company to determine how the subject company's risk profile compares with the group to determine the appropriate placement of the ROE within the range of results established using the proxy group companies. In my direct testimony, I evaluated various regulatory and business risks to which Consumers Energy is subject relative to the proxy group and concluded that the Company has slightly greater regulatory and business risk than the proxy group.[209]

Second, as shown in Exhibit AB-6, Mr. Walters compares Consumers Energy's proposed common equity ratio to the common equity ratios of the proxy group holding companies, which include corporate-level debt that is not part of the regulated or financial capital structure of their respective operating utilities. A more appropriate benchmark for the Company's proposal is a comparison to the capital structures of the utility operating companies. As discussed in the direct testimony of Company witness Bleckman, the average authorized common equity ratio for the regulated operating subsidiaries of my proxy group companies over the period of 2020 through April 2025 was 51.85%.[210] The Company's proposed equity ratio of 50.75% is below the average and therefore, is reasonable.

Q. Do you agree with Mr. Megginson that a utility should not recover flotation costs if the equity is issued at the parent company level?

A. No. Mr. Megginson's position with respect to the recovery of flotation costs related to equity issuances is inconsistent with his position on the recovery of the costs associated

[209] Bulkley Direct, at 37-53.

[210] Bleckman Direct, at 10-11 and Exhibit A-29 (MRB-10).

with debt issuances.[211] Mr. Megginson acknowledges that the cost of debt issuances should be and are recovered by utilities; however, he suggests that the cost of issuing equity should be born at the parent company level because that is where equity is issued. I disagree entirely. The cost of equity capital that is raised on behalf of the operating company results in a permanent reduction in the overall capital that is received through an issuance and is properly reflected in the cost of equity for the operating company that is in receipt of the equity capital.

Q. Does this conclude your rebuttal testimony?

A. Yes.

[211] Megginson Direct, at 37.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

ANN E. BULKLEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.26%	10.68%	11.77%
90-Day Avg. Stock Price	9.33%	10.76%	11.84%
180-Day Avg. Stock Price	9.40%	10.82%	11.91%
Average	9.33%	10.75%	11.84%
Median Results:			
30-Day Avg. Stock Price	9.65%	10.37%	11.19%
90-Day Avg. Stock Price	9.74%	10.42%	11.23%
180-Day Avg. Stock Price	9.85%	10.46%	11.20%
Average	9.75%	10.42%	11.21%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.28%	11.24%	11.19%
Current Bloomberg Beta	11.27%	11.23%	11.17%
Long-term Avg. *Value Line* Beta	11.51%	11.47%	11.42%
ECAPM:			
Current *Value Line* Beta	11.80%	11.77%	11.73%
Current Bloomberg Beta	11.79%	11.76%	11.72%
Long-term Avg. *Value Line* Beta	11.97%	11.94%	11.90%
Bond Yield Risk Premium	10.76%	10.66%	10.53%

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.03	$65.12	3.12%	3.22%	6.00%	6.80%	6.60%	6.47%	9.21%	9.68%	10.02%
Ameren Corporation	AEE	$2.84	$100.25	2.83%	2.94%	6.50%	7.90%	7.90%	7.43%	9.43%	10.37%	10.84%
American Electric Power Company, Inc.	AEP	$3.72	$109.81	3.39%	3.50%	6.50%	7.07%	6.40%	6.66%	9.90%	10.16%	10.58%
Avista Corporation	AVA	$1.96	$36.66	5.35%	5.50%	5.50%	5.98%	5.80%	5.76%	10.99%	11.26%	11.48%
Dominion Resources, Inc.	D	$2.67	$59.75	4.47%	4.72%	6.00%	13.98%	13.60%	11.19%	10.60%	15.91%	18.76%
DTE Energy Company	DTE	$4.36	$136.68	3.19%	3.29%	4.50%	7.41%	7.00%	6.30%	7.76%	9.59%	10.72%
Entergy Corporation	ETR	$2.40	$89.29	2.69%	2.80%	3.00%	13.00%	9.50%	8.50%	5.73%	11.30%	15.86%
Evergy, Inc.	EVRG	$2.67	$72.23	3.70%	3.81%	7.50%	5.87%	5.70%	6.36%	9.50%	10.17%	11.34%
IDACORP, Inc.	IDA	$3.44	$126.41	2.72%	2.82%	6.00%	8.60%	8.20%	7.60%	8.80%	10.43%	11.44%
NextEra Energy, Inc.	NEE	$2.27	$72.78	3.11%	3.24%	8.50%	7.58%	7.90%	7.99%	10.81%	11.23%	11.75%
OGE Energy Corporation	OGE	$1.69	$44.68	3.77%	3.89%	6.50%	6.64%	6.30%	6.48%	10.19%	10.37%	10.53%
Pinnacle West Capital Corporation	PNW	$3.58	$88.45	4.05%	4.14%	5.00%	6.90%	2.10%	4.67%	6.19%	8.81%	11.09%
Portland General Electric Company	POR	$2.10	$42.26	4.97%	5.10%	6.50%	5.30%	3.40%	5.07%	8.45%	10.16%	11.63%
PPL Corporation	PPL	$1.09	$36.14	3.02%	3.13%	7.50%	7.42%	7.70%	7.54%	10.55%	10.67%	10.83%
Southern Company	SO	$2.96	$92.78	3.19%	3.30%	6.50%	6.72%	6.80%	6.67%	9.79%	9.97%	10.10%
Xcel Energy Inc.	XEL	$2.28	$73.35	3.11%	3.23%	7.00%	8.06%	7.80%	7.62%	10.22%	10.85%	11.29%
Mean				3.54%	3.66%	6.19%	7.83%	7.04%	7.02%	9.26%	10.68%	11.77%
Median				3.19%	3.29%	6.50%	7.24%	6.90%	6.67%	9.65%	10.37%	11.19%

Notes:
[1] Bloomberg Professional as of September 30, 2025
[2] Bloomberg Professional 30-day average as of September 30, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.03	$63.26	3.21%	3.31%	6.00%	6.80%	6.60%	6.47%	9.31%	9.78%	10.11%
Ameren Corporation	AEE	$2.84	$98.00	2.90%	3.01%	6.50%	7.90%	7.90%	7.43%	9.49%	10.44%	10.91%
American Electric Power Company, Inc.	AEP	$3.72	$106.86	3.48%	3.60%	6.50%	7.07%	6.40%	6.66%	9.99%	10.25%	10.68%
Avista Corporation	AVA	$1.96	$37.03	5.29%	5.45%	5.50%	5.98%	5.80%	5.76%	10.94%	11.21%	11.43%
Dominion Resources, Inc.	D	$2.67	$57.81	4.62%	4.88%	6.00%	13.98%	13.60%	11.19%	10.76%	16.07%	18.92%
DTE Energy Company	DTE	$4.36	$135.01	3.23%	3.33%	4.50%	7.41%	7.00%	6.30%	7.80%	9.63%	10.76%
Entergy Corporation	ETR	$2.40	$85.96	2.79%	2.91%	3.00%	13.00%	9.50%	8.50%	5.83%	11.41%	15.97%
Evergy, Inc.	EVRG	$2.67	$69.59	3.84%	3.96%	7.50%	5.87%	5.70%	6.36%	9.65%	10.32%	11.48%
IDACORP, Inc.	IDA	$3.44	$120.93	2.84%	2.95%	6.00%	8.60%	8.20%	7.60%	8.93%	10.55%	11.57%
NextEra Energy, Inc.	NEE	$2.27	$71.99	3.15%	3.27%	8.50%	7.58%	7.90%	7.99%	10.85%	11.27%	11.78%
OGE Energy Corporation	OGE	$1.69	$44.45	3.79%	3.91%	6.50%	6.64%	6.30%	6.48%	10.21%	10.39%	10.55%
Pinnacle West Capital Corporation	PNW	$3.58	$89.46	4.00%	4.10%	5.00%	6.90%	2.10%	4.67%	6.14%	8.76%	11.04%
Portland General Electric Company	POR	$2.10	$41.15	5.10%	5.23%	6.50%	5.30%	3.40%	5.07%	8.59%	10.30%	11.77%
PPL Corporation	PPL	$1.09	$35.13	3.10%	3.22%	7.50%	7.42%	7.70%	7.54%	10.64%	10.76%	10.92%
Southern Company	SO	$2.96	$91.78	3.23%	3.33%	6.50%	6.72%	6.80%	6.67%	9.83%	10.01%	10.13%
Xcel Energy Inc.	XEL	$2.28	$70.61	3.23%	3.35%	7.00%	8.06%	7.80%	7.62%	10.34%	10.97%	11.41%
Mean				3.61%	3.74%	6.19%	7.83%	7.04%	7.02%	9.33%	10.76%	11.84%
Median				3.23%	3.34%	6.50%	7.24%	6.90%	6.67%	9.74%	10.42%	11.23%

Notes:
[1] Bloomberg Professional as of September 30, 2025
[2] Bloomberg Professional 90-day average as of September 30, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.03	$61.87	3.28%	3.39%	6.00%	6.80%	6.60%	6.47%	9.38%	9.85%	10.19%
Ameren Corporation	AEE	$2.84	$96.89	2.93%	3.04%	6.50%	7.90%	7.90%	7.43%	9.53%	10.47%	10.95%
American Electric Power Company, Inc.	AEP	$3.72	$104.26	3.57%	3.69%	6.50%	7.07%	6.40%	6.66%	10.08%	10.34%	10.77%
Avista Corporation	AVA	$1.96	$37.53	5.22%	5.37%	5.50%	5.98%	5.80%	5.76%	10.87%	11.13%	11.36%
Dominion Resources, Inc.	D	$2.67	$55.51	4.81%	5.08%	6.00%	13.98%	13.60%	11.19%	10.95%	16.27%	19.13%
DTE Energy Company	DTE	$4.36	$131.69	3.31%	3.42%	4.50%	7.41%	7.00%	6.30%	7.89%	9.72%	10.84%
Entergy Corporation	ETR	$2.40	$83.88	2.86%	2.98%	3.00%	13.00%	9.50%	8.50%	5.90%	11.48%	16.05%
Evergy, Inc.	EVRG	$2.67	$67.27	3.97%	4.10%	7.50%	5.87%	5.70%	6.36%	9.78%	10.45%	11.62%
IDACORP, Inc.	IDA	$3.44	$116.64	2.95%	3.06%	6.00%	8.60%	8.20%	7.60%	9.04%	10.66%	11.68%
NextEra Energy, Inc.	NEE	$2.27	$70.21	3.23%	3.36%	8.50%	7.58%	7.90%	7.99%	10.93%	11.35%	11.86%
OGE Energy Corporation	OGE	$1.69	$43.94	3.84%	3.96%	6.50%	6.64%	6.30%	6.48%	10.26%	10.44%	10.60%
Pinnacle West Capital Corporation	PNW	$3.58	$89.37	4.01%	4.10%	5.00%	6.90%	2.10%	4.67%	6.15%	8.77%	11.04%
Portland General Electric Company	POR	$2.10	$41.30	5.08%	5.21%	6.50%	5.30%	3.40%	5.07%	8.57%	10.28%	11.75%
PPL Corporation	PPL	$1.09	$34.54	3.16%	3.27%	7.50%	7.42%	7.70%	7.54%	10.69%	10.81%	10.98%
Southern Company	SO	$2.96	$89.23	3.32%	3.43%	6.50%	6.72%	6.80%	6.67%	9.93%	10.10%	10.23%
Xcel Energy Inc.	XEL	$2.28	$69.15	3.30%	3.42%	7.00%	8.06%	7.80%	7.62%	10.41%	11.04%	11.49%
Mean				3.68%	3.80%	6.19%	7.83%	7.04%	7.02%	9.40%	10.82%	11.91%
Median				3.31%	3.43%	6.50%	7.24%	6.90%	6.67%	9.85%	10.46%	11.20%

Notes:
[1] Bloomberg Professional as of September 30, 2025
[2] Bloomberg Professional 180-day average as of September 30, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Ameren Corporation	AEE	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
American Electric Power Company, Inc.	AEP	4.79%	0.65	13.34%	8.55%	10.35%	11.10%
Avista Corporation	AVA	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Dominion Resources, Inc.	D	4.79%	0.80	13.34%	8.55%	11.63%	12.06%
DTE Energy Company	DTE	4.79%	0.80	13.34%	8.55%	11.63%	12.06%
Entergy Corporation	ETR	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Evergy, Inc.	EVRG	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
IDACORP, Inc.	IDA	4.79%	0.70	13.34%	8.55%	10.78%	11.42%
NextEra Energy, Inc.	NEE	4.79%	0.90	13.34%	8.55%	12.49%	12.70%
OGE Energy Corporation	OGE	4.79%	0.85	13.34%	8.55%	12.06%	12.38%
Pinnacle West Capital Corporation	PNW	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Portland General Electric Company	POR	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
PPL Corporation	PPL	4.79%	0.80	13.34%	8.55%	11.63%	12.06%
Southern Company	SO	4.79%	0.70	13.34%	8.55%	10.78%	11.42%
Xcel Energy Inc.	XEL	4.79%	0.70	13.34%	8.55%	10.78%	11.42%
Mean						11.28%	11.80%
Median						11.20%	11.74%

Notes:
[1] Bloomberg Professional 30-day average as of September 30, 2025
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2026 - Q1 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Ameren Corporation	AEE	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
American Electric Power Company, Inc.	AEP	4.62%	0.65	13.34%	8.72%	10.29%	11.05%
Avista Corporation	AVA	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Dominion Resources, Inc.	D	4.62%	0.80	13.34%	8.72%	11.60%	12.03%
DTE Energy Company	DTE	4.62%	0.80	13.34%	8.72%	11.60%	12.03%
Entergy Corporation	ETR	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Evergy, Inc.	EVRG	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
IDACORP, Inc.	IDA	4.62%	0.70	13.34%	8.72%	10.73%	11.38%
NextEra Energy, Inc.	NEE	4.62%	0.90	13.34%	8.72%	12.47%	12.69%
OGE Energy Corporation	OGE	4.62%	0.85	13.34%	8.72%	12.03%	12.36%
Pinnacle West Capital Corporation	PNW	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Portland General Electric Company	POR	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
PPL Corporation	PPL	4.62%	0.80	13.34%	8.72%	11.60%	12.03%
Southern Company	SO	4.62%	0.70	13.34%	8.72%	10.73%	11.38%
Xcel Energy Inc.	XEL	4.62%	0.70	13.34%	8.72%	10.73%	11.38%
Mean						11.24%	11.77%
Median						11.16%	11.71%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Ameren Corporation	AEE	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
American Electric Power Company, Inc.	AEP	4.40%	0.65	13.34%	8.94%	10.21%	10.99%
Avista Corporation	AVA	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Dominion Resources, Inc.	D	4.40%	0.80	13.34%	8.94%	11.55%	12.00%
DTE Energy Company	DTE	4.40%	0.80	13.34%	8.94%	11.55%	12.00%
Entergy Corporation	ETR	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Evergy, Inc.	EVRG	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
IDACORP, Inc.	IDA	4.40%	0.70	13.34%	8.94%	10.66%	11.33%
NextEra Energy, Inc.	NEE	4.40%	0.90	13.34%	8.94%	12.45%	12.67%
OGE Energy Corporation	OGE	4.40%	0.85	13.34%	8.94%	12.00%	12.34%
Pinnacle West Capital Corporation	PNW	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Portland General Electric Company	POR	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
PPL Corporation	PPL	4.40%	0.80	13.34%	8.94%	11.55%	12.00%
Southern Company	SO	4.40%	0.70	13.34%	8.94%	10.66%	11.33%
Xcel Energy Inc.	XEL	4.40%	0.70	13.34%	8.94%	10.66%	11.33%
Mean						11.19%	11.73%
Median						11.11%	11.67%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14

[2] Value Line

[3] Market Return

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.79%	0.74	13.34%	8.55%	11.16%	11.70%
Ameren Corporation	AEE	4.79%	0.71	13.34%	8.55%	10.90%	11.51%
American Electric Power Company, Inc.	AEP	4.79%	0.71	13.34%	8.55%	10.83%	11.46%
Avista Corporation	AVA	4.79%	0.71	13.34%	8.55%	10.85%	11.47%
Dominion Resources, Inc.	D	4.79%	0.68	13.34%	8.55%	10.57%	11.26%
DTE Energy Company	DTE	4.79%	0.77	13.34%	8.55%	11.39%	11.88%
Entergy Corporation	ETR	4.79%	0.82	13.34%	8.55%	11.84%	12.22%
Evergy, Inc.	EVRG	4.79%	0.74	13.34%	8.55%	11.15%	11.69%
IDACORP, Inc.	IDA	4.79%	0.74	13.34%	8.55%	11.13%	11.68%
NextEra Energy, Inc.	NEE	4.79%	0.79	13.34%	8.55%	11.54%	11.99%
OGE Energy Corporation	OGE	4.79%	0.87	13.34%	8.55%	12.26%	12.53%
Pinnacle West Capital Corporation	PNW	4.79%	0.78	13.34%	8.55%	11.44%	11.91%
Portland General Electric Company	POR	4.79%	0.74	13.34%	8.55%	11.12%	11.68%
PPL Corporation	PPL	4.79%	0.88	13.34%	8.55%	12.30%	12.56%
Southern Company	SO	4.79%	0.73	13.34%	8.55%	11.04%	11.62%
Xcel Energy Inc.	XEL	4.79%	0.70	13.34%	8.55%	10.78%	11.42%
Mean						11.27%	11.79%
Median						11.14%	11.69%

Notes:
[1] Bloomberg Professional 30-day average as of September 30, 2025
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2026 - Q1 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.62%	0.74	13.34%	8.72%	11.12%	11.67%
Ameren Corporation	AEE	4.62%	0.71	13.34%	8.72%	10.85%	11.47%
American Electric Power Company, Inc.	AEP	4.62%	0.71	13.34%	8.72%	10.79%	11.42%
Avista Corporation	AVA	4.62%	0.71	13.34%	8.72%	10.80%	11.44%
Dominion Resources, Inc.	D	4.62%	0.68	13.34%	8.72%	10.51%	11.22%
DTE Energy Company	DTE	4.62%	0.77	13.34%	8.72%	11.35%	11.85%
Entergy Corporation	ETR	4.62%	0.82	13.34%	8.72%	11.81%	12.20%
Evergy, Inc.	EVRG	4.62%	0.74	13.34%	8.72%	11.10%	11.66%
IDACORP, Inc.	IDA	4.62%	0.74	13.34%	8.72%	11.09%	11.65%
NextEra Energy, Inc.	NEE	4.62%	0.79	13.34%	8.72%	11.50%	11.96%
OGE Energy Corporation	OGE	4.62%	0.87	13.34%	8.72%	12.24%	12.51%
Pinnacle West Capital Corporation	PNW	4.62%	0.78	13.34%	8.72%	11.40%	11.88%
Portland General Electric Company	POR	4.62%	0.74	13.34%	8.72%	11.08%	11.65%
PPL Corporation	PPL	4.62%	0.88	13.34%	8.72%	12.28%	12.54%
Southern Company	SO	4.62%	0.73	13.34%	8.72%	10.99%	11.58%
Xcel Energy Inc.	XEL	4.62%	0.70	13.34%	8.72%	10.73%	11.39%
Mean						11.23%	11.76%
Median						11.09%	11.66%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.40%	0.74	13.34%	8.94%	11.06%	11.63%
Ameren Corporation	AEE	4.40%	0.71	13.34%	8.94%	10.79%	11.43%
American Electric Power Company, Inc.	AEP	4.40%	0.71	13.34%	8.94%	10.72%	11.38%
Avista Corporation	AVA	4.40%	0.71	13.34%	8.94%	10.74%	11.39%
Dominion Resources, Inc.	D	4.40%	0.68	13.34%	8.94%	10.44%	11.16%
DTE Energy Company	DTE	4.40%	0.77	13.34%	8.94%	11.30%	11.81%
Entergy Corporation	ETR	4.40%	0.82	13.34%	8.94%	11.78%	12.17%
Evergy, Inc.	EVRG	4.40%	0.74	13.34%	8.94%	11.05%	11.62%
IDACORP, Inc.	IDA	4.40%	0.74	13.34%	8.94%	11.03%	11.61%
NextEra Energy, Inc.	NEE	4.40%	0.79	13.34%	8.94%	11.46%	11.93%
OGE Energy Corporation	OGE	4.40%	0.87	13.34%	8.94%	12.21%	12.49%
Pinnacle West Capital Corporation	PNW	4.40%	0.78	13.34%	8.94%	11.35%	11.85%
Portland General Electric Company	POR	4.40%	0.74	13.34%	8.94%	11.02%	11.60%
PPL Corporation	PPL	4.40%	0.88	13.34%	8.94%	12.25%	12.52%
Southern Company	SO	4.40%	0.73	13.34%	8.94%	10.93%	11.54%
Xcel Energy Inc.	XEL	4.40%	0.70	13.34%	8.94%	10.67%	11.34%
Mean						11.17%	11.72%
Median						11.04%	11.61%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.79%	0.78	13.34%	8.55%	11.42%	11.90%
Ameren Corporation	AEE	4.79%	0.75	13.34%	8.55%	11.24%	11.77%
American Electric Power Company, Inc.	AEP	4.79%	0.70	13.34%	8.55%	10.74%	11.39%
Avista Corporation	AVA	4.79%	0.81	13.34%	8.55%	11.70%	12.11%
Dominion Resources, Inc.	D	4.79%	0.73	13.34%	8.55%	11.06%	11.63%
DTE Energy Company	DTE	4.79%	0.79	13.34%	8.55%	11.56%	12.01%
Entergy Corporation	ETR	4.79%	0.78	13.34%	8.55%	11.49%	11.95%
Evergy, Inc.	EVRG	4.79%	0.94	13.34%	8.55%	12.83%	12.96%
IDACORP, Inc.	IDA	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
NextEra Energy, Inc.	NEE	4.79%	0.78	13.34%	8.55%	11.45%	11.93%
OGE Energy Corporation	OGE	4.79%	0.95	13.34%	8.55%	12.95%	13.05%
Pinnacle West Capital Corporation	PNW	4.79%	0.77	13.34%	8.55%	11.38%	11.87%
Portland General Electric Company	POR	4.79%	0.78	13.34%	8.55%	11.45%	11.93%
PPL Corporation	PPL	4.79%	0.86	13.34%	8.55%	12.13%	12.43%
Southern Company	SO	4.79%	0.70	13.34%	8.55%	10.81%	11.44%
Xcel Energy Inc.	XEL	4.79%	0.69	13.34%	8.55%	10.67%	11.34%
Mean						11.51%	11.97%
Median						11.44%	11.91%

Notes:
[1] Bloomberg Professional 30-day average as of September 30, 2025
[2] Long-Term Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2026 - Q1 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.62%	0.78	13.34%	8.72%	11.38%	11.87%
Ameren Corporation	AEE	4.62%	0.75	13.34%	8.72%	11.20%	11.73%
American Electric Power Company, Inc.	AEP	4.62%	0.70	13.34%	8.72%	10.69%	11.35%
Avista Corporation	AVA	4.62%	0.81	13.34%	8.72%	11.67%	12.09%
Dominion Resources, Inc.	D	4.62%	0.73	13.34%	8.72%	11.02%	11.60%
DTE Energy Company	DTE	4.62%	0.79	13.34%	8.72%	11.53%	11.98%
Entergy Corporation	ETR	4.62%	0.78	13.34%	8.72%	11.45%	11.92%
Evergy, Inc.	EVRG	4.62%	0.94	13.34%	8.72%	12.82%	12.95%
IDACORP, Inc.	IDA	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
NextEra Energy, Inc.	NEE	4.62%	0.78	13.34%	8.72%	11.42%	11.90%
OGE Energy Corporation	OGE	4.62%	0.95	13.34%	8.72%	12.94%	13.04%
Pinnacle West Capital Corporation	PNW	4.62%	0.77	13.34%	8.72%	11.34%	11.84%
Portland General Electric Company	POR	4.62%	0.78	13.34%	8.72%	11.42%	11.90%
PPL Corporation	PPL	4.62%	0.86	13.34%	8.72%	12.11%	12.42%
Southern Company	SO	4.62%	0.70	13.34%	8.72%	10.76%	11.41%
Xcel Energy Inc.	XEL	4.62%	0.69	13.34%	8.72%	10.62%	11.30%
Mean						11.47%	11.94%
Median						11.40%	11.88%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[2] Long-Term Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.40%	0.78	13.34%	8.94%	11.33%	11.83%
Ameren Corporation	AEE	4.40%	0.75	13.34%	8.94%	11.14%	11.69%
American Electric Power Company, Inc.	AEP	4.40%	0.70	13.34%	8.94%	10.62%	11.30%
Avista Corporation	AVA	4.40%	0.81	13.34%	8.94%	11.63%	12.06%
Dominion Resources, Inc.	D	4.40%	0.73	13.34%	8.94%	10.96%	11.55%
DTE Energy Company	DTE	4.40%	0.79	13.34%	8.94%	11.48%	11.95%
Entergy Corporation	ETR	4.40%	0.78	13.34%	8.94%	11.40%	11.89%
Evergy, Inc.	EVRG	4.40%	0.94	13.34%	8.94%	12.81%	12.94%
IDACORP, Inc.	IDA	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
NextEra Energy, Inc.	NEE	4.40%	0.78	13.34%	8.94%	11.37%	11.86%
OGE Energy Corporation	OGE	4.40%	0.95	13.34%	8.94%	12.93%	13.03%
Pinnacle West Capital Corporation	PNW	4.40%	0.77	13.34%	8.94%	11.29%	11.81%
Portland General Electric Company	POR	4.40%	0.78	13.34%	8.94%	11.37%	11.86%
PPL Corporation	PPL	4.40%	0.86	13.34%	8.94%	12.08%	12.39%
Southern Company	SO	4.40%	0.70	13.34%	8.94%	10.70%	11.36%
Xcel Energy Inc.	XEL	4.40%	0.69	13.34%	8.94%	10.55%	11.25%
Mean						11.42%	11.90%
Median						11.35%	11.85%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14

[2] Long-Term Beta

[3] Market Return

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL VALUE LINE BETA

Company	Ticker	[1] 2013	[2] 2014	[3] 2015	[4] 2016	[5] 2017	[6] 2018	[7] 2019	[8] 2020	[9] 2021	[10] 2022	[11] 2023	[12] 2024	[13] Average
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.85	0.90	0.90	0.78
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.85	0.90	0.90	0.75
American Electric Power Company, Inc.	AEP	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.75	0.80	0.80	0.70
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.90	0.90	0.95	0.81
Dominion Resources, Inc.	D	0.70	0.70	0.70	0.65	0.65	0.60	0.55	0.80	0.85	0.85	0.85	0.90	0.73
DTE Energy Company	DTE	0.80	0.75	0.75	0.65	0.65	0.55	0.55	0.95	0.95	0.95	0.95	1.00	0.79
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.95	0.95	1.00	0.78
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.90	0.90	0.95	0.94
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0.80	0.80	0.85	0.85	0.75
NextEra Energy, Inc.	NEE	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.95	1.00	1.05	0.78
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	1.00	1.05	1.10	0.95
Pinnacle West Capital Corporation	PNW	0.75	0.70	0.75	0.70	0.70	0.55	0.50	0.90	0.90	0.90	0.95	0.95	0.77
Portland General Electric Company	POR	0.75	0.80	0.80	0.70	0.70	0.60	0.55	0.85	0.90	0.85	0.90	0.95	0.78
PPL Corporation	PPL	0.65	0.60	0.70	0.70	0.75	0.70	0.70	1.15	1.10	1.05	1.10	1.10	0.86
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.90	0.95	0.95	0.70
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.80	0.85	0.85	0.69
Mean		0.72	0.73	0.75	0.68	0.69	0.59	0.57	0.91	0.90	0.89	0.93	0.95	0.79

Notes:
[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Value Line, Dated December 29, 2023.
[12] Value Line, Dated December 27, 2024.

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.31%
[2] Estimate of the S&P 500 Growth Rate	11.95%
[3] S&P 500 Estimated Required Market Return	13.34%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	321.64843	49.04	15,773.64		11.17%		-9.85%	
American Express Co	AXP	695.88223	332.16	231,144.24	0.56%	0.99%	0.01%	15.03%	0.08%
Verizon Communications Inc	VZ	4216.32481	43.95	185,307.48	0.45%	6.28%	0.03%	2.27%	0.01%
Texas Pacific Land Corp	TPL	22.97941	933.64	21,454.50		0.69%			
Broadcom Inc	AVGO	4722.36502	329.91	1,557,955.44		0.72%		40.05%	
Boeing Co/The	BA	756.1577	215.83	163,201.52				31.71%	
Solventum Corp	SOLV	173.3878	73	12,657.31	0.03%			1.28%	0.00%
Caterpillar Inc	CAT	468.47892	477.15	223,534.72	0.54%	1.27%	0.01%	6.56%	0.04%
JPMorgan Chase & Co	JPM	2749.75385	315.43	867,354.86	2.11%	1.90%	0.04%	8.55%	0.18%
Chevron Corp	CVX	2047.39391	155.29	317,939.80	0.77%	4.40%	0.03%	15.39%	0.12%
Coca-Cola Co/The	KO	4303.66725	66.32	285,419.21	0.69%	3.08%	0.02%	5.90%	0.04%
AbbVie Inc	ABBV	1766.55825	231.54	409,028.90	0.99%	2.83%	0.03%	13.98%	0.14%
Walt Disney Co/The	DIS	1797.93383	114.5	205,863.42	0.50%	0.87%	0.00%	13.12%	0.07%
Corpay Inc	CPAY	70.61438	288.06	20,341.18	0.05%			12.12%	0.01%
Extra Space Storage Inc	EXR	212.25361	140.94	29,915.02	0.07%	4.60%	0.00%	3.14%	0.00%
Exxon Mobil Corp	XOM	4263.24702	112.75	480,681.10	1.17%	3.51%	0.04%	11.40%	0.13%
Phillips 66	PSX	404.12427	136.02	54,968.98		3.53%		22.37%	
General Electric Co	GE	1060.43939	300.82	319,001.38		0.48%		20.51%	
HP Inc	HPQ	934.70185	27.23	25,451.93		4.25%		-0.60%	
Home Depot Inc/The	HD	995.38665	405.19	403,320.72	0.98%	2.27%	0.02%	5.04%	0.05%
Monolithic Power Systems Inc	MPWR	47.892	920.64	44,091.29		0.68%			
International Business Machines Corp	IBM	931.51924	282.16	262,837.47	0.64%	2.38%	0.02%	6.68%	0.04%
Johnson & Johnson	JNJ	2408.33887	185.42	446,554.19	1.09%	2.80%	0.03%	7.35%	0.08%
Lululemon Athletica Inc	LULU	113.46808	177.93	20,189.38	0.05%			1.24%	0.00%
McDonald's Corp	MCD	713.60443	303.89	216,857.25	0.53%	2.33%	0.01%	8.63%	0.05%
Merck & Co Inc	MRK	2497.78321	83.93	209,638.94	0.51%	3.86%	0.02%	15.57%	0.08%
3M Co	MMM	532.6297	155.18	82,653.48	0.20%	1.88%	0.00%	6.99%	0.01%
American Water Works Co Inc	AWK	203.19716	139.19	28,283.01	0.07%	2.38%	0.00%	6.60%	0.00%
Bank of America Corp	BAC	7406.94731	51.59	382,124.41		2.17%			
Pfizer Inc	PFE	5685.5505	25.48	144,867.83	0.35%	6.75%	0.02%	0.11%	0.00%
Procter & Gamble Co/The	PG	2340.48526	153.65	359,615.56	0.87%	2.75%	0.02%	4.08%	0.04%
AT&T Inc	T	7150.38548	28.24	201,926.89	0.49%	3.93%	0.02%	4.63%	0.02%
Travelers Cos Inc/The	TRV	225.13384	279.22	62,861.87		1.58%		54.50%	
RTX Corp	RTX	1338.54183	167.33	223,978.20	0.54%	1.63%	0.01%	7.41%	0.04%
Analog Devices Inc	ADI	491.95544	245.7	120,873.45	0.29%	1.61%	0.00%	17.18%	0.05%
Walmart Inc	WMT	7972.85112	103.06	821,682.04	2.00%	0.91%	0.02%	8.46%	0.17%
Cisco Systems Inc	CSCO	3953.19695	68.42	270,477.74	0.66%	2.40%	0.02%	8.32%	0.05%
Intel Corp	INTC	4651.583	33.55	156,060.61	0.38%			9.28%	0.04%
General Motors Co	GM	952.0778	60.97	58,048.18	0.14%	0.98%	0.00%	6.04%	0.01%
Microsoft Corp	MSFT	7433.16638	517.95	3,850,008.53	9.36%	0.70%	0.07%	14.84%	1.39%
Dollar General Corp	DG	220.10603	103.35	22,747.96	0.06%	2.28%	0.00%	5.24%	0.00%
Cigna Group/The	CI	266.92807	288.25	76,942.02	0.19%	2.10%	0.00%	10.86%	0.02%
Kinder Morgan Inc	KMI	2222.07762	28.31	62,907.02	0.15%	4.13%	0.01%	8.46%	0.01%
Citigroup Inc	C	1840.8979	101.5	186,851.14		2.36%		25.65%	
American International Group Inc	AIG	554.00385	78.54	43,511.46	0.11%	2.29%	0.00%	19.99%	0.02%
Altria Group Inc	MO	1679.89095	66.06	110,973.60	0.27%	6.42%	0.02%	4.72%	0.01%
HCA Healthcare Inc	HCA	233.9935	426.2	99,728.03	0.24%	0.68%	0.00%	10.76%	0.03%
International Paper Co	IP	527.98209	46.4	24,498.37		3.99%		54.45%	
Hewlett Packard Enterprise Co	HPE	1319.45006	24.56	32,405.69	0.08%	2.12%	0.00%	7.61%	0.01%
Abbott Laboratories	ABT	1740.45901	133.94	233,117.08	0.57%	1.76%	0.01%	9.97%	0.06%
Aflac Inc	AFL	534.83149	111.7	59,740.68		2.08%		25.77%	
Air Products and Chemicals Inc	APD	222.55364	270.9299	60,296.44	0.15%	2.64%	0.00%	3.42%	0.01%
Super Micro Computer Inc	SMCI	594.27331	47.94	28,489.46	0.07%			19.06%	0.01%
Royal Caribbean Cruises Ltd	RCL	271.62766	323.58	87,893.28		1.24%		22.77%	
Hess Corp	HES	445.24698	68.81	30,637.44	0.07%	0.47%	0.00%	12.54%	0.01%
Lennox International Inc	LII	35.12428	529.36	18,593.39		0.98%			
Archer-Daniels-Midland Co	ADM	480.46448	59.74	28,702.95	0.07%	3.41%	0.00%	4.70%	0.00%
Automatic Data Processing Inc	ADP	44.76425	649.54	29,076.17		0.15%			
Verisk Analytics Inc	VRSK	405.08952	293.5	118,893.77		2.10%			
AutoZone Inc	AZO	139.71497	251.51	35,139.71		0.72%			
Linde PLC	LIN	16.72871	4290.24	71,770.18	0.17%			13.66%	0.02%
Avery Dennison Corp	AVY	468.90953	475	222,732.03	0.54%	1.26%	0.01%	8.66%	0.05%
Enphase Energy Inc	ENPH	77.98159	162.17	12,646.27	0.03%	2.32%	0.00%	6.84%	0.00%
MSCI Inc	MSCI	77.36524	567.41	43,897.81		1.27%			
Ball Corp	BALL	272.1489	50.42	13,721.75	0.03%	1.59%	0.00%	12.27%	0.00%
Axon Enterprise Inc	AXON	78.50444	717.64	56,337.93				28.56%	
Dayforce Inc	DAY	158.00648	68.89	10,885.07					
Carrier Global Corp	CARR	851.02284	59.7	50,806.06	0.12%	1.51%	0.00%	11.41%	0.01%
Bank of New York Mellon Corp/The	BK	705.24082	108.96	76,843.04	0.19%	1.95%	0.00%	14.85%	0.03%
Otis Worldwide Corp	OTIS	392.47523	91.43	35,884.01		1.84%			
Baxter International Inc	BAX	513.62106	22.77	11,695.15	0.03%	2.99%	0.00%	12.49%	0.00%
Becton Dickinson & Co	BDX	286.62747	187.17	53,648.06	0.13%	2.22%	0.00%	7.29%	0.01%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Berkshire Hathaway Inc	BRK/B	1378.54564	502.74	693,050.04					
Best Buy Co Inc	BBY	210.10127	75.62	15,887.86	0.04%	5.03%	0.00%	4.17%	0.00%
Boston Scientific Corp	BSX	1481.75163	97.63	144,663.41	0.35%			14.86%	0.05%
Bristol-Myers Squibb Co	BMY	2035.43584	45.1	91,798.16		5.50%		82.51%	
Brown-Forman Corp	BF/B	303.60888	27.08	8,221.73	0.02%	3.35%	0.00%	2.43%	0.00%
Coterra Energy Inc	CTRA	763.13997	23.65	18,048.26		3.72%		30.08%	
Hilton Worldwide Holdings Inc	HLT	235.19375	259.44	61,018.67	0.15%	0.23%	0.00%	12.75%	0.02%
Carnival Corp	CCL	1167.54105	28.91	33,753.61				21.87%	
Builders FirstSource Inc	BLDR	110.54693	121.25	13,403.82				-4.21%	
UDR Inc	UDR	331.34719	37.26	12,346.00	0.03%	4.62%	0.00%	1.33%	0.00%
Clorox Co/The	CLX	122.30941	123.3	15,080.75	0.04%	4.02%	0.00%	0.34%	0.00%
Paycom Software Inc	PAYC	57.8768	208.14	12,046.48	0.03%	0.72%	0.00%	9.16%	0.00%
CMS Energy Corp	CMS	299.33546	73.26	21,929.32	0.05%	2.96%	0.00%	7.51%	0.00%
Colgate-Palmolive Co	CL	808.22082	79.94	64,609.17	0.16%	2.60%	0.00%	4.85%	0.01%
EPAM Systems Inc	EPAM	55.69691	150.79	8,398.54					
Conagra Brands Inc	CAG	479.04969	18.31	8,771.40		7.65%		-7.51%	
Airbnb Inc	ABNB	429.07956	121.42	52,098.84	0.13%			10.47%	0.01%
Consolidated Edison Inc	ED	360.65167	100.52	36,252.71	0.09%	3.38%	0.00%	5.20%	0.00%
Corning Inc	GLW	856.61871	82.03	70,268.43	0.17%	1.37%	0.00%	18.16%	0.03%
GoDaddy Inc	GDDY	138.44902	136.83	18,943.98					
Cummins Inc	CMI	137.78604	422.37	58,196.69	0.14%	1.89%	0.00%	10.71%	0.02%
Caesars Entertainment Inc	CZR	716.05159	198.26	141,964.39	0.35%	0.65%	0.00%	8.10%	0.03%
Danaher Corp	DHR	454.39915	89.7	40,759.60		5.08%		-1.37%	
Target Corp	TGT	121.79033	195.45	23,803.92	0.06%	1.35%	0.00%	4.68%	0.00%
Williams-Sonoma Inc	WSM	270.32939	457.26	123,610.82		1.42%		-2.85%	
Deere & Co	DE	853.43363	61.17	52,204.54		4.36%		23.10%	
Dominion Energy Inc	D	445.66693	49.01	21,842.14	0.05%			15.53%	0.01%
Dover Corp	DOV	137.13445	166.83	22,878.14	0.06%	1.25%	0.00%	11.53%	0.01%
Alliant Energy Corp	LNT	256.96923	67.41	17,322.30	0.04%	3.01%	0.00%	6.09%	0.00%
Steel Dynamics Inc	STLD	147.20459	139.43	20,524.74	0.05%	1.43%	0.00%	13.77%	0.01%
Duke Energy Corp	DUK	777.02168	123.75	96,156.43	0.23%	3.44%	0.01%	7.44%	0.02%
Regency Centers Corp	REG	181.55331	72.9	13,235.24	0.03%	3.87%	0.00%	5.02%	0.00%
Eaton Corp PLC	ETN	389.3	374.25	145,695.53	0.35%	1.11%	0.00%	13.81%	0.05%
Ecolab Inc	ECL	283.62491	273.86	77,673.52	0.19%	0.95%	0.00%	13.00%	0.02%
Revvity Inc	RVTY	116.07258	87.65	10,173.76	0.02%	0.32%	0.00%	6.16%	0.00%
Dell Technologies Inc	DELL	336.90462	141.77	47,762.97	0.12%	1.48%	0.00%	16.92%	0.02%
Emerson Electric Co	EMR	562.8	131.18	73,828.10	0.18%	1.61%	0.00%	10.06%	0.02%
EOG Resources Inc	EOG	545.99342	112.12	61,216.78		3.64%			
Aon PLC	AON	215.6266	356.58	76,888.13	0.19%	0.84%	0.00%	10.12%	0.02%
Entergy Corp	ETR	446.40907	93.19	41,600.86	0.10%	2.58%	0.00%	5.80%	0.01%
Equifax Inc	EFX	123.79738	256.53	31,757.74	0.08%	0.78%	0.00%	10.18%	0.01%
EQT Corp	EQT	624.06446	54.43	33,967.83		1.16%		41.56%	
IQVIA Holdings Inc	IQV	170	189.94	32,289.80	0.08%			8.97%	0.01%
Gartner Inc	IT	75.7358	262.87	19,908.67					
FedEx Corp	FDX	235.95546	235.81	55,640.66	0.14%	2.46%	0.00%	9.05%	0.01%
Brown & Brown Inc	BRO	329.84281	93.79	30,935.96	0.08%	0.64%	0.00%	11.27%	0.01%
Ford Motor Co	F	3909.00822	11.96	46,751.74		5.02%		-1.10%	
NextEra Energy Inc	NEE	2059.29259	75.49	155,456.00	0.38%	3.00%	0.01%	7.39%	0.03%
Franklin Resources Inc	BEN	519.19548	23.13	12,008.99		5.53%		-0.14%	
Garmin Ltd	GRMN	192.49395	246.22	47,395.86	0.12%	1.46%	0.00%	11.16%	0.01%
Freeport-McMoRan Inc	FCX	1435.77413	39.22	56,311.06		1.53%		24.99%	
Expand Energy Corp	EXE	238.14568	106.24	25,300.60		5.52%			
Dexcom Inc	DXCM	392.15527	67.29	26,388.13				23.31%	
General Dynamics Corp	GD	268.99334	341	91,726.73	0.22%	1.76%	0.00%	14.95%	0.03%
General Mills Inc	GIS	533.41642	50.42	26,894.86		4.84%		-2.94%	
Genuine Parts Co	GPC	139.09229	138.6	19,278.19		2.97%			
Atmos Energy Corp	ATO	160.52357	170.75	27,409.40		2.04%			
WW Grainger Inc	GWW	47.83224	952.96	45,582.21	0.11%	0.95%	0.00%	4.41%	0.00%
Halliburton Co	HAL	852.6021	24.6	20,974.01		2.76%			
L3Harris Technologies Inc	LHX	187.0948	305.41	57,140.62	0.14%	1.57%	0.00%	12.88%	0.02%
Healthpeak Properties Inc	DOC	694.92345	19.15	13,307.78	0.03%	6.37%	0.00%	4.24%	0.00%
Insulet Corp	PODD	70.39253	308.73	21,732.29				25.99%	
Fortive Corp	FTV	338.33635	48.99	16,575.10		0.49%			
Hershey Co/The	HSY	148.11072	187.05	27,704.11		2.93%		-8.41%	
Synchrony Financial	SYF	372.05755	71.05	26,434.69	0.06%	1.69%	0.00%	16.89%	0.01%
Hormel Foods Corp	HRL	549.99843	24.74	13,606.96		4.69%			
Arthur J Gallagher & Co	AJG	256.4	309.74	79,417.34		0.84%			
Mondelez International Inc	MDLZ	1293.94541	62.47	80,832.77	0.20%	3.20%	0.01%	1.85%	0.00%
CenterPoint Energy Inc	CNP	652.7284	38.8	25,325.86	0.06%	2.27%	0.00%	8.98%	0.01%
Humana Inc	HUM	120.27182	260.17	31,291.12	0.08%	1.36%	0.00%	14.02%	0.01%
Willis Towers Watson PLC	WTW	97.54799	345.45	33,697.95	0.08%	1.07%	0.00%	7.47%	0.01%
Illinois Tool Works Inc	ITW	291.5	260.76	76,011.54	0.18%	2.47%	0.00%	1.93%	0.00%
CDW Corp/DE	CDW	131.06075	159.28	20,875.36	0.05%	1.57%	0.00%	6.38%	0.00%
Trane Technologies PLC	TT	222.51536	421.96	93,892.58	0.23%	0.89%	0.00%	11.32%	0.03%
Interpublic Group of Cos Inc/The	IPG	366.26639	27.91	10,222.49	0.02%	4.73%	0.00%	9.40%	0.00%
International Flavors & Fragrances Inc	IFF	256.28708	61.54	15,771.91	0.04%	2.60%	0.00%	2.12%	0.00%
Generac Holdings Inc	GNRC	58.67595	167.4	9,822.35				20.91%	
NXP Semiconductors NV	NXPI	252.1146	227.73	57,414.06	0.14%	1.78%	0.00%	5.71%	0.01%
Kellanova	K	347.6692	82.02	28,515.83	0.07%	2.83%	0.00%	1.79%	0.00%
Broadridge Financial Solutions Inc	BR	117.12932	238.17	27,896.69		1.64%			
Kimberly-Clark Corp	KMB	679.49863	21.85	14,847.05	0.04%	4.58%	0.00%	3.88%	0.00%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Kimco Realty Corp	KIM	2850.79261	281.24	801,756.91	1.95%	0.71%	0.01%	18.09%	0.35%
Oracle Corp	ORCL	662.67821	67.41	44,671.14	0.11%	2.08%	0.00%	6.37%	0.01%
Kroger Co/The	KR	227.60164	126.04	28,686.91		1.59%		-9.37%	
Lennar Corp	LEN	946.45676	763	722,146.51	1.76%	0.79%	0.01%	18.00%	0.32%
Eli Lilly & Co	LLY	136.59098	275.105	37,576.86	0.09%			10.93%	0.01%
Charter Communications Inc	CHTR	207.4264	100.39	20,823.54		0.25%			
Loews Corp	L	560.8249	251.31	140,940.91	0.34%	1.91%	0.01%	6.54%	0.02%
Lowe's Cos Inc	LOW	53.14001	430.31	22,866.68		1.23%			
Hubbell Inc	HUBB	75.28728	162.76	12,253.76		1.74%			
IDEX Corp	IEX	491.62404	201.53	99,076.99	0.24%	1.79%	0.00%	8.31%	0.02%
Marsh & McLennan Cos Inc	MMC	209.36364	70.39	14,737.11	0.04%	1.76%	0.00%	6.47%	0.00%
Masco Corp	MAS	312.5	486.71	152,096.88		0.79%			
S&P Global Inc	SPGI	1282.68588	95.24	122,163.00	0.30%	2.98%	0.01%	5.90%	0.02%
Medtronic PLC	MDT	1165.87213	9.9	11,542.13		4.85%		-2.32%	
Viatris Inc	VTRS	1268.32638	75.39	95,619.13	0.23%	3.53%	0.01%	6.43%	0.01%
CVS Health Corp	CVS	418.71669	77.9	32,618.03	0.08%	2.11%	0.00%	6.31%	0.01%
DuPont de Nemours Inc	DD	1119.1251	167.32	187,252.01		0.27%		28.55%	
Micron Technology Inc	MU	166.60389	457.29	76,186.29	0.19%	0.95%	0.00%	8.26%	0.02%
Motorola Solutions Inc	MSI	104.59013	245.25	25,650.73	0.06%	1.17%	0.00%	13.77%	0.01%
Cboe Global Markets Inc	CBOE	1098.44973	84.31	92,610.30	0.23%	1.19%	0.00%	16.41%	0.04%
Newmont Corp	NEM	1188.01574	69.73	82,840.34	0.20%	2.29%	0.00%	19.22%	0.04%
NIKE Inc	NKE	470.85501	43.3	20,388.02		2.59%			
NiSource Inc	NI	224.61489	300.41	67,476.56		1.80%			
Norfolk Southern Corp	NSC	222.76844	82.91	18,469.73	0.04%	3.76%	0.00%	12.73%	0.01%
Principal Financial Group Inc	PFG	371.11518	71.14	26,401.13	0.06%	4.23%	0.00%	4.40%	0.00%
Eversource Energy	ES	143.18298	609.32	87,244.25	0.21%	1.52%	0.00%	4.95%	0.01%
Northrop Grumman Corp	NOC	3203.44121	83.82	268,512.44	0.65%	2.15%	0.01%	14.00%	0.09%
Wells Fargo & Co	WFC	229.53545	135.43	31,085.99	0.08%	1.62%	0.00%	18.58%	0.01%
Nucor Corp	NUE	984.43974	47.25	46,514.78		2.03%			
Occidental Petroleum Corp	OXY	193.72289	81.53	15,794.23	0.04%	3.43%	0.00%	7.99%	0.00%
Omnicom Group Inc	OMC	629.75598	72.97	45,953.29	0.11%	5.65%	0.01%	8.97%	0.01%
ONEOK Inc	OKE	199.38398	172.1	34,313.98	0.08%	1.16%	0.00%	11.82%	0.01%
Raymond James Financial Inc	RJF	2197.8374	15.08	33,143.39	0.08%	0.66%	0.00%	8.91%	0.01%
PG&E Corp	PCG	126.54407	758.15	95,939.39	0.23%	0.95%	0.00%	7.61%	0.02%
Parker-Hannifin Corp	PH	484.64	58.74	28,467.75		1.12%			
Rollins Inc	ROL	739.51524	37.16	27,480.39	0.07%	2.93%	0.00%	7.34%	0.00%
PPL Corp	PPL	217.75981	86.22	18,775.25	0.05%			16.62%	0.01%
Aptiv PLC	APTV	1248.94231	94.59	118,137.45		3.30%			
ConocoPhillips	COP	197.29757	132.13	26,068.93		0.67%		-2.19%	
PulteGroup Inc	PHM	119.42724	89.66	10,707.85		3.99%			
Pinnacle West Capital Corp	PNW	393.80738	200.93	79,127.72	0.19%	3.38%	0.01%	10.42%	0.02%
PNC Financial Services Group Inc/The	PNC	225.7	105.11	23,723.33	0.06%	2.70%	0.00%	6.81%	0.00%
PPG Industries Inc	PPG	398.68051	271.99	108,437.11					
DoorDash Inc	DASH	586.20849	246.95	144,764.19		0.16%		50.71%	
Progressive Corp/The	PGR	248.16085	106.61	26,456.43		0.41%			
Veralto Corp	VLTO	499.07975	83.46	41,653.20	0.10%	3.02%	0.00%	8.76%	0.01%
Public Service Enterprise Group Inc	PEG	198.80892	68.56	13,630.34	0.03%			9.31%	0.00%
Cooper Cos Inc/The	COO	384.83401	55.28	21,273.62	0.05%	5.99%	0.00%	9.60%	0.00%
Edison International	EIX	1493.87884	34.37	51,344.62		3.32%		-4.18%	
Schlumberger NV	SLB	1815.2193	95.47	173,298.99	0.42%	1.13%	0.00%	19.98%	0.08%
Charles Schwab Corp/The	SCHW	249.33332	346.26	86,334.16	0.21%	0.91%	0.00%	6.92%	0.01%
Sherwin-Williams Co/The	SHW	71.90733	262.33	18,863.45	0.05%	0.34%	0.00%	8.04%	0.00%
West Pharmaceutical Services Inc	WST	106.68516	108.6	11,586.01	0.03%	4.05%	0.00%	1.56%	0.00%
J M Smucker Co/The	SJM	52.16337	346.53	18,076.17	0.04%	2.47%	0.00%	4.10%	0.00%
Snap-on Inc	SNA	230.95396	188	43,419.34	0.11%	0.66%	0.00%	9.13%	0.01%
AMETEK Inc	AME	2085.41868	97.97	204,308.47				-3.85%	
Uber Technologies Inc	UBER	1100.19364	94.77	104,265.35	0.25%	3.12%	0.01%	6.75%	0.02%
Southern Co/The	SO	1289.43517	45.72	58,952.98	0.14%	4.55%	0.01%	9.19%	0.01%
Truist Financial Corp	TFC	525.18771	31.91	16,758.74		2.26%		58.26%	
Southwest Airlines Co	LUV	379.29277	76.62	29,061.41	0.07%	0.47%	0.00%	6.85%	0.00%
W R Berkley Corp	WRB	154.79225	74.33	11,505.71		4.47%			
Stanley Black & Decker Inc	SWK	175.45285	288.85	50,679.56	0.12%	4.15%	0.01%	2.40%	0.00%
Public Storage	PSA	1256.86538	145.71	183,137.85	0.45%			18.74%	0.08%
Arista Networks Inc	ANET	478.21236	82.34	39,376.01		2.62%			
Sysco Corp	SYY	683.01458	67.63	46,192.28	0.11%	1.06%	0.00%	16.37%	0.02%
Corteva Inc	CTVA	909.13717	183.73	167,035.77	0.41%	3.09%	0.01%	11.04%	0.04%
Texas Instruments Inc	TXN	178.2053	84.49	15,056.57	0.04%	0.09%	0.00%	10.03%	0.00%
Textron Inc	TXT	377.61212	485.02	183,149.43	0.45%	0.35%	0.00%	7.56%	0.03%
Thermo Fisher Scientific Inc	TMO	1112.93875	144.54	160,864.17	0.39%	1.18%	0.00%	8.43%	0.03%
TJX Cos Inc/The	TJX	81.00354	142.97	11,581.08		0.76%			
Globe Life Inc	GL	654.38544	109.95	71,949.68	0.17%	1.46%	0.00%	15.92%	0.03%
Johnson Controls International plc	JCI	44.83836	546.75	24,515.37	0.06%			4.39%	0.00%
Ulta Beauty Inc	ULTA	593.04367	236.37	140,177.73	0.34%	2.34%	0.01%	7.79%	0.03%
Union Pacific Corp	UNP	171.85625	174.92	30,061.10	0.07%			12.93%	0.01%
Keysight Technologies Inc	KEYS	905.67363	345.3	312,729.10	0.76%	2.56%	0.02%	14.00%	0.11%
UnitedHealth Group Inc	UNH	737.09167	170.85	125,932.11		2.41%		24.34%	
Blackstone Inc	BX	454.47119	69.99	31,808.44	0.08%	2.74%	0.00%	9.69%	0.01%
Ventas Inc	VTR	83.1	287.06	23,854.69	0.06%	1.00%	0.00%	8.77%	0.01%
Labcorp Holdings Inc	LH	132.12416	307.62	40,644.03	0.10%	0.64%	0.00%	14.51%	0.01%
Vulcan Materials Co	VMC	721.511	24.79	17,886.26		3.39%		-8.95%	
Weyerhaeuser Co	WY	1221.17743	63.35	77,361.59		3.16%		22.27%	

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Williams Cos Inc/The	WMB	312.40558	329.07	102,803.30	0.25%	0.47%	0.00%	16.22%	0.04%
Constellation Energy Corp	CEG	307.63637	718.54	221,049.04				80.10%	
WEC Energy Group Inc	WEC	321.8664	114.59	36,882.67	0.09%	3.12%	0.00%	7.65%	0.01%
Adobe Inc	ADBE	418.6	352.75	147,661.15	0.36%			14.13%	0.05%
Vistra Corp	VST	338.82032	195.92	66,381.68	0.16%	0.46%	0.00%	10.35%	0.02%
AES Corp/The	AES	712.04956	13.16	9,370.57	0.02%	5.35%	0.00%	11.17%	0.00%
Expeditors International of Washington Inc	EXPD	135.71852	122.59	16,637.73	0.04%	1.26%	0.00%	4.89%	0.00%
Amgen Inc	AMGN	538.36185	282.2	151,925.71	0.37%	3.37%	0.01%	5.37%	0.02%
Apple Inc	AAPL	14840.39	254.63	3,778,808.51	9.19%	0.41%	0.04%	14.26%	1.31%
Autodesk Inc	ADSK	213	317.67	67,663.71	0.16%			15.08%	0.02%
Cintas Corp	CTAS	404.39145	205.26	83,005.39		0.88%			
Comcast Corp	CMCSA	3682.76213	31.09	114,497.07	0.28%	4.25%	0.01%	1.88%	0.01%
Molson Coors Beverage Co	TAP	185.38756	45.25	8,388.79	0.02%	4.15%	0.00%	0.78%	0.00%
KLA Corp	KLAC	131.68453	1078.6	142,034.93	0.35%	0.70%	0.00%	10.30%	0.04%
Marriott International Inc/MD	MAR	271.45784	260.44	70,698.48	0.17%	1.03%	0.00%	10.15%	0.02%
Fiserv Inc	FI	543.59318	128.93	70,085.47					
McCormick & Co Inc/MD	MKC	253.0412	66.91	16,930.99	0.04%	2.69%	0.00%	6.37%	0.00%
PACCAR Inc	PCAR	525.10339	98.32	51,628.17		1.34%		-3.95%	
Costco Wholesale Corp	COST	443.47709	925.63	410,495.70	1.00%	0.56%	0.01%	6.75%	0.07%
Stryker Corp	SYK	382.3073	369.67	141,327.54	0.34%	0.91%	0.00%	10.57%	0.04%
Tyson Foods Inc	TSN	285.76038	54.3	15,516.79	0.04%	3.68%	0.00%	18.82%	0.01%
Lamb Weston Holdings Inc	LW	139.35248	58.08	8,093.59		2.55%		-2.55%	
Applied Materials Inc	AMAT	796.64243	204.74	163,104.57	0.40%	0.90%	0.00%	7.67%	0.03%
Cardinal Health Inc	CAH	237.58268	156.4493	37,169.64	0.09%	1.31%	0.00%	13.03%	0.01%
Cincinnati Financial Corp	CINF	156.37642	158.1	24,723.11	0.06%	2.20%	0.00%	3.48%	0.00%
Paramount Global	PARA	298.12353	169.47	50,522.99	0.12%	0.94%	0.00%	0.38%	0.00%
DR Horton Inc	DHI	250.2073	201.7	50,466.81	0.12%	0.38%	0.00%	10.70%	0.01%
Electronic Arts Inc	EA	46.18907	318.16	14,695.51		1.72%			
Erie Indemnity Co	ERIE	24.00366	1496.53	35,922.20					
Fair Isaac Corp	FICO	1147.63662	49.04	56,280.10	0.14%	1.79%	0.00%	11.06%	0.02%
Fastenal Co	FAST	156.26929	197.62	30,881.94	0.08%	3.04%	0.00%	12.35%	0.01%
M&T Bank Corp	MTB	591.42618	80.65	47,698.52	0.12%	2.83%	0.00%	8.88%	0.01%
Xcel Energy Inc	XEL	661.88724	44.55	29,487.08		3.59%			
Fifth Third Bancorp	FITB	1240.80692	111	137,729.57		2.85%		29.15%	
Gilead Sciences Inc	GILD	140.23254	75.85	10,636.64	0.03%	3.69%	0.00%	15.87%	0.00%
Hasbro Inc	HAS	1458.80004	17.27	25,193.48	0.06%	3.59%	0.00%	14.17%	0.01%
Huntington Bancshares Inc/OH	HBAN	668.82594	178.14	119,144.65	0.29%	1.66%	0.00%	17.51%	0.05%
Welltower Inc	WELL	146.6146	140.08	20,537.77	0.05%			0.90%	0.00%
Biogen Inc	BIIB	191.2333	134.6	25,740.00	0.06%	2.38%	0.00%	9.85%	0.01%
Northern Trust Corp	NTRS	89.97878	217.93	19,609.08	0.05%	2.29%	0.00%	11.26%	0.01%
Packaging Corp of America	PKG	359.89414	126.76	45,620.18		3.41%			
Paychex Inc	PAYX	1079	166.36	179,502.44	0.44%	2.14%	0.01%	7.74%	0.03%
QUALCOMM Inc	QCOM	325.22627	152.39	49,561.23	0.12%	1.06%	0.00%	5.82%	0.01%
Ross Stores Inc	ROST	80.00469	638.89	51,114.20	0.12%			13.50%	0.02%
IDEXX Laboratories Inc	IDXX	1136.7	84.6	96,164.82		2.88%		-0.30%	
Starbucks Corp	SBUX	1096.51584	18.69	20,493.88	0.05%	4.39%	0.00%	19.79%	0.01%
KeyCorp	KEY	210.51946	63.06	13,275.36		0.89%		-1.49%	
Fox Corp	FOXA	235.58103	57.29	13,496.44		0.98%		-1.49%	
Fox Corp	FOX	283.69534	115.17	32,673.19	0.08%	2.92%	0.00%	12.69%	0.01%
State Street Corp	STT	455.25095	24.63	11,212.83	0.03%			16.72%	0.00%
Norwegian Cruise Line Holdings Ltd	NCLH	1556.18945	48.33	75,210.64	0.18%	4.30%	0.01%	9.63%	0.02%
US Bancorp	USB	114.25952	73.41	8,387.79		1.85%			
A O Smith Corp	AOS	615.86911	28.39	17,484.52	0.04%	1.76%	0.00%	13.08%	0.01%
Gen Digital Inc	GEN	219.71524	102.64	22,551.57		4.95%		-0.94%	
T Rowe Price Group Inc	TROW	402.83032	220.83	88,957.02	0.22%	1.49%	0.00%	11.23%	0.02%
Waste Management Inc	WM	176.26624	134.67	23,737.77		3.03%		-2.05%	
Constellation Brands Inc	STZ	445.96377	22.94	10,230.41	0.02%	3.66%	0.00%	14.17%	0.00%
Invesco Ltd	IVZ	278.805	682.91	190,398.72		0.70%			
Intuit Inc	INTU	1596.33576	158.96	253,753.53	0.62%	2.52%	0.02%	10.15%	0.06%
Morgan Stanley	MS	539.67967	64.22	34,658.23		2.83%		29.58%	
Microchip Technology Inc	MCHP	250.95514	490.38	123,063.38	0.30%			17.74%	0.05%
Crowdstrike Holdings Inc	CRWD	398.69029	282.25	112,530.33	0.27%	1.37%	0.00%	4.11%	0.01%
Chubb Ltd	CB	222.41928	67.49	15,011.08	0.04%			7.67%	0.00%
Hologic Inc	HOLX	431.34899	53.16	22,930.51		3.16%		24.02%	
Citizens Financial Group Inc	CFG	107.31884	217.17	23,306.43	0.06%	0.15%	0.00%	13.93%	0.01%
Jabil Inc	JBL	848.49668	107.81	91,476.43	0.22%			10.54%	0.02%
O'Reilly Automotive Inc	ORLY	263.50533	214.65	56,561.42		1.86%		20.50%	
Allstate Corp/The	ALL	381.89806	64.73	24,720.26	0.06%	4.28%	0.00%	3.64%	0.00%
Equity Residential	EQR	1358.43528	25.51	34,653.68	0.08%	3.61%	0.00%	6.51%	0.01%
Keurig Dr Pepper Inc	KDP	687.54288	17.02	11,701.98		4.70%		-0.96%	
Host Hotels & Resorts Inc	HST	195.27615	84.81	16,561.37				25.00%	
Incyte Corp	INCY	326.48476	187.67	61,271.39	0.15%	4.58%	0.01%	1.32%	0.00%
Simon Property Group Inc	SPG	114.83241	63.05	7,240.18		5.27%			
Eastman Chemical Co	EMN	142.38302	193.17	27,504.13	0.07%	3.62%	0.00%	5.18%	0.00%
AvalonBay Communities Inc	AVB	352	103.74	36,516.48	0.09%	5.21%	0.00%	8.23%	0.01%
Prudential Financial Inc	PRU	736.0429	83.53	61,481.66		7.85%		-0.74%	
United Parcel Service Inc	UPS	98.49061	247.44	24,370.52		1.02%			
Walgreens Boots Alliance Inc	WBA	124.38439	772.54	96,091.92	0.23%	0.42%	0.00%	13.50%	0.03%
STERIS PLC	STE	233.46506	499.21	116,548.09	0.28%	2.64%	0.01%	11.53%	0.03%
McKesson Corp	MCK	193.87788	312.53	60,592.65	0.15%	0.70%	0.00%	10.33%	0.02%
Lockheed Martin Corp	LMT	639.51731	212.58	135,948.59		1.13%		22.86%	

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Cencora Inc	COR	297.99253	31.58	9,410.60		4.94%		-2.52%	
Capital One Financial Corp	COF	59.52413	299.81	17,845.93	0.04%			9.42%	0.00%
The Campbell's Company	CPB	56.1863	226.95	12,751.48		1.45%			
Waters Corp	WAT	203.96784	94.37	19,248.45	0.05%			9.96%	0.00%
Nordson Corp	NDSN	116.31376	190.36	22,141.49	0.05%	3.15%	0.00%	10.59%	0.01%
Dollar Tree Inc	DLTR	229.74594	76.02	17,465.29	0.04%	3.51%	0.00%	5.78%	0.00%
Darden Restaurants Inc	DRI	240.62215	35.32	8,498.77	0.02%	2.15%	0.00%	16.37%	0.00%
Evergy Inc	EVRG	2.8698	8034.66	23,057.87	0.06%			1.72%	0.00%
Match Group Inc	MTCH	199.61839	118.46	23,646.79	0.06%	1.76%	0.00%	7.34%	0.00%
NVR Inc	NVR	210.16814	140.78	29,587.47	0.07%	0.80%	0.00%	5.03%	0.00%
NetApp Inc	NTAP	71.5	132.87	9,500.21	0.02%			10.59%	0.00%
Old Dominion Freight Line Inc	ODFL	281.17166	133.39	37,505.49	0.09%	1.56%	0.00%	8.89%	0.01%
DaVita Inc	DVA	295.34823	101.94	30,107.80		3.08%			
Hartford Insurance Group Inc/The	HIG	234.81506	88.12	20,691.90		1.59%			
Iron Mountain Inc	IRM	272.49	351.26	95,714.84	0.23%			14.66%	0.03%
Estee Lauder Cos Inc/The	EL	43.26181	523.16	22,632.85					
Cadence Design Systems Inc	CDNS	56.38801	204.44	11,527.96	0.03%	0.39%	0.00%	10.17%	0.00%
Tyler Technologies Inc	TYL	148.42757	76.98	11,425.95		3.69%		-9.02%	
Universal Health Services Inc	UHS	111.82344	190.58	21,311.31	0.05%	1.68%	0.00%	1.06%	0.00%
Skyworks Solutions Inc	SWKS	112.4344	349.53	39,299.20	0.10%	1.50%	0.00%	14.56%	0.01%
Quest Diagnostics Inc	DGX	1183.59922	26.04	30,820.92		6.14%		-4.68%	
Rockwell Automation Inc	ROK	468.25123	192.32	90,054.08		3.54%		23.73%	
Kraft Heinz Co/The	KHC	104.1703	562.27	58,571.83	0.14%	0.63%	0.00%	8.03%	0.01%
American Tower Corp	AMT	10664.9121	219.57	2,341,694.75	5.69%			16.62%	0.95%
Regeneron Pharmaceuticals Inc	REGN	72.6652	148.93	10,822.03		1.56%			
Amazon.com Inc	AMZN	38.69301	313.56	12,132.58	0.03%	1.16%	0.00%	13.40%	0.00%
Jack Henry & Associates Inc	JKHY	158.37552	74.34	11,773.64	0.03%	3.77%	0.00%	1.39%	0.00%
Ralph Lauren Corp	RL	1220.92111	123.75	151,088.99		0.53%		26.21%	
BXP Inc	BXP	403.12632	196.23	79,105.48	0.19%	0.24%	0.00%	17.38%	0.03%
Amphenol Corp	APH	310.65174	170.26	52,891.57	0.13%	2.65%	0.00%	17.29%	0.02%
Howmet Aerospace Inc	HWM	185.74867	493.39	91,646.54	0.22%			9.76%	0.02%
Valero Energy Corp	VLO	118.09116	132.4	15,635.27	0.04%	1.87%	0.00%	15.51%	0.01%
Synopsys Inc	SNPS	622.8527	246.6	153,595.48		2.64%			
CH Robinson Worldwide Inc	CHRW	56.35029	1318.02	74,270.81	0.18%			12.86%	0.02%
Accenture PLC	ACN	277.5357	152	42,185.43	0.10%	1.87%	0.00%	9.48%	0.01%
TransDigm Group Inc	TDG	926.175	114.52	106,065.56	0.26%	3.53%	0.01%	5.72%	0.01%
Yum! Brands Inc	YUM	577.12618	45.82	26,443.92		3.88%		-4.30%	
Prologis Inc	PLD	93.4	279.57	26,111.84		1.10%			
FirstEnergy Corp	FE	149.00594	414.3201	61,736.16	0.15%	0.10%	0.00%	14.67%	0.02%
VeriSign Inc	VRSN	121.2684	66.37	8,048.58	0.02%			4.67%	0.00%
Quanta Services Inc	PWR	270.40992	104.38	28,225.39	0.07%	2.72%	0.00%	8.89%	0.01%
Henry Schein Inc	HSIC	37.80677	286.49	10,831.26		1.54%			
Ameren Corp	AEE	24300	186.58	4,533,894.00		0.02%		39.00%	
ANSYS Inc	ANSS	488.39594	67.07	32,756.72		1.85%			
FactSet Research Systems Inc	FDS	358.47651	447.23	160,321.45	0.39%			15.50%	0.06%
NVIDIA Corp	NVDA	184.47021	258.36	47,659.72				58.37%	
Cognizant Technology Solutions Corp	CTSH	312.21582	229.48	71,647.29	0.17%	1.09%	0.00%	9.49%	0.02%
Intuitive Surgical Inc	ISRG	457	90.95	41,564.15	0.10%	1.28%	0.00%	10.81%	0.01%
Take-Two Interactive Software Inc	TTWO	302.72109	796.35	241,071.94	0.59%	2.01%	0.01%	13.64%	0.08%
Republic Services Inc	RSG	107.37901	193.35	20,761.73	0.05%	2.30%	0.00%	8.73%	0.00%
eBay Inc	EBAY	652.47246	89.335	58,288.63		2.89%			
Goldman Sachs Group Inc/The	GS	179	476.48	85,289.92		0.79%			
SBA Communications Corp	SBAC	408.97399	49.31	20,166.51				-3.65%	
Sempra	SRE	32.40989	5399.27	174,989.75	0.43%	0.71%	0.00%	16.74%	0.07%
Moody's Corp	MCO	57.44717	323.19	18,566.35	0.05%			7.13%	0.00%
ON Semiconductor Corp	ON	143.38553	75.76	10,862.89	0.03%			4.90%	0.00%
Booking Holdings Inc	BKNG	49.21418	156.46	7,700.05	0.02%			3.67%	0.00%
F5 Inc	FFIV	634.8	35.06	22,256.09	0.05%	2.74%	0.00%	4.26%	0.00%
Akamai Technologies Inc	AKAM	155.69102	55.63	8,661.09		0.58%			
Charles River Laboratories International Inc	CRL	5817	243.1	1,414,112.70	3.44%	0.35%	0.01%	12.93%	0.44%
MarketAxess Holdings Inc	MKTX	85.84652	177.35	15,224.88	0.04%	1.15%	0.00%	5.69%	0.00%
Devon Energy Corp	DVN	424.92635	1198.92	509,452.70				26.62%	
Bio-Techne Corp	TECH	2475.77228	19.53	48,351.83				40.59%	
Alphabet Inc	GOOGL	283.50043	128.35	36,387.28	0.09%	0.77%	0.00%	7.99%	0.01%
Allegion plc	ALLE	237.96909	81.65	19,430.18					
Netflix Inc	NFLX	225.1783	323.12	72,759.61		2.12%		-0.92%	
Agilent Technologies Inc	A	360.37704	270.19	97,370.27	0.24%	1.85%	0.00%	5.71%	0.01%
Warner Bros Discovery Inc	WBD	207.51775	141.43	29,349.24	0.07%	3.08%	0.00%	6.37%	0.00%
Trimble Inc	TRMB	573.79524	88.45	50,752.19	0.12%	1.22%	0.00%	15.63%	0.02%
Elevance Health Inc	ELV	1556.58934	162.2	252,478.79	0.61%	3.63%	0.02%	11.27%	0.07%
CME Group Inc	CME	952	237	225,624.00	0.55%	0.70%	0.00%	12.74%	0.07%
Juniper Networks Inc	JNPR	397.45252	82.62	32,837.53		0.10%			
DTE Energy Co	DTE	39.24063	287.91	11,297.77	0.03%	1.88%	0.00%	14.49%	0.00%
Nasdaq Inc	NDAQ	107.61382	498.69	53,665.94		0.66%			
Philip Morris International Inc	PM	665.02605	82.37	54,778.20	0.13%	2.76%	0.00%	12.81%	0.02%
Ingersoll Rand Inc	IR	209.06857	113.22	23,670.74	0.06%	1.41%	0.00%	7.22%	0.00%
Salesforce Inc	CRM	1864.27701	35.51	66,200.48	0.16%	1.46%	0.00%	6.33%	0.01%
Roper Technologies Inc	ROP	587.1	77.77	45,658.77	0.11%			8.64%	0.01%
Huntington Ingalls Industries Inc	HII	94.27157	491.25	46,310.91	0.11%	1.30%	0.00%	10.55%	0.01%
MetLife Inc	MET	50.84515	297.16	15,109.14					
Tapestry Inc	TPR	198.09598	98.5	19,512.45	0.05%	0.97%	0.00%	4.65%	0.00%

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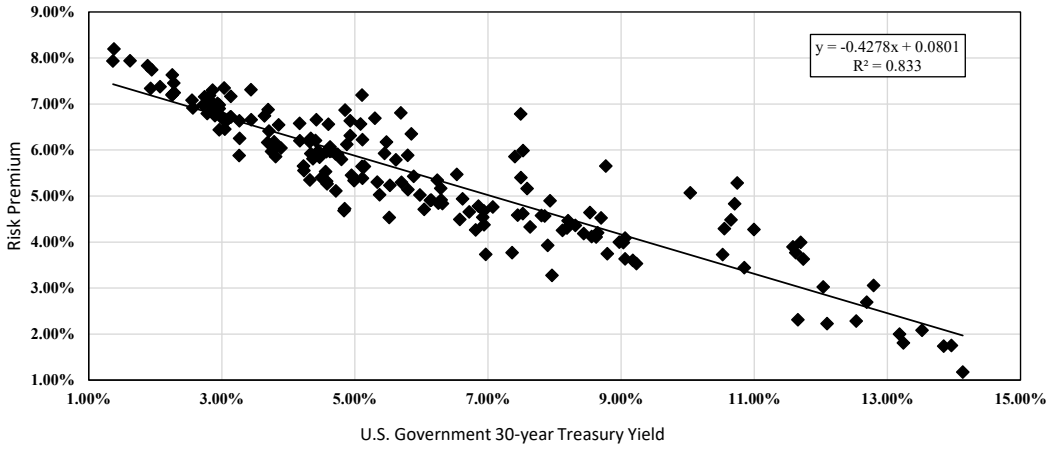
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
CSX Corp	CSX	297.55433	157.56	46,882.66					
Edwards Lifesciences Corp	EW	106.85273	106.78	11,409.73	0.03%	3.93%	0.00%	1.63%	0.00%
Ameriprise Financial Inc	AMP	897.27417	568.81	510,378.52	1.24%	0.53%	0.01%	15.34%	0.19%
Zebra Technologies Corp	ZBRA	323.2707	142.4	46,033.75	0.11%			8.38%	0.01%
Zimmer Biomet Holdings Inc	ZBH	146.84504	44.87	6,588.94	0.02%			15.69%	0.00%
Camden Property Trust	CPT	572.42309	168.48	96,441.84	0.23%	1.14%	0.00%	14.37%	0.03%
CBRE Group Inc	CBRE	522.14418	42.57	22,227.68		4.05%		72.38%	
Mastercard Inc	MA	522.37858	65.94	34,445.64		2.43%			
CarMax Inc	KMX	1340.885	39.19	52,549.28	0.13%			15.60%	0.02%
Intercontinental Exchange Inc	ICE	103.97653	128.27	13,337.07	0.03%	0.78%	0.00%	4.22%	0.00%
Fidelity National Information Services Inc	FIS	234.47273	163.4	38,312.84					
Smurfit WestRock PLC	SW	50.45921	216.6	10,929.46		1.48%			
Chipotle Mexican Grill Inc	CMG	193.4308	161.95	31,326.12		1.09%			
Wynn Resorts Ltd	WYNN	892.30835	26.37	23,530.17	0.06%	4.02%	0.00%	7.96%	0.00%
Live Nation Entertainment Inc	LYV	976.42819	67.31	65,723.38	0.16%			14.71%	0.02%
Assurant Inc	AIZ	317.37833	34.68	11,006.68	0.03%	2.54%	0.00%	3.57%	0.00%
NRG Energy Inc	NRG	985.87912	48.72	48,032.03	0.12%	1.89%	0.00%	9.16%	0.01%
Monster Beverage Corp	MNST	118.19213	213.75	25,263.57	0.06%	0.75%	0.00%	18.12%	0.01%
Regions Financial Corp	RF	331.77994	124.34	41,253.52	0.10%	4.05%	0.00%	1.97%	0.00%
Baker Hughes Co	BKR	161.97296	89.7	14,528.97		2.23%		-4.53%	
Mosaic Co/The	MOS	128.29733	188.96	24,243.06	0.06%	0.85%	0.00%	9.35%	0.01%
Expedia Group Inc	EXPE	357.78646	24.28	8,687.06		4.12%			
CF Industries Holdings Inc	CF	82.13689	201.96	16,588.37		1.51%		93.41%	
APA Corp	APA	5430	243.55	1,322,476.50	3.21%	0.34%	0.01%	12.93%	0.42%
Leidos Holdings Inc	LDOS	107.24765	220.53	23,651.32				37.61%	
Alphabet Inc	GOOG	1698.68253	341.38	579,896.24	1.41%	0.69%	0.01%	13.36%	0.19%
TKO Group Holdings Inc	TKO	117.07114	139.73	16,358.35	0.04%	4.34%	0.00%	1.55%	0.00%
First Solar Inc	FSLR	243.40969	147.5	35,902.93		1.08%			
Discover Financial Services	DFS	304.02031	192.74	58,596.87	0.14%	1.89%	0.00%	7.16%	0.01%
Visa Inc	V	1622.84369	161.79	262,559.88				31.34%	
Mid-America Apartment Communities Inc	MAA	529.95167	56.87	30,138.35	0.07%	1.62%	0.00%	9.79%	0.01%
Xylem Inc/NY	XYL	146.41484	273.73	40,078.13	0.10%	0.88%	0.00%	9.57%	0.01%
Marathon Petroleum Corp	MPC	20.59904	1227.61	25,287.59	0.06%			7.93%	0.00%
Tractor Supply Co	TSCO	119.53647	149.86	17,913.74	0.04%	0.85%	0.00%	13.35%	0.01%
Advanced Micro Devices Inc	AMD	967.73153	44.97	43,518.89					
ResMed Inc	RMD	1066.36978	32.61	34,774.32	0.08%	5.52%	0.00%	4.24%	0.00%
Mettler-Toledo International Inc	MTD	766.26603	84.08	64,427.65	0.16%			10.99%	0.02%
VICI Properties Inc	VICI	117.68293	81.08	9,541.73		2.00%		83.68%	
Copart Inc	CPRT	389.07976	25.83	10,049.93	0.02%			18.60%	0.00%
Jacobs Solutions Inc	J	64.40402	267.66	17,238.38	0.04%	3.84%	0.00%	2.46%	0.00%
Albemarle Corp	ALB	423.65036	84.37	35,743.38				40.81%	
Fortinet Inc	FTNT	914.30609	60.5205	55,334.26	0.13%	5.34%	0.01%	3.14%	0.00%
Moderna Inc	MRNA	2274.26158	182.42	414,870.80				40.62%	
Essex Property Trust Inc	ESS	170.95318	200.47	34,270.98	0.08%	0.50%	0.00%	14.51%	0.01%
CoStar Group Inc	CSGP	37.31801	310.07	11,571.20	0.03%	1.61%	0.00%	5.27%	0.00%
Realty Income Corp	O	346.92213	120.06	41,651.47	0.10%	0.33%	0.00%	19.43%	0.02%
Westinghouse Air Brake Technologies Corp	WAB	1369.0772	140.44	192,273.20	0.47%	4.05%	0.02%	3.51%	0.02%
Palantir Technologies Inc	PLTR	295.48149	219.53	64,867.05	0.16%	1.29%	0.00%	10.89%	0.02%
Pool Corp	POOL	289.48612	143.1	41,425.46		2.80%			
Western Digital Corp	WDC	668.9	203.62	136,201.42	0.33%			11.82%	0.04%
PepsiCo Inc	PEP	208	920.28	191,418.24					
TE Connectivity PLC	TEL	243.6087	87.63	21,347.43	0.05%	1.35%	0.00%	6.71%	0.00%
Diamondback Energy Inc	FANG	86.26612	100.18	8,642.14	0.02%	4.51%	0.00%	4.15%	0.00%
Palo Alto Networks Inc	PANW	272.19104	34.66	9,434.14	0.02%			9.69%	0.00%
ServiceNow Inc	NOW	534.79476	112.5	60,164.41	0.15%	3.31%	0.00%	5.30%	0.01%
Church & Dwight Co Inc	CHD	613.00822	29.33	17,979.53	0.04%	3.95%	0.00%	3.59%	0.00%
Federal Realty Investment Trust	FRT	119.7927	203.02	24,320.31				21.45%	
MGM Resorts International	MGM	96.79928	134.17	12,987.56	0.03%	1.31%	0.00%	13.09%	0.00%
American Electric Power Co Inc	AEP	1261.0323	133.9	168,852.22	0.41%	0.78%	0.00%	14.44%	0.06%
Invitation Homes Inc	INVH	62.13191	128.92	8,010.05	0.02%			4.49%	0.00%
PTC Inc	PTC	163.93126	110.76	18,157.03	0.04%	0.90%	0.00%	9.47%	0.00%
JB Hunt Transport Services Inc	JBHT	456.56204	75.1	34,287.81	0.08%	0.19%	0.00%	6.34%	0.01%
Lam Research Corp	LRCX	256.39065	391.64	100,412.83					
Mohawk Industries Inc	MHK	2308.35994	8.18	18,882.38	0.05%	6.23%	0.00%	8.74%	0.00%
GE HealthCare Technologies Inc	GEHC	2168.96248	734.38	1,592,842.67	3.87%	0.29%	0.01%	16.81%	0.65%
Pentair PLC	PNR	1125.41904	239.38	269,402.81		1.70%			
Vertex Pharmaceuticals Inc	VRTX	64.34122	954.66	61,423.99	0.15%	0.75%	0.00%	7.70%	0.01%
Amcor PLC	AMCR	634.89656	210.5	133,645.73	0.32%	2.26%	0.01%	8.09%	0.03%
Meta Platforms Inc	META	172.95895	83.34	14,414.40		6.34%		-1.68%	
T-Mobile US Inc	TMUS	773.96367	143.18	110,816.12	0.27%			14.47%	0.04%
United Rentals Inc	URI	652.9484	56.75	37,054.82	0.09%	1.32%	0.00%	4.60%	0.00%
Alexandria Real Estate Equities Inc	ARE	212.96828	236.06	50,273.29		1.22%		23.91%	
Honeywell International Inc	HON	327.70387	96.5	31,623.42	0.08%			7.43%	0.01%
Delta Air Lines Inc	DAL	188.0312	34.55	6,496.48		0.58%			
United Airlines Holdings Inc	UAL	491.133	35.68	17,523.63				-21.26%	
Seagate Technology Holdings PLC	STX	549.574	72.27	39,717.71				34.36%	
News Corp	NWS	60.306	630.28	38,009.67		0.53%		-9.33%	
Centene Corp	CNC	575.38125	133.27	76,681.06	0.19%	1.53%	0.00%	12.27%	0.02%
Apollo Global Management Inc	APO	159.07353	137.64	21,894.88	0.05%	0.35%	0.00%	15.18%	0.01%
Martin Marietta Materials Inc	MLM	955.37841	67.06	64,067.68	0.16%			12.38%	0.02%
Teradyne Inc	TER	3325.15089	444.72	1,478,761.10					

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
PayPal Holdings Inc	PYPL	154.85334	1165.87	180,538.86	0.44%	1.79%	0.01%	12.40%	0.05%
Tesla Inc	TSLA	373.2203	90.73	33,862.28	0.08%			2.01%	0.00%
Blackrock Inc	BLK	890.94873	129.95	115,778.79		0.57%			
KKR & Co Inc	KKR	705.76446	22.93	16,183.18	0.04%	6.11%	0.00%	3.37%	0.00%
Arch Capital Group Ltd	ACGL	41.94329	350.23	14,689.80		2.28%		29.71%	
Dow Inc	DOW	46.8885	586.04	27,478.54	0.07%			10.05%	0.01%
Everest Group Ltd	EG	272.22394	614.9	167,390.50		0.16%			
Teledyne Technologies Inc	TDY	33.94892	431.71	14,656.09	0.04%	1.61%	0.00%	9.94%	0.00%
Domino's Pizza Inc	DPZ	376.77633	30.71	11,570.80		0.65%			
GE Vernova Inc	GEV	1009.53563	45.01	45,439.20	0.11%	3.55%	0.00%	7.22%	0.01%
News Corp	NWSA	242.60711	83.08	20,155.80		1.20%			
Exelon Corp	EXC	435.47006	96.49	42,018.51		4.40%		32.78%	
Global Payments Inc	GPN	72.48637	125.22	9,076.74	0.02%			10.93%	0.00%
Crown Castle Inc	CCI	1919.06992	16.23	31,146.50		5.11%		32.40%	
Align Technology Inc	ALGN	215.19185	167.54	36,053.24		2.39%		21.00%	
Kenvue Inc	KVUE	200.06202	81.25	16,255.04	0.04%	3.45%	0.00%	2.09%	0.00%
Targa Resources Corp	TRGP	148.34336	101.37	15,037.57	0.04%			4.14%	0.00%
Bunge Global SA	BG	257.29319	30.54	7,857.73		3.93%			
LKQ Corp	LKQ	217	240.73	52,238.41					
Deckers Outdoor Corp	DECK	443.18347	146.32	64,846.61	0.16%	1.37%	0.00%	8.70%	0.01%
Workday Inc	WDAY	1064.65341	18.92	20,143.24		1.06%			
Zoetis Inc	ZTS	226.15913	337.49	76,326.44				-3.18%	
Equinix Inc	EQIX	341.05044	172.88	58,960.80	0.14%	2.82%	0.00%	6.48%	0.01%
Digital Realty Trust Inc	DLR	97.86399	783.24	76,650.99		2.40%		32.66%	
Molina Healthcare Inc	MOH	686.45361	53.79	36,924.34	0.09%	1.86%	0.00%	8.34%	0.01%
Las Vegas Sands Corp	LVS	54.2	191.36	10,371.71				-9.17%	

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional as of September 30, 2025
[5] Bloomberg Professional as of September 30, 2025
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of September 30, 2025
[9] Equals [7] x [8]
[10] Value Line, as of September 30, 2025
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9126763
R Square	0.8329780
Adjusted R Square	0.8320552
Standard Error	0.0058114
Observations	183

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03049	0.03049	902.68968	0.00000
Residual	181	0.00611	0.00003		
Total	182	0.03660			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0801	0.00	83.53	0.0000	0.0783	0.0820	0.0783	0.0820
U.S. Govt. 30-year Treasury	(0.4278)	0.01	(30.04)	0.0000	(0.4558)	(0.3997)	(0.4558)	(0.3997)

	[7] U.S. Govt. 30-year Treasury [7]	[8] Risk Premium [8]	[9] ROE [9]
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.79%	5.97%	10.76%
Blue Chip Near-Term Projected Forecast (Q1 2026 - Q1 2027) [5]	4.62%	6.04%	10.66%
Blue Chip Long-Term Projected Forecast (2027-2031) [6]	4.40%	6.13%	10.53%
AVERAGE			10.65%

Notes:
[1] Source: Regulatory Research Associates, rate cases through September 30, 2025
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: S&P Capital IQ Pro, 30-day average as of September 30, 2025
[5] Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.080145 + (-0.427757 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1980.1	13.97%	11.66%	2.31%
1980.2	14.25%	10.52%	3.73%
1980.3	14.30%	10.85%	3.45%
1980.4	14.32%	12.10%	2.23%
1981.1	14.82%	12.53%	2.28%
1981.2	15.05%	13.24%	1.81%
1981.3	15.31%	14.13%	1.17%
1981.4	15.59%	13.85%	1.74%
1982.1	15.71%	13.96%	1.75%
1982.2	15.60%	13.52%	2.08%
1982.3	15.85%	12.79%	3.06%
1982.4	16.03%	10.75%	5.28%
1983.1	15.54%	10.71%	4.83%
1983.2	15.13%	10.65%	4.48%
1983.3	15.39%	11.62%	3.77%
1983.4	15.37%	11.74%	3.63%
1984.1	15.06%	12.04%	3.02%
1984.2	15.18%	13.18%	2.00%
1984.3	15.38%	12.69%	2.69%
1984.4	15.69%	11.70%	3.99%
1985.1	15.48%	11.58%	3.90%
1985.2	15.27%	11.00%	4.27%
1985.3	14.84%	10.55%	4.29%
1985.4	15.11%	10.04%	5.07%
1986.1	14.42%	8.77%	5.65%
1986.2	14.27%	7.49%	6.78%
1986.3	13.26%	7.40%	5.86%
1986.4	13.52%	7.53%	5.99%
1987.1	12.90%	7.49%	5.40%
1987.2	13.17%	8.53%	4.64%
1987.3	13.14%	9.06%	4.08%
1987.4	12.76%	9.23%	3.53%
1988.1	12.74%	8.63%	4.11%
1988.2	12.70%	9.06%	3.63%
1988.3	12.78%	9.18%	3.60%
1988.4	12.97%	8.97%	4.00%
1989.1	13.02%	9.04%	3.99%
1989.2	13.22%	8.70%	4.52%
1989.3	12.38%	8.12%	4.26%
1989.4	12.83%	7.93%	4.90%
1990.1	12.62%	8.44%	4.19%
1990.2	12.85%	8.65%	4.20%
1990.3	12.54%	8.79%	3.75%
1990.4	12.68%	8.56%	4.12%
1991.1	12.66%	8.20%	4.46%
1991.2	12.67%	8.31%	4.36%
1991.3	12.49%	8.19%	4.30%
1991.4	12.42%	7.85%	4.57%
1992.1	12.38%	7.81%	4.58%
1992.2	11.83%	7.90%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.76%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.32%	4.84%
1993.4	11.04%	6.14%	4.91%
1994.1	11.07%	6.58%	4.49%
1994.2	11.13%	7.36%	3.77%
1994.3	12.75%	7.59%	5.16%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.72%	4.65%
1995.4	11.58%	6.24%	5.35%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.97%	3.73%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.82%	4.26%
1997.2	11.62%	6.94%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.15%	4.91%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.48%	6.17%
1998.4	12.30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.80%	5.14%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%
2000.1	11.21%	6.30%	4.92%
2000.2	11.00%	5.98%	5.02%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.45%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.53%	5.23%
2001.4	11.99%	5.30%	6.69%
2002.1	10.05%	5.52%	4.53%
2002.2	11.41%	5.62%	5.79%
2002.3	11.65%	5.09%	6.56%
2002.4	11.57%	4.93%	6.63%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.34%	5.30%
2004.3	10.75%	5.11%	5.64%
2004.4	11.24%	4.93%	6.31%
2005.1	10.63%	4.71%	5.92%
2005.2	10.31%	4.47%	5.84%
2005.3	11.08%	4.42%	6.66%
2005.4	10.63%	4.65%	5.98%
2006.1	10.70%	4.63%	6.07%
2006.2	10.79%	5.14%	5.64%
2006.3	10.35%	5.00%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.79%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.96%
2008.3	10.43%	4.45%	5.98%
2008.4	10.39%	3.64%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.25%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.37%	5.81%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.20%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.70%	6.88%
2011.4	10.39%	3.04%	7.35%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.94%	7.01%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.16%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.27%	6.63%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.05%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.70%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.25%
2019.4	9.89%	2.26%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.19%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.26%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.69%	1.95%	7.74%
2022.1	9.45%	2.25%	7.20%
2022.2	9.50%	3.05%	6.45%
2022.3	9.14%	3.26%	5.88%
2022.4	9.94%	3.89%	6.04%
2023.1	9.72%	3.75%	5.97%
2023.2	9.67%	3.81%	5.86%
2023.3	9.79%	4.23%	5.55%
2023.4	9.85%	4.58%	5.27%
2024.1	9.67%	4.32%	5.35%
2024.2	9.90%	4.58%	5.32%
2024.3	9.88%	4.23%	5.65%
2024.4	9.90%	4.50%	5.40%
2025.1	9.83%	4.72%	5.11%
2025.2	9.52%	4.84%	4.68%
2025.3	9.57%	4.85%	4.73%
AVERAGE	11.46%	6.03%	5.44%
MEDIAN	11.00%	5.11%	5.55%

Mr. Megginson Constant Growth DCF
As Filed

Company	Ticker	Annualized Dividend	Closing Monthly Stock Price				Dividend Yield	Expected Dividend Yield	Projected EPS Growth Rates			Cost of Equity
			Jun-25	Jul-25	Aug-25	Average			Value Line	Zacks	Average	
Alliant Energy	LNT	$2.03	$60.47	$65.01	$64.62	$63.37	3.20%	3.30%	6.00%	6.59%	6.30%	9.60%
Ameren	AEE	$2.84	$96.04	$101.13	$100.56	$99.24	2.86%	2.96%	6.50%	7.86%	7.18%	10.14%
DTE Energy	DTE	$4.36	$132.46	$138.41	$138.92	$136.60	3.19%	3.28%	4.50%	6.98%	5.74%	9.02%
Evergy	EVRG	$2.67	$68.93	$70.80	$71.95	$70.56	3.78%	3.91%	7.50%	5.73%	6.62%	10.52%
OGE Energy	OGE	$1.68	$44.38	$45.42	$45.09	$44.96	3.74%	3.86%	6.50%	6.32%	6.41%	10.27%
Pinnacle West	PNW	$3.58	$89.47	$90.62	$91.34	$90.48	3.96%	4.03%	5.00%	2.12%	3.56%	7.59%
Portland General Electric	POR	$2.10	$40.63	$41.12	$42.46	$41.40	5.07%	5.20%	6.50%	3.39%	4.95%	10.14%
PPLCorporation	PPL	$1.09	$33.89	$35.69	$36.47	$35.35	3.08%	3.20%	7.50%	7.67%	7.59%	10.79%
											Average:	**9.76%**
											Median:	**10.14%**

Mr. Megginson Constant Growth DCF
As Adjusted to Update Calculation of Stock Prices

Company	Ticker	Annualized Dividend	Average Monthly Stock Price				Dividend Yield	Expected Dividend Yield	Projected EPS Growth Rates			Cost of Equity
			Jun-25	Jul-25	Aug-25	Average			Value Line	Zacks	Average	
Alliant Energy	LNT	$2.03	$60.30	$62.78	$65.61	$62.90	3.23%	3.33%	6.00%	6.59%	6.30%	9.62%
Ameren	AEE	$2.84	$94.90	$97.08	$100.65	$97.54	2.91%	3.02%	6.50%	7.86%	7.18%	10.20%
DTE Energy	DTE	$4.36	$131.87	$133.99	$138.15	$134.67	3.24%	3.33%	4.50%	6.98%	5.74%	9.07%
Evergy	EVRG	$2.67	$66.66	$68.54	$71.84	$69.01	3.87%	4.00%	7.50%	5.73%	6.62%	10.61%
OGE Energy	OGE	$1.68	$43.69	$44.49	$45.26	$44.48	3.78%	3.90%	6.50%	6.32%	6.41%	10.31%
Pinnacle West	PNW	$3.58	$88.55	$90.10	$91.51	$90.05	3.98%	4.05%	5.00%	2.12%	3.56%	7.61%
Portland General Electric	POR	$2.10	$39.99	$40.33	$41.93	$40.75	5.15%	5.28%	6.50%	3.39%	4.95%	10.23%
PPLCorporation	PPL	$1.09	$33.60	$34.92	$36.24	$34.92	3.12%	3.24%	7.50%	7.67%	7.59%	10.82%
											Median:	**10.21%**

Mr. Coppola Constant Growth DCF
As Filed

Company	Ticker	Projected Avg. Annual Dividend (2025/2026)	Average 30-Day High/Low Stock Price	Expected Dividend Yield	Projected EPS Growth Rates			Cost of Equity
					Value Line	Yahoo! Finance	Average	
Alliant Energy	LNT	$2.10	$62.43	3.36%	6.00%	6.19%	6.09%	9.46%
Ameren	AEE	$2.94	$96.99	3.03%	6.50%	7.20%	6.85%	9.88%
American Electric Power	AEP	$3.89	$105.57	3.68%	6.50%	5.82%	6.16%	9.84%
CenterPoint Energy	CNP	$0.92	$36.69	2.51%	6.50%	N/A	6.50%	9.01%
Consolidated Edison	ED	$3.50	$100.77	3.47%	6.00%	5.48%	5.74%	9.21%
DTE Energy	DTE	$4.56	$134.15	3.40%	4.50%	5.68%	5.09%	8.49%
Evergy	EVRG	$2.78	$68.78	4.04%	N/A	6.04%	6.04%	10.08%
IDACORP	IDA	$3.59	$118.00	3.04%	6.00%	N/A	6.00%	9.04%
OGE Energy	OGE	$1.72	$44.25	3.89%	6.50%	5.34%	5.92%	9.80%
Portland General Electric	POR	$2.14	$40.71	5.26%	6.50%	4.00%	5.25%	10.51%
WEC Energy	WEC	$3.69	$105.81	3.49%	6.00%	7.01%	6.51%	9.99%
							Average:	**9.57%**

Mr. Coppola Constant Growth DCF
As Filed with All Growth Rates

Company	Ticker	Projected Avg. Annual Dividend (2025/2026)	Average 30-Day High/Low Stock Price	Expected Dividend Yield	Projected EPS Growth Rates			Cost of Equity
					Value Line	Yahoo! Finance	Average	
Alliant Energy	LNT	$2.10	$62.43	3.36%	6.00%	6.19%	6.09%	9.46%
Ameren	AEE	$2.94	$96.99	3.03%	6.50%	7.20%	6.85%	9.88%
American Electric Power	AEP	$3.89	$105.57	3.68%	6.50%	5.82%	6.16%	9.84%
CenterPoint Energy	CNP	$0.92	$36.69	2.51%	6.50%	8.17%	7.34%	9.84%
Consolidated Edison	ED	$3.50	$100.77	3.47%	6.00%	5.48%	5.74%	9.21%
DTE Energy	DTE	$4.56	$134.15	3.40%	4.50%	5.68%	5.09%	8.49%
Evergy	EVRG	$2.78	$68.78	4.04%	7.50%	6.04%	6.77%	10.81%
IDACORP	IDA	$3.59	$118.00	3.04%	6.00%	7.64%	6.82%	9.86%
OGE Energy	OGE	$1.72	$44.25	3.89%	6.50%	5.34%	5.92%	9.80%
Portland General Electric	POR	$2.14	$40.71	5.26%	6.50%	4.00%	5.25%	10.51%
WEC Energy	WEC	$3.69	$105.81	3.49%	6.00%	7.01%	6.51%	9.99%
							Average:	**9.79%**

Mr. Coppola Constant Growth DCF
As Filed with All Growth Rates and Updated through August 31, 2025

Company	Ticker	Projected Avg. Annual Dividend (2024/2025)	Average 30-Day Stock Price	Expected Dividend Yield	Projected EPS Growth Rates			Cost of Equity
					Value Line	Zacks	Average	
Alliant Energy	LNT	$2.10	$65.25	3.22%	6.00%	6.60%	6.30%	9.52%
Ameren	AEE	$2.94	$100.94	2.91%	6.50%	7.90%	7.20%	10.11%
American Electric Power	AEP	$3.89	$111.53	3.49%	6.50%	6.40%	6.45%	9.94%
CenterPoint Energy	CNP	$0.92	$38.02	2.42%	6.50%	7.80%	7.15%	9.57%
Consolidated Edison	ED	$3.50	$101.73	3.44%	6.00%	6.40%	6.20%	9.64%
DTE Energy	DTE	$4.56	$138.89	3.28%	4.50%	7.00%	5.75%	9.03%
Evergy	EVRG	$2.78	$70.99	3.91%	7.50%	5.70%	6.60%	10.51%
IDACORP	IDA	$3.59	$124.57	2.88%	6.00%	8.20%	7.10%	9.98%
OGE Energy	OGE	$1.72	$45.19	3.81%	6.50%	6.30%	6.40%	10.21%
Portland General Electric	POR	$2.14	$41.96	5.10%	6.50%	3.40%	4.95%	10.05%
WEC Energy	WEC	$3.69	$108.21	3.41%	6.00%	7.00%	6.50%	9.91%
							Average:	**9.86%**

Mr. Walters's Constant Growth DCF Using Projected EPS Growth Rates
As Filed

Company	Ticker	Annualized Dividend	13-Week Avg. Stock Price	Expected Dividend Yield	Projected EPS Growth Rates				Cost of Equity
					Zacks	S&P	I/B/E/S	Average	
Alliant Energy Corporation	LNT	$2.03	$63.75	3.39%	6.59%	6.80%	6.40%	6.60%	9.99%
Ameren Corporation	AEE	$2.84	$98.85	3.11%	7.86%	7.72%	8.90%	8.16%	11.27%
American Electric Power Company, Inc.	AEP	$3.72	$108.24	3.67%	6.43%	7.07%	6.65%	6.72%	10.38%
Avista Corporation	AVA	$1.96	$37.33	5.58%	5.82%	5.98%	6.90%	6.23%	11.81%
Dominion Resources, Inc.	D	$2.67	$58.53	5.19%	13.59%	13.98%	n/a	13.79%	18.98%
DTE Energy Company	DTE	$4.36	$136.09	3.43%	6.98%	7.33%	6.90%	7.07%	10.50%
Duke Energy Corporation	DUK	$4.26	$120.29	3.78%	6.56%	6.69%	6.77%	6.67%	10.45%
Entergy Corporation	ETR	$2.40	$86.44	3.05%	9.46%	10.15%	9.65%	9.75%	12.80%
Evergy, Inc.	EVRG	$2.67	$70.27	4.02%	5.73%	5.87%	6.00%	5.87%	9.89%
IDACORP, Inc.	IDA	$3.44	$121.31	3.07%	8.20%	8.60%	8.00%	8.27%	11.34%
NextEra Energy, Inc.	NEE	$2.27	$72.88	3.35%	7.89%	7.63%	8.05%	7.86%	11.21%
OGE Energy Corporation	OGE	$1.69	$44.65	4.01%	6.32%	6.64%	5.60%	6.19%	10.19%
Pinnacle West Capital Corporation	PNW	$3.58	$90.38	4.08%	2.12%	4.51%	2.20%	2.94%	7.02%
Portland General Electric Company	POR	$2.10	$41.57	5.25%	3.39%	4.66%	3.49%	3.85%	9.09%
PPL Corporation	PPL	$1.09	$35.46	3.31%	7.67%	7.42%	7.80%	7.63%	10.94%
Southern Company	SO	$2.96	$92.82	3.41%	6.77%	6.58%	7.25%	6.87%	10.27%
Xcel Energy Inc.	XEL	$2.28	$70.80	3.48%	7.79%	8.06%	8.80%	8.22%	11.70%
								Average	**11.05%**
								Median	**10.50%**

Mr. Walters's Constant Growth DCF Using Projected EPS Growth Rates
Updated Proxy Group to Remove DUK (Recent M&A Activity)

Company	Ticker	Annualized Dividend	13-Week Avg. Stock Price	Expected Dividend Yield	Projected EPS Growth Rates				Cost of Equity
					Zacks	S&P	I/B/E/S	Average	
Alliant Energy Corporation	LNT	$2.03	$63.75	3.39%	6.59%	6.80%	6.40%	6.60%	9.99%
Ameren Corporation	AEE	$2.84	$98.85	3.11%	7.86%	7.72%	8.90%	8.16%	11.27%
American Electric Power Company, Inc.	AEP	$3.72	$108.24	3.67%	6.43%	7.07%	6.65%	6.72%	10.38%
Avista Corporation	AVA	$1.96	$37.33	5.58%	5.82%	5.98%	6.90%	6.23%	11.81%
Dominion Resources, Inc.	D	$2.67	$58.53	5.19%	13.59%	13.98%	n/a	13.79%	18.98%
DTE Energy Company	DTE	$4.36	$136.09	3.43%	6.98%	7.33%	6.90%	7.07%	10.50%
Entergy Corporation	ETR	$2.40	$86.44	3.05%	9.46%	10.15%	9.65%	9.75%	12.80%
Evergy, Inc.	EVRG	$2.67	$70.27	4.02%	5.73%	5.87%	6.00%	5.87%	9.89%
IDACORP, Inc.	IDA	$3.44	$121.31	3.07%	8.20%	8.60%	8.00%	8.27%	11.34%
NextEra Energy, Inc.	NEE	$2.27	$72.88	3.35%	7.89%	7.63%	8.05%	7.86%	11.21%
OGE Energy Corporation	OGE	$1.69	$44.65	4.01%	6.32%	6.64%	5.60%	6.19%	10.19%
Pinnacle West Capital Corporation	PNW	$3.58	$90.38	4.08%	2.12%	4.51%	2.20%	2.94%	7.02%
Portland General Electric Company	POR	$2.10	$41.57	5.25%	3.39%	4.66%	3.49%	3.85%	9.09%
PPL Corporation	PPL	$1.09	$35.46	3.31%	7.67%	7.42%	7.80%	7.63%	10.94%
Southern Company	SO	$2.96	$92.82	3.41%	6.77%	6.58%	7.25%	6.87%	10.27%
Xcel Energy Inc.	XEL	$2.28	$70.80	3.48%	7.79%	8.06%	8.80%	8.22%	11.70%
								Average	**11.09%**
								Median	**10.72%**

Mr. Bandyk DCF
As Filed
(Two Step with EPS Growth Rates and GDP Growth Rate)

Company	Ticker	Annualized Dividend	Stock Price	Expected Dividend Yield	Projected EPS Growth Rates				Weight on EPS	Long-Term Gwth Rate	Weight LT Gwth	Cost of Equity
					Zacks	S&P	Value Line	Average				
Alliant Energy Corporation	LNT	$2.03	$65.70	3.19%	6.70%	6.81%	6.00%	6.50%	80.00%	3.80%	20.00%	9.15%
Ameren Corporation	AEE	$2.84	$101.61	2.89%	6.70%	6.88%	6.50%	6.69%	80.00%	3.80%	20.00%	9.00%
American Electric Power Company, Inc.	AEP	$3.72	$111.68	3.44%	6.30%	6.69%	6.50%	6.50%	80.00%	3.80%	20.00%	9.40%
Avista Corporation	AVA	$1.96	$37.24	5.42%	6.10%	5.88%	5.50%	5.83%	80.00%	3.80%	20.00%	10.84%
Dominion Resources, Inc.	D	$2.67	$60.44	4.66%	13.60%	13.49%	6.00%	11.03%	80.00%	3.80%	20.00%	14.25%
DTE Energy Company	DTE	$4.36	$138.49	3.25%	7.60%	7.87%	4.50%	6.66%	80.00%	3.80%	20.00%	9.34%
Duke Energy Corporation	DUK	$4.18	$123.29	3.50%	6.30%	6.32%	6.00%	6.21%	80.00%	3.80%	20.00%	9.22%
Entergy Corporation	ETR	$2.40	$89.41	2.78%	9.50%	8.88%	3.00%	7.13%	80.00%	3.80%	20.00%	9.24%
Evergy, Inc.	EVRG	$2.67	$72.20	3.81%	5.70%	5.72%	7.50%	6.31%	80.00%	3.80%	20.00%	9.62%
IDACORP, Inc.	IDA	$3.44	$126.05	2.83%	8.50%	8.23%	6.00%	7.58%	80.00%	3.80%	20.00%	9.65%
NextEra Energy, Inc.	NEE	$2.27	$73.52	3.20%	7.80%	7.11%	8.50%	7.80%	80.00%	3.80%	20.00%	10.21%
NorthWestern Corporation	NWE	$2.64	$56.51	4.80%	6.10%	5.94%	4.50%	5.51%	80.00%	3.80%	20.00%	9.97%
OGE Energy Corporation	OGE	$1.69	$44.90	3.87%	6.10%	5.92%	6.50%	6.17%	80.00%	3.80%	20.00%	9.57%
Pinnacle West Capital Corporation	PNW	$3.58	$91.26	4.01%	2.10%	5.55%	5.00%	4.22%	80.00%	3.80%	20.00%	8.14%
TXNM Energy	TXNM	$1.63	$56.82	2.94%	3.00%	6.55%	4.50%	4.68%	80.00%	3.80%	20.00%	7.44%
Portland General Electric Company	POR	$2.00	$42.51	4.83%	3.40%	6.54%	6.50%	5.48%	80.00%	3.80%	20.00%	9.98%
PPL Corporation	PPL	$1.09	$36.51	3.09%	6.80%	7.27%	7.50%	7.19%	80.00%	3.80%	20.00%	9.60%
Southern Company	SO	$2.88	$93.76	3.17%	6.50%	6.33%	6.50%	6.44%	80.00%	3.80%	20.00%	9.09%
Xcel Energy Inc.	XEL	$2.28	$72.98	3.23%	6.90%	7.26%	7.00%	7.05%	80.00%	3.80%	20.00%	9.64%
											Average:	**9.65%**

Mr. Bandyk DCF

Adjusted to Reflect Constant Growth DCF and Updated to Remove DUK, NWE, and TXNM (Recent M&A Activity)

Company	Ticker	Annualized Dividend	Stock Price	Expected Dividend Yield	Projected EPS Growth Rates				Cost of Equity
					Zacks	S&P	Value Line	Average	
Alliant Energy Corporation	LNT	$2.03	$65.70	3.19%	6.70%	6.81%	6.00%	6.50%	9.69%
Ameren Corporation	AEE	$2.84	$101.61	2.89%	6.70%	6.88%	6.50%	6.69%	9.58%
American Electric Power Company, Inc.	AEP	$3.72	$111.68	3.44%	6.30%	6.69%	6.50%	6.50%	9.94%
Avista Corporation	AVA	$1.96	$37.24	5.42%	6.10%	5.88%	5.50%	5.83%	11.24%
Dominion Resources, Inc.	D	$2.67	$60.44	4.66%	13.60%	13.49%	6.00%	11.03%	15.69%
DTE Energy Company	DTE	$4.36	$138.49	3.25%	7.60%	7.87%	4.50%	6.66%	9.91%
Entergy Corporation	ETR	$2.40	$89.41	2.78%	9.50%	8.88%	3.00%	7.13%	9.91%
Evergy, Inc.	EVRG	$2.67	$72.20	3.81%	5.70%	5.72%	7.50%	6.31%	10.12%
IDACORP, Inc.	IDA	$3.44	$126.05	2.83%	8.50%	8.23%	6.00%	7.58%	10.41%
NextEra Energy, Inc.	NEE	$2.27	$73.52	3.20%	7.80%	7.11%	8.50%	7.80%	11.01%
OGE Energy Corporation	OGE	$1.69	$44.90	3.87%	6.10%	5.92%	6.50%	6.17%	10.04%
Pinnacle West Capital Corporation	PNW	$3.58	$91.26	4.01%	2.10%	5.55%	5.00%	4.22%	8.22%
Portland General Electric Company	POR	$2.00	$42.51	4.83%	3.40%	6.54%	6.50%	5.48%	10.31%
PPL Corporation	PPL	$1.09	$36.51	3.09%	6.80%	7.27%	7.50%	7.19%	10.28%
Southern Company	SO	$2.88	$93.76	3.17%	6.50%	6.33%	6.50%	6.44%	9.61%
Xcel Energy Inc.	XEL	$2.28	$72.98	3.23%	6.90%	7.26%	7.00%	7.05%	10.29%
								Average:	**10.39%**

Mr. Megginson CAPM Analysis with Historical Market Risk Premium

As Filed

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1928-2024)**	**Historical Long-Term Government Bond Return (1928-2024)**	**Market Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.58%	0.80	11.79%	4.85%	6.94%	10.13%
Ameren Corporation	AEE	4.58%	0.80	11.79%	4.85%	6.94%	10.13%
DTE Energy Company	DTE	4.58%	0.80	11.79%	4.85%	6.94%	10.13%
Evergy, Inc.	EVRG	4.58%	0.75	11.79%	4.85%	6.94%	9.79%
OGE Energy Corporation	OGE	4.58%	0.85	11.79%	4.85%	6.94%	10.48%
Pinnacle West Capital Corporation	PNW	4.58%	0.75	11.79%	4.85%	6.94%	9.79%
Portland General Electric Company	POR	4.58%	0.75	11.79%	4.85%	6.94%	9.79%
PPL Corporation	PPL	4.58%	0.80	11.79%	4.85%	6.94%	10.13%
						Average:	**10.05%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: Exhibit S-4, Schedule D-5, page 6 of 14
[4] Source: Exhibit S-4, Schedule D-5, page 6 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Megginson CAPM Analysis
with Historical Market Risk Premium

As Adjusted to Account for Inverse Relationship in Interest Rates and the Market Risk Premium

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1926-2024)**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.58%	0.80	12.17%	4.58%	7.59%	10.65%
Ameren Corporation	AEE	4.58%	0.80	12.17%	4.58%	7.59%	10.65%
DTE Energy Company	DTE	4.58%	0.80	12.17%	4.58%	7.59%	10.65%
Evergy, Inc.	EVRG	4.58%	0.75	12.17%	4.58%	7.59%	10.27%
OGE Energy Corporation	OGE	4.58%	0.85	12.17%	4.58%	7.59%	11.03%
Pinnacle West Capital Corporation	PNW	4.58%	0.75	12.17%	4.58%	7.59%	10.27%
Portland General Electric Company	POR	4.58%	0.75	12.17%	4.58%	7.59%	10.27%
PPL Corporation	PPL	4.58%	0.80	12.17%	4.58%	7.59%	10.65%
						Average:	**10.56%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: *Kroll* Cost of Capital Navigator.
[4] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Megginson CAPM Analysis
with Projected Market Risk Premium

As Adjusted to Utilize Mr. Megginson's Approach in Case No. U-21540

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Company's Projected Mkt Return in Direct Testimony**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.58%	0.80	12.58%	4.58%	8.00%	10.98%
Ameren Corporation	AEE	4.58%	0.80	12.58%	4.58%	8.00%	10.98%
DTE Energy Company	DTE	4.58%	0.80	12.58%	4.58%	8.00%	10.98%
Evergy, Inc.	EVRG	4.58%	0.75	12.58%	4.58%	8.00%	10.58%
OGE Energy Corporation	OGE	4.58%	0.85	12.58%	4.58%	8.00%	11.38%
Pinnacle West Capital Corporation	PNW	4.58%	0.75	12.58%	4.58%	8.00%	10.58%
Portland General Electric Company	POR	4.58%	0.75	12.58%	4.58%	8.00%	10.58%
PPL Corporation	PPL	4.58%	0.80	12.58%	4.58%	8.00%	10.98%
						Average:	**10.88%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[4] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Coppola CAPM Analysis

As Filed

		[1]	[2]	[3]	[4]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Market Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.40%	0.80	7.35%	10.28%
Ameren Corporation	AEE	4.40%	0.80	7.35%	10.28%
American Electric Power Company, Inc.	AEP	4.40%	0.70	7.35%	9.55%
CenterPoint Energy, Inc.	CNP	4.40%	0.85	7.35%	10.65%
Consolidated Edison, Inc.	ED	4.40%	0.65	7.35%	9.18%
DTE Energy Company	DTE	4.40%	0.80	7.35%	10.28%
Evergy, Inc.	EVRG	4.40%	0.75	7.35%	9.91%
IDACORP, Inc.	IDA	4.40%	0.70	7.35%	9.55%
OGE Energy Corporation	OGE	4.40%	0.85	7.35%	10.65%
Portland General Electric Company	POR	4.40%	0.75	7.35%	9.91%
Wisconsin Energy Corporation	WEC	4.40%	0.70	7.35%	9.55%
				Average:	**9.98%**

Notes:
[1] Source: Exhibit AG-38
[2] Source: Exhibit AG-38
[3] Source: Exhibit AG-38
[4] Equals [1] + [2] x [3]

Mr. Coppola CAPM Analysis

As Adjusted to Account for Inverse Relationship in Interest Rates and the Market Risk Premium and Update Risk-Free Rate

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1926-2024)**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.60%	0.80	12.17%	4.60%	7.57%	10.66%
Ameren Corporation	AEE	4.60%	0.80	12.17%	4.60%	7.57%	10.66%
American Electric Power Company, Inc.	AEP	4.60%	0.70	12.17%	4.60%	7.57%	9.90%
CenterPoint Energy, Inc.	CNP	4.60%	0.85	12.17%	4.60%	7.57%	11.03%
Consolidated Edison, Inc.	ED	4.60%	0.65	12.17%	4.60%	7.57%	9.52%
DTE Energy Company	DTE	4.60%	0.80	12.17%	4.60%	7.57%	10.66%
Evergy, Inc.	EVRG	4.60%	0.75	12.17%	4.60%	7.57%	10.28%
IDACORP, Inc.	IDA	4.60%	0.70	12.17%	4.60%	7.57%	9.90%
OGE Energy Corporation	OGE	4.60%	0.85	12.17%	4.60%	7.57%	11.03%
Portland General Electric Company	POR	4.60%	0.75	12.17%	4.60%	7.57%	10.28%
Wisconsin Energy Corporation	WEC	4.60%	0.70	12.17%	4.60%	7.57%	9.90%
						Average:	**10.35%**

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2.
[2] Source: Exhibit AG-38
[3] Source: *Kroll* Cost of Capital Navigator.
[4] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2.
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Bandyk CAPM Analysis

As Filed

Projected Market Risk Premium & Risk-Free Rate - Dr. Damodaran

Company	Ticker	[1] Risk-Free Rate	[2] *Value Line* Raw Beta	[3] Market Risk Premium	[4] Cost of Equity	[5] *Bloomberg* Raw Beta	[6] Market Risk Premium	[7] Cost of Equity
Alliant Energy Corporation	LNT	4.23%	0.92	4.05%	7.96%	0.66	4.05%	6.90%
Ameren Corporation	AEE	4.23%	0.85	4.05%	7.67%	0.60	4.05%	6.66%
American Electric Power Company, In	AEP	4.23%	0.77	4.05%	7.35%	0.61	4.05%	6.70%
Avista Corporation	AVA	4.23%	0.92	4.05%	7.96%	0.61	4.05%	6.70%
Dominion Resources, Inc.	D	4.23%	0.85	4.05%	7.67%	0.54	4.05%	6.42%
DTE Energy Company	DTE	4.23%	1.00	4.05%	8.28%	0.70	4.05%	7.07%
Duke Energy Corporation	DUK	4.23%	0.85	4.05%	7.67%	0.55	4.05%	6.46%
Entergy Corporation	ETR	4.23%	1.00	4.05%	8.28%	0.76	4.05%	7.31%
Evergy, Inc.	EVRG	4.23%	0.92	4.05%	7.96%	0.66	4.05%	6.90%
IDACORP, Inc.	IDA	4.23%	0.77	4.05%	7.35%	0.66	4.05%	6.90%
NextEra Energy, Inc.	NEE	4.23%	1.08	4.05%	8.60%	0.70	4.05%	7.07%
NorthWestern Corporation	NWE	4.23%	1.00	4.05%	8.28%	0.78	4.05%	7.39%
OGE Energy Corporation	OGE	4.23%	1.08	4.05%	8.60%	0.85	4.05%	7.67%
Pinnacle West Capital Corporation	PNW	4.23%	0.92	4.05%	7.96%	0.70	4.05%	7.07%
TXNM Energy	TXNM	4.23%	0.85	4.05%	7.67%	0.72	4.05%	7.15%
Portland General Electric Company	POR	4.23%	0.92	4.05%	7.96%	0.66	4.05%	6.90%
PPL Corporation	PPL	4.23%	1.15	4.05%	8.89%	0.87	4.05%	7.75%
Southern Company	SO	4.23%	0.92	4.05%	7.96%	0.64	4.05%	6.82%
Xcel Energy Inc.	XEL	4.23%	0.77	4.05%	7.35%	0.58	4.05%	6.58%
Average					**7.97%**			**6.97%**

Notes:
[1] Source: Exhibit CUB-5
[2] Source: Exhibit CUB-4
[3] Source: Exhibit CUB-5
[4] Equals [1] + [2] x [3]
[5] Source: Exhibit CUB-4
[6] Source: Exhibit CUB-5
[7] Equals [1] + [5] x [6]

Projected Market Risk Premium & Risk-Free Rate - *Kroll*

Company	Ticker	[1] Risk-Free Rate	[2] *Value Line* Raw Beta	[3] Market Risk Premium	[4] Cost of Equity	[5] *Bloomberg* Raw Beta	[6] Market Risk Premium	[7] Cost of Equity
Alliant Energy Corporation	LNT	4.76%	0.92	5.00%	9.36%	0.66	5.00%	8.06%
Ameren Corporation	AEE	4.76%	0.85	5.00%	9.01%	0.60	5.00%	7.76%
American Electric Power Company, In	AEP	4.76%	0.77	5.00%	8.61%	0.61	5.00%	7.81%
Avista Corporation	AVA	4.76%	0.92	5.00%	9.36%	0.61	5.00%	7.81%
Dominion Resources, Inc.	D	4.76%	0.85	5.00%	9.01%	0.54	5.00%	7.46%
DTE Energy Company	DTE	4.76%	1.00	5.00%	9.76%	0.70	5.00%	8.26%
Duke Energy Corporation	DUK	4.76%	0.85	5.00%	9.01%	0.55	5.00%	7.51%
Entergy Corporation	ETR	4.76%	1.00	5.00%	9.76%	0.76	5.00%	8.56%
Evergy, Inc.	EVRG	4.76%	0.92	5.00%	9.36%	0.66	5.00%	8.06%
IDACORP, Inc.	IDA	4.76%	0.77	5.00%	8.61%	0.66	5.00%	8.06%
NextEra Energy, Inc.	NEE	4.76%	1.08	5.00%	10.16%	0.70	5.00%	8.26%
NorthWestern Corporation	NWE	4.76%	1.00	5.00%	9.76%	0.78	5.00%	8.66%
OGE Energy Corporation	OGE	4.76%	1.08	5.00%	10.16%	0.85	5.00%	9.01%
Pinnacle West Capital Corporation	PNW	4.76%	0.92	5.00%	9.36%	0.70	5.00%	8.26%
TXNM Energy	TXNM	4.76%	0.85	5.00%	9.01%	0.72	5.00%	8.36%
Portland General Electric Company	POR	4.76%	0.92	5.00%	9.36%	0.66	5.00%	8.06%
PPL Corporation	PPL	4.76%	1.15	5.00%	10.51%	0.87	5.00%	9.11%
Southern Company	SO	4.76%	0.92	5.00%	9.36%	0.64	5.00%	7.96%
Xcel Energy Inc.	XEL	4.76%	0.77	5.00%	8.61%	0.58	5.00%	7.66%
Average					**9.38%**			**8.14%**

Notes:
[1] Source: Exhibit CUB-5
[2] Source: Exhibit CUB-4
[3] Source: Exhibit CUB-5
[4] Equals [1] + [2] x [3]
[5] Source: Exhibit CUB-4
[6] Source: Exhibit CUB-5
[7] Equals [1] + [5] x [6]

Mr. Bandyk CAPM Analysis

As Adjusted

Exclude 10-Year Treasury Bond Yield as Risk-Free Rate and Rely On Market Return Using CGDCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
			Value Line			Market		*Bloomberg*			Market	
Company	**Ticker**	**Risk-Free Rate**	**Raw Beta**	**Market Return**	**Risk-Free Rate**	**Risk Premium**	**Cost of Equity**	**Raw Beta**	**Market Return**	**Risk-Free Rate**	**Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.66	12.58%	4.76%	7.82%	9.92%
Ameren Corporation	AEE	4.76%	0.85	12.58%	4.76%	7.82%	11.41%	0.60	12.58%	4.76%	7.82%	9.45%
American Electric Power Company, In	AEP	4.76%	0.77	12.58%	4.76%	7.82%	10.78%	0.61	12.58%	4.76%	7.82%	9.53%
Avista Corporation	AVA	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.61	12.58%	4.76%	7.82%	9.53%
Dominion Resources, Inc.	D	4.76%	0.85	12.58%	4.76%	7.82%	11.41%	0.54	12.58%	4.76%	7.82%	8.98%
DTE Energy Company	DTE	4.76%	1.00	12.58%	4.76%	7.82%	12.58%	0.70	12.58%	4.76%	7.82%	10.24%
Duke Energy Corporation	DUK	4.76%	0.85	12.58%	4.76%	7.82%	11.41%	0.55	12.58%	4.76%	7.82%	9.06%
Entergy Corporation	ETR	4.76%	1.00	12.58%	4.76%	7.82%	12.58%	0.76	12.58%	4.76%	7.82%	10.70%
Evergy, Inc.	EVRG	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.66	12.58%	4.76%	7.82%	9.92%
IDACORP, Inc.	IDA	4.76%	0.77	12.58%	4.76%	7.82%	10.78%	0.66	12.58%	4.76%	7.82%	9.92%
NextEra Energy, Inc.	NEE	4.76%	1.08	12.58%	4.76%	7.82%	13.21%	0.70	12.58%	4.76%	7.82%	10.24%
NorthWestern Corporation	NWE	4.76%	1.00	12.58%	4.76%	7.82%	12.58%	0.78	12.58%	4.76%	7.82%	10.86%
OGE Energy Corporation	OGE	4.76%	1.08	12.58%	4.76%	7.82%	13.21%	0.85	12.58%	4.76%	7.82%	11.41%
Pinnacle West Capital Corporation	PNW	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.70	12.58%	4.76%	7.82%	10.24%
TXNM Energy	TXNM	4.76%	0.85	12.58%	4.76%	7.82%	11.41%	0.72	12.58%	4.76%	7.82%	10.39%
Portland General Electric Company	POR	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.66	12.58%	4.76%	7.82%	9.92%
PPL Corporation	PPL	4.76%	1.15	12.58%	4.76%	7.82%	13.76%	0.87	12.58%	4.76%	7.82%	11.57%
Southern Company	SO	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.64	12.58%	4.76%	7.82%	9.77%
Xcel Energy Inc.	XEL	4.76%	0.77	12.58%	4.76%	7.82%	10.78%	0.58	12.58%	4.76%	7.82%	9.30%
Average							**11.98%**					**10.05%**

Notes:
[1] Source: Exhibit CUB-5
[2] Source: Exhibit CUB-4
[3] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[4] Source: Exhibit CUB-5
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]
[7] Source: Exhibit CUB-4
[8] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[9] Source: Exhibit CUB-5
[10] Equals [8] - [9]
[11] Equals [1] + [7] x [10]
[12] Equals average of [6] and [11]

Mr. Megginson
Risk Premium Analysis

Evidence That Risk Premium Is Understated

Year	[1] Electric Utility Returns	[2] A-Rated Utility Bond Yield	[3] Utility Bond Risk Prem.	[4] 30 yr. Treasury Bond Yield	[5] Treasury Bond Risk Prem.
1932	-3.18%	5.85%	-9.03%	3.69%	-6.87%
1933	-21.03%	7.22%	-28.25%	3.12%	-24.15%
1934	-19.96%	5.36%	-25.32%	3.18%	-23.14%
1935	74.92%	4.29%	70.63%	2.81%	72.11%
1936	19.64%	3.83%	15.81%	2.77%	16.87%
1937	-34.80%	4.03%	-38.83%	2.66%	-37.46%
1938	18.92%	3.74%	15.18%	2.64%	16.28%
1939	9.95%	3.38%	6.57%	2.40%	7.55%
1940	-15.91%	3.10%	-19.01%	2.23%	-18.14%
1941	-30.03%	3.06%	-33.09%	1.94%	-31.97%
1942	15.21%	3.06%	12.15%	2.46%	12.75%
1943	53.69%	2.99%	50.70%	2.44%	51.25%
1944	6.78%	2.97%	3.81%	2.46%	4.32%
1945	52.05%	2.75%	49.30%	2.34%	49.71%
1946	9.56%	2.76%	6.80%	2.04%	7.52%
1947	-15.57%	3.05%	-18.62%	2.13%	-17.70%
1948	8.56%	3.06%	5.50%	2.40%	6.16%
1949	22.18%	2.78%	19.40%	2.25%	19.93%
1950	6.79%	2.86%	3.93%	2.12%	4.67%
1951	15.48%	3.29%	12.19%	2.38%	13.10%
1952	16.89%	3.22%	13.67%	2.66%	14.23%
1953	9.93%	3.38%	6.55%	2.84%	7.09%
1954	24.57%	3.11%	21.46%	2.79%	21.78%
1955	8.36%	3.35%	5.01%	2.75%	5.61%
1956	4.05%	3.91%	0.14%	2.99%	1.06%
1957	7.63%	4.36%	3.27%	3.44%	4.19%
1958	35.82%	4.49%	31.33%	3.27%	32.55%
1959	3.11%	4.96%	-1.85%	4.01%	-0.90%
1960	20.37%	4.65%	15.72%	4.26%	16.11%
1961	32.17%	4.65%	27.52%	3.83%	28.34%
1962	0.33%	4.44%	-4.11%	4.00%	-3.67%
1963	9.28%	4.46%	4.82%	3.89%	5.39%
1964	16.12%	4.54%	11.58%	4.15%	11.97%
1965	2.91%	4.83%	-1.92%	4.19%	-1.28%
1966	-3.78%	5.67%	-9.45%	4.49%	-8.27%
1967	-2.84%	6.67%	-9.51%	4.59%	-7.43%
1968	10.36%	6.87%	3.49%	5.50%	4.86%
1969	-13.20%	8.59%	-21.79%	5.95%	-19.15%
1970	10.03%	8.48%	1.55%	6.74%	3.29%
1971	2.20%	7.90%	-5.70%	6.32%	-4.12%
1972	3.60%	7.48%	-3.88%	5.87%	-2.27%
1973	-18.92%	8.24%	-27.16%	6.51%	-25.43%
1974	-20.63%	10.27%	-30.90%	7.27%	-27.90%
1975	44.17%	10.11%	34.06%	7.99%	36.18%
1976	27.02%	8.62%	18.40%	7.89%	19.13%
1977	11.20%	8.64%	2.56%	7.14%	4.06%
1978	-2.37%	9.70%	-12.07%	7.90%	-10.27%
1979	5.65%	11.79%	-6.14%	8.86%	-3.21%
1980	8.73%	14.63%	-5.90%	9.97%	-1.24%
1981	17.63%	16.29%	1.34%	11.55%	6.08%
1982	33.70%	14.43%	19.27%	13.50%	20.20%
1983	13.63%	13.52%	0.11%	10.38%	3.25%
1984	21.73%	13.11%	8.62%	11.74%	9.99%
1985	27.66%	10.97%	16.69%	11.25%	16.41%
1986	27.56%	9.12%	18.44%	8.98%	18.58%
1987	-7.41%	10.98%	-18.39%	7.92%	-15.33%
1988	15.74%	10.06%	5.68%	8.97%	6.77%

Mr. Megginson
Risk Premium Analysis

Evidence That Risk Premium Is Understated

Year	[1] Electric Utility Returns	[2] A-Rated Utility Bond Yield	[3] Utility Bond Risk Prem.	[4] 30 yr. Treasury Bond Yield	[5] Treasury Bond Risk Prem.
1989	28.60%	9.44%	19.16%	8.81%	19.79%
1990	3.56%	9.73%	-6.17%	8.19%	-4.63%
1991	28.55%	8.88%	19.67%	8.22%	20.33%
1992	4.19%	8.43%	-4.24%	7.26%	-3.07%
1993	10.16%	7.34%	2.82%	7.17%	2.99%
1994	-13.47%	8.76%	-22.23%	6.59%	-20.06%
1995	30.06%	7.23%	22.83%	7.60%	22.46%
1996	1.84%	7.59%	-5.75%	6.18%	-4.34%
1997	20.33%	7.16%	13.17%	6.64%	13.69%
1998	21.17%	6.91%	14.26%	5.83%	15.34%
1999	-18.62%	8.14%	-26.76%	5.57%	-24.19%
2000	69.24%	7.84%	61.40%	6.50%	62.74%
2001	-7.24%	7.83%	-15.07%	5.53%	-12.77%
2002	-10.25%	6.93%	-17.18%	5.59%	-15.84%
2003	29.39%	6.27%	23.12%	4.80%	24.59%
2004	30.24%	5.92%	24.32%	5.02%	25.22%
2005	25.14%	5.80%	19.34%	4.69%	20.45%
2006	16.63%	5.81%	10.82%	4.68%	11.95%
2007	20.11%	6.16%	13.95%	4.86%	15.25%
2008	-27.84%	6.54%	-34.38%	4.45%	-32.29%
2009	12.47%	5.79%	6.68%	3.47%	9.00%
2010	6.46%	5.56%	0.90%	4.25%	2.21%
2011	19.71%	4.33%	15.38%	3.82%	15.89%
2012	1.64%	4.00%	-2.36%	2.46%	-0.82%
2013	12.69%	4.81%	7.88%	2.88%	9.81%
2014	30.65%	3.94%	26.71%	3.41%	27.24%
2015	-4.60%	4.39%	-8.99%	2.47%	-7.07%
2016	18.18%	4.22%	13.96%	2.30%	15.88%
2017	13.35%	3.75%	9.60%	2.67%	10.68%
2018	1.99%	4.26%	-2.27%	2.97%	-0.98%
2019	27.30%	3.48%	23.82%	2.58%	24.72%
2020	1.55%	2.71%	-1.16%	1.67%	-0.12%
2021	17.01%	3.04%	13.97%	1.91%	15.10%
2022	1.67%	5.44%	-3.77%	3.97%	-2.30%
2023	-5.69%	5.16%	-10.85%	4.03%	-9.72%
2024	15.17%	5.60%	9.57%	4.40%	10.77%
Average	10.83%	6.27%	4.56%	4.96%	5.89%
		Avg. Risk Premium If Interest Rate < 6.27%	**7.76%**	**Avg. Risk Premium If Interest Rate < 4.96%**	**7.19%**

Source:
[1] Exhibit S-4, Schedule D5, at 11
[2] Exhibit S-4, Schedule D5, at 11
[3] Equals [1] - [2]
[4] Exhibit S-4, Schedule D5, at 11
[5] Equals [1] - [4]

Mr. Coppola
Risk Premium Analysis

Evidence That Risk Premium Is Understated

Year	[1] Electric Utility Returns	[2] A-Rated Utility Bond Yield	[3] Utility Bond Risk Prem.
1932	-2.73%	5.85%	-8.58%
1933	-22.17%	7.22%	-29.39%
1934	-21.13%	5.36%	-26.49%
1935	77.49%	4.29%	73.20%
1936	19.47%	3.83%	15.64%
1937	-37.55%	4.03%	-41.58%
1938	19.84%	3.74%	16.10%
1939	10.09%	3.38%	6.71%
1940	-17.64%	3.10%	-20.74%
1941	-32.99%	3.06%	-36.05%
1942	15.61%	3.06%	12.55%
1943	55.98%	2.99%	52.99%
1944	6.62%	2.97%	3.65%
1945	53.82%	2.75%	51.07%
1946	9.63%	2.76%	6.87%
1947	-16.97%	3.05%	-20.02%
1948	8.59%	3.06%	5.53%
1949	23.02%	2.78%	20.24%
1950	6.54%	2.86%	3.68%
1951	15.97%	3.29%	12.68%
1952	17.46%	3.22%	14.24%
1953	9.96%	3.38%	6.58%
1954	25.45%	3.11%	22.34%
1955	8.41%	3.35%	5.06%
1956	3.91%	3.91%	0.00%
1957	7.70%	4.36%	3.34%
1958	36.92%	4.49%	32.43%
1959	3.03%	4.96%	-1.93%
1960	20.88%	4.65%	16.23%
1961	32.95%	4.65%	28.30%
1962	0.14%	4.44%	-4.30%
1963	9.36%	4.46%	4.90%
1964	16.28%	4.54%	11.74%
1965	2.75%	4.83%	-2.08%
1966	-4.14%	5.67%	-9.81%
1967	-3.26%	6.67%	-9.93%
1968	10.54%	6.87%	3.67%
1969	-14.23%	8.59%	-22.82%
1970	10.25%	8.48%	1.77%
1971	1.96%	7.90%	-5.94%
1972	3.41%	7.48%	-4.07%
1973	-21.21%	8.24%	-29.45%
1974	-24.43%	10.27%	-34.70%
1975	47.27%	10.11%	37.16%
1976	28.40%	8.62%	19.78%
1977	11.22%	8.64%	2.58%
1978	-3.86%	9.70%	-13.56%
1979	4.82%	11.79%	-6.97%
1980	8.14%	14.63%	-6.49%
1981	17.95%	16.29%	1.66%
1982	35.82%	14.43%	21.39%
1983	13.72%	13.52%	0.20%
1984	22.75%	13.11%	9.64%
1985	29.23%	10.97%	18.26%
1986	29.03%	9.12%	19.91%
1987	-9.06%	10.98%	-20.04%
1988	16.52%	10.06%	6.46%
1989	30.12%	9.44%	20.68%
1990	3.30%	9.73%	-6.43%
1991	29.89%	8.88%	21.01%

Mr. Coppola
Risk Premium Analysis

Evidence That Risk Premium Is Understated

Year	[1] Electric Utility Returns	[2] A-Rated Utility Bond Yield	[3] Utility Bond Risk Prem.
1992	4.23%	8.43%	-4.20%
1993	10.37%	7.34%	3.03%
1994	-15.16%	8.76%	-23.92%
1995	31.53%	7.23%	24.30%
1996	1.51%	7.59%	-6.08%
1997	21.17%	7.16%	14.01%
1998	21.79%	6.91%	14.88%
1999	-20.04%	8.14%	-28.18%
2000	71.42%	7.84%	63.58%
2001	-25.34%	7.83%	-33.17%
2002	-23.18%	6.93%	-30.11%
2003	28.01%	5.78%	22.23%
2004	29.37%	5.46%	23.91%
2005	24.70%	5.56%	19.14%
2006	16.38%	5.83%	10.55%
2007	21.08%	6.06%	15.02%
2008	-27.73%	5.99%	-33.72%
2009	12.01%	5.88%	6.13%
2010	6.13%	5.64%	0.49%
2011	19.11%	4.09%	15.02%
2012	1.46%	3.95%	-2.49%
2013	12.27%	4.75%	7.52%
2014	29.90%	3.94%	25.96%
2015	-3.07%	4.39%	-7.46%
2016	18.24%	4.22%	14.02%
2017	13.26%	3.60%	9.66%
2018	2.13%	4.65%	-2.52%
2019	26.91%	3.48%	23.43%
2020	1.52%	2.71%	-1.19%
2021	16.81%	2.95%	13.86%
2022	1.61%	5.25%	-3.64%
2023	-5.70%	6.01%	-11.71%
2024	15.13%	5.54%	9.59%
Average	10.52%	6.26%	4.27%
		Avg. Risk Premium If Interest Rate < 6.26%	**7.29%**

Source:
[1] Workpaper AG-3B
[2] Workpaper AG-3B
[3] Equals [1] - [2]

Mr. Coppola Risk Premium Analysis
As Filed v. As Updated

	As Filed		As Updated	
Bond Yield				
Projected Near Term 30 Year Treasury Yield	4.40%	[1]	4.60%	[6]
Spread - Utility Bond Yield ("A" Rated) v. 30 Year Treasury Bond Yield	1.16%	[2]	1.19%	[7]
Projected Near Term Utility Bond Yield	5.56%	[3]	5.79%	[8]
Risk Premium				
Historical Utility Bond Risk Premium	4.25%	[4]	4.27%	[9]
Cost of Equity	**9.81%**	[5]	**10.06%**	[10]

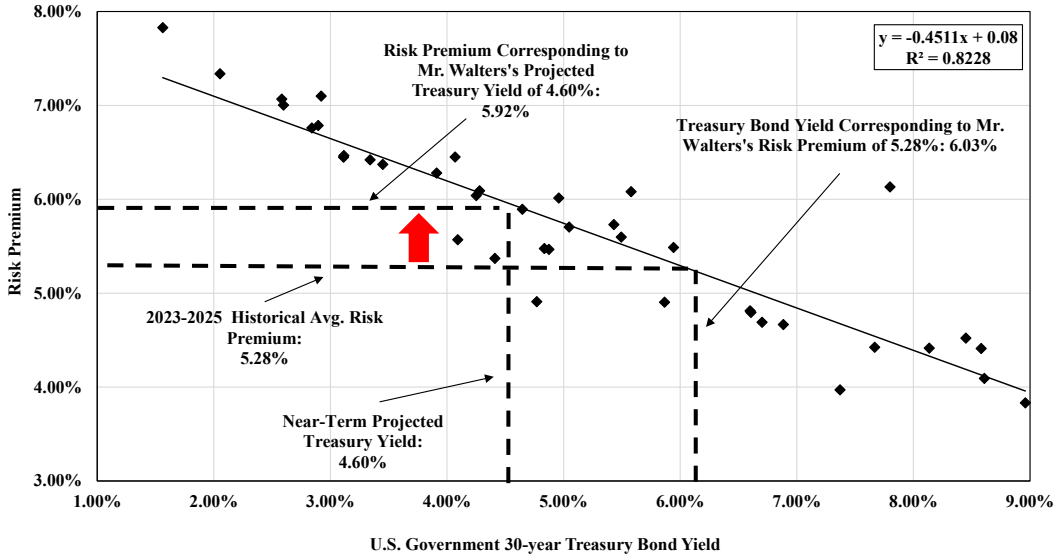
[1] Exhibit AG-39 (as relied on in Exhibit AG-38)
[2] Exhibit AG-39 and Workpaper AG-39A
[3] Equals [1] + [2]
[4] Exhibit AG-39 and Workpaper AG-39B
[5] Equals [3] + [4]
[6] *Blue Chip Financial Forecast* , Vol. 44, No. 10, October 1, 2025, at 2.
[7] Correction to average shown on Workpaper AG-39A
[8] Equals [6] + [7]
[9] Actual average shown on Workpaper AG-39B
[10] Equals [8] + [9]

Mr. Walters's Risk Premium Analysis
As Adjusted Treasury Bond Approach

Year	[1] Authorized Electric Returns	[2] 30 yr. Treasury Bond Yld	[3] Indicated Risk Premium
1986	13.93%	7.80%	6.13%
1987	12.99%	8.58%	4.41%
1988	12.79%	8.96%	3.83%
1989	12.97%	8.45%	4.52%
1990	12.70%	8.61%	4.09%
1991	12.55%	8.14%	4.41%
1992	12.09%	7.67%	4.42%
1993	11.41%	6.60%	4.81%
1994	11.34%	7.37%	3.97%
1995	11.55%	6.88%	4.67%
1996	11.39%	6.70%	4.69%
1997	11.40%	6.61%	4.79%
1998	11.66%	5.58%	6.08%
1999	10.77%	5.87%	4.90%
2000	11.43%	5.94%	5.49%
2001	11.09%	5.49%	5.60%
2002	11.16%	5.43%	5.73%
2003	10.97%	4.96%	6.01%
2004	10.75%	5.05%	5.70%
2005	10.54%	4.65%	5.89%
2006	10.34%	4.87%	5.47%
2007	10.31%	4.83%	5.48%
2008	10.37%	4.28%	6.09%
2009	10.52%	4.07%	6.45%
2010	10.29%	4.25%	6.04%
2011	10.19%	3.91%	6.28%
2012	10.02%	2.92%	7.10%
2013	9.82%	3.45%	6.37%
2014	9.76%	3.34%	6.42%
2015	9.60%	2.84%	6.76%
2016	9.60%	2.60%	7.00%
2017	9.68%	2.90%	6.79%
2018	9.56%	3.11%	6.45%
2019	9.65%	2.58%	7.07%
2020	9.39%	1.56%	7.83%
2021	9.39%	2.05%	7.34%
2022	9.58%	3.12%	6.47%
2023	9.66%	4.09%	5.57%
2024	9.78%	4.41%	5.37%
2025	9.68%	4.77%	4.91%
Average (All Years)	10.82%	5.13%	5.68%
Average (2023 - 2025)	9.71%	4.42%	5.28%

Source:
[1] Exhibit AB-14
[2] Exhibit AB-14
[3] Equals [1] - [2]

Mr. Walters's Risk Premium Analysis
As Adjusted Treasury Bond Approach



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9070927
R Square	0.8228171
Adjusted R Square	0.8181544
Standard Error	0.0042878
Observations	40

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00324	0.00324	176.46770	0.00000
Residual	38	0.00070	0.00002		
Total	39	0.00394			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0800	0.00	42.78	0.0000	0.0762	0.0838	0.0762	0.0838
30-year Treasury bond yield	(0.4511)	0.03	(13.28)	0.0000	(0.5198)	(0.3824)	(0.5198)	(0.3824)

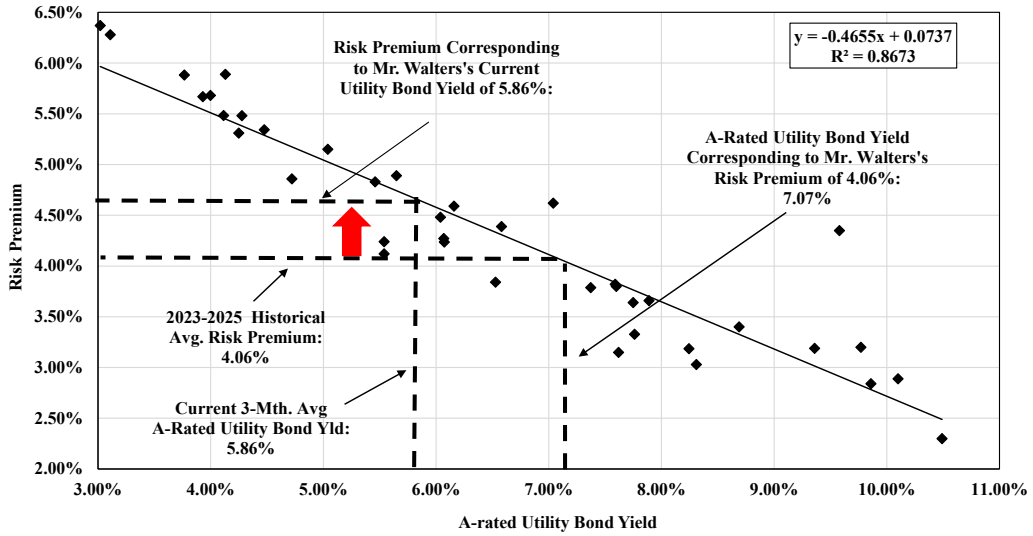
	30-year Treasury Bond Yield	Risk Premium	ROE
Mr. Walters's Adjusted Treasury Bond Approach Using Regression	4.60%	5.92%	10.52%

Mr. Walters's Risk Premium Analysis
As Adjusted Utility Bond Approach

Year	[1] Authorized Electric Returns	[2] A-Rated Utility Bond Yld	[3] Indicated Risk Premium
1986	13.93%	9.58%	4.35%
1987	12.99%	10.10%	2.89%
1988	12.79%	10.49%	2.30%
1989	12.97%	9.77%	3.20%
1990	12.70%	9.86%	2.84%
1991	12.55%	9.36%	3.19%
1992	12.09%	8.69%	3.40%
1993	11.41%	7.59%	3.82%
1994	11.34%	8.31%	3.03%
1995	11.55%	7.89%	3.66%
1996	11.39%	7.75%	3.64%
1997	11.40%	7.60%	3.80%
1998	11.66%	7.04%	4.62%
1999	10.77%	7.62%	3.15%
2000	11.43%	8.24%	3.19%
2001	11.09%	7.76%	3.33%
2002	11.16%	7.37%	3.79%
2003	10.97%	6.58%	4.39%
2004	10.75%	6.16%	4.59%
2005	10.54%	5.65%	4.89%
2006	10.34%	6.07%	4.27%
2007	10.31%	6.07%	4.24%
2008	10.37%	6.53%	3.84%
2009	10.52%	6.04%	4.48%
2010	10.29%	5.46%	4.83%
2011	10.19%	5.04%	5.15%
2012	10.02%	4.13%	5.89%
2013	9.82%	4.48%	5.34%
2014	9.76%	4.28%	5.48%
2015	9.60%	4.12%	5.48%
2016	9.60%	3.93%	5.67%
2017	9.68%	4.00%	5.68%
2018	9.56%	4.25%	5.31%
2019	9.65%	3.77%	5.88%
2020	9.39%	3.02%	6.37%
2021	9.39%	3.11%	6.28%
2022	9.58%	4.72%	4.86%
2023	9.66%	5.54%	4.12%
2024	9.78%	5.54%	4.24%
2025	9.68%	5.87%	3.81%
Average (All Years)	10.82%	6.48%	4.33%
Average (2023 - 2025)	9.71%	5.65%	4.06%

Source:
[1] Exhibit AB-15
[2] Exhibit AB-15
[3] Equals [1] - [2]

Mr. Walters's Risk Premium Analysis
As Adjusted Utility Bond Approach



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9232458
R Square	0.8523829
Adjusted R Square	0.8484982
Standard Error	0.0040565
Observations	40

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00361	0.00361	219.42275	0.00000
Residual	38	0.00063	0.00002		
Total	39	0.00424			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0733	0.00	34.52	0.0000	0.0690	0.0776	0.0690	0.0776
A-rated Utility Bond Yield	(0.4625)	0.03	(14.81)	0.0000	(0.5257)	(0.3993)	(0.5257)	(0.3993)

	Bond Yield	Risk Premium	ROE
3-Month Avg. A-rated Utility Bond Yield as of Aug 2025	5.86%	4.62%	10.48%
6-Month Avg. A-rated Utility Bond Yield as of of Aug 2025	5.88%	4.61%	10.49%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case

Case No. U-21870
Work Paper AG-37B
September 30, 2025
Page 1 of 1

Growth Rates - Per Value Line and as published by Yahoo'

Line	Company	Ticker	Average	See Footnotes below
	(a)	(b)	(c)	
Value Line Growth				
1	Alliant Energy	LNT	6.00%	
2	Ameren	AEE	6.50%	
3	American Electric Power	AEP	6.50%	
4	CenterPoint Energy	CNP	6.50%	
5	Consolidated Edison	ED	6.00%	
6	DTE Energy	DTE	4.50%	
7	Evergy	EVRG	7.50%	**Do Not Include***
8	IDACORP	IDA	6.00%	
9	OGE Energy	OGE	6.50%	
10	Portland General Electric	POR	6.50%	
11	WEC Energy	WEC	6.00%	
12	Average		6.23%	

		Ticker	2025	2026	Average	
Yahoo Growth - 2025 &2026						
13	Alliant Energy	LNT	5.45%	6.92%	6.19%	
14	Ameren	AEE	7.16%	7.23%	7.20%	
15	American Electric Power	AEP	4.93%	6.70%	5.82%	
16	CenterPoint Energy	CNP	8.19%	8.14%	8.17%	**Do Not Include****
17	Consolidated Edison	ED	4.15%	6.80%	5.48%	
18	DTE Energy	DTE	5.62%	5.74%	5.68%	
19	Evergy	EVRG	5.87%	6.20%	6.04%	
20	IDACORP	IDA	6.17%	9.11%	7.64%	**Do Not Include****
21	OGE Energy	OGE	3.87%	6.80%	5.34%	
22	Portland General Electric	POR	2.96%	5.04%	4.00%	
23	WEC Energy	WEC	7.29%	6.73%	7.01%	
24	Average				6.23%	

* Evergy's EPS Growth reflects 6% growth vs. Value Line's stated earnings growth of 7.5%

** These short-term growth rates are inconsistent with longer term estimates

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case

Case No. U-21870
Workpaper AG-39A
September 30, 2025
Page 1 of 2

30 Year Utility Debt Issues Rated "A" by Moody's and S & P in 2023 and 2024*

Line	Issuer	Date in 2024		Ratings		Issue Rate	Spread vs. 30 Yr. US Treas.
	(a)	(b)		(c)		(d)	(e)
	30 Year Utility "A" Rated **						
1	Union Electric	Jan	3	A2	A	5.25%	123
2	Northern Natural Gas	Jan	29	A2	A-	5.63%	127
3	Patomac Electric	Feb	26	A2	A	5.50%	110
4	Public Service Electric & Gas	Feb	28	A1	A	5.46%	108
5	Entergy Louisiana	Mar	4	A2	A	5.70%	135
6	Indianappolis Power & Light	Mar	7	A2	A-	5.75%	147
7	Duke Energy Ohio	Mar	11	A2	A	5.55%	130
8	San Diego Gas & Electric	Mar	18	A1	A	5.55%	115
9	Public Service of Colorado	Apr	1	A1	A	5.75%	130
10	Consolidated Edison of New York	May	6	A3	A-	5.75%	110
11	Commenwealth Edison	May	6	A1	A	5.65%	105
12	Entergy Arkansas	May	7	A2	A	5.75%	118
13	Entergy Mississippi	May	13	A2	A	5.85%	123
14	Baltimore Gas & Electric	June	3	A3	A	5.65%	110
15	Southwestern Public Service	June	3	A3	A-	6.00%	150
16	Pudget Sound Energy	June	4	A2	A-	5.69%	120
17	Oncor Delivery	June	17	A1	A+	5.55%	115
18	Ameren Illinois	June	17	A1	A	5.55%	115
19	Public Service Electric & Gas	Aug	1	A1	A	5.30%	105
20	Entergy Texas	Aug	12	A3	A	5.55%	140
21	Oklahoma Electric & Gas	Aug	12	A3	A-	5.60%	130
22	Wisconsin Electric Power	Sep	9	A2	A-	5.05%	108
23	Atmos Energy	Sep	17	A1	A-	5.00%	108
24	Consolidated Edison of New York	Nov	14	A3	A-	5.25%	70
25	***Average Spread "A" Rated or Better***					5.56%	**116**

* From Company Exhibi A-28 (MRB-9), and SEC filings

** Excludes long-term debt issued by California utility companies

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case

Case No. U-21870
Workpaper AG-39A
September 30, 2025
Page 2 of 2

30 Year Utility Debt Issues Rated "A" by Moody's and S & P in 2023 and 2024*

Line	Issuer	Date in 2023		Ratings		Issue Rate	Spread vs. 30 Yr. US Treas.
	(a)	(b)		(c)		(d)	(e)
	30 Year Utility "A" Rated ***						
1	Connecticut Light & Power	Jan	3	A1	A+	5.25%	135
2	Commenwealth Edison	Jan	3	A1	A	5.30%	140
3	Public Service of New Hampshire	Jan	4	A1	A+	3.70%	133
4	Tuscon Electric & Power	Feb	15	A3	A-	5.50%	175
5	Union Electric	Feb	27	A2	A	5.45%	155
6	PPL Electric	Feb	27	A1	A+	5.25%	145
7	San Diego Gas & Electric	Mar	6	A2	A	5.35%	150
8	Evergy Kansas Central	Mar	7	A2	A	5.70%	185
9	Idaho Power	Mar	9	A2	A-	5.50%	170
10	AEP Transmission	Mar	9	A2	A-	5.40%	157
11	Duke Energy Ohio	Mar	20	A2	A	5.65%	200
12	Centerpoint-Houston Electric	Mar	20	A2	A	5.30%	165
13	Oklahoma Gas & Electric	Mar	21	A3	A-	5.60%	190
14	Indiana Michigan Power	Mar	21	A3	A-	5.63%	190
15	Public Service Electric & Gas	Mar	23	A1	A	5.75%	142
16	Public Service of Colorado	Mar	27	A1	A	5.25%	155
17	Baltimore Gas & Electric	May	8	A3	A	5.40%	158
18	Pudget Sound Energy	May	15	A2	A-	5.45%	160
19	Public Energy Elec. & Gas	Aug	3	A1	A	5.45%	115
20	Entergy Texas	Aug	8	A3	A	5.80%	160
21	Nevada :pwer	Sep	11	A2	A+	6.00%	163
22	Sierra Pacific Power	Sep	13	A2	A+	5.90%	160
23	Dominion Energy S. C.	Oct	4	A2	A	6.25%	140
24	Atmos Energy	Oct	5	A1	A-	6.20%	133
25	Duke Energy Florida	Nov	6	A1	A	6.20%	142
26	Consolidated Edison of NY	Nov	20	A3	A-	5.90%	137
27	Average Rate and Spread					6.01%	**156**

* From Company Exhibi A-28 (MRB-9), and SEC filings

** Excludes long-term debt issued by California utility companies

MICHIGAN PUBLIC SERVICE COMMISSION **Case U-21870**
Consumers Energy - Electric Rate Case Work Paper AG-39B Pg 1 of 2
Electric Risk Premium Analysis (Pg 1 data per Mergent PU Manual)

		Moody's Electric Utility Common Stocks					Ylds. on	Electric
Line	Year	Yr End Avg. Mkt. Price	Avg. Divi-dent p/sh	% Market Gain/Loss	Dividend Yield	Total Return	"A" Rated Util. Bonds	Stocks vs. Bonds
1	1931	$ 43.23						
2	1932	39.42	$ 2.63	-8.81%	6.08%	-2.73%	5.85%	-8.58%
3	1933	28.73	1.95	-27.12%	4.95%	-22.17%	7.22%	-29.39%
4	1934	21.06	1.60	-26.70%	5.57%	-21.13%	5.36%	-26.49%
5	1935	36.06	1.32	71.23%	6.27%	77.49%	4.29%	73.20%
6	1936	41.60	1.48	15.36%	4.10%	19.47%	3.83%	15.64%
7	1937	24.24	1.74	-41.73%	4.18%	-37.55%	4.03%	-41.58%
8	1938	27.55	1.50	13.66%	6.19%	19.84%	3.74%	16.10%
9	1939	28.85	1.48	4.72%	5.37%	10.09%	3.38%	6.71%
10	1940	22.22	1.54	-22.98%	5.34%	-17.64%	3.10%	-20.74%
11	1941	13.45	1.44	-39.47%	6.48%	-32.99%	3.06%	-36.05%
12	1942	14.29	1.26	6.25%	9.37%	15.61%	3.06%	12.55%
13	1943	21.01	1.28	47.03%	8.96%	55.98%	2.99%	52.99%
14	1944	21.09	1.31	0.38%	6.24%	6.62%	2.97%	3.65%
15	1945	31.14	1.30	47.65%	6.16%	53.82%	2.75%	51.07%
16	1946	32.71	1.43	5.04%	4.59%	9.63%	2.76%	6.87%
17	1947	25.60	1.56	-21.74%	4.77%	-16.97%	3.05%	-20.02%
18	1948	26.20	1.60	2.34%	6.25%	8.59%	3.06%	5.53%
19	1949	30.57	1.66	16.68%	6.34%	23.02%	2.78%	20.24%
20	1950	30.81	1.76	0.79%	5.76%	6.54%	2.86%	3.68%
21	1951	33.85	1.88	9.87%	6.10%	15.97%	3.29%	12.68%
22	1952	37.85	1.91	11.82%	5.64%	17.46%	3.22%	14.24%
23	1953	39.61	2.01	4.65%	5.31%	9.96%	3.38%	6.58%
24	1954	47.56	2.13	20.07%	5.38%	25.45%	3.11%	22.34%
25	1955	49.35	2.21	3.76%	4.65%	8.41%	3.35%	5.06%
26	1956	48.96	2.32	-0.79%	4.70%	3.91%	3.91%	0.00%
27	1957	50.30	2.43	2.74%	4.96%	7.70%	4.36%	3.34%
28	1958	66.37	2.50	31.95%	4.97%	36.92%	4.49%	32.43%
29	1959	65.77	2.61	-0.90%	3.93%	3.03%	4.96%	-1.93%
30	1960	76.82	2.68	16.80%	4.07%	20.88%	4.65%	16.23%
31	1961	99.32	2.81	29.29%	3.66%	32.95%	4.65%	28.30%
32	1962	96.49	2.97	-2.85%	2.99%	0.14%	4.44%	-4.30%
33	1963	102.31	3.21	6.03%	3.33%	9.36%	4.46%	4.90%
34	1964	115.54	3.43	12.93%	3.35%	16.28%	4.54%	11.74%
35	1965	114.86	3.86	-0.59%	3.34%	2.75%	4.83%	-2.08%
36	1966	105.99	4.11	-7.72%	3.58%	-4.14%	5.67%	-9.81%
37	1967	98.19	4.34	-7.36%	4.09%	-3.26%	6.67%	-9.93%
38	1968	104.04	4.50	5.96%	4.58%	10.54%	6.87%	3.67%

	Moody's Electric Utility Common Stocks					Ylds. on	Electric
Year	Yr End Avg. Mkt. Price	Avg. Divi-dent p/sh	% Market Gain/Loss	Dividend Yield	Total Return	"A" Rated Util. Bonds	Stocks vs. Bonds
1969	$ 84.62	$ 4.61	-18.67%	4.43%	-14.23%	8.59%	-22.82%
1970	88.59	4.70	4.69%	5.55%	10.25%	8.48%	1.77%
1971	85.56	4.77	-3.42%	5.38%	1.96%	7.90%	-5.94%
1972	83.61	4.87	-2.28%	5.69%	3.41%	7.48%	-4.07%
1973	60.87	5.01	-27.20%	5.99%	-21.21%	8.24%	-29.45%
1974	41.17	4.83	-32.36%	7.93%	-24.43%	10.27%	-34.70%
1975	55.66	4.97	35.20%	12.07%	47.27%	10.11%	37.16%
1976	66.29	5.18	19.10%	9.31%	28.40%	8.62%	19.78%
1977	68.19	5.54	2.87%	8.36%	11.22%	8.64%	2.58%
1978	59.75	5.81	-12.38%	8.52%	-3.86%	9.70%	-13.56%
1979	56.41	6.22	-5.59%	10.41%	4.82%	11.79%	-6.97%
1980	54.42	6.58	-3.53%	11.66%	8.14%	14.63%	-6.49%
1981	57.20	6.99	5.11%	12.84%	17.95%	16.29%	1.66%
1982	70.26	7.43	22.83%	12.99%	35.82%	14.43%	21.39%
1983	72.03	7.87	2.52%	11.20%	13.72%	13.52%	0.20%
1984	80.16	8.26	11.29%	11.47%	22.75%	13.11%	9.64%
1985	94.98	8.61	18.49%	10.74%	29.23%	10.97%	18.26%
1986	113.66	8.89	19.67%	9.36%	29.03%	9.12%	19.91%
1987	94.24	9.12	-17.09%	8.02%	-9.06%	10.98%	-20.04%
1988	100.94	8.87	7.11%	9.41%	16.52%	10.06%	6.46%
1989	122.52	8.82	21.38%	8.74%	30.12%	9.44%	20.68%
1990	117.77	8.79	-3.88%	7.17%	3.30%	9.73%	-6.43%
1991	144.02	8.95	22.29%	7.60%	29.89%	8.88%	21.01%
1992	141.06	9.05	-2.06%	6.28%	4.23%	8.43%	-4.20%
1993	146.70	8.99	4.00%	6.37%	10.37%	7.34%	3.03%
1994	115.50	8.96	-21.27%	6.11%	-15.16%	8.76%	-23.92%
1995	142.90	9.02	23.72%	7.81%	31.53%	7.23%	24.30%
1996	136.00	9.06	-4.83%	6.34%	1.51%	7.59%	-6.08%
1997	155.73	9.06	14.51%	6.66%	21.17%	7.16%	14.01%
1998	181.84	7.83	16.77%	5.03%	21.79%	6.91%	14.88%
1999	137.30	8.10	-24.49%	4.45%	-20.04%	8.14%	-28.18%
2000	227.09	8.27	65.40%	6.02%	71.42%	7.84%	63.58%
Avg. for 69 Years Ended 2000					11.13%	6.69%	4.44%
Avg. for 24 Years Ended 2024 (Page 2)					8.79%	5.02%	3.77%
Wtd. Avg. for 93 Years					10.52%	6.26%	**4.27%**
Equity Risk Premium						***USE***	***4.25%***

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
AG Workpapers

Case No.: U-21870
Exhibit No.: A-207 (AEB-3)
Page: 5 of 6
Witness: AEBulkley
Date: October 2025

MICHIGAN PUBLIC SERVICE COMMISSION **Case U-21870**

Consumers Energy - Electric Rate Case Work Pa¡ Work Paper AG-39B Pg 2 of 2

Electric Risk Premium Analysis
(Dow Jones Utility Returns by Year 2001-2024)

		Return of the Dow Jones Utilities*				A Rated
		Dec. 31	%	Div.	Total	Utility
Line	Year	Close	Change	Yield	Return	Bonds**
1	2000	412.16				
2	2001	293.94	-28.68%	3.34%	-25.34%	7.83%
3	2002	215.18	-26.79%	3.61%	-23.18%	6.93%
4	2003	266.90	24.04%	3.97%	28.01%	5.78%
5	2004	334.95	25.50%	3.87%	29.37%	5.46%
6	2005	405.11	20.95%	3.75%	24.70%	5.56%
7	2006	456.77	12.75%	3.63%	16.38%	5.83%
8	2007	537.53	17.68%	3.40%	21.08%	6.06%
9	2008	370.76	-31.03%	3.30%	-27.73%	5.99%
10	2009	398.01	7.35%	4.66%	12.01%	5.88%
11	2010	404.99	1.75%	4.38%	6.13%	5.64%
12	2011	464.68	14.74%	4.37%	19.11%	4.09%
13	2012	453.09	-2.49%	3.95%	1.46%	3.95%
14	2013	490.57	8.27%	4.00%	12.27%	4.75%
15	2014	618.08	25.99%	3.91%	29.90%	3.94%
16	2015	577.82	-6.51%	3.44%	-3.07%	4.39%
17	2016	659.61	14.15%	4.09%	18.24%	4.22%
18	2017	723.37	9.67%	3.59%	13.26%	3.60%
19	2018	712.93	-1.44%	3.57%	2.13%	4.65%
20	2019	879.17	23.32%	3.59%	26.91%	3.48%
21	2020	864.64	-1.65%	3.18%	1.52%	2.71%
22	2021	980.78	13.43%	3.38%	16.81%	2.95%
23	2022	967.40	-1.36%	2.97%	1.61%	5.25%
24	2023	881.67	-8.86%	3.16%	-5.70%	6.01%
25	2024	982.24	11.41%	3.72%	15.13%	5.54%
24	24 Year Average (Data to page 1)				**8.79%**	**5.02%**

* Per Information available from Yahoo and Value Line
** Mergent Public Utility Manual for 2001 and Bloomberg for all other data

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
AG Workpapers

Case No.: U-21870
Exhibit No.: A-207 (AEB-3)
Page: 6 of 6
Witness: AEBulkley
Date: October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case

Case No. U-21870
Work paper AG-38A
September 30, 2025
Page 1 of 1

CAPM Market Risk Premium (MRP) Analysis*

Line	Year	Large Co. Total Returns	Long-Term Gov. Bonds Income	Difference	Year	Large Co. Total Returns	Long-Term Gov. Bonds Income	Difference	Year	Large Co. Total Returns	Long-Term Gov. Bonds Income	Difference
1	1926	11.62%	3.73%	7.89%	1958	43.36%	3.27%	40.09%	1991	30.47%	8.22%	22.25%
2	1927	37.49%	3.41%	34.08%	1959	11.96%	4.01%	7.95%	1992	7.62%	7.26%	0.36%
3	1928	43.61%	3.22%	40.39%	1960	0.47%	4.26%	-3.79%	1993	10.08%	7.17%	2.91%
4	1929	-8.42%	3.47%	-11.89%	1961	26.89%	3.83%	23.06%	1994	1.32%	6.59%	-5.27%
5	1930	-24.90%	3.32%	-28.22%	1962	-8.73%	4.00%	-12.73%	1995	37.58%	7.60%	29.98%
6	1931	-43.34%	3.33%	-46.67%	1963	22.80%	3.89%	18.91%	1996	22.96%	6.18%	16.78%
7	1932	-8.19%	3.69%	-11.88%	1964	16.48%	4.15%	12.33%	1997	33.36%	6.64%	26.72%
8	1933	53.99%	3.12%	50.87%	1965	12.45%	4.19%	8.26%	1998	28.58%	5.83%	22.75%
9	1934	-1.44%	3.18%	-4.62%	1966	-10.06%	4.49%	-14.55%	1999	21.04%	5.57%	15.47%
10	1935	47.67%	2.81%	44.86%	1967	23.98%	4.59%	19.39%	2000	-9.10%	6.50%	-15.60%
11	1936	33.92%	2.77%	31.15%	1968	11.06%	5.50%	5.56%	2001	-11.89%	5.53%	-17.42%
12	1937	-35.03%	2.66%	-37.69%	1969	-8.50%	5.95%	-14.45%	2002	-22.10%	5.59%	-27.69%
13	1938	31.12%	2.64%	28.48%	1970	3.86%	6.74%	-2.88%	2003	28.68%	4.80%	23.88%
14	1939	-0.41%	2.40%	-2.81%	1971	14.30%	6.32%	7.98%	2004	10.88%	5.02%	5.86%
15	1940	-9.78%	2.23%	-12.01%	1972	18.99%	5.87%	13.12%	2005	4.91%	4.69%	0.22%
16	1941	-11.59%	1.94%	-13.53%	1973	-14.69%	6.51%	-21.20%	2006	15.79%	4.68%	11.11%
17	1942	20.34%	2.46%	17.88%	1974	-26.47%	7.27%	-33.74%	2007	5.49%	4.86%	0.63%
18	1943	25.90%	2.44%	23.46%	1975	37.23%	7.99%	29.24%	2008	-37.00%	4.45%	-41.45%
19	1944	19.75%	2.46%	17.29%	1976	23.93%	7.89%	16.04%	2009	26.46%	3.47%	22.99%
20	1945	36.44%	2.34%	34.10%	1977	-7.16%	7.14%	-14.30%	2010	15.06%	4.25%	10.81%
21	1946	-8.07%	2.04%	-10.11%	1978	6.57%	7.90%	-1.33%	2011	2.11%	3.81%	-1.70%
22	1947	5.71%	2.13%	3.58%	1979	18.61%	8.86%	9.75%	2012	16.00%	2.46%	13.54%
23	1948	5.50%	2.40%	3.10%	1980	32.50%	9.97%	22.53%	2013	32.39%	2.88%	29.51%
24	1949	18.79%	2.25%	16.54%	1981	-4.92%	11.55%	-16.47%	2014	13.69%	3.41%	10.28%
25	1950	31.71%	2.12%	29.59%	1982	21.55%	13.50%	8.05%	2015	1.38%	2.47%	-1.09%
26	1951	24.02%	2.38%	21.64%	1983	22.56%	10.38%	12.18%	2016	11.96%	2.30%	9.66%
27	1952	18.37%	2.66%	15.71%	1984	6.27%	11.74%	-5.47%	2017	21.83%	2.67%	19.16%
28	1953	-0.99%	2.84%	-3.83%	1985	31.73%	11.25%	20.48%	2018	-4.38%	2.82%	-7.20%
29	1954	52.62%	2.79%	49.83%	1986	18.67%	8.98%	9.69%	2019	31.49%	2.55%	28.94%
30	1955	31.56%	2.75%	28.81%	1987	5.25%	7.92%	-2.67%	2020	18.40%	1.53%	16.87%
31	1956	6.56%	2.99%	3.57%	1988	16.61%	8.97%	7.64%	2021	28.71%	1.73%	26.98%
32	1957	-10.78%	3.44%	-14.22%	1989	31.69%	8.81%	22.88%	2022	-18.11%	2.61%	-20.72%
33					1990	-3.10%	8.19%	-11.29%	2023	26.29%	4.03%	22.26%
34									2024	25.02%	4.78%	20.24%
35									**99 Yr. Avg.**	12.29%	4.84%	7.32%
36												
37									**MRP Based on 99 Year History**			**7.32%**

*Data from 2023 SBBI Yearbook, by Ibbotson and Duff & Phelps and for 2023 and 2024 as follows
Lg. Co. Returns www.slickcharts.com/sp500/returns by Polygon
LT Gov. Bonds Year End Yield of 30 Year US Treasury Bond per US Treasury

USE ***7.35%***

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

JESSICA R. BYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Jessica R. Byrom, and my business address is One Energy Plaza, Jackson, MI 49201.

Q. Are you the same Jessica R. Byrom who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Brittany Klocke on the topics of the Company's Low and Medium Income ("LMI") Customer Support Enhancement project and its Customer Information Technology ("IT") and IT Enhancements (Customer Self-Service Mobile Application, Web Chat AI, Web Dashboard Redesign, and Web Rebate for Personalization projects—collectively Product Family Enhancements – Customer – Capital project); Urban Core Collective's ("UCC") witnesses Sergio Cira-Reyes' and Tabitha William's testimony regarding the Company's assistance plans and affordability, including its Percent of Income Payment Plan ("PIPP"), its LMI project, and the findings of the Company's regression modeling; and the Clean Energy Organizations ("CEO") witness Boratha Tan's testimony regarding the Company's regression modeling and consequent findings.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

Staff Witness Klocke Regarding the Company's Website

Q. In much of her recommendation against the Company's various technology programs, Ms. Klocke indicates that disallowances should be based on whether the technology provides duplicative functionality with the Company's website (page 5, lines 15-18; page 6, lines 3-7; page 9, lines 20-22; page 12, lines 14-18; page 14, lines 15-16; page 15, lines 1-6; page 16, lines 8-10; and page 18, line 18). What is the Company's response?

A. As discussed in relation to each recommended disallowance noted below, the Company maintains that having duplicate channels in which a customer can choose to interact depending on their preferences, abilities, and access is reasonable. The Company has stated and reiterates here that the Mobile App and chat functions are not intended to have all the functionality of the website, nor are they intended to replace the website or other customer channels. The customer IT projects referenced by Ms. Klocke provide support for specific yet complex interactions that are not necessary in all channels of communication.

In approving the Company's Mobile App in Case No. U-21389, the Commission agreed with the Company's arguments that, "while there may be some redundancy in the functions of the app and the website, there is value in offering varying communication channels to meet customer needs. As pointed out by Consumers in its exceptions, it could be argued that there is redundancy between the functions of call centers and the company's website as both are avenues to receive customer payment. As technologies and customer preferences evolve, the Commission finds that duly supported, reasonable, and prudent expenditures to meet those preferences are appropriate for recovery." MPSC Case No. U-21389, March 1, 2024, Order, page 83.

The Company agrees with Ms. Klocke that a current and robust website is beneficial to an organization that provides a large volume and wide variety of information and resources to its customer base. The Company has requested and received support for its website redesign (Case Nos. U-21308, U-21224, and U-21490) and has been delayed in fully realizing its stated plans.

Q. What improvements have been made to the website since 2023 and what improvements are projected to be made?

A. Since 2023, the Company has made progressive improvements on the website through a regular monthly cadence of releases to bring new functionality and experience to customers. Notable improvements include navigation and homepage refresh, redesigning the account dashboard, adding additional accessibility functionality for the visually impaired, launching the Simplified Enrollment flow for LMI customers, improvements to the outage experience, and more. Additionally, the Company is in the process of migrating the Company's website from an on-premises solution to a cloud solution to enable more agile enhancements, improve the site's architecture, and ensure continued support of a critical channel for customers.

Q. Why are investments in website functionality still prudent considering a delayed website redesign?

A. Investments in Web Chat AI and the LMI Customer Support Enhancement remain important front-end enhancements to provide better service to customers, increase access to assistance and programs, and overall help customer self-service more effectively within this digital channel.

The Website Redesign Project was intended to upgrade the back-end architecture of the website to improve features for personalization for customers, alleviate potential cyber security concerns, and improve site reliability, as well as making front-end improvements for enhanced usability. Front-end improvements are still necessary and important to ensure that customers can satisfactorily be served on the website and projects like the LMI Customer Support enhancement, Web Chat AI, and website dashboard redesign would not have been in scope of the original Website Redesign Project.

Q. Why will the Company not be pursuing a total website redesign through 2028?

A. With the Company's transition to the S4HANA platform, a total website redesign would not be prudent at this time as rework would be required to connect to the new infrastructure. The Company remains committed to updating its website to provide accurate and up-to-date information for all its customers. As the Company works through the IT solutions in progress to achieve this goal, it also remains committed to growing channels utilized by customers..

Staff Witness Klocke Regarding Product Family Enhancements -Customer - Capital Project

Q. Ms. Klocke recommends several disallowances for IT projects that fall within the Product Family Enhancements Customer-Capital line. Does the Company, in general, agree with Ms. Klocke's reasoning?

A. No. The tools that Ms. Klocke puts forth for disallowance, specifically the Mobile App, Web Chat AI, Web Dashboard Redesign, and Web Rebate for Personalization, are based on industry research that showed customer desire for said applications or are being developed to provide an avenue for customers to more easily find or customize information. Two of the four projects are currently operational and utilized by customers

and consequently require updating and maintenance. For those projects previously supported in rate cases, Staff has not pointed to any circumstances that have emerged since the Commission issued orders[1] supporting these projects that should cause them to be revisited. In providing different channels of communication, it becomes a necessary obligation for the Company to update and maintain the tools customers prefer to use.

Moreover, customer enhancement projects are often small. These projects allow for quickly-made changes or fixes, or stem from emergent work. To undertake many of these projects only when the larger, more complex web redesigns take place would make them less relevant and potentially less cost effective based on timing and workload. If the Company were limited to making these small changes in alignment with larger projected work, it could be years before the small changes are implemented. This would be an ineffective use of development resources and leave customers without a dynamic experience and service.

From the emerging Web Chat AI tool to the Click to Chat tool available to business customers and the established and popular Mobile App, investments into these enhancements ensure these tools work as requested or expected. To that end, the associated investment should be considered reasonable and prudent.

[1] Mobile App-Case No: U-21389
LMI Customer Support Enhancement Project-Case No: U-21806

Q. Starting on page 5, line 1, of her testimony, Ms. Klocke has recommended a decrease of $1,056,334 in historical capital costs for the year ended December 31, 2024 and $1,305,671 in capital costs for the year ending December 31, 2025 for the Mobile Application line item in the Product Family Enhancements – Customer – Capital category. How does the Company respond?

A. The Company disagrees with several of Ms. Klocke's assertions, including that the Mobile App is duplicative of the Company's website, that the Mobile App is not being utilized as much as the website, and the overall lack of support Staff has continued to have for the app.

Q. Please explain.

A. The Company has consistently supported the development and launch of its Mobile Application for several reasons, including those outlined below. However, the primary reason the Company disagrees with any disallowance is that the Mobile Application is in existence and is in daily use by customers. Therefore, the enhancements and updates are necessary to keep the app relevant and accurate.

Q. Are there additional reasons the Company disagrees?

A. Several, which are detailed below:

1) The Commission took no position on the Mobile App in Case No. U-21224, which was settled. However, as noted above, the Commission expressly approved the Mobile App project on its merits in Case No. U-21389 finding that duplicative functionality does not negate the Company's pursuit of multiple channels in which Customers may interact with the Company.

2) The Mobile App is not a carbon copy of website functionality, nor was it conceived in this way. As the Company has stated several times, the Mobile App has separate functionality and has the added benefit of not needing a web interface to interact with the Company. The Mobile App was developed to provide a streamlined experience for customers, allowing them to complete common interactions quickly and efficiently on their phones, with features like simple login and direct access.

Q. On page 7, lines 3 through 8, Staff witness Klocke states "In the Commission Order for Case No. U-20697 part of the rationale behind the Commission's decision to disallow the requested costs for the App were because it was anticipated that just 30% of the Company's customers would use it. Now after several years of availability, the App's usage has plateaued at under 30%. That reason alone demonstrates that the App has not proved its usefulness and further cost recovery for it should be denied." What is the Company's response?

A. Since its launch, the Mobile App has continued to be extensively downloaded and utilized. As noted in Ms. Klocke's Exhibit S-10.1, the Mobile App has been downloaded 1 million times to date, and use continues to increase with a current share of digital traffic at 29.8%. This is the second most used communication channel, closely following the Mobile Website. As of September 2025, the Company has recorded over 2 million outage map views, 100,000 outage reports, and 7.9 million bill payments via the Mobile App. Additionally, "projected usage through 2025 is 16.7 million sessions, growing to 18.9 million sessions in 2026." Together, these statistics provide strong validation that the Mobile App is a popular and useful tool with increasing interest and use. While it is such, it should be supported, maintained, and responsive to customer needs. The related enhancement dollars should be allowed to support and enrich the Mobile App experience.

Q. On page 14, beginning at line 8 of her testimony, Ms. Klocke has recommended a reduction for the Web Chat AI line item in the Product Family Enhancements – Customer – Capital category, representing $157,574 in capital expenditures for the partial bridge year ending April 30, 2026 and $315,148 in capital and $19,896 in operating and maintenance ("O&M") for the partial test year ending December 31, 2026, stating Web Chat AI is redundant technology. How does the Company respond?

A. The Company maintains that chat functionality is a valued customer channel of choice—as noted by Ms. Klock herself on page 16, line 8, and as such should be supported, maintained, and updated, as necessary. Additionally, Web Chat AI remains in the early stages of enhancement and consequently cost savings are unquantified at this time. The Company remains committed to the tool as an alternative channel of interaction with the Company. Not every customer has an issue or question that rises to the level of calling a service center and the Web Chat AI tool will provide relevant information in an instant and the customer may interact according to their situation.

The Company has previously cited JD Power findings regarding chat tools, including one that found that live chat has become the leading digital contact method for online customers with 42% of customers preferring live chat compared to just 23% for email. The development and maintenance of these tools are not driven by utility preference but are a direct response to the expressed needs and expectations of the customers the Company serves. Furthermore, peer institutions have both similar tools and similar restrictions to customer assistance hours (see Help Center | DTE Energy[2] and Contact Us |

[2] https://www.dteenergy.com/us/en/quicklinks/help-center.html

AEP Energy[3]), setting Consumers Energy on equal footing with its peers, implementing best practices by providing customers with channels of choice.

Q. On page 16, beginning at line 11, Ms. Klocke has recommended a reduction for the Web Dashboard Redesign line item in the Product Family Enhancements – Customer – Capital category in the amount of $525,246 in capital costs for the bridge year ending December 31, 2025, citing overlap with the Company's LMI Project. Does the Company agree?

A. The Company notes that there is overlap between the LMI project enrollment flow and what is envisioned to be the outcome of the Web Dashboard Redesign. Both provide the Company with opportunities to (a) engage customers of all income levels by providing programs and services suited to their needs and (b) provide specialized information for the Company's LMI customers. The LMI simplified enrollment is available to all customers but is targeted to the LMI customer. The simplified enrollment streamlines the enrollment process by making it more intuitive and minimizing barriers to completion. In comparison, the Web Dashboard Redesign will provide personalized information to all customers on a standard landing page (the Account Dashboard). These are two opportunities to engage all customers, and a second opportunity for LMI customers to find the information they need.

Although the Company disagrees with the reasoning for the recommended disallowance, it is removing the related dollars in this case. Please see Company witness Baker's rebuttal testimony for additional information.

[3] https://www.aepenergy.com/contact-us/#:~:text=Chat,am%20%E2%80%93%207%3A00%20pm

Q. Please provide additional information about the scope of the Web Dashboard Redesign.

A. Customers previously lacked visibility into which programs they were enrolled, eligible, or recommended to join, including energy reduction programs, payment offerings, and demand response ("DR") initiatives. The Web Dashboard Redesign focuses on overall customer engagement, both pre- and post-enrollment in programs.

Q. On page 17, beginning at line 19, Ms. Klocke has recommended a reduction for the Web Rebate for Personalization line item in the Product Family Enhancements – Customer – Capital category in the amount of $87,541 for the partial bridge year ending April 30, 2026 and $175,082 in capital and $16,580 in O&M for the partial test year ending December 31, 2026, citing lack of information, existing information, and speculative costs. Does the Company agree?

A. No. Web Rebate personalization allows the Company to provide specialized information based on Customer input. Instead of a one-size-fits-all page of available rebates, this project can identify customers with insight into their personal situation and they may proceed accordingly. Ultimately, the customer is the beneficiary of finding rebates that fit their needs.

Although the Company disagrees with the reasoning for the recommended disallowance, it is removing the related dollars in this case. Please see Company witness Baker's rebuttal testimony for additional information.

LMI Customer Support Enhancements that Fall Under the Product Family Enhancements – Customer – Capital, and the LMI Simplified Enrollment Project

Q. In her direct testimony (page 7, starting at line 13), Ms. Klocke recommends a full disallowance of $525,246 in capital expenditures for the bridge year period ending December 31, 2025 for enhancements to the LMI Customer Support Enhancements that fall under the Product Family Enhancements – Customer – Capital, as well as total disallowance for the $1.87 million in capital expenditures for the entire LMI Simplified Enrollment project for the test year ending April 30, 2027. How does the Company respond?

A. The Company maintains its support of this LMI initiative and the belief that the tool is useful and worth support, maintenance, and additional development.

Q. Please describe the lifecycle of the LMI Support Enhancement project.

A. Since its inception, the project has shown increasing use and success.

This project was initially conceived in response to the following factors: 1) only 1 in 6 LMI customers engage in assistance programs, 2) 36% of all Consumers Energy customers assumed they are not eligible for utility payment assistance, 3) 33% lacked awareness of available assistance, and 4) 18% did not know where to start the application process. Recognizing that the LMI customer population may be growing in response to socio-economic factors, the Company's stated core functions for the project have been four-fold:

- streamlining enrollment—providing clear, step-by-step guidance through enrollment processes, and ensuring the enrollment information is mobile friendly;
- creating proactive communications—using data to proactively reach out to LMI customers with education and options;

- integrating new programs—and redesigning if necessary to meet the needs of the LMI customers; and
- continuous improvement and feedback—incorporating feedback about what works and what doesn't.

Q. What are Staff witness Klocke's recommendations for the project and its related enhancements?

A. On page 8 of her testimony, starting at line 17 and continuing through page 9, line 7, Ms. Klocke discusses the first core function of the LMI project, and its related cost ($600,0000), stating that the money is earmarked to create a structure in which customers can find and enroll in programs relevant to them and their needs. No new programs are created with this funding. She states that it is unclear why this much money is needed "for this function that amounts to directing customers where to enroll in programs" (page 9, line 7).

Q. Is this an accurate assessment of what simplified enrollment can do?

A. No. Ms. Klocke misunderstands both the investment in and the purpose of the Simplified Enrollment's User Flow. The funding request reflects the work required to continue development, testing, and maintenance of a digital tool with a personalized, human-centered interface that addresses complex processes and long-standing barriers for LMI customers. The flow itself is not merely to direct customers to or provide information on programs, it is also to assist customers in enrolling in programs that will aid in meeting their energy needs. As such, it fills a critical gap in the Company's current service model that goes beyond simply making the information available. It is a reasonable and prudent initiative that directly supports equity and ease of access for the customers who need it most.

Q. Similarly, UCC witness Cira-Reyes indicates, on page 35, lines 11-16 of his direct testimony that while appreciated, UCC has found it difficult to see the benefit of the LMI project. How does the Company respond?

A. The Company notes that Mr. Cira-Reyes understands the motivation behind the development of the LMI project. However, he also contends that the Company's assistance programs are numerous, varied, and come with an array of different qualifications (page 36, lines 13-14), and that "there is a persistent lack of information available to LMI customers on how they may sign up for these programs" (page 36, lines 17-18). The Company has made effort to simplify the assistance process via the LMI project, putting information and qualifications into a flow that helps inform the customer, narrow their view, and help them save time and money by pursuing only those programs that work with their unique circumstances.

The LMI digital tool was developed to address the very persistent challenges Mr. Cira-Reyes details throughout his testimony, such as lack of awareness, confusion about eligibility, and difficulty navigating the application process. These challenges disproportionately affect low-income households, who are often already struggling with affordability and energy insecurity. A disallowance of this project means effectively deferring meaningful relief and continuing to rely on fragmented systems that are not meeting the needs of these customers.

Q. Has the Commission supported the development of the LMI Enhancement project?

A. Yes. In its September 30, 2025 Order in Case No. U-21806, the Commission notably supported the project, stating "The need to simplify and streamline the process for LMI customers to access support is a priority of the Commission and will continue to be assessed

and refined in future proceedings. Accordingly, finding the LMI Customer Support Enhancement project to be reasonable and prudent overall (with the caveat that the Commission expects to see real progress by the company on its website redesign project)…" (page 144).

Q. Has the LMI project shown progress toward successfully meeting these goals?

A. Yes.

- Since launch, 78,000 customers have engaged with the tool, and 52,000 have self-identified as LMI, confirming strong visibility and interest from the intended user base.
- Of those engaged, 35% completed the full eligibility assessment, successfully identifying one or more programs for which they qualify.
- 25,000 customers have completed the enrollment flow, and nearly 20% enrolled in more than one offering, highlighting the tool's effectiveness in simplifying access to multiple programs.
- This streamlined experience reduces enrollment barriers and helps customers navigate offerings like Energy Waste Reduction ("EWR"), DR, Payment Plans, and Energy Assistance offerings.
- 69% of surveyed customers rated the tool "extremely easy to use."
- Direct customer comments reinforce this ease and appreciation:
  - *"Very easy to do and understand thanks. I am a senior citizen."*
  - *"This was a wonderful surprise after dealing with shutoff notices. It was easy to use and seemed designed to be user friendly."*
  - *"Thank you for the recommendations and opportunities listed! I need all the help I can get."*
- The tool has generated 52,000 new LMI self-identifications, data the Company did not previously have.
- On April 20, 2025, Green Giving was added to the simplified digital enrollment experience. In just the first hour, six customers enrolled—matching the total enrollments agencies achieved in the previous six weeks.
  - Since then, the Company has enrolled 515 low-income customers digitally in Green Giving, while agencies have enrolled 10 customers.

- By implementing the tool, the Company has reduced the need to send over 300,000 emails to promote individual products to reach enrollment goals, streamlining the Company's outreach efforts and maximizing efficiency.
- Continued success enables:
    - More effective outreach for affordability and energy efficiency programs.
    - Future offerings designed for real customer needs.
    - Advance equity goals by prioritizing Environmental Justice ("EJ") and LMI communities.

These results affirm that the tool is immediately delivering on its intended purpose: reducing enrollment barriers, increasing program visibility, and helping LMI customers more easily access the support they need. Continued monitoring and feedback collection will allow the Company to further refine the tool and expand its impact in the months ahead.

UCC Witnesses Cira-Reyes and Williams on the Company's Assistance Programs and PIPP

Q. On page 32, line 6 of his testimony, UCC witness Cira-Reyes states that the Company's bill assistance programs do NOT sufficiently address the energy burdens experienced by residential customers in its service territory. How does the Company respond?

A. As evidenced by its LMI project, the Company recognizes that some customers have a need for assistance in meeting their energy burden. Additionally, the Company must balance investment into infrastructure, safety, and reliability with the need for assistance—as recognized by Mr. Cira-Reyes on page 32, lines 1 through 2. Consequently, the Company works within the current funding and administration structures, as well as working with community agencies and assistance providers to secure and provide available assistance.

Q. On page 36, lines 17-19 of his direct testimony, Mr. Cira-Reyes states that "there is a persistent lack of information available to LMI customers on how they may sign up for these programs" and further states, at page 37, line 8, that it appears that enrollment in multiple assistance programs leads to certain customers receiving less assistance than they should. What is the Company's response?

A. These are two concrete examples of why the Company deployed the LMI Simplified Enrollment flow as discussed above. Customers can enter relevant information and receive insight into which program or programs would be most beneficial for their needs. Additionally, there is dedicated information on the Company's website detailing assistance programs, with eligibility requirements, agency contact information, and other key messages.

Q. UCC witness Williams echoes Mr. Cira-Reyes' statements, starting at page 6, lines 1 through 2, she states "Payment assistance programs are often unreliable and difficult to navigate…" How does the Company respond?

A. While it is true that there are steps that customers have to navigate to sign up for payment assistance programs, these steps are essential parts of the process at the State level to ensure compliance with income thresholds. The Company employs several strategies to ensure that customers are aware of potential program offerings, including, but not limited to: ensuring program details and enrollment requirements are available on the website; digital marketing to eligible customers letting them know about available payment assistance programs; and working with agencies to make the enrollment process as easy as possible. Additionally, this is the cornerstone behind the LMI project – lowering barriers to entry for customers to programs that can help make their bills more affordable.

The Company understands the frustration when payment programs feel unreliable, whether due to delays, unclear eligibility, or inconsistent communication. Many of these challenges stem from systemic issues outside the Company's direct control, as it does not own nor administer the programs itself. However, the Company remains deeply committed to improving customer experience and helping bridge those gaps wherever possible.

The Company actively pursues new and existing avenues of identifying and communicating with customers and specifically the LMI population as noted below:

- The Company participates in State, utility, and agency workgroups to identify barriers to enrollment, collaborate on solutions, and align communication strategies/messaging;
- The Company connects agencies to grant funding so that they may market these programs to customers at no cost, increasing awareness and access;
- The Customer Experience design and web teams work together to ensure the website clearly outlines available programs, allowing customers to filter options based on their specific needs;
- Accessible straight-forward messaging is included across posters, emails, flyers, and digital platforms to make information easier to understand and navigate;
- When customers enroll or graduate off programs, the Company often sends communications providing recommendations for next steps, such as enrollment in EWR programs or payment plan options such as Pick Your Due Date;
- The Company regularly trains the direct payment office staff and customer service representatives ("CSRs") on energy assistance programs so they can better guide customers through the complex system and connect them to the help they need;
- The Company uses journey mapping to proactively identify customers who may need help in the future, reaching out through email and call campaigns to connect them with resources before they reach a crisis point;
- The Company regularly publishes press releases and newsletters to keep the public and partner agencies informed of program updates, policy changes, and new funding opportunities;

- The Company provides millions of dollars in gift funding to support customers who may not typically qualify or to assist agencies that have exhausted their resources;
- The Company has developed tools that allow customers to input their information and receive personalized program recommendations; and
- The Company is currently exploring partnerships with agencies like 2-1-1 to improve database search optimization through grants and in-kind support.

Consumers Energy remains committed to continuing this work and connecting customers to assistance as seamlessly and effectively as possible.

Q. Also on page 6, lines 2 through 5, and later on page 30, starting at line 18, Ms. Williams suggests that some of the difficulty with assistance programs are due to inconsistent communication and a lack of proactive consumer outreach and engagement that might be remedied via more proactive engagement with community leaders and publication of the organizations with which the Company works. Mr. Cira-Reyes echoes the statement on page 77, lines 2 through 14. Please explain the Company's interaction with community leaders and assistance organizations.

A. The Company is very active in the community and works with community leaders and assistance organizations across the state. There is a dedicated staff of community outreach partners and a dedicated member of the Company's internal low-income team that works exclusively with Michigan Energy Assistance Program ("MEAP") agencies throughout the state of Michigan.

To address concerns around inconsistent communication and limited proactive outreach, Consumers Energy's Community Affairs, Energy Assistance, and EWR teams prioritize direct engagement with customers and community partners, regularly attending and hosting community events to educate customers about available offerings. A dedicated outreach energy assistance staff member connects with approximately 25 new

organizations each month and participates in around 30 customer-facing events annually across 8 counties.

Using census tract and ALICE data, along with arrears analysis, the Company identifies two primary focus areas—LMI areas with high need and untapped eligibility—to target education and intervention efforts. The outreach team also works closely with Community Affairs, External Relations, Government Affairs, and other customer-facing groups to ensure programs are promoted in meetings and events across the state, reaching a wide range of stakeholders who can help socialize these offerings to those in need.

In addition to public outreach, the team offers in-person and virtual trainings to any interested agency, providing resources such as low-literacy flyers, business cards with 2-1-1 information, and enrollment in the Company's quarterly agency newsletter to keep agencies informed of the latest updates. As part of the Company's collaboration with 2-1-1, the team identified inconsistencies in how MEAP program language was presented across agencies, which had previously caused confusion for both 2-1-1 representatives and customers. The team led an initiative to standardize that language across the system, improving clarity and alignment for all involved.

Q. On page 25, starting at line 13, Ms. Williams indicates that the Company's information is hard to understand for people with disabilities. Ms. Williams also recommends, at page 30, lines 12-17, that the Company's representatives be trained in multiple languages. How does the Company respond?

A. The Company offers the option for customers to converse with a CSR in Spanish through the Company's Contact Center. However, expanding language access is not feasible and would not be cost effective.

Q. Similarly, on page 30, lines 8 and 9, UCC witness Williams echoes Mr. Cira-Reyes' statement about customers being unaware that assistance programs exist until "they are already in crisis." Consequently, Ms. Williams urges the Company to automatically enroll customers in Winter Protection and assistance plans without any required applications as the application process often requires the involvement of a third party and is difficult to navigate. How does the Company respond?

A. Requirements exist at the state level to qualify customers for energy assistance, and the Company expanding access to customers outside of those programs would put that burden on existing customers to subsidize those costs. Programs that delay shut offs for customers with affordability concerns preclude those customers from receiving State Emergency Relief ("SER"). The Company does proactive marketing to customers that might be eligible for programs ahead of being in crisis and this is the cornerstone of the LMI project--to help make customers proactively aware of program offerings that can help them if they are struggling to pay their bills.

To help combat the concern of customers only becoming aware of assistance programs when they are in crisis, Consumers Energy's Energy Assistance team invests in proactive outreach strategies, including customer journey mapping and segmentation, to identify those at risk and connect them to help before they reach a critical point. The team uses data to anticipate need and launch targeted email and call campaigns to intervene early. While the Company does automatically enroll customers who receive the Home Heating Credit ("HHC") into the Winter Protection Plan, some customers have called to disenroll, expressing frustration that they were not given a choice. It is important to note that while Winter Protection helps prevent shutoffs during the cold months, it does not address

long-term affordability. In fact, customers often exit the program with a larger, more difficult-to-manage balance. That is why the team prioritizes connecting customers to comprehensive, sustainable assistance plans like the Consumers Affordable Resource for Energy ("CARE") program, that promote long-term energy security and help them make lasting changes.

Additionally, this year the Company partnered with the Essential Needs Task Force to support efforts aimed at identifying areas of greatest need within the community. By leveraging insights into customer trends and service usage, this collaboration helped guide outreach and funding strategies, particularly in geographical areas facing the most significant challenges. The Company remains committed to improving access, reducing barriers, and doing everything within its control to connect customers to assistance as seamlessly and effectively as possible.

Q. In subsequent testimony, Mr. Cira-Reyes states that the Company is "knowingly charging rates that are unaffordable, which leads customers to choose among basic needs." (page 40, lines 9-10). Is this an accurate characterization?

A. No. In general, agencies[4] work individually with the customer to evaluate needs, present program options, and allow the customer to decide which program best fits their needs. Consumers Energy does not directly validate income or gather household and income data from customers. As a result, the Company does not have an accurate method for calculating customers' energy burden. Instead, this responsibility is assigned to the agencies who maintain customer relationships, to provide the intended support. The Company charges

[4] Residential Income Credit (RIA), Residential Senior Credit (RSC) and the Low-Income Assistance Credit (LIAC) are administered by the Company.

rates. The Company then provides information, energy-saving programs, and opportunities to seek assistance.

Q. On page 37, starting at line 16 and continuing through page 38, line 9, Mr. Cira-Reyes provides a hypothetical application of multiple assistance credits as applied to a qualifying account, and concludes that it appears that the hypothetical application "made the customer's bill $63.59 more expensive each month." How does the Company respond?

A. The Company does not agree with this characterization of credit application. In this hypothetical scenario, the assistance credits in each case help lower the customer's energy bill, billed for energy they have used. The Company has many programs available to assist customers lower their overall energy usage via EWR programs, DR, time of use rates, appliance recycling, participating in the green giving program (which also provides bill credits), and more. When added to the available assistance, a customer's bill is effectively less expensive per month.

Q. On page 36, lines 4 through 6 of his direct testimony, Mr. Cira-Reyes states "Many households that are at or above 150% of the FPL cutoff also struggle to pay their energy bill and do not receive assistance from Consumers currently." How does the Company respond?

A. The Company recognizes that social and economic factors are creating economic concerns across a broad spectrum of customers, including the moderate-income customers. Moderate income customers are typically capable of paying a bill but may be insecure or without funds for one or more billing cycles due to emergencies, changes in employment, or increased cost of other commodities. The Company has recently expanded its assistance

focus to include this moderate-income customer, focusing on energy efficiency and other methods of saving on their energy costs.

UCC Witness Cira-Reyes and PIPP

Q. Mr. Cira-Reyes recommends a solution for a unified, universally applicable LMI solution and Ms. Williams (page 31, line 7) concurs. What do they suggest?

A. Starting on page 41, line 11, of his direct testimony, Mr. Cira-Reyes supports a PIPP, "an individual income-based alternative to the mix of programs that Consumers offers currently."

Q. What is a PIPP?

A. A PIPP is a payment program based on a fixed percentage of customer income, providing an outcome that is by its nature individualized to that customer.

Q. Has the Company initiated a PIPP program?

A. Yes. As detailed in the Company's May 1, 2025 Report, the Company filed an application for ex parte approval of a PIPP pilot for natural gas and combination customers on March 9, 2021, in Case No. U-21021. The Company revised its application in its December 3, 2021 filing to include electric customers. The Commission issued an order on February 10, 2022, in Case No. U-21021 approving the Company's amended application for a PIPP pilot for both electric and natural gas services. The Company implemented and evaluated a PIPP pilot exploring additional ways to support households under 150% of the Federal Poverty Level ("FPL").

Q. What were the conclusions of the PIPP pilot?

A. As referenced in the filing, the results were threefold:

- Although the program metrics were comparable to those of existing Affordable Payment Plans ("APP"), the cost of maintaining a PIPP would be substantially

higher. This increase in cost would be particularly pronounced if PIPP were extended to all active low-income customers.

- The analysis determined that low-income customers are both successful and satisfied with the existing CARE programs, which are supported by MEAP.
    - New Legislation and significant work have been accomplished in partnership with state lawmakers, the MPSC, Community Action Agencies, and utilities across Michigan aimed at reforming MEAP to expand eligibility and funding.
- Considering all the cross-functional efforts to enhance MEAP and maintain a consistent customer experience, while also reducing customer confusion by modifying historic program designs, Consumers Energy recommends continuing with the existing MEAP and its current APP, CARE MB, to fully realize the benefits of the reform.

Q. How does Mr. Cira-Reyes respond to the conclusions in the report?

A. Mr. Cira-Reyes states his belief, at page 43, lines 6 through 7, of his direct testimony, that the Company has not "explained sufficiently why it will not implement a PIPP program." He then continues to discuss the Company's conclusions, including discussion on page 43, line 38, of his direct testimony indicating that "the Company recommended abandoning the PIPP program, citing 'substantially higher' costs. Specifically, the Company estimated that PIPP would cost $232 million per year in comparison to CARE MB, which would cost an estimated $156 million per year."

Q. Is this an accurate summary?

A. Yes. The Company reached this conclusion based on the data collected in the pilot.

Q. Were there other factors in the Company's decision not to pursue a PIPP?

A. While the financial cost/benefit analysis contributed to the recommendation to not pursue a PIPP plan, additional factors included success and continued customer satisfaction with other existing APPs.

Q. On page 44, startling at line 1 of his direct testimony, Mr. Cira-Reyes states that the Company "measured the benefit of these programs in terms of their disconnection rates. I believe energy affordability, especially for customers most in need, is a more important metric and should be factored into the decision about whether Consumers should move forward with a PIPP program." Later, on page 46, lines 3 through 11, of his direct testimony, he also recommends that the Commission require the Company to adopt a PIPP. How does the Company respond?

A. As noted, the Company has reported on its PIPP pilot in the open and active Case No. U-21021 docket. At the present time, the opportunity to comment on the pilot, the report, and any suggested guidelines for assistance programming remains most appropriate in that docket.

The Company's Regression Analysis

Q. On page 53, starting at line 7, of his direct testimony, Mr. Cira-Reyes discusses the Company's regression analysis and findings. What is the history of the regression analysis?

A. In this case, a regression analysis was conducted and submitted in response to two Commission actions. In its Order in Case No. U-21389, the Commission directed the Company to conduct a regression analysis related to EJ reliability. While the Company pursued a study in 2024, a regression analysis was not presented in Case No. U-21585. In its final Order in Case No. U-21585, the Commission directed the Company to additionally include information about residential shutoffs in its regression analysis. In the first quarter of 2025, the Company conducted the required regression analysis.

Q. What were the findings of the analysis related to the Customer space?

A. As noted in my direct testimony on page 45, lines 19-21, the analysis found that when all other modeled variables are held constant increasing Percentage Minority Population in a census tract is statistically significant and associated with increasing disconnection rate.

Q. On page 53, lines 11 through 12, of his direct testimony, Mr. Cira-Reyes states "In other words, and to be direct, there is a racial bias in the Company's shutoff rates." In lines 15 through 16, he further argues that "Consumers confirmed in discovery that those employees have access to customers' names and addresses, which can nonetheless serve as race-identifying data points." What is the Company's response to these statements?

A. The Company responds that at this point in its analysis there may well be a racial component to the Company's shutoff rates, but there is no racial bias, and certainly no purposeful bias. There are numerous factors that go into a Company-supported shut off, and neither race nor socio-economic stats are included.

As noted in the Company's response to a UCC discovery question (please reference Exhibit UCC-51), only a select group of the Company's employees have access to or need customer names and addresses for various tasks and communications. Typical customer information and account data available to the Company's employees is detailed in the UCC exhibit. To insinuate that employees associate names and addresses with disconnection in any way and race in the disconnection process is groundless speculation. Furthermore, when processing remote disconnections, which comprise the bulk of the residential disconnections processed annually, Company employees can only see the internal customer account number eligible for disconnection and not the customer's name or

address, further reducing any bias Mr. Cira-Reyes is insinuating exists within the Company's process.

If either element were found to be true after assessment, appropriate corrective action would be taken.

Q. How has the Company addressed the Percentage Minority Population significance finding?

A. The Company committed to standing up a cross-functional team to examine data relevant to the regression analysis, customer data related to payment behaviors, reviewing customer processes, etc. The cross-functional team includes members from credit & collections, data analytics, community affairs, and Diversity, Equity, and Inclusion.

Q. Has the Company's assessment lead to any conclusions or actions?

A. While the Company originally committed to completing its assessment in September 2025, the timeline has been expanded to December 31, 2025 to allow for additional input and analysis.

Q. On page 53, lines 7 through 8, of his direct testimony, Mr. Cira-Reyes takes issue with this timeline, stating "regression analysis revealed racial disparities in shutoff data for which the Company has provided neither an explanation nor concrete mitigation plans." How does the Company respond?

A. As noted above, the Company has committed to addressing the issue noted in the regression analysis. This is a complex and complicated finding that requires not only additional assessment but also planning and coordination for any identified solutions.

Q. Beginning on page 8 of his direct testimony, CEO witness Tan also discusses the regression analysis. What are his conclusions?

A. On page 12, lines 19 through 20, and continuing on page 13, Mr. Tan notes that the Company provided an analysis updated between filing and Staff and Intervenor testimony. He requests, on page 13, lines 2 through 5, of his direct testimony, that the Company provide an update in this rebuttal testimony.

Q. What updates can the Company report?

A. The Company is currently completing cross-functional problem solving to understand payment behaviors of customers and will have an update to share at the end of 2025.

Q. Mr. Tan also recommends, on page 13, lines 5 through 7 of his direct testimony, that "the Company continue to run Exponent's regression analysis on residential disconnections to track its progress to address any potential inequitable disconnection rates." How does the Company respond?

A. Since the initial regression results were communicated, the Company has conducted robust cross-functional problem solving to identify potential point of cause and design a pilot to test countermeasures. The pilot is scheduled to begin next month and the Company plans to share results at the end of 2025. The Company would be open to having further conversation on revisiting the regression analysis within an aligned timeframe that allows adequate time for the Company's pilot actions to conclude and inform next steps.

Q. On page 14, lines 13 through 17, of his direct testimony, CEO witness Tan states "Both Exponent's and the CEO's disconnection regression analyses demonstrate that the Company's disproportionately impacts BIPOC households. Until Consumers proposes a solution to mitigate this disparity, I request the Commission issue a moratorium on residential disconnections." Similarly, UCC witness Cira-Reyes, on page 54, lines 17 through 19, of his direct testimony, calls for a moratorium on shut-offs, stating at page 55, lines 1 through 4, that if a moratorium is not required the Company will continue to create compensable harm. What is the Company's response?

A. The Company recognizes that the findings of the regression analysis require and are worthy of analysis. The intersection of race and energy disconnections is a topic much larger than one glance and one conclusion. The Company must assess many layers of operations, procedures, and even access to come to a final assessment and action plan. As noted, the Company has committed to this analysis and self-scrutiny.

Requiring the Company to stop disconnections would have a negative effect on all customers, with associated cost and cost recovery compromised. Additionally, a disconnection moratorium would not stop customers from accruing bills and could put customers in a position for their energy bills to become unaffordable due to past due balances. Finally, to receive SER funding customers must be in possession of a shut-off notice, meaning that customers would be locked out from receiving assistance to help make their bills more affordable.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Amy M. Conrad, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Amy M. Conrad who previously submitted testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut the direct testimony and exhibits presented by witnesses for the Attorney General and the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") regarding Consumers Energy Company's ("Consumers Energy" or the "Company") incentive compensation plan and the recommendations to exclude incentive compensation costs from the revenue requirement in this case. For the reasons discussed in my direct testimony and in this rebuttal testimony, the Commission should find that the incentive compensation costs linked to operational measures that Consumers Energy is seeking to recover in this case are a reasonable cost of doing business and should be included in rates. Consumers Energy has acted reasonably in paying its employees at market levels. It would be unreasonable not to allow the Company to have that reasonable and appropriate business expense recovered in rates.

Q. How is your rebuttal testimony organized?

A. In Section I of my rebuttal testimony, I address the direct testimony and exhibits presented by Attorney General witness Sebastian Coppola. In Section II, I address the direct testimony and exhibits presented by Staff witness Theresa McMillan-Sepkoski.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

I. REBUTTAL TO ATTORNEY GENERAL WITNESS COPPOLA

Q. At page 178, lines 12 through 13, of his direct testimony, Mr. Coppola states: "Generally, the Company's short-term incentive plans are too heavily weighted toward financial measures that mostly benefit shareholders and not customers." Do you agree?

A. No, the Company is not requesting recovery of any Employee Incentive Compensation Plan ("EICP") dollars in this case related to the financial metrics**.** The Company in this case is seeking recovery only for the incentive costs at target level associated with the operational goals portion of the short-term incentive (EICP) for both non-officers and all officers. Consumers Energy has adopted incentives that are designed to emphasize operational performance criteria in areas that are critical to the Company's utility business and customers. Focusing employees on these goals provides both qualitative and quantitative benefits for Consumers Energy's utility customers.

Q. At page 179, lines 11 through 14, Mr. Coppola states: "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." Do you agree?

A. No. Employees, as a whole, must re-earn the incentive/at-risk portion of compensation each year. Moving to a banded goals payout for each operational measure sets minimum (thresholds), targets, and maximum payout. The Company is only seeking recovery of target level payout. It is common market practice to use individual goals that set minimums (thresholds), targets, and maximum goals (banded goals) with payout percentages based on level of achievement. Structuring the payout to consider performance of each goal

individually also ensures that employees have an independent motivation to achieve each goal regardless of whether another goal may be off target to meet payout levels during the year. This removes any potential mis-incentive to "give up" on one goal just because another may have become unlikely to be achieved. Each goal has the ability to earn an EICP payout on its own achievement, so every goal remains important and employee motivation to attain each goal individually remains high.

Rewarding employees for the level of achievement aligns pay for performance. Employees know what the minimum level of achievement is to receive a payout and have visibility to what above target rewards they can receive for over achievement. This structure motivates employees to attain the target or goal but still allows for recognition for some below target performance and additional reward for above target performance.

If the threshold to achieve a payout was set at a level viewed as unachievable, it would be difficult to maintain employee motivation and would result in less customer benefits. Overall compensation levels including the EICP are established at a target (100%) level that is not excessive. The incentive compensation portion of the Company's total compensation ensures that employees are provided a reasonable incentive to achieve exceptional performance levels. The Company's proposal to include incentive compensation costs at target levels will result in the Company absorbing the incentive compensation costs in those years when the actual payouts are greater than target level. Thus, shareholders will absorb any resulting increase in costs arising from above target performance.

Q. At page 179, lines 15 through 16, of his direct testimony, Mr. Coppola states: "[T]he fact that the performance measures use CMS Energy financial information and comingle electric and gas business measures is a concern." Do you agree?

A. No. For purposes of efficiency and improved service, the Company has combined operations and structured the incentive goals to deliver customer value through continuous improvement, safety, quality, cost, delivery, morale, and financial performance measures. Performance in these areas is critical for the Company's success in its electric public utility business. For that reason, the incentive plan contains both gas and electric measures. The related incentive expense is then allocated between electric and gas businesses based on multiple factors determined by the Accounting Department based on the type of activities the departments or business units perform. These factors include but are not limited to: (i) percentage of time; (ii) property, plant, and investments; (iii) operating revenue; (iv) headcount; and (v) labor. The quantified benefits relate to overall Company priorities. Both electric reliability and methane emission reduction are essential to the Company's organizational priorities. The Company ensures the EICP is quantified to ensure electric customers pay for the benefits they receive and given the combined Company operations it is reasonable to include both goals in the EICP. The value specifically for electric customers far exceeds the total EICP costs allocated to electric customers.

Q. At page 180, of his direct testimony, Mr. Coppola states: "The Company has indicated that it continues to pay salary increases each year with increases well above the rate of inflation over the last five years". Do you agree?

A. No. For rate making purposes, the Company follows the direction of the Commission's Order in Case No. U-20963 and uses the same inflation factor to adjust both labor and

non-labor expenses for determining projected labor costs. Consumers Energy's compensation is designed to be competitive with what is seen in the labor market including rewarding and motivating talent rather than trying to keep up with inflation.

Q. At pages 180 through 182 of his direct testimony, Mr. Coppola discusses various reasons that he disagrees with the Company's request to recover incentive compensation costs in rates. Do the concerns and issues he has identified in his direct testimony provide a valid basis to not allow any recovery of incentive compensation costs in rates?

A. No. I disagree with his analysis and his conclusions. Mr. Coppola's conclusion that Consumers Energy's incentive compensation plans do not benefit customers is not correct. A wide body of research supports the view that, when properly selected and implemented, as has been done with the Consumers Energy plans, incentives motivate employees, focus employees on a company's goals, and increase both individual work performance and team performance. The overall compensation levels are reasonable. The incentive compensation is part of the overall reasonable compensation level, not an addition to it.

Q. At page 183 of his direct testimony, Mr. Coppola states that "the average achievement rate for the past five years was 66%." Do you agree?

A. No. I disagree with his analysis and his conclusions. The EICP operational payouts averaged 105% as illustrated in Part III_086 (years 2020 through 2023) and U21870-AG-CE-0672_Conrad_ATT_1 (2024) and shown in the table below:

Performance Year	Operational Goal Payout %
2020	125%
2021	75%
2022	109%
2023	94%
2024	124%
5 Year Average	105%

The Company is requesting recovery of target level payout for operational measures only. When setting payout levels, the threshold is set at a level of achievement that can typically be reached 80 to 90% of the time in a ten-year period. Maximum payout is for exceptional performance (10% to 20% of the time in a 10-year period). These levels are to engage the employees in meeting the goals. Employees must re-earn the incentive at-risk portion of compensation each year. If the threshold to achieve a payout were set at a level viewed as not achievable, it would be difficult to maintain employee motivation and would result in fewer customer benefits. When goals are challenging yet achievable, employees are motivated to increase productivity and performance to achieve the goal.

II. REBUTTAL TO STAFF WITNESS MCMILLAN-SEPKOSKI

Q. What is the pay process for officer incentive targets?

A. As stated on page 21 of my direct testimony, Consumers Energy creates a compensation package for officers that delivers base salary, annual incentives, and long-term incentives (excluded from the Company's request in this rate case) targeted at the 50th percentile of the market, as defined by a Compensation Peer Group approved by the Compensation Committees of the Boards of Directors. Annually, the Compensation Committees engage an independent third-party consultant to provide advice and information regarding compensation practices of a Compensation Peer Group.

Q. Is survey data information for the third-party consultant proprietary information?

A. Yes. Consumers Energy's Compensation Committees engage an independent third-party consultant to provide information regarding officer compensation practices of the Compensation Peer Group as well as additional information from Willis Towers Watson published surveys of compensation in the public utility sector and general industry.

The Willis Towers Watson survey sources used by Pay Governance are produced solely for use by database participants and are maintained by Willis Towers Watson in connection with the participant's own internal human resources management department. The surveys are the confidential and proprietary work product of Willis Towers Watson, which owns all related intellectual property rights. Pay Governance has written consent from both Willis Towers Watson and CMS Energy to use the surveys on CMS Energy's behalf. Pay Governance is prohibited from using or reproducing the database and survey reports prepared by Willis Towers Watson.

Q. Is the proprietary nature of officer compensation the reason the Company did not provide Staff with the compensation level of the top five officers compared to market median referenced in Staff Exhibit S-9.2?

A. Yes. As illustrated in the Company's response shown in Staff Exhibit S-9.2, the market median information requested is confidential, proprietary, and commercially sensitive data belonging to third parties. Consumers Energy is contractually prohibited from sharing this information.

Although the Company is prohibited from sharing the market data used in setting compensation for its top five officers, the Company recognizes that it could be helpful for Staff to have access to some market data to evaluate the reasonableness of the

compensation included in rates for the Company's top five officers. Therefore, the Company compiled and provided non-confidential market data using the following compensation elements from the Compensation Peer Group's publicly filed proxy statements: salary, stock awards, and non-equity incentive.

Because this market data uses only publicly available non-proprietary information, it does not perfectly represent the information that the Company used to benchmark and assist the Compensation Committee to determine compensation for Consumers Energy's top five officers. But, that does not support the conclusion that it is inadequate to support the level of compensation for the Company's top five officers. First, the proprietary benchmarking information alone does not mechanically decide how compensation will be set. When making pay adjustments, the Compensation Committee considers the CEO's recommendations, along with proprietary Compensation Peer Group data, internal equity, tenure, and other proprietary market data from surveys provided by the independent compensation consultant. Actual compensation decisions are based on the following as described on page 22 through page 26 in my testimony. Second, the data provided in Exhibit A-74 (AMC-4) is sufficiently consistent with the proprietary data that it does allow Staff to see a valid comparison of the compensation of the highest paid through the 2nd, 3rd, 4th, and 5th highest paid named officers compared to the Company's compensation peer group. As Staff indicated, it was able to review the proprietary Pay Governance report under the following conditions set forth by the proprietary owners, Pay Governance:

> That it will review these materials in the presence of an appropriate representative of CMS and shall keep these extracts strictly confidential and shall not copy or distribute these extracts to any other party, shall use them solely for the purpose of this inquiry and shall exempt Pay Governance

from public disclosure under any other inquiry or applicable freedom of information or open records acts.

As the owner of the reports, these were the conditions Pay Governance set forth. The report contained the same data shared with the Compensation Committee of the Board for their decision making on officer compensation.

Q. Do you agree with Staff's recommendation to exclude the top five officer operational goal annual incentive expense?

A. No. As stated above, having the officers hold specific operational measures provides a stronger linkage to Company operational incentive priorities that support customer benefits. This is a result of the addition of 30% of officer pay directly linked to operational measures. Starting in 2022, the officer operational goal modifier was removed, and the operating cash flow measure was replaced with the same operational measures as non-officers with a weighting of 30%.

In previous cases, the Company regarded the work performed by the top five officers as focused broadly across the entire CMS Energy enterprise; however, in light of the move to a 30% weighting on Consumers Energy-specific operational measures for EICP, we now have a measurable component of their compensation linked directly to work on behalf of the utility and to operational outcomes that benefit customers. Under the Company's current proposal in this case, shareholders continue to bear 100% of the cost of incentive compensation for financial measures and above target operational measure performance.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

PATRICK D. DALY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Patrick D. Daly, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Patrick D. Daly who previously presented direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to:

- Respond to Attorney General ("AG") witness Sebastian Coppola's recommendations regarding the accounting treatment of the Company's SAP S4/HANA project;
- Address arguments and recommendations from AG witness Coppola and Citizens Utility Board of Michigan ("CUB") witness Richard J. Bunch concerning the Company's Low Voltage Distribution ("LVD") forestry ramp-up proposal;
- Rebut recommendations from Natural Resources Defense Council, Sierra Club, and CUB (collectively "MNSC") witness Douglas B. Jester related to the Company's LVD pole replacement investments;
- Respond to AG witness Coppola's recommendation regarding the Company's working capital cash balance; and
- Present an adjusted revenue deficiency reflecting the rebuttal position of Consumers Energy witnesses.

Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-208 (PDD-63)	Adjusted Revenue Deficiency for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-209 (PDD-64)	Adjusted Rate Base for the Projected 12-Month Period Ending April 30, 2027;

Exhibit A-210 (PDD-65)	Adjusted Utility Plant for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-211 (PDD-66)	Capital Spending Reconciliation for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-212 (PDD-67)	Adjusted Working Capital for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-213 (PDD-68)	Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-214 (PDD-69)	Reconciliation of Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-215 (PDD-70)	Adjusted Operations & Maintenance Expenses for the Projected 12-Month Period Ending April 30, 2027;
Exhibit A-216 (PDD-71)	Income Tax Effect of Interest for the Projected 12-Month Period Ending April 30, 2027; and
Exhibit A-217 (PDD-72)	Interest Synchronization Adjustment for the Projected 12-Month Period Ending April 30, 2027.

Q. Are there any statements you would like to make regarding your rebuttal testimony?

A. Yes. Items not specifically addressed in my rebuttal testimony should not be construed to indicate my agreement with them.

Accounting for SAP S4/HANA

Q. Please describe AG witness Coppola's recommendations regarding the SAP S4/HANA project.

A. On page 95 of his direct testimony, Mr. Coppola indicates that the project is too premature to justify including any capital expenditures in this rate case. He also recommends the Commission reject the Company's proposal to defer forecasted operating and maintenance ("O&M") costs into a regulatory asset citing his perception of a lack of firm project execution plans. Additionally, while not explicitly addressed, Mr. Coppola appears to

oppose the Company's accounting proposal to extend the amortization period for the cloud implementation costs related to the SAP S4/HANA Software as a Solution ("SaaS") solutions to 15 years.

Q. Does the Company agree that SAP S4/HANA costs should not be included in this case?

A. No. Company witness Stacy H. Baker continues to support the inclusion of the SAP S4/HANA project, as outlined in her rebuttal testimony.

Q. Do you agree with Mr. Coppola that the accounting requests related to the SAP S4/HANA project should be denied?

A. No. As explained in my direct testimony, approving the deferral of O&M expenses will allow the Company to align cost recovery with the period over which the project delivers benefits. The same rationale applies to the request to amortize cloud implementation costs over 15 years. These proposals help mitigate customer rate impact by smoothing expenses over the life of the project. Mr. Coppola offers no specific critique of these accounting requests beyond asserting that the project is too preliminary for inclusion in this case.

Q. Has the Commission previously approved the Company's requested accounting treatment for SAP S4/HANA investments?

A. Yes. In the Commission's September 30, 2025 Order in Consumers Energy's gas rate case, Case No. U-21806, the Commission agreed with Consumers and found "*the company's request to defer investment O&M expense over the 15-year life of the project and to amortize cloud computing costs associated with the project over the same 15-year period will lessen impacts to customer rates*" (page 226). This supports the Company's proposed accounting treatment, and I recommend the Commission reject Mr. Coppola's proposal.

LVD Forestry Ramp Up

Q. Please describe the Company's proposal with respect to its LVD Line Clearing Program expenditures in this case.

A. As outlined in my direct testimony, the Company is proposing to increase its LVD Line Clearing Program O&M expenditures significantly above historical levels to obtain a five-year clearing cycle and more aggressive line clearing on targeted three-phase primary lines. Additionally, the Company requested approval to defer "ramp-up" or "incremental expenditures" above a defined "baseline" expense as a regulatory asset once the ramp-up begins and through its completion (i.e. beginning in 2026 and through the 2030-2031 test period). As explained in my direct testimony, the benefit of this proposal is to better match the benefits provided by the "ramp-up" to the recovery of costs and to mitigate rate impact to customers.

Q. Did the MPSC Staff ("Staff") or other intervenors oppose the Company's proposed "ramp-up" spending levels or the request to defer such costs to a regulatory asset?

A. No. In fact, there is broad support for the Company's total proposed LVD O&M expenses and the proposal to defer "ramp-up" costs to a regulatory asset. The following excerpts from the parties' testimony illustrate this support:

- AG witness Coppola, "*agree[s] in principle with the proposal to defer the line or tree clearing costs above a reasonable threshold*" (page 174, lines 14 to 15).
- CUB witness Bunch testified, "*I support the Company's operational plan and spending level, which I consider to be consistent with the recommendations of the Liberty Audit. I also agree that the line clearing surge costs should be held as regulatory assets*" (page 39, lines 12 to 14).
- Staff witness Duell indicated, "*Staff supports the requested $186,684,000 for the projected test year O&M expense. It is crucial to allow Consumers to spend the full amount for line clearing to increase the resiliency of Consumers Energy's electric distribution system"* (page 7, lines 23 to 25) and

> "*Staff supports the Company's proposal to recover LVD line clearing O&M spending in the test period as a regulatory asset*" (page 8, lines 16 to 17).

Given the absence of opposition and broad support from intervenors, I recommend the Commission approve the Company's proposal to defer ramp-up forestry costs as a regulatory asset.

Q. Is there any opposition to the Company's proposed cost recovery mechanism for the resulting forestry "ramp-up" regulatory asset?

A. Yes. As explained in my direct testimony, the Company proposed securitizing the regulatory asset once it reaches an appropriate balance. This was conditional upon receiving a return on the regulatory asset at the Company's prevailing weighted average cost of capital ("WACC") during the "ramp-up" period and until securitization takes place. However, both Staff witness Duell and AG witness Coppola opposed this approach, contending that the Company should only earn a return at its short-term debt rate. Company witness Marc R. Bleckman addresses these concerns in his rebuttal testimony, reaffirming support for the Company's original cost recovery proposal and defending the use of WACC as a fair and reasonable return.

Q. Please describe any other opposition raised with respect to the Company's forestry "ramp-up" proposal.

A. Baseline expenses represent the amount of funding that is included in rates for the test year. Under the Company's proposal, any expenses incurred above the defined baseline would be deferred to the regulatory asset. On page 174 on his direct testimony, AG witness Coppola asserts that the Company has calculated "baseline" O&M expenses that are too high, which results in a reduced opportunity to defer and securitize a higher amount of tree clearing costs. CUB witness Bunch makes a similar assertion on pages 39 through 40 of

his direct testimony, arguing the Company's approach to calculate the "baseline" O&M expense is speculative.

Q. How did AG witness Coppola and CUB witness Bunch develop their proposed LVD Line Clearing O&M baseline?

A. On page 175 of his direct testimony, Mr. Coppola indicates that the historical period (2024) forestry expenses represents a reasonable baseline of tree clearing expenses for the projected test year "baseline." Mr. Bunch also utilizes 2024 historical spend but adjusts the baseline figure for inflation factors to arrive at the projected test year amount as described on page 40 of his direct testimony.

Q. Do you agree with this approach?

A. I do not. The approach taken by AG witness Coppola and CUB witness Bunch is overly simplistic and fails to reflect the operational and strategic planning embedded in the Company's acceleration to a five-year LVD line clearing cycle as supported by Company witness Sara E. Stewart's direct and rebuttal testimony. Mr. Coppola and Mr. Bunch's reliance on 2024 historical spending, either directly or with minimal inflation adjustments, ignores the Company's demonstration that the cost of achieving the ramp-up (and the resulting future "steady-state maintenance" of the cycle) is significantly higher than maintaining historical levels of expense in which the Company was on a seven-year effective cycle. Their approach disregards changes that are appropriately considered in a projected test year. The use of a projected test year is intended to account for such forward-looking changes.

Company witness Stewart provided detailed direct testimony outlining the fundamental shift in operations required to transition to a five-year LVD line clearing

cycle. Her testimony also supported the estimated annual expense to maintain the LVD system on a five-year cycle in a steady state once the cycle is achieved in 2031. The expense assumptions within her testimony and supporting exhibits were built on factors such as overall crew resourcing, the elimination of all back-log miles, the consideration of overtime for both local and out-of-state tree crews, among other items. The projected test year "baseline" expense was derived from this forward-looking analysis and brought back to test period dollars. Notably, no intervenor disputed the Company's total LVD Line Clearing O&M request for the projected test period, which was built utilizing these assumptions.

The methodology proposed by Mr. Coppola and Mr. Bunch appears designed to suppress the test year "baseline," thereby limiting the Company's ability to recover a substantial portion of O&M costs within the LVD expense included in base rates. Company witness Bleckman's rebuttal testimony describes the negative credit implications of adopting a lower baseline. Coupled with Mr. Coppola's proposal to allow only a short-term debt rate on the regulatory asset, this punitive approach undermines the reliability goals of the program which have broad support in this case and are consistent with the Liberty Consulting Group ("Liberty") Audit recommendations adopted by the Commission. Additionally, the methodology used to establish the baseline should be weighed against the Company's deliberate effort to balance reliability improvements with customer affordability. Once again, by deferring and securitizing these costs, the Company is mitigating immediate customer rate impacts.

For these reasons, the baseline methodology proposed by Mr. Coppola and Mr. Bunch lacks merit. I continue to support Company witness Stewart's approach to

calculating the LVD baseline expense for the test year as reasonable, well-supported by the evidence in this case, and aligned with long-term reliability objectives. I recommend that the Commission adopt the Company's methodology for calculating the LVD baseline line clearing expenses and reject the alternative proposals offered by Mr. Coppola and Mr. Bunch.

Q. Do you have any final observations related to Mr. Coppola and Mr. Bunch's recommendation for the proposed baseline level of forestry expense?

A. Yes. As discussed above, Mr. Coppola uses the Company's actual 2024 forestry spend of $110.2 million as the basis for his proposed baseline. On page 40 of his direct testimony, Mr. Bunch applies an inflation adjustment to the Company's 2024 actual forestry expense to yield a baseline of approximately $114 million.

Company witness Stewart's direct testimony, specifically Figure 20, outlines authorized and actual forestry spending across the Company's five most recent rate cases. This data shows a consistent upward trend, reflecting the Company's commitment to achieving a shorter forestry cycle. In the Company's most recent rate case, Case No. U-21585, the Commission authorized the Company to spend approximately $125 million in forestry. This currently authorized amount is in excess of Mr. Coppola and Mr. Bunch's proposed baseline amounts. The continued upward trend in both actual and authorized spending supports the reasonableness of the Company's proposed baseline. It would be unreasonable to set the baseline level of forestry expense below currently authorized spending levels, particularly as the Company transitions to a more aggressive five-year forestry cycle that requires increased investment. Therefore, Mr. Coppola and Mr. Bunch's proposed baseline levels are too low and should be rejected by the Commission.

LVD Pole Replacement Surge Proposal

Q. What does MNSC witness Jester recommend with respect to LVD pole replacements?

A. On page 16 of his direct testimony, Mr. Jester recommends the Commission order the Company to defer and propose securitization of its projected spending for a surge in LVD pole replacements. Mr. Jester proposes a baseline spending amount for LVD pole replacements of $25 million and recommends that all pole replacement costs exceeding this amount be considered as surge expenditures.

Q. How do you respond?

A. I disagree with Mr. Jester's proposal. First, the Company objects to the use of securitizations for these investments in its distribution system. Historically, utility securitizations have been reserved for the recovery of stranded costs associated with assets that no longer provide a benefit to customers and/or material non-recurring expenses. The decision to propose securitization for the forestry ramp up expenditures was made to mitigate the rate impacts from the increase in this operating expense. It was also intended to spread the cost to customers more evenly over the time horizon of the anticipated benefits.

Unlike line clearing, which is a recurring operational expense, capital investments such as LVD pole replacements result in long-lived assets that provide long-term benefit to customers and merit inclusion in the Company's permanent capital structure. These expenditures should be recovered through traditional rate base treatment, allowing for depreciation over time and proper cost allocation across the customers who benefit. For these reasons, I recommend the Commission reject Mr. Jester's proposal.

Working Capital Cash Balance

Q. Please describe AG witness Coppola's recommendations regarding the Company's cash balance included in working capital.

A. On pages 102 through 103 of his direct testimony, Mr. Coppola recommends that the Company's projected test year cash balance included in working capital of $50.4 million be reduced by $41.4 million to $9.0 million. He arrives at this figure by first calculating a three-year average cash balance of $25.1 million, then removing $16.1 million of cash held in interest-bearing accounts, which he argues should not be included in working capital. Mr. Coppola asserts that his calculation of a $9.0 million cash balance more accurately reflects the Company's operational cash needs.

Q. How do you respond?

A. I do not agree with Mr. Coppola's proposed methodology. Company witness Bleckman refutes the AG's position with respect to the Company's projected cash balance of $50.4 million. Furthermore, even if the Commission were to reject the Company's methodology to calculate its projected working capital cash balance, it should not adopt Mr. Coppola's flawed proposal.

First, it is inappropriate to exclude cash held in interest-bearing accounts from the working capital calculation. These funds are maintained in unrestricted operating accounts and are readily available to meet the Company's short-term liquidity and operational needs. Moreover, the interest income generated from these accounts is included as a direct offset to the revenue requirement. This treatment is reflected in the projected Net Operating Income shown on Exhibit A-13 (PDD-37), line 6.

Second, even if the Commission rejected the Company's proposed approach as described by Company witness Bleckman, which it should not, then the appropriate cash balance should be the historical 13-month average of $36.4 million as shown on Exhibit A-12 (PDD-34), line 1 (column d), not a three-year average balance as proposed by Mr. Coppola. It is the long-standing practice of the Company, and one accepted by the Commission, to calculate working capital utilizing a 13-month average of historical balances. Mr. Coppola's methodology results in an understatement of the Company's actual working capital cash needs.

I recommend the Commission reject Mr. Coppola's arguments and adopt the Company's as-filed capital cash balance of $50.4 million as supported by Company witness Bleckman.

Adjusted Revenue Deficiency

Q. Please describe Exhibits A-208 (PDD-63) through A-217 (PDD-72).

A. Exhibits A-208 (PDD-63) through A-217 (PDD-72) present the calculation of the Company's adjusted revenue deficiency for the projected 12-month period ending April 30, 2027. As shown on Exhibit A-208 (PDD-63), line 10, column (e), the Company has recalculated a test year revenue deficiency of $407.7 million, a reduction of $28.2 million from the Company's original filing in this case.

Q. Why is the Company proposing an adjusted test year revenue deficiency?

A. Based on certain facts and circumstances revealed subsequent to filing the case, the Company believes it is appropriate and necessary to make certain adjustments.

Q. Please summarize the proposed adjustments to the revenue deficiency.

A. The Company has made the following adjustments to its originally filed revenue deficiency:

1. Total decrease to net utility plant of $37.2 million, depreciation expense of $1.3 million, and property taxes of $0.5 million. A list of the individual adjustments, with descriptions and sources, is provided in Exhibit A-210 (PDD-65) and Exhibit A-211 (PDD-66);

2. Total decrease of $0.7 million to other O&M. A list of the individual adjustments, with descriptions and sources, is provided in Exhibit A-215 (PDD-70); and

3. A decrease in the Company's calculation of overall cost of capital from 6.35% to 6.30% as described in the rebuttal testimony of Company witness Bleckman.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-21870

EXHIBITS

OF

PATRICK D. DALY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Revenue Deficiency
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-208 (PDD-63)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source - Adjustments	(c) Initial Filing {1}	(d) Adjustments	(e) Rebuttal Position
1	Rate Base	Exhibit No.: A-209 (PDD-64)	15,367,518	(37,159)	15,330,358
2	Adjusted Net Operating Income	Exhibit No.: A-213 (PDD-68)	707,746	11,243	718,989
3	Overall Rate of Return	Line 2 / line 1	4.61%	0.08%	4.69%
4	Required Rate of Return	Exhibit No.: A-187 (MRB-22)	6.35%	-0.05%	6.30%
5	Income Required	Line 1 * line 4	975,589	(9,433)	966,156
6	Income Deficiency (Sufficiency)	Line 5 - line 2	267,843	(20,675)	247,167
7	Revenue Conversion Factor		1.3381	1.3381	1.3381
8	Revenue Deficiency (Sufficiency)	Line 6 * line 7	358,395	(27,665)	330,730
9	Return On - Campbell Regulatory Asset	Ex. A-81 (PDD-57), Line 5	77,486	(502)	76,984
10	Adjusted revenue deficiency (sufficiency)	Line 8 + Line 9	435,881	(28,167)	407,714

Notes

{1} Source: Exhibit No.: A-11 (PDD-28)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Rate Base
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-209 (PDD-64)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source - Adjustments	(c) Initial Filing {1}	(d) Adjustments	(e) Rebuttal Position
1	Total Utility Plant	Exhibit No.: A-211 (PDD-66)	19,958,747	(38,248)	19,920,498
2	Depreciation Reserve	Exhibit No.: A-211 (PDD-66)	(6,650,643)	1,089	(6,649,554)
3	Customer Advances for Construction	-	(66,473)	-	(66,473)
4	Net Utility Plant	Sum of lines 1 through 3	13,241,630	(37,159)	13,204,471
5	Working Capital	Exhibit No.: A-212 (PDD-67)	2,125,887	-	2,125,887
6	Total Rate Base	Line 4 + line 5	15,367,518	(37,159)	15,330,358

Notes

{1} Source: Exhibit No.: A-12 (PDD-31)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Utility Plant
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-210 (PDD-65)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Utility Plant	(d) Depreciation Reserve	(e) Net Utility Plant
1	Utility Plant - Initial Filing	Exhibit No.: A-12 (PDD-31)	19,958,747	(6,650,643)	13,308,103
	Adjustments				
2	Update to 2025 HVD Substatio	Exhibit No.: A-211 (PDD-66), line 1	(10,992)	437	(10,555)
3	EGLE-MIEJ Grant Work	Exhibit No.: A-211 (PDD-66), line 2	(3,479)	93	(3,386)
4	Facilities - Other Equipment	Exhibit No.: A-211 (PDD-66), line 3	(49)	1	(48)
5	Facilities - Emergent Repairs	Exhibit No.: A-211 (PDD-66), line 4	(474)	4	(471)
6	LVD Lines Capacity	Exhibit No.: A-211 (PDD-66), line 5	(9,360)	140	(9,220)
7	ARP Collaboration Project	Exhibit No.: A-211 (PDD-66), line 6	(116)	13	(103)
8	Service Restoration Artificial Int	Exhibit No.: A-211 (PDD-66), line 7	(59)	7	(52)
9	HVD New Business - Cancellec	Exhibit No.: A-211 (PDD-66), line 8	(10,310)	154	(10,156)
10	Peer-Peer Automation	Exhibit No.: A-211 (PDD-66), line 9	(1,030)	20	(1,010)
11	CVR Underspending	Exhibit No.: A-211 (PDD-66), line 10	(1,617)	53	(1,564)
12	ARP-Field Device Asset Manag	Exhibit No.: A-211 (PDD-66), line 11	(62)	7	(55)
13	Product Family Enhancements	Exhibit No.: A-211 (PDD-66), line 12	(525)	140	(385)
14	Product Family Enhancements	Exhibit No.: A-211 (PDD-66), line 13	(175)	20	(155)
15	Total Adjustments	Sum of lines 2 through 11	(38,248)	1,089	(37,159)
16	Utility Plant - Rebuttal Position	Line 1 + line 15	19,920,498	(6,649,554)	13,270,944

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Spending Reconciliation
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-211 (PDD-66)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
				Cap Ex Adj. Increase / (Decrease)						Projected Test Year Impacts					
Line No.	Description	Schedule B-5 Category	Source	12-Mo Ended 12/31/24 Increase / (Decrease)	12-Mo Ending 12/31/25 Increase / (Decrease)	4-Mo Ending 04/30/26 Increase / (Decrease)	12-Mo Ending 04/30/27 Increase / (Decrease)	Composite Deprec. Rate	Property Tax Rate	Total CapEx Adjustment Increase / (Decrease)	Avg. Plant Adjustment Increase / (Decrease)	Avg. Accum. Deprec. Increase / (Decrease)	Avg. Net RB Increase / (Decrease)	Deprec. Increase / (Decrease)	Prop. Tax Increase / (Decrease)
1	Update to 2025 HVD Substations Reliability Spending	Electric Distribution - Distribution	Staff witness Durfee	-	(10,992)	-	-	2.98%	1.33%	(10,992)	(10,992)	(437)	(10,555)	(328)	(147)
2	EGLE-MIEJ Grant Work	Electric Distribution - Distribution	AG - Coppola	-	(1,385)	(1,385)	(1,420)	2.98%	1.33%	(4,189)	(3,479)	(93)	(3,386)	(104)	(46)
3	Facilities - Other Equipment	Operations Support -Common Other	Staff witness Hunter	-	-	-	(98)	5.15%	1.33%	(98)	(49)	(1)	(48)	(3)	(1)
4	Facilities - Emergent Repairs	Operations Support -Common Stuctures	Staff witness Hunter	-	-	-	(949)	1.56%	1.33%	(949)	(474)	(4)	(471)	(7)	(6)
5	LVD Lines Capacity	Electric Distribution - Distribution	Staff witness Boutet	-	-	-	(18,720)	2.98%	1.33%	(18,720)	(9,360)	(140)	(9,220)	(279)	(125)
6	ARP Collaboration Project	Information Technology - Intangibles/Compu	Staff witness Zichi	-	-	(46)	(139)	20.00%	1.33%	(185)	(116)	(13)	(103)	(23)	(2)
7	Service Restoration Artificial Intelligence Project	Information Technology - Intangibles/Compu	Staff witness Duell	-	-	(31)	(57)	20.00%	1.33%	(88)	(59)	(7)	(52)	(12)	(1)
8	HVD New Business - Cancelled Project	Electric Distribution - Distribution	ABATE - Fitzhenry	-	-	-	(20,619)	2.98%	1.33%	(20,619)	(10,310)	(154)	(10,156)	(307)	(138)
9	Peer-Peer Automation	Electric Distribution - Distribution	AG - Coppola	-	-	(895)	(270)	2.98%	1.33%	(1,165)	(1,030)	(20)	(1,010)	(31)	(14)
10	CVR Underspending	Electric Distribution - Distribution	Staff - Boutet	-	(1,159)	(92)	(733)	2.98%	1.33%	(1,984)	(1,617)	(53)	(1,564)	(48)	(22)
11	ARP-Field Device Asset Management	Information Technology - Intangibles/Compu	Staff witness Zichi	-	-	(25)	(74)	20.00%	1.33%	(99)	(62)	(7)	(55)	(12)	(1)
12	Product Family Enhancements - Customer - Capital (We	Information Technology - Intangibles/Compu	Staff witness Zichi	-	(525)	-	-	20.00%	1.33%	(525)	(525)	(140)	(385)	(105)	(7)
13	Product Family Enhancements - Customer - Capital (We	Information Technology - Intangibles/Compu	Staff witness Zichi	-	-	(88)	(175)	20.00%	1.33%	(263)	(175)	(20)	(155)	(35)	(2)
14	Total		Sum of lines 1 through 10	-	(14,060)	(2,561)	(43,254)			(59,875)	(38,248)	(1,089)	(37,159)	(1,294)	(511)

Notes

Source: Col. (h): WP-PDD-24
Source: Col. (i): Exhibit No.: A-161 (BJV-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Working Capital
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-212 (PDD-67)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Initial Filing {1}	(c) Adjustments	(d) Rebuttal Position
1	Cash, cash equivalents, and restricted cash	$ 50,385	$ -	$ 50,385
2	Accounts and notes receivable	280,141	-	280,141
3	Fuel Stock	64,489	-	64,489
4	Materials and supplies	216,848	-	216,848
5	Allowances	14	-	14
6	Prepayments	933,846	-	933,846
7	Accrued revenue	329,191	-	329,191
8	Deferred taxes	272,280	-	272,280
9	Deferred debits	998,077	-	998,077
10	Total assets	3,145,271	-	3,145,271
11	Accounts payable	474,206	-	474,206
12	Customer deposits	22,955	-	22,955
13	Accrued interest	66,062	-	66,062
14	Dividends payable	24,539	-	24,539
15	Accrued taxes	256,080	-	256,080
16	Other liabilities	72,728	-	72,728
17	Deferred credits	102,814	-	102,814
18	Total liabilities	1,019,384	-	1,019,384
19	Working capital	$ 2,125,887	$ -	$ 2,125,887

Notes

{1} Source: Exhibit No.: A-12 (PDD-34)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-213 (PDD-68)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Initial Filing {1}	(c) Adjustments {2}	(d) Rebuttal Position
1	Sales Revenues	4,758,415	-	4,758,415
2	Other Revenues	262,208	-	262,208
3	Total Operating Revenue	5,020,623	-	5,020,623
4	Power supply costs	2,313,242	-	2,313,242
5	Other O&M Expense	804,952	(694)	804,259
6	Depreciation and Amortization	813,088	(1,294)	811,793
7	Property Taxes	280,500	(511)	279,989
8	General Taxes	36,638	-	36,638
9	Other (Local) Taxes	1,150	(55)	1,095
10	State Income Tax	33,324	(1,813)	31,511
11	Federal Income Tax	46,009	(6,875)	39,135
12	Total Operating Expenses	4,328,903	(11,242)	4,317,662
13	Net Operating Income	691,720	11,242	702,961
14	AFUDC	16,026	1	16,027
15	Net Operating Income, Including AFUDC	707,746	11,243	718,989
	Net Operating Income Adjustments			
16	Income Tax Effect of Interest {3}	---- Included in Lines 12, 13, and 14 ----		
17	Interest Synchronization Adjustment {3}	---- Included in Lines 12, 13, and 14 ----		
18	Total Adjusted Net Operating Income	707,746	11,243	718,989

Notes

{1} Source: Col.(b): Exhibit No.: A-13 (PDD-36)
{2} Source: Col.(c): Exhibit No.: A-214 (PDD-69)
{3} Income tax effects of interest and interest synchronization adjustments are included in the calculation of local, state, and federal income tax. The separate calculations can be found on Exhibit No.: A-216 (PDD-71) Exhibit No.: A-217 (PDD-72)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Reconciliation of Adjusted Net Operating Income
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-214 (PDD-69)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Sales Revenues	(d) Other Revenues	(e) Pwr Supply Costs	(f) Other O&M	(g) Deprec. & Amort.	(h) Property Taxes	(i) General Taxes	(j) CIT	(k) SIT	(l) FIT	(m) NOI	(n) AFUDC	(o) Adjusted NOI
1	Adjusted Net Operating Income - Initial Filing	Exhibit No.: A-13 (PDD-36)	4,758,415	262,208	2,313,242	804,952	813,088	280,500	36,638	1,150	33,324	46,009	691,720	16,026	707,746
	Adjustments														
2	HVD Lines Reliability	AG - Coppola	-	-	-	(677)	-	-	-	1	35	134	506	-	506
3	Product Family Enhancements - Customer - Capit	Staff witness Zichi	-	-	-	(17)	-	-	-	0	1	3	12	1	13
4	Depreciation	Exhibit No.: A-211 (PDD-66) col.(r	-	-	-	-	(1,294)	-	-	2	68	257	967	-	967
5	Property Tax Expense	Exhibit No.: A-211 (PDD-66) col.(c	-	-	-	-	-	(511)	-	1	27	101	382	-	382
6	General Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-
7	Income Tax Effect of Interest	Exhibit No.: A-216 (PDD-71)	-	-	-	-	-	-	-	(57)	(1,866)	(7,074)	8,997	-	8,997
8	Interest Synchronization Adjustment	Exhibit No.: A-217 (PDD-72)	-	-	-	-	-	-	-	(2)	(78)	(297)	378	-	378
9	Total Adjustments	Sum of lines 2 through 8	-	-	-	(694)	(1,294)	(511)	-	(55)	(1,813)	(6,875)	11,242	1	11,243
10	Adjusted Net Operating Income - Rebuttal Position	Line 1 + line 9	4,758,415	262,208	2,313,242	804,259	811,793	279,989	36,638	1,095	31,511	39,135	702,961	16,027	718,989

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Operations & Maintenance Expenses
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-215 (PDD-70)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	Description	Initial Filing {1}	Adjustments {2}	Rebuttal Position
	(a)	(b)	(c)	(d)
1	Electric Distribution & Restoration	300,994	(677)	300,317
2	Forestry	186,684	-	186,684
3	Generation	103,732	-	103,732
4	Operations Support	13,600	-	13,600
5	Information Technology Operations	55,297	-	55,297
6	Information Technology Investments	24,789	(17)	24,773
7	Information Technology - Security Operations	11,362	-	11,362
8	Information Technology - Security Investments	1,513	-	1,513
9	Customer Interactions	23,532	-	23,532
10	Billing & Payment	11,427	-	11,427
11	Demand Response	34,630	-	34,630
12	Pension Plans A/B	(45,156)	-	(45,156)
13	Defined Company Contribution Plan	16,507	-	16,507
14	401(k) Employees' Savings Plan	12,731	-	12,731
15	Active Health Care/Life Insurance/LTD	33,385	-	33,385
16	Retiree Health Care and Life Insurance	(48,867)	-	(48,867)
17	Other Benefits	2,780	-	2,780
18	Pension/OPEB Volatility Mechanism Amortization	(99)	-	(99)
19	Corporate Services	36,968	-	36,968
20	Uncollectible Expense	20,274	-	20,274
21	Injuries & Damages	5,083	-	5,083
22	Incentive Compensation	2,211	-	2,211
23	Job Work Expense	1,278	-	1,278
24	Interest expense on security deposits	298	-	298
25	Total Other O&M Expense	$ 804,952	$ (694)	$ 804,258

Notes

{1} Source: Col. (e), Exhibit No.: A-13 (PDD-41)
{2} Source: Col. (g), Exhibit No.: A-214 (PDD-69)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Income Tax Effect of Interest
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-216 (PDD-71)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exhibit No.: A-209 (PDD-64)	15,330,358
2	Weighted Cost of Debt, Excluding JDITC	Exhibit No.: A-187 (MRB-22)	0.0186
3	Allowable Interest Expense	Line 1 * Line 2	285,481
4	Projected Pro-Forma Interest Expense - Initial Filing	Exhibit No.: A-13 (PDD-49)	249,872
5	Increase/ (Decrease) In Allowable Interest Deduction	Line 3 - Line 4	35,609
6	Impact on Taxable Income	Line 5 * -1	(35,609)
7	Impact on Local Income Taxes	Line 6 * Local Income Tax Rate	(57)
8	Impact on State Income Taxes	Line 6 * State Income Tax Rate	(1,866)
9	Impact on Federal Taxable Income	Line 6 - Line 7 - line 8	(33,686)
10	Impact on Federal Income Tax	Line 9 * Federal Income Tax Rate	(7,074)
11	Impact on Net Operating Income	(Line 7 + Line 8 + Line 10) *-1	8,997

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Interest Synchronization Adjustment
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-217 (PDD-72)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exhibit No.: A-209 (PDD-64)	15,330,358
2	JDITC Debt-Related Portion of the Capital Structure	Exhibit No.: A-187 (MRB-22)	0.0023
3	Portion of Rate Base Funded by JDITC	Line 1 * Line 2	34,903
4	Cost of JDITC - Debt Portion	Exhibit No.: A-187 (MRB-22)	0.0443
5	Allowable JDITC Interest Expense	Line 3 * Line 4	1,545
6	Projected Pro-Forma Interest Expense - Initial Filing	Exhibit No.: A-13 (PDD-50)	51
7	Increase/ (Decrease) in Allowable JDITC Interest Expense	Line 5 - Line 6	1,494
8	Impact on Taxable Income	Line 7 * -1	(1,494)
9	Impact on Local Income Tax	Line 8 * Local Income Tax Rate	(2)
10	Impact on State Income Tax	Line 8 * State Income Tax Rate	(78)
11	Impact on Federal Taxable Income	Line 8 - Line 9 - line 10	(1,414)
12	Impact on Federal Income Tax	Line 11 * Federal Income Tax Rate	(297)
13	Impact on Net Operating Income	(Line 9 + Line 10 + Line 12) *-1	378

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

EMILY A. DAVIS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Emily A. Davis, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Emily A. Davis who previously submitted direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to cost of service issues raised in the direct testimony of Citizens Utility Board of Michigan ("CUB") witness Richard J. Bunch and Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and CUB (collectively "MNSC") witness Caroline Palmer.

Q. Are you sponsoring any exhibits?

A. No.

Q. How is your rebuttal testimony organized?

A. My rebuttal testimony is organized as follows:

I. <u>Distribution Reliability Roadmap Cost Allocation</u>

II. <u>EAC Report & Distribution Cost Allocation</u>

III. <u>AMI Meter Cost Allocation</u>

IV. <u>MAOAM Project Cost Allocation</u>

Q. Please provide a summary of your recommendations.

A. The Consumers Energy Company ("Consumers Energy" or the "Company") recommends that the Michigan Public Service Commission ("MPSC" or the "Commission") adopt the Cost of Service Study ("COSS") proposals outlined in my direct testimony and: (i) reject

Mr. Bunch's proposal to have the Company conduct an analysis of the Company's allocation of distribution reliability investments and propose changes in its next Electric Rate Case; (ii) reject Ms. Palmer's proposal to reject the Company's allocation of distribution costs including batteries and criticism of the Electric Asset Categorization ("EAC") Report (iii) reject Ms. Palmer's proposed allocation of Advance Meter Infrastructure ("AMI") meters and continuation of the AMI business case; and (iv) reject Ms. Palmer's proposed allocation of Multi-Account Online Account Management ("MAOAM") project costs. Company witness Laura M. Connolly responds to Ms. Palmer's proposals related to data centers.

I. Distribution Reliability Roadmap Cost Allocation

Q. On page 42 of his revised direct testimony Mr. Bunch states he has concerns with how the Company is allocating its Reliability Roadmap (or the "Roadmap") spending stating that "Reliability improvements are allocated using the same factors as other distribution system expenditures but may not have the same cost causation." What is your response?

A. There is nothing fundamentally different about the Company's investment in distribution infrastructure and maintenance in the Roadmap. The Company has always made investments in reliability; the Roadmap is simply a reference to the Company's formal plans to invest in its distribution system to achieve 2nd Quartile System Average Interruption Duration Index (SAIDI) excluding Major Event Days. To the extent the Roadmap calls for investments in different types of distribution equipment, those results

will be reflected in the COSS and allocated using Commission approved allocators for that equipment.

Q. On page 47 of his revised direct testimony Mr. Bunch states "I recommend the Commission require the Company to conduct an analysis of its allocation methodology for distribution costs, particularly to the extent that distribution investments are justified on the basis of reliability and propose revisions as part of its next rate case." What is your response?

A. In addition to being unnecessary, practically speaking, it's unclear how Mr. Bunch would have the Company break out and isolate the Roadmap and/or reliability investment in the COSS. The COSS breaks out distribution costs by FERC account and in some cases, voltage level and related details. The Company has not undertaken any study or analysis of the time and resources it would take to isolate/breakout Roadmap related projects within the existing COSS categories.

Finally, while Mr. Bunch raises general concerns about distribution cost allocation, he provides no specific recommendation of different allocators to use. Mr. Bunch (or any intervenor) is free to develop and propose specific changes to the COSS allocators for consideration by the Company, Staff, Intervenors and the Commission. For the reasons I list above the Commission should reject Mr. Bunch's proposal.

II. <u>EAC Report & Distribution Cost Allocation</u>

Q. On page 17 of her direct testimony Ms. Palmer states that she disagrees with the new EAC report and recommends that "…the Commission reject Consumers' proposed new distribution COSS allocations to downstream-voltage customers based on the updated EAC report." She also recommends that the Company reconsider the voltage

categories built into the COSS and offer recommendations in its next rate case. What is your response?

A. Ms. Palmer appears to conflate her concerns about the allocation factors applied to Low Voltage Distribution ("LVD") assets and the EAC report itself, which simply serves to provide more robust detail on the Company's substation, land and High Voltage Distribution ("HVD") line distribution assets.

The EAC report did not change the categorization of LVD energized lines, line equipment or batteries from the Company's last rate case nor did it fundamentally change how distribution costs are allocated. The Company's use of Class Peak and the logic underpinning the allocation of distribution facilities in this case is consistent with what the Commission has approved in the past. Ms. Palmer proposes that the Commission reject the Company's allocation of distribution costs to LVD connected customers but does not offer any specific alternative allocator(s) for the Commission to consider.

Regarding the Company's voltage categories, the Company has not changed and has no plans to change its voltage level definitions which align with the Company's tariff and internal asset classification and management. Ms. Palmer's vague recommendation to reconsider the Company's voltage classifications is not accompanied by any proposed alternative or clear benefit/value.

Q. On page 17 of her direct testimony, Ms. Palmer argues that the new EAC categories introduce a false precision that is no longer fully representative of reality. What is your response?

A. It appears as though Ms. Palmer is arguing that the EAC report categories offer more precision than what in her view is needed. Nothing prevents Ms. Palmer or other

intervenors from aggregating detail from the EAC Report or proposing the same allocator for multiple line items in the COSS.

Q. On page 16 of her direct testimony, Ms. Palmer states that "Due to bidirectional power flows, lower voltage assets are now being used to serve some of the requirements of higher voltage customers; therefore, higher voltage customers benefit from (and thus help cause) costs related to low voltage assets and should pay a fair share of these costs." What is your response?

A. As explained in the rebuttal testimony of Company witness Scott A McPhail, the extent of bidirectional power flow between the LVD and HVD system is de minimis. The rare occasion when bi-directional power flow occurs does not fundamentally change what has caused/driven the Company to build out and maintain the infrastructure on its LVD system. Ms. Palmer's argument about bidirectional power flow is not new or suddenly more relevant because of the EAC report which as stated above only serves to provide better more transparent information about the Company's land, substation and HVD line facilities.

Q. On page 18 of her testimony Ms. Palmer states that the Company has not demonstrated that batteries only serve LVD customers and proposes that Consumers allocate distribution batteries to all distribution customers. What is your response?

A. The EAC report made no changes to the breakout or allocation of battery costs in the COSS which was proposed by the Company and approved by the Commission with no objections from Staff and intervenors in the Company's 2023 ERC (Case No. U-21389). Nothing has materially changed from 2023 to the present case.

The COSS treats distribution-related battery plant the same way it treats other distribution plant assets because they are deployed to serve a similar purpose. Currently the only distribution batteries in service are connected to the LVD system which is why they are allocated to LVD customers. Ms. Palmer argues that batteries benefit customers across all distribution levels, presumably a reference to her argument on bi-directional power flow, but as discussed above those rare occurrences are not what is causing the Company to invest in LVD batteries.

III. AMI Meter Cost Allocation

Q. How does the Company allocate meter plant in service in the COSS?

A. The Company allocates meter plant in service using a weighted customer allocator (allocator 170) which takes into account the number of customers and the cost of the meter since primary rate customers' meter costs are higher than residential customers. Using an allocator based solely on customer count (allocator 160) would assign over 87% of meter plant to residential customers but the weighted customer (allocator 170) assigns 60%.

Q. On pages 7 through 8 of her testimony Ms. Palmer states that technology and cost responsibility are changing rapidly and that AMI meters are being used to provide a host of benefits (reduced energy theft, peak demand reduction, and energy consumption savings) which should cause the Commission to rethink how AMI meter costs are allocated. What is your response?

A. While AMI meters provide several benefits, the fact remains that the installation and investment in a meter is driven by the need to connect and serve a customer. The existence of other benefits does not change the fact that the addition of a customer requires a meter.

The Company's weighted customer allocator appropriately captures how customers drive the utilities investment in metering infrastructure.

Ms. Palmer cites rapidly changing technology however AMI meters and the benefits they provide are not new; the Company began to fully deploy electric AMI meters in its service territory nearly 15 years ago and during that time the Commission has consistently relied on the weighted customer allocator to fairly apportion meter costs amongst customer classes.

Q. On pages 9 through 10 of her testimony Ms. Palmer outlines her proposal to allocate AMI meter plant using a new AMI allocator weighted 36% on total energy use, 17% on Class Peak and 47% on the existing meter allocator. She explains that she arrived at these percentages by categorizing AMI benefits from the Company's most recent AMI business case as either customer, demand or energy related. What is your response?

A. The total impact to customers from Ms. Palmer's proposed changes to meter cost allocation are unclear and difficult to determine in part because she does not address the allocation of non-AMI meters which are included in the Company's meter plant (FERC 370). Less than 0.04% of AMI meters serve primary rate customers[1] but Ms. Palmer's proposed composite allocator for AMI costs would assign 22% of AMI meter costs to primary rate customers.

Ms. Palmer's categorization of the avoided costs from the AMI business case is also oversimplified. She assumes, for example, that the benefits from "AMI Induced Conservation & Energy Efficiency" accrue to all customers in proportion to the total energy allocator. Her justification appears to be that the benefit is energy related so must accrue

[1] =690/1,950,536 Consumers Response to U21870-ABATE-CE-0758

(and should be allocated) to all customers based on energy use. This view provides no consideration or comparison of whether energy use truly captures the realization of the different benefits (e.g. system benefits from lower peak energy usage and the AMI customer's direct energy savings) to customers. In addition, Ms. Palmer proposes to divide the entire AMI meter cost between these benefits without considering/comparing the cost of a non-AMI meter to calculate the AMI "premium" incurred to realize those benefits.

For the reasons above the Commission should reject Ms. Palmer's proposed AMI meter cost allocator and her request for the Company to continue producing and filing an AMI business case.

IV. MAOAM Cost Allocation

Q. On page 20 of her testimony Ms. Palmer recommends that the Company continue to break out MAOAM project costs in the COSS and proposes that the Company develop a new allocator based on the proportion of customers that have multiple logins which she states is currently only Commercial & Industrial ("C&I") customers. What is your response?

A. As outlined in the Company's response to discovery request U21870-MNSC-CE-215 approximately 115,000 residential customers have multiple accounts and could use the MAOAM tool compared to approximately 40,000 C&I customers. Around 50,000 customers manage a combination of residential and C&I accounts. Today the Company uses a third-party tool (Bill Trust) that is only available to C&I customers which does not reflect future utilization of the MAOAM tool which will be made available to all customers. If the Company were to develop an allocator based on the proportion of customers by class that could use the tool (e.g. multiple logins) that attributes 100% of the combination

accounts to C&I, 56.2% of MAOAM costs would be allocated to the residential class compared to 62.7% using the existing COSS labor allocator cited by Ms. Palmer.

The Company was previously ordered to break out MAOAM costs because that tool was only going to be available to C&I customers. That is no longer true. Therefore, the Company believes MAOAM costs should be allocated in the same manner as other IT projects which negates the need to separately identify and allocate MAOAM costs in the COSS.

While Ms. Palmer may maintain the importance of doing a MAOAM study in the Company's future rate cases to account for that difference, the Company believes that precision, while a reasonable objective, needs to be considered in the context of the benefit and cost of providing that detail. The COSS is responsible for allocating over $5.4 billion and the revenue requirement associated with the MAOAM project in the test year is approximately $0.30 million. Allocating 62.7% of those costs to residential customers amounts to $0.19 million compared to $0.17 million using the 56.2% figure. Performing and filing a study in every rate case for a project that has a 1/10,000 of a penny impact on residential rates does not warrant the internal and external resources to do that study and sets an unrealistic precedent for any and all future projects and customer offerings.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

MATTHEW J. FOSTER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Matthew J. Foster, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Matthew J. Foster who previously presented direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the following arguments and recommendations made by Sergio Cira-Reyes on behalf of Urban Core Collective ("UCC"):

- The Michigan Public Service Commission ("MPSC" or the "Commission") should require Consumers Energy to provide detailed descriptions of each of its corporate memberships in future rate applications;
- The Commission should disallow recovery of corporate memberships where there is no clear benefit to customers and where a significant portion of membership dues are used to fund political advocacy; and
- The Commission should disallow recovery of the entirety of Consumers Energy's Edison Electric Institute ("EEI") membership fees of $770,775.

Q. What is UCC's reasoning for requesting the Commission to require the Company to provide detailed descriptions of each of its corporate memberships in future rate cases?

A. As stated on pages 80 (starting on line 5) and 81 of UCC witness Cira-Reyes' direct testimony, "[t]he company provided limited information about its corporate

memberships[and] could initially only estimate a maximum of $8,353 in corporate membership costs disclosed in the O&M expenses." On page 81, line 10, UCC witness Cira-Reyes states, "[t]his cost discrepancy is concerning because the Company has provided neither a sufficient description of the benefits and functions related to the…membership dues and fees that the Company seeks to recover, nor a sufficient explanation for how these membership dues are accounted for in Corporate Services O&M expenses." UCC witness Cira-Reyes continues on page 81, line 18, stating, "Consumers' lack of transparency and lack of sufficient explanation of each trade membership makes recovery unjustified."

Q. Does the Company agree that there has been a lack of transparency related to corporate memberships in the initial filing?

A. No. The Company does not agree there was a lack of transparency surrounding its corporate memberships. Workpaper WP-PDD-18 of Company witness Patrick D. Daly in this instant case discloses the Company's corporate memberships, including the total cost of the memberships, the disallowed lobbying-related expenses, and the amount of membership dues disallowed pursuant to the MPSC's Order in Case No. U-15245.

Q. Does the Company agree to provide descriptions of each of its corporate memberships in future electric rate case applications?

A. Yes. The Company agrees to provide descriptions along with the associated benefits of its corporate memberships in future electric rate case filings to further support the benefits of its memberships to its customers.

Q. What is UCC's reasoning for requesting the Commission to disallow recovery of corporate memberships?

A. As discussed starting on page 82, line 3, of UCC witness Cira-Reyes' testimony, "[t]he Company's descriptions of benefits to customers are inadequate to justify recovery for [corporate membership] expenses." UCC witness Cira-Reyes continues on page 83, line 4, stating, "…the Company offered no evidence in its initial case and has not provided any information through discovery to suggest that the recipients of membership dues spend those funds exclusively on services that directly benefit ratepayers."

In addition, UCC witness Cira-Reyes states on page 84, line 19, "that groups for which Consumers seeks recovery for its membership dues engage in political advocacy," which undermines the interests of ratepayers. On page 85, lines 17 and 18, UCC witness Cira-Reyes continues stating, "…ratepayers should not be obligated to fund political advocacy."

Q. Does the Company agree that corporate membership dues do not have a benefit to the ratepayer?

A. No. The benefits the Company and its customers receive from corporate memberships generally fit into one or more of the following broad categories:

- Benchmarking - helps the Company understand how its performance and practices compare to its peers, which can lead to improved service for customers;
- Facilitate collaboration – bring stakeholders together to share best practices related to energy efficiency, clean energy transition, and grid planning;
- Research – provides access to research that the Company would otherwise have to perform on its own, and leads to access to information at a lower cost than if each member organization performed the research on their own; and

- Networking – helps build relationships with peers that improves the flow of communication between people and companies leading to a greater awareness of industry trends, emerging technologies, emerging issues, and resources.

Q. Does the Company agree that membership dues related to public advocacy or lobbying should not be recovered from customers?

A. Yes. The Company agrees that lobbying activity included in corporate membership dues should not be recovered from customers. Workpaper WP-PDD-18 discloses the dues, donations, and lobbying costs disallowed for recovery from customers. Included in UCC's Exhibit UCC-73, and described on page 84, lines 10 through 13, of UCC witness Cira-Reyes direct testimony, EEI estimated that at least 14.1% of membership dues would be used for lobbying alone in 2025. Workpaper WP-PDD-18, column (f) shows the percentage of lobbying-related dues the Company has excluded from recovery from customers. Furthermore, on workpaper WP-PDD-18, line 6 and 7, the Company disallowed 16% of EEI dues and 27% of EEI Industry Issues dues from membership dues expense. These disallowed percentages are greater than the 14.1% estimated by EEI and discussed in witness Cira-Reyes' direct testimony.

Q. On pages 91 through 93 of UCC witness Cira-Reyes' testimony, he lists other states' public service commissions that have taken steps to limit or disallow recovery of trade associations that fund political activity. Has the MPSC taken steps to limit the recovery of membership dues for trade organizations that engage in political advocacy?

A. Yes. In its June 10, 2008 Order in Case No. U-15245, the Commission adopted adjustments to the Company's dues and lobbying expense in order to remove expenses for lobbying aimed at increasing utility shareholder value as well as reductions related to

organizations engaged in political activism and lobbying. The Company continues to include deductions in line with Rate Case No. U-15245 and excludes 33.3% of corporate membership dues in addition to the disallowance of political advocacy-related lobbying expenses from its Corporate Service O&M expenses.

Q. How does the Company respond to the claim that its membership in the EEI does not provide benefits to customers?

A. The Company disagrees with the assertion that EEI membership does not benefit customers. EEI provides a wide range of services and collaborative opportunities that directly support the Company's ability to deliver safe, reliable, and affordable service. These benefits extend across multiple operational and strategic workstreams, including Distribution, Generation, IT, Supply Chain, and Corporate Services. Specific examples of how EEI participation benefits customers include:

- **Mutual Assistance Coordination**: EEI facilitates a nationwide mutual assistance network that enables the Company to quickly mobilize resources for storm restoration. This structure is unique in the utility industry and has proven essential during major outage events.
- **Cybersecurity and Technology Best Practices**: EEI provides access to leading security initiatives and threat intelligence, helping the Company protect customer data and critical infrastructure.
- **Customer Support:** EEI supports collaboration among members by facilitating the exchange of best practices in customer service including enhancing the customer experience by expanding digital platforms, offering more online resources, and improving self-service capabilities.
- **Supplier Diversity and Networking**: EEI supports the identification of diverse suppliers and promotes best practices in inclusive procurement, contributing to economic development and equity in the communities we serve.
- **Regulatory Preparedness**: EEI provides insights into federal regulatory developments, such as FERC Order 2222, which informs the Company's planning for Distributed Energy Resource (DER) integration and grid modernization.

- **Transportation Electrification**: EEI facilitates sharing of best practices from electrification programs across the country, supporting Michigan's clean energy transition and customer adoption of electric vehicles.

- **Industry Expertise and Innovation**: EEI convenes experts on topics such as battery operations, decarbonization, grid modernization, energy efficiency, and non-wire alternatives, helping the Company evaluate emerging technologies and strategies that benefit customers.

These services are foundational to the Company's ability to operate efficiently, respond to emergencies, and plan for the future. EEI membership is a prudent investment that supports customer value, and the associated costs are reasonable and appropriately included in Corporate Services O&M.

Q. Does the Company support recovery of a portion of corporate membership dues?

A. Yes. Corporate Services O&M seeks recovery of $830,705 of corporate membership dues. The $830,705 included for recovery in this rate case is approximately 46% of the total membership dues costs. Seeking partial recovery of the membership dues ensures no expenses associated with public advocacy, lobbying, or solely benefiting shareholders are included for recovery in the rate case filing.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

ALEX M. GAST

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Alex M. Gast, and my business address is One Energy Plaza, Jackson, MI 49201.

Q. Are you the same Alex M. Gast who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Joshua S. Towslee and Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United ("MEIU") witness Brett Sproul.

Staff Witness Towslee

Q. Starting on page 3, line 15 of his testimony, Staff witness Towslee has recommended the Company include the following items related to the Whole Home Optimization Demand Response ("DR") in its relevant filings during the pilot period: pilot costs, allocation of remaining funds, energy savings, technologies that will be tested and evaluated, cost-effectiveness assessments, and plans for participants once the pilot period ends. How does the Company respond?

A. The Company is supportive of this request by Staff and will include these items related to the Whole Home Optimization Pilot in annual DR Reconciliations going forward. If the pilot is approved and the Commission adopts Staff's recommendation.

Q. Starting on page 5, line 4 of his testimony, Staff witness Towslee recommended that the Company's proposed changes to the DR regulatory construct be deferred to the Commission's decision in Case No. U-21637. How does the Company respond?

A. The Company appreciates Staff's support for amending the related construct, however, remains concerned about the timing of the changes in relation to the upcoming 2026 DR filing that would reconcile the 2025 plan and introduce the 2027 plan. Because the Company's proposed change would be included in its 2026 DR filing, which takes place in May, the Company would need a decision sooner than that anticipated in Case No. U-21637, which has no definitive schedule for a Commission order. If the Commission were not to decide on this issue in the instant case or the pending 2024 DR Reconciliation case (Case No. U-21906), the Company would likely not be able to file planned DR costs for 2027 and would have to include planned DR spend in its subsequent electric rate case filing.

MEIU Witness Sproul

Q. Starting on page 20, line 7 of his testimony, MEIU witness Sproul has recommended the Company's proposals to reduce the customer demand savings levels for both Critical Peak Pricing ("CPP") and Peak Time Rewards ("PTR"), reduce the PTR bill credit, and discontinue the PTR program customer enrollment incentives be rejected. Overall, how does the Company respond?

A. The Company disagrees. Accurate savings values and increasing program cost-effectiveness are both important for all DR programs to ensure the Company's DR portfolio is predictable and maintains cost-effectiveness. The Company's proposal to reduce customer demand savings levels for CPP and PTR aims to align expected demand reduction with actual demand savings. Relying on the higher numbers to predict the benefit CPP and

PTR provide during an event creates risk for the Company if those higher values cannot be attained. If expected demand reduction is not aligned with actual demand savings it would negatively impact the Company's ability to economically serve the load The Company agrees with MEIU witness Sproul that the programs have changed since the 2022 Cadmus study, but this only increases the need to reduce expected demand savings per customer, as higher enrollment means the Company would expect larger total actual demand savings during an event.

Q. How does the Company respond to MEIU witness Sproul's specific recommendations for the PTR?

A. Similar to the discussion above, given the increase in program enrollment, the Company's proposal to reduce the PTR bill credit aims to reduce the total cost of calling an event, which would be material without the Company's proposal. Discontinuing the PTR customer enrollment incentive also contributes to DR portfolio cost-effectiveness and limits enrollment, making future events more cost-effective. If there was a need to boost enrollment, the Company could offer an enrollment incentive at that time.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Quentin A. Guinn, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Quentin A. Guinn who previously filed direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address Attorney General witness Sebastian Coppola's recommendations that the Michigan Public Service Commission ("MPSC" or the "Commission") (i) remove forecasted capital expenditures in the amount of $4,600,000 and $6,146,000 for the 16 months ending April 30, 2026 related to the Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall, respectively; (ii) remove projected test year capital expenditures in the amount of $3,390,000 and $12,107,000 related to the Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall, respectively; (iii) remove projected test year expenditures in the amount of $2,706,000 for Emergent Repairs; (iv) remove forecasted test year capital expenditures in the amount of $4,371,000 related to the Vehicle Capital Replacement Plan; (v) remove forecasted test year capital expenditures in the amount of $28,771,000 for the Vehicle Expansion Plan; and (vi) direct the Company to present a thorough plan in its next electric rate case addressing the utilization of vehicles and field equipment and the impact of reduced vehicle purchases in future years. Next, I will address MPSC Staff ("Staff") witness Jessica Duell's recommendations that the Commission (i) remove forecasted capital expenditures

in the amount of $1,306,000 and $1,129,500 for the four months ending April 30, 2026 related to the Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall, respectively; and (ii) remove forecasted test year capital expenditures in the amount of $1,695,000 and $6,053,500 related to the Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall, respectively. I will also address Natural Resources Defense Counsel, Sierra Club, and Citizen's Utility Board of Michigan (collectively ("MNSC") witness Douglas B. Jester's recommendation that the Company should revise its fleet electrification target so that all light-duty vehicle replacements are fulfilled by electric vehicles no later than 2030. Finally, I will withdraw from this case test year capital expenditures in the amount of $98,200 for Other Equipment and $948,000 for Emergent Repairs.

Q. Are you sponsoring any exhibits in connection with your rebuttal testimony?

A. No.

Q. Does the Company agree with Attorney General witness Coppola's assertion on pages 82 through 84 of his direct testimony that the Commission should remove forecasted capital expenditures associated with Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall because the Company has not made a compelling case that having two fully staffed control/dispatch centers is advantageous and in the best interest of customers?

A. No. As outlined in the rebuttal testimony of Company witness Andrew R. Snider, staffing both control/dispatch centers is essential for operational resilience and risk mitigation.

Q. Does the Company agree with Attorney General witness Coppola's assertion on pages 84 and 85 of his direct testimony that the Commission should remove from rate base in this rate case forecasted capital expenditures for Emergent Repairs because they are "placeholder amounts"?

A. No. Emergent Repairs includes unplanned corrective maintenance and break fix repair of assets. Specific projects that constitute these projected expenses are unknowable in advance. For this reason, the Company uses a five-year average to determine Emergent Repair capital expenditures. The Commission has accepted this rationale and granted the Company recovery for Emergent Repairs in multiple prior rate cases including Case Nos. U-21806, U-21585, U-21389, U-21224, and U-20963.

Q. Does the Company agree with Attorney General witness Coppola's assertion on pages 87 and 88 of his direct testimony that the Commission should remove forecasted capital expenditures for the Vehicle Capital Replacement Plan because the inflation adjusted cost of the units requested for the projected test year, using a three-year historical average (2022-2024), is less than the total amount requested for the projected test year?

A. No. The method used by Attorney General witness Coppola to determine the projected test year amount for the Vehicle Capital Replacement Plan is incorrect. The use of a three-year historical average is insufficient to maintain the Company's Vehicle Capital Replacement Plan, which brings with it increased maintenance expense. Beginning with the test year amount of $17,943,000 allowed by the Commission for the Vehicle Capital Replacement Plan in Case No. U-20963, the Company calculates each successive calendar year amount for the Vehicle Capital Replacement Plan by adding an inflation factor to the previous

calendar year's amount. The projected test year amount in each case is then pro-rated accordingly. The Commission has approved the use of this method in every rate case since Case No. U-20963.

Q. On pages 85 and 86 of his direct testimony, Attorney General witness Coppola contends that the Company's capital expenditures for the Vehicle Capital Expansion Plan, shown on Exhibit A-104 (QAG-5), line 3, should be reduced because Mr. Coppola's direct testimony in this case proposed to (i) reject the Company's overhead to undergrounding program and (ii) reduced the Company's low voltage distribution ("LVD") capital programs and projects. Do you agree?

A. No. As outlined in the rebuttal testimony of Company witness Michael P. Kelly, the reliability benefits of the undergrounding program and other LVD capital program and projects far exceed the cost of alternatives to improving reliability. In addition, the Company faces an acute risk of some members of its frontline workforce being without vehicles and equipment necessary to perform reliability work (i.e. stranded labor) should the Vehicle Capital Expansion Plan be disallowed as recommended by Mr. Coppola.

Q. On page 89 of his direct testimony, Attorney General witness Coppola recommends that the Commission direct the Company to present a thorough plan in its next electric rate case that addresses the utilization of vehicles and field equipment and the impact of reduced vehicle purchases in future years. Do you agree?

A. Yes. The Company will present a thorough plan in the next electric rate case that addresses the utilization of vehicles and field equipment and the impact of reduced vehicle purchases in future years.

Q. Does the Company agree with Staff witness Duell's recommendations, on pages 19 through 20 of her direct testimony, that the Commission reduce forecasted capital expenditures associated with the Control Dispatch Center Grand Rapids and Control Dispatch Center Parnall because it underspent what was requested in Case No. U-21585?

A. No. As outlined in the rebuttal testimony of Company witness Snider, the Control Dispatch Center project was fully disallowed in Case No. U-21585. Therefore, the projected spend in Case No. U-21585 is not relevant in this case nor was the Company required to execute the projected spend in Case No. U-21585.

Q. Do you agree with MNSC witness Jester's recommendation, at pages 16 through 18 of his direct testimony, that the Company should revise its fleet electrification target so that all light-duty vehicle replacements are fulfilled by electric vehicles no later than 2030?

A. No. To fulfill all light-duty vehicle replacements with electric vehicles no later than 2030 would require the Company to depart from the Fleet Capital Replacement Plan Filter and Blended Factor methods outlined in my direct testimony and used to prioritize fleet replacement purchases. The Commission has approved the Company's use of these methods to prioritize fleet replacement purchases. In addition, the Company would be required to determine what amount of Vehicle Capital Replacement Plan capital is required to replace all light duty vehicles with electric vehicles by 2030. At this time, the Company is uncertain whether Mr. Jester's recommendation can be achieved based on the Vehicle Capital Replacement Plan's historical spending amounts. Finally, Mr. Jester's recommendation may require the Company to prioritize the replacement of light duty

vehicles with electric vehicles to the detriment of replacing heavy duty vehicles and equipment that is more directly relevant to performing electric system reliability work such as bucket trucks.

Q. Does the Company agree with Staff witness Hunter Hansen's recommendation, on pages 4 through 5 of his direct testimony, that the Commission reduce forecasted test year capital expenditures in the amount of $98,200 for Other Equipment?

A. Yes. The Company agrees.

Q. Is the Company withdrawing $98,200 in forecasted capital expenditures related to its Other Equipment projection from this case?

A. Yes. The Company is amending its forecasted capital expenditures for Other Equipment, Exhibit A-102 (QAG-3) as follows: reducing line 1 of Exhibit A-102 (QAG-3) from $670,191 to $571,991 for the 12 months ending April 30, 2027.

Q. Does the Company agree with Staff witness Hansen's recommendation, on pages 4 through 5 of his direct testimony, that the Commission reduce forecasted test year capital expenditures in the amount of $948,800 for Emergent Repairs?

A. Yes. The Company agrees.

Q. Is the Company withdrawing $948,800 in forecasted capital expenditures related to its Emergent Repairs projection from this case?

A. Yes. The Company is amending its forecasted capital expenditures for Emergent Repairs, Exhibit A-102 (QAG-3) as follows: reducing line 7 of Exhibit A-102 (QAG-3) from $2,705,793 to $1,756,993 for the 12 months ending April 30, 2027.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

MEGAN L. HAYWARD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Megan L. Hayward, and my business address is 1945 W Parnall Rd, Jackson, Michigan 49201.

Q. Are you the same Megan L. Hayward who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Ally Durfee; Attorney General witness Sebastian Coppola; and Association of Businesses Advocating Tariff Equity ("ABATE") witnesses Jessica A. York and Colin T. Fitzhenry.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. I am sponsoring the following exhibit:

Exhibit A-218 (MLH-6) Discovery Response 21870-AG-CE-0466.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

I. REBUTTAL OF STAFF WITNESS DURFEE

Q. Do you have any overall comments on Ms. Durfee's analysis of and recommendations regarding the Company's projected High Voltage Distribution ("HVD") capital investments?

A. In each of the HVD capital sub-programs where Ms. Durfee recommends a disallowance, she does so on the basis of (a) reviewing the Company's year-to-date spending through June 2025 in the relevant sub-program; (b) translating that spending into a percentage of

the Company's filed projection for the 2025 calendar year, as shown in Exhibit A-95 (MPK-3); (c) assuming that the average monthly spending for the first six months of 2025 will be carried forward into the future on a linear basis; and (d) recommending bridge period and test year disallowances based on the differences between the Company's filed projections and the amounts implied by those linear projections.

Q. Are there any flaws with this approach?

A. Yes. I will address Ms. Durfee's analysis of each sub-program separately, but it is important to note that many HVD capital sub-programs will not have a consistent month-by-month spending level, nor can future spending levels be projected linearly based on a short-term amount of data. Many HVD projects, particularly in substations, require temporary system reconfigurations in order to deenergize certain components while not interrupting any customers. Because of this, many types of HVD projects can only be undertaken during certain parts of the year. This can be due to weather, electric load conditions, or other limitations that impact when system reconfigurations are needed before the work can be undertaken. Furthermore, many HVD projects are large and complex and therefore may not have closely similar spending levels each and every month.

Q. What is Ms. Durfee's recommendation regarding the HVD Substations Reliability sub-program?

A. On page 6 of her direct testimony, Ms. Durfee calculates that, through June 2025, the Company only spent a fraction of what would be needed to be on track to spend its full 2025 calendar year projection. Staff witness Durfee assumes a linear monthly spending level to project how much she believes the Company will actually spend in 2025 and then

uses that amount to recommend disallowances not only for 2025, but also on a prorated basis for the first four months of 2026 and for the entire test year.

Q. Do you agree with this recommendation?

A. No, I do not agree with the dollar value that Ms. Durfee is recommending for disallowance. Since the time the Company provided year-to-date actuals through June 2025 in discovery in this case, the Company has been reevaluating the feasibility of its projected spending levels for HVD Substations Reliability. This reevaluation is consistent with Ms. Durfee's approach to this sub-program of evaluating how much is likely to be invested, although the Company was completing this evaluation prior to Ms. Durfee filing her testimony.

Many projects in the HVD Substations Reliability sub-program require full or partial substation planned outages in order to affect the system reconfigurations described above, for the safety of the crews performing the work. Because HVD substations are large backbone pieces of the Company's entire system, with large numbers of customers served by each one, the Company can only take these partial substation outages in significant numbers at certain times of the year. Most notably, the Company is limited in how many outages it can take on HVD substations during the summer, when loads are high and therefore the Company cannot easily transfer load to alternative substations.

The Company's 2025 projected investment was based on the Company's proposed spending in Case No. U-21585. The Order in that case, and therefore the Commission's approval for that spending, was received on March 21, 2025. This was only a handful of weeks before the onset of warmer weather and higher loads, which limited the Company's ability to fully invest through the end of June.

The Company has now reevaluated its plan for the remainder of the bridge period, and the Company projects that its total bridge period investment will be $22,230,000 for the HVD Substations Reliability sub-program, as shown in Exhibit A-219 (MPK-29), line 4. Rather than the full disallowance level recommended by Ms. Durfee, the Commission should approve that amount for the bridge period, which would translate into a disallowance of $10,992,000 for the portion of the bridge period ending on December 31, 2025. This is a reduction from the Company's requested 2025 bridge period amount, and is driven by an unseasonably warm fall that has further prevented the Company from taking the requisite outages to safely conduct the planned work. Additionally, the Commission should not approve Ms. Durfee's disallowance for the test year. Given the experiences from the unseasonably warm weather experienced in 2025, the Company is developing contingencies if this weather pattern recurs in the future in order to ensure all planned work can be completed. The Company will do this primarily by focusing increasing work in the earlier months of the year preceding warmer weather.

Q. What is Ms. Durfee's recommendation regarding the Transformer Bank Replacement and Substation Rebuilds sub-program?

A. On page 7 of her direct testimony, Ms. Durfee calculates that, through June 2025, the Company only spent a fraction of what would be needed to be on track to spend its full 2025 calendar year projection. She assumes a linear monthly spending level to project how much she believes the Company will actually spend in 2025 and then uses that amount to recommend disallowances not only for 2025, but also on a prorated basis for the first four months of 2026 and for the entire test year.

Q. Do you agree with this recommendation?

A. No. As with HVD Substations Reliability, the Company faced limitations over the summer and into the early fall in its ability to take needed planned outages. Additionally, many of the projects in this sub-program are very large and come with permitting requirements, and the Company faced permitting delays earlier this year. For example, the Buskirk Creek rebuild project (see Exhibit A-109 (MLH-3), page 3, line 9) was delayed in receiving a necessary permit from the Department of Environment, Great Lakes, and Energy earlier in 2025, causing an approximately two-month shift in the project schedule and causing over $4 million in investment to be shifted from 2025 to 2026. These factors combined to cause year-to-date spending through June to be lower than projected.

Q. Has the Company recently evaluated its projected spending for Transformer Bank Replacements and Substation Rebuilds?

A. Yes. The Company continues to forecast that it will be able to catch up and achieve the full projected bridge period amount, as shown in Exhibit A-219 (MPK-29), line 6. This will be achieved primarily through scheduling a greater portion of planned work in the earlier part of the year preceding the warmer months, as well as ramping up work again when it is cooler later in the year. Therefore, Ms. Durfee's recommended disallowance should not be adopted for the bridge period. Furthermore, since the Company will spend at its projected bridge period level, Ms. Durfee's logic for a test year disallowance is no longer relevant, and the Commission should not approve her recommended test year disallowance.

Q. What is Ms. Durfee's recommendation regarding the Metro Rehabilitation sub-program?

A. On pages 8 and 9 of her direct testimony, Ms. Durfee calculates that, through June 2025, the Company only spent a fraction of what would be needed to be on track to spend its full 2025 calendar year projection. She assumes a linear monthly spending level to project how much she believes the Company will actually spend in 2025 and then uses that amount to recommend disallowances not only for 2025, but also on a prorated basis for the first four months of 2026 and for the entire test year.

Q. Do you agree with this recommendation?

A. No. Although spending in the first half of 2025 may have been lower than projections would indicate, the Company's updated spending and forecast shows that the Company's spending projection are still reasonable. Refer to Exhibit A-219 (MPK-29), line 7. Metro Rehabilitation work consists of crushed concrete-encased duct bank replacement and manhole rehabilitation. These types of projects are primarily executed once frost has receded. Therefore, investments are frequently skewed towards the later part of the year. The Company's forecasted investments in Metro Rehabilitation for 2025 are still close to those projected in the Company's filing, with increases based on two projects actively in construction and one project with bidding activities for construction completed. Therefore, Ms. Durfee's recommended disallowance should not be adopted for the bridge period. Furthermore, since the Company will spend at its projected bridge period level, Ms. Durfee's logic for a test year disallowance is no longer relevant, and the Commission should not approve her recommended test year disallowance.

Q. What is Ms. Durfee's recommendation regarding the System Control Projects sub-program?

A. On page 10 of her direct testimony, Ms. Durfee calculates that, through June 2025, the Company only spent a fraction of what would be needed to be on track to spend its full 2025 calendar year projection. She assumes a linear monthly spending level to project how much she believes the Company will actually spend in 2025 and then uses that amount to recommend disallowances not only for 2025, but also on a prorated basis for the first four months of 2026 and for the entire test year.

Q. Do you agree with this recommendation?

A. No. Although spending in the first half of 2025 may have been lower than projections would indicate, the Company's projections, especially for 2026 and 2027, are still reasonable reflections of likely spending amounts. The history of this sub-program, as shown in Exhibit A-95 (MPK-3), line 44, shows that spending has been somewhat variable from year to year. Most notably, the Company's actual spending in 2024 was $896,000. In other parts of the instant case, Staff uses 2024 actuals as a proxy for what the Company is apparently capable of investing; Ms. Durfee does not rely on this logic, but Staff witness Ryan Boutet does so in his analysis of Low Voltage Distribution ("LVD") Zonal Health Improvement projects, for example.

In the instant case, the Company is projecting to invest much less in System Control Projects than it did in 2024. This indicates that the Company is capable of investing at projected levels, and Ms. Durfee's proposed disallowance should not be adopted.

Q. What is Ms. Durfee's recommendation regarding the LVD Substations Demand Failures sub-program?

A. On page 11 of her direct testimony, Ms. Durfee notes that the unit costs for transformers have overall been steady or declining from 2020 through 2024, and that the average cost was approximately $700,000. The Company's projected unit cost, as derived from Figure 66 in my direct testimony, is $845,000. Ms. Durfee recommends a disallowance based on the difference between this cost and the historical average.

Q. Do you agree with this recommendation?

A. No. Ms. Durfee states that she has calculated a five-year average unit cost of $700,000 based on the data presented in Exhibit A-130 (MPK-20). However, the average cost is actually higher than this. Exhibit A-130 (MPK-20), page 2, line 30, shows that the Company spent $13,357,103 over five years on 18 transformers in this sub-program, which yields an average of $742,061. But beyond that, transformer unit costs are still generally increasing, as shown by recent market data. During the latter part of 2024, the Company made purchase orders based on competitive bids for transformers, with 33 similar sized transformers costing an average of $812,000, indicating a recent increase. This supports the Company's projected bridge period and test year unit costs, and Ms. Durfee's recommendation for disallowance should not be adopted.

Q. What is Ms. Durfee's recommendation regarding the Metro Demand Failures sub-program?

A. On page 12 of her direct testimony, Ms. Durfee calculates that, through June 2025, the Company only spent a fraction of what would be needed to be on track to spend its full 2025 calendar year projection. She assumes a linear monthly spending level to project how

much she believes the Company will actually spend in 2025 and then uses that amount to recommend disallowances not only for 2025, but also on a prorated basis for the first four months of 2026 and for the entire test year.

Q. Do you agree with this recommendation?

A. No. Like other sub-programs in the Demand Failures Program, the Metro Demand Failures sub-program is based on emergent needs that the Company must address quickly after they arise. Because of this, projected Demand Failures investments are usually heavily based on historical actuals, which provide a good proxy of what will likely be needed in the near-term future. Considering the Company's history in the Metro Demand Failures sub-program, as shown in Exhibit A-95 (MPK-3), line 36, historical actual spending has come in on both sides of the historical average of $339,000. That historical average, encompassing five years of data, is a much better indicator of likely needs through the rest of the bridge period and the test year than simply looking at six months of data. The Company's test year projection is closely aligned with the five-year average and should be approved by the Commission. The Company's bridge year projection is also reasonably close to the historical average, but if the Commission does authorize a bridge period disallowance, it should only do so in such a way that bridge period spending will also be aligned with the five-year average, instead of the much lower amount recommended by Ms. Durfee.

II. REBUTTAL OF ATTORNEY GENERAL WITNESS COPPOLA

Q. What is Mr. Coppola's recommendation regarding the LVD Substations Rehabilitation sub-program?

A. On page 48 of his direct testimony, Mr. Coppola observes that the Company is planning to increase its rate of replacing Allis Chalmers transformers in order to complete the

replacement of all remaining units by the end of the test year. Mr. Coppola recommends that the Company moderate the impact on rates by spreading this work out over four years, and proposed a disallowance based on the resulting reduction in bridge period and test year work.

Q. Do you agree with this recommendation?

A. No. Allis Chalmers transformers have a long-documented history of issues, and the Company's approach in the instant case is based on finally resolving this ongoing matter. The Company should not drag the process out further, and the Commission should approve the Company's projection.

Furthermore, the Company's bridge period projections were made by taking into account the Commission's approved spending levels from Case No. U-21585. During the bridge period, which is already in its tenth month, the Company has been making investments in line with what the Commission previously found to be reasonable and prudent. If the Commission does not agree with the Company's plan to finish Allis Chalmers transformer replacements in the test year in the instant case, it should not adopt any bridge period disallowances, and any lengthening of the Company's plan to complete the replacements should apply to the test year only.

Q. Does Mr. Coppola have other recommendations regarding LVD Substations Rehabilitation?

A. On pages 49 and 50 of his direct testimony, Mr. Coppola argues that the Company has not substantiated its increased unit costs for the Equipment Replacement and Regulatory investment category, and proposes a disallowance based on this. He further notes that the

Company is planning an increased number of projects in the bridge period and test year, and proposes to hold the number of projects at the three-year historical average as well.

Q. Do you agree with this recommendation?

A. No. Regarding unit costs, page 92, line 13, through page 93, line 12, of my direct testimony makes clear that this investment category includes a diverse range of project types, and unit costs can vary accordingly based on project specifics (see also page 91, lines 11 through 15). Furthermore, page 93, lines 13 through 19, of my direct testimony indicates that a number of projects span multiple years, which skews the ability to calculate year-by-year unit costs since project costs may not have uniformity across the duration of the project. Exhibit A-109 (MLH-3), page 5, indicates that bridge period projects range from $149,000 to $1,485,000. Exhibit A-110 (MLH-4), page 5, indicates that test year projects range from $330,000 to $3,381,000. This indicates that individual projects are variable enough in this investment category that unit cost analysis is not appropriate.

Regarding the number of units itself, Mr. Coppola offers no reason at all for why the Company should be held to the three-year average. Given the lack of reasoning, this recommendation should also be rejected by the Commission. As with Allis Chalmers transformer replacements, I note that the Company has been making bridge period investments for several months in line with what the Commission previously found reasonable and prudent in Case No. U-21585, and the Commission should not make any bridge period disallowances that would negatively impact work already done under the Commission's prior authorization.

Q. What is Mr. Coppola's recommendation regarding the LVD Substations Capacity sub-program?

A. On page 51 of his direct testimony, Mr. Coppola indicates support for the Company's New Substations projection in the bridge period, but he states that the Company's projection of 11 New Substations in the test year is excessive since this is a greater number than the Company has done recently. He proposed a disallowance based on keeping the Company's units at constant levels.

Q. Do you agree with this recommendation?

A. No. As stated on page 132, lines 9 through 12, of my direct testimony, I explained how projects are identified based on identified capacity needs and work to mitigate planning criteria violations. Since the number of projects is dependent on pockets of local load growth, the number can vary from year to year. Each of the 11 test year projects in this case have been identified as necessary to prevent system overloads due to local load growth. Mr. Coppola's recommendation, if followed, would result in the Company irresponsibly ignoring known load growth pockets on its system, increasing overload risk.

Q. Does Mr. Coppola have any other recommendations regarding LVD Substations Capacity?

A. On page 52 of his direct testimony, Mr. Coppola takes issue with the Company's projection for growth in the Existing Substations investment category, finding that the Company has not provided specific supporting information. He cites discovery response 21870-AG-CE-0477, which he has included as Exhibit AG-11, stating that it did not provide sufficient information to justify why the Company's bridge period projects are all necessary. Based

on this, he recommends holding the number of projects at recent historical levels, with associated bridge period and test year disallowances.

Q. Do you agree with this recommendation?

A. No. In discovery request 21870-AG-CE-0477c, the Attorney General asked the Company, "For the existing substation projects, identify what problems are being addressed and at which existing locations." In response, the Company explained that my direct testimony already describes what problems are being addressed by these projects and Exhibits A-109 (MLH-3) and A-110 (MLH-4) already identify the locations. Mr. Coppola laments that the Company's response did not identify overload levels, but this was not asked for in the discovery request. The Company can only answer the questions it is asked; it cannot guess what specific data points are sought if the request does not indicate what they are. In this instance, the Company answered the question that was asked. It is arbitrary for Mr. Coppola to then argue that the Company did not provide a type of detail that has not been sought by any party.

Finally, I will note that LVD Substations Capacity is another sub-program in which the Company has been making bridge period investments for several months in line with what the Commission found reasonable and prudent in Case No. U-21585, and the Commission should not make the substantial bridge period disallowances sought by Mr. Coppola that would affect work already done under the Commission's prior authorization.

Q. How does Mr. Coppola address the HVD lines system?

A. On page 53 of his direct testimony, Mr. Coppola states that the Company's HVD system is "in much better shape" than its LVD system, based on the relative level of HVD-caused

outages compared to LVD-caused outages. He surmises that a short line clearing cycle and a base level of capital improvements is sufficient for the HVD system, and that increases in HVD capital are not needed "across the board." He says he will bring this critical eye to the Company's HVD lines and substations investments in the instant case.

Q. How do you respond to this?

A. As I discuss at length in my direct testimony, the Company's HVD lines and substations investment are heavily driven by asset health assessment in order to maintain the system's redundancies that are designed to prevent large-scale HVD outages from happening in the first place. See in particular pages 12 through 19 of my direct testimony, with the conclusion on page 19, line 11, through page 20, line 2, regarding the consequences of not investing in the HVD system at proposed levels. Despite the HVD system's share of total System Average Interruption Duration Index ("SAIDI"), it is still critical to invest in improving it in order to maintain it as the backbone of the system.

Q. What is Mr. Coppola's recommendation regarding HVD line rebuilds in the HVD Lines Reliability sub-program?

A. On page 54 of his direct testimony, Mr. Coppola supports the Company's bridge period plan for HVD line rebuilds, but argues that the test year work volume is too high, as it represents a 50% increase from the highest volume year in recent history. He recommends that the test year workplan be limited to 40 miles, and proposes a disallowance based on this.

Q. Do you agree with this recommendation?

A. No. It is an inexact process of determining the actual number of miles of HVD line rebuilds in a given year. The Company's practice has been to count miles toward the year that the

project is complete, and this can make there appear to be dramatic variation in year-over-year work levels even when the Company is completing fairly equivalent amounts of work from year to year. As shown in Exhibit A-109 (MLH-3), page 1, there are eight bridge period HVD line rebuild projects that will carry over beyond the bridge period, and therefore count as zero miles for the bridge period in the total in Figure 21 of my direct testimony. As shown in Exhibit A-110 (MLH-4), page 1, these projects will be completed during the test year, which means all those miles are recorded in the test year in Figure 21 as well. Meanwhile, the test year only has three projects that are carried forward into the next year. In short, while Figure 21 contains mileage numbers that imply a large increase in work volume in the test year, this is not actually what is happening. If one considers the dollar amounts for the bridge period and the test year in Figure 21, they indicate a relatively flat amount of work rather than a dramatic increase.

The Company's bridge year projection in the instant case is informed by what the Company proposed and what the Commission approved in Case No. U-21585. The test year in the instant case is meant to essentially be a continuation of that work level. The only thing obscuring this is the misalignment in miles reported for each year, for the reasons given above. As shown by the projected investment levels, the Company's test year plan is simply a continuation of what the Commission approved in Case No. U-21585. For this reason, Mr. Coppola's recommendation, premised on the idea that the test year represents a major increase in work, should be rejected.

To make another point, the discussion above highlights how many projects carry over from year to year, since they can be large in scope. This means the Company relies on consistent funding levels from year to year to keep projects on track and ensure they

can actually be completed. If the Commission orders the Company to reduce its test year spending, and therefore its test year work, by approximately 40% as Mr. Coppola suggests, then the Company will be impaired in its ability to complete bridge year projects already underway in alignment with the Commission's Order in Case No. U-21585.

Q. What is Mr. Coppola's recommendation for pole top rehabilitation projects in the HVD Lines Reliability sub-program?

A. Mr. Coppola presents his argument on page 55 of his direct testimony, and it is essentially the same as his argument for HVD line rebuilds: that the bridge period appears reasonable, but that the test year represents a stark increase in work. He recommends a similar disallowance based on limiting the test period work level to recent actual levels.

Q. Do you agree with this recommendation?

A. No. My response is essentially the same as my response to Mr. Coppola regarding HVD line rebuilds, namely that much of the apparent variation in miles from year to year is due to the Company's practice of recording all the miles in the year that the project is completed. Mr. Coppola's recommendation should be rejected for the same reasons given in my discussion of HVD line rebuilds.

Q. What is Mr. Coppola's recommendation regarding HVD pole replacements?

A. On pages 56 and 57 of his direct testimony, Mr. Coppola notes that the Company's projected increase in work is driven by a need to address a backlog of red-tagged poles, and he reviews the data provided by the Company in discovery on the development of this backlog since 2016. Mr. Coppola avers that it would be unduly burdensome to completely clear the backlog by 2027 as the Company proposes, and he recommends spreading this

process over five years instead. He calculates proposed bridge period and test year disallowances based on the difference between the two replacement rates.

Q. Do you agree with this recommendation?

A. No. In discovery request 21870-AG-CE-0465a, the Attorney General asked the Company to "Explain why the Company built a backlog of 2,250 poles and did not address the replacement of those poles timely in prior years." In response, the Company reminded the Attorney General that the reduction of the pole backlog is in alignment with the recommendations set forth in the MPSC's audit report. Furthermore, poles are red tagged because they have reached an unacceptable state of deterioration. As referenced in 21870-AG-CE-0465a, the Company's past practices of integrating individual pole replacements into larger projects has been a factor in the increase of the backlog, but this does not change the fact that these poles are in fact deteriorated and present a risk to both safety and reliability if they fail. Allowing a significant number of red-tagged poles to remain on the system for up to two additional years simply increases or extends that risk to the public, to employees, and to reliability.

Q. What is Mr. Coppola's recommendation regarding the Circuit Breakers investment category in the HVD Substations Reliability sub-program?

A. On page 59 of his direct testimony, Mr. Coppola states that the Company's recent average level of circuit breaker replacements was 17 per year, and he argues that there is no justification for why this work volume increases substantially in the bridge period and test year. He also argues that unit costs increase by too much from the bridge period to the test year with no explanation. He recommends disallowances based on holding the Company

to 40 circuit breaker replacements per year, approximately double the Company's recent level, and holding unit costs at recent levels plus inflation.

Q. Do you agree with this recommendation?

A. No. Please note that, in my rebuttal to Ms. Durfee, I have already conceded some of the Company's overall proposed investment level in the HVD Substations Reliability sub-program, but Mr. Coppola's total recommended disallowances for the sub-program are greater.

The recent levels of circuit breaker replacements predate the Company's development of the Reliability Roadmap, which was published in September 2023, and which first began to actually impact investment levels in 2025. The Reliability Roadmap included a thorough review of HVD substation asset health, which led to the conclusion that the Company needed to increase investment in replacing various substation components, including circuit breakers. This is included in Figure 109 in Exhibit A-129 (MPK-19).

Mr. Coppola's proposed disallowance is further premised on his claim that the Company provided "no specific explanation" for why the Company must replace more circuit breakers. But this is not true. Page 62, line 10, through page 63, line 5, of my direct testimony explains the issues with circuit breakers, namely that many of them are now severely obsolete, are in poor asset health, and replacement parts are scarce. The situation is similar to that discussed above in my rebuttal regarding LVD Substation Capacity: Mr. Coppola asserts that the Company has not been specific without any reference to details that the Company did provide and gives no indication of what an appropriate level of specificity would be.

Q. What is Mr. Coppola's recommendation regarding the "Other/Miscellaneous" investment category in the HVD Substations Reliability sub-program?

A. On page 60 of his direct testimony, Mr. Coppola argues that the Company did not provide any specific justification for its projected work volume in this investment category, and he recommends disallowances that would limit the Company's investment level to double the recent actual level.

Q. Do you agree with this recommendation?

A. No. Once again, Mr. Coppola says the Company has not provided enough specific information without ever saying what the requisite level of specificity is. The Company's plan for the "Other/Miscellaneous" investment category is on a similar trajectory to that of Circuit Breakers, with an increase from recent levels driven by the review of asset health that started with the Reliability Roadmap; in fact, the Company provided this explanation in discovery response 21870-AG-CE-0469, which has been provided as Exhibit AG-13. Part of Mr. Coppola's criticism appears to be based on the Company's response to 21870-AG-CE-0469b, in which the Attorney General asked about the "Other/Miscellaneous" investment category. This question asked, "Identify expenditures of $1 million or greater in Other and explain what they entail for the bridge period and projected test year." The Company's response explained this in an appropriate amount of detail. In no other place does the Attorney General ask further questions or even engage with the level of detail provided by the Company.

Q. What is Mr. Coppola's recommendation regarding so-called "premature projects"?

A. In discovery, the Attorney General asked the Company to provide a list of HVD projects that exceed $3 million, and to provide information on the current development level of the

project. The Company did so, and Mr. Coppola has provided this as Exhibit AG-14. Mr. Coppola's ultimate conclusion is that the large majority of such projects are at a stage where he calls them "premature" for inclusion in rate base, and he recommends their disallowance.

Q. How do you respond to this?

A. The reasonableness of Mr. Coppola's recommendation varies depending on which projects he is assessing. Considering the bridge period first, he notes that two projects, both in the HVD Strategic Customers New Business sub-program, have been cancelled, and he recommends their disallowance. Although it would normally be reasonable to remove money allocated for cancelled projects, the HVD Strategic Customers New Business sub-program is unique in that the Company enters into contracts with customers to perform projects, and executes work based on those agreements with customers. In the event that a project is cancelled because of customer action (or inaction), the investments were still reasonable and prudent at the time they were made. In this sub-program, actual costs already incurred for these projects should not be disallowed. See my rebuttal to ABATE witnesses York and Fitzhenry for further discussion of this issue.

Mr. Coppola states that the $7,349,000 in the HVD Strategic Customers New Business sub-program for High Probability Projects is a placeholder amount, which the Commission has ruled should be excluded from rate base. But that is not true in this instance. In Case No. U-21585, the Commission ruled that it was reasonable and prudent for the Company to strategically procure critical inventory designed to make it easier to execute on high-probability projects in this sub-program when they arise. The Company's projected investment in the bridge period is consistent with the Commission's decision.

Finally, at page 63 of his direct testimony, Mr. Coppola notes that two other projects in the Transformer Bank Replacement and Substation Rebuilds sub-program are "still in the early phase of development, and it is uncertain if and when they will be completed and at what specific cost," and he believes they should be disallowed. Here, Mr. Coppola has not fully understood the two projects in question. The Alma and Blackstone substation rebuild projects are multi-year projects. As Exhibit AG-13 shows, they will not be fully complete with construction until 2028 or 2029. But Exhibit AG-13 also shows that property acquisition is already ongoing for these projects, meaning capital costs are already being incurred. Both of these projects were included in the Company's proposal in Case No. U-21585 in what was then called the HVD Lines and Substations Rehabilitation sub-program; the Commission's Order in that case approved 95% of the Company's filed test year position, indicating that these projects were reasonable and prudent. Therefore, the Company is in fact already engaging in early work for these projects, which is directly contrary to the idea they are uncertain.

The Commission should reject Mr. Coppola's proposed bridge period disallowances for so-called "premature" projects, with the possible exception of money not spent on cancelled HVD Strategic Customers New Business projects. The two cancelled projects shown in Exhibit AG-14, page 3, total $27,305,000 for the bridge period. A total of $16,652,000 was spent on those projects prior to cancellation, which means the maximum disallowance for these cancellations should be $10,653,000.

Q. How do you respond to Mr. Coppola's recommendations on so-called "premature" projects in the test year?

A. Mr. Coppola notes that one HVD Strategic Customers New Business project, a dedicated customer substation for $20,619,000, has been cancelled, and he recommends its disallowance. As I will also discuss in my rebuttal to ABATE witness Fitzhenry, this is a reasonable recommendation. Mr. Coppola also calls out the High Probability Projects line item in the HVD Strategic Customers New Business sub-program and recommends its disallowance on the basis that it is a placeholder like in the bridge period. Regarding this recommendation, my response is the same as it was regarding the bridge period, that in this instance the Commission found in Case No. U-21585 that this type of investment was reasonable and prudent, and it should not be disallowed. In discovery request 21870-AG-CE-0480a, the Attorney General asked the Company for specific projects with signed contracts, where two projects were described to have been signed since the case was filed and make up a portion of the High Probability Projects.

Q. Can you discuss the specific so-called "premature" projects in the test year that Mr. Coppola proposes for disallowance?

A. Exhibit AG-14, page 4, lists the Alden, Leslie, and Morrice HVD line rebuild projects. For each of these projects, the Company has indicated that engineering design is already well underway and that construction is on schedule for late 2026 and/or early 2027. Mr. Coppola may want to characterize engineering design as an "early phase of development," but that is not accurate. Engineering design follows project approval and scoping, and is generally completed concurrently with procurement of easements, major equipment, or construction activities. Engineering design is not an early project phase.

Mr. Coppola provides no explanation for why the Company's stated construction schedule is inaccurate; he simply implies that it must be. Since the Company's response shows that construction will take place on these projects during the test year, they are not "premature." It is important to note that the three projects in question are multi-year projects that are not scheduled to be fully complete until later in 2027, which is a common occurrence for HVD line rebuilds.

Exhibit AG-14, page 6, lists the Alma and Blackstone substation rebuild projects. As I have already explained regarding the bridge period, these are multi-year projects that the Commission has already found reasonable and prudent and for which costs are already being incurred.

Exhibit AG-14, page 7, lists the Washington Avenue civil project in Metro Rehabilitation. As the exhibit shows, this project is already well into its engineering design phase now, and Mr. Coppola has given no reason for why the Company would not be able to complete this project during the test year.

Exhibit AG-14, page 8, lists two projects in the HVD Lines and Substations Capacity sub-program. The Company has stated that the Linden 46 kV project design will be complete in the first quarter of 2026, which allows for over a year after design is complete until the end of the test year to complete the proposed investment. For the Wealthy Street Substation project, the Company has stated that design for this will be completed in the first quarter of 2027, well before the end of the test year, and the requested spend in the test year represents design costs and long lead material procurement costs. Mr. Coppola has given no evidence for why the Company's schedule is not accurate.

Exhibit AG-14, page 10, lists two Metro Relocations projects associated with Kalamazoo Avenue. As shown in the exhibit, engineering design is already well underway on these projects, and Mr. Coppola has given no reason for why the Company would not be able to complete these projects during the test year, given that there will be well over one year between the end of design and the end of the test year. It is also worth mentioning that this project is tied to the well-publicized Kalamazoo Avenue two-way street conversion project.[1] With this major street planned for reconstruction, the Company is working with the City of Kalamazoo and its engineering teams to coordinate efforts on Metro system work. There is, quite simply, nothing uncertain about whether this project will happen.

In short, the Commission should reject these proposed test year disallowances, with the exception of the one cancelled project worth $20,619,000.

Q. Does Mr. Coppola have any other recommendations that you wish to address?

A. On pages 64 through 66 of his direct testimony, Mr. Coppola provides further discussion on the HVD Strategic Customers New Business projects that were cancelled. One of his recommendations is that any pre-cancellation costs incurred should not be recovered, which I address in my rebuttal to ABATE witness York. Much of the remainder of Mr. Coppola's concerns seem to stem from the idea that "even after the project is completed and the customer begins operations there is still a high degree of risk that the customer may cease operations or decide to move to another state." While this may be theoretically true, it is not clear that there is actually a high risk of this happening. Projects in this sub-program are typically associated with very large commercial or industrial

[1] Refer to https://www.kalamazoocity.org/Community/Projects/Streets-for-All/Streets-for-All-Kalamazoo-Ave-2026-2027

customers who are themselves making large capital investments in new or expanded factories or other large facilities. Once a business has made a significant investment in a facility and actually commenced operations, the likelihood of suddenly moving to another state is also a low risk indeed.

III. REBUTTAL OF ABATE WITNESS YORK

Q. What is Ms. York's recommendation regarding the HVD Strategic Customers New Business sub-program?

A. On page 30 of her direct testimony, Ms. York notes that the bridge period includes $4,340,000 tied to a project that has been cancelled following the customer's continued postponement of work. She recommends that this amount be disallowed from the bridge period, and that the Company should recover costs from the customer if possible.

Q. Do you agree with this recommendation?

A. No. In this instance, the Company had a signed contract with the customer. In prior rate cases, the Commission has routinely found that having a signed contract with the customer results in the associated investments being reasonable and prudent. Furthermore, this project was presented in Case No. U-21585 and approved by the Commission. It is reasonable, then, that the Company made the investments as its contract with the customer required while it was in force.

As stated in my direct testimony, the Company is seeking recovery from the customer already and will refund any amounts received to customers. In the meantime, it would be unreasonable to prohibit the Company from recovering these costs. If this amount is disallowed, it would create a disincentive for the Company to make needed investment to accommodate new large customers, since there would be an implied risk that

the customer could cancel the deal and leave the Company suddenly facing reasonable and prudent investments that it could not recover on.

Q. What is Ms. York's recommendation regarding Right of Way ("ROW") procurement for HVD projects?

A. On pages 30 and 31 of her direct testimony, Ms. York states that the Company did not provide certain details about its ROW projections, and therefore she recommends that the entire bridge period and test year projected investments be disallowed.

Q. Do you agree with this recommendation?

A. No. Even if Ms. York wanted to argue that some amount of projected ROW procurement was speculative, it would not be reasonable to argue that all of it is and is therefore ripe for disallowance. As shown in Exhibit A-130 (MPK-20), page 2, line 9, the Company has incurred millions of dollars in ROW costs in historical years (note that, through 2023, all HVD ROW costs were assigned to the HVD Lines and Substations Capacity sub-program, which is why they are shown there historically in that exhibit).

But Ms. York is not right to argue that the projected ROW procurement is speculative in the first place. In discovery response 21870-AG-CE-0466, the Company identified HVD Lines Reliability projects for which ROW procurement is needed. Ms. York does not seem to have accounted for this supporting evidence, which is provided as Exhibit A-218 (MLH-6).

IV. REBUTTAL OF ABATE WITNESS FITZHENRY

Q. What is Mr. Fitzhenry's general assessment of the Company's proposed HVD capital expenditures?

A. On pages 24 and 25 of his direct testimony, Mr. Fitzhenry notes that the Liberty Consulting Group ("Liberty") audit in Case No. U-21305 did not find a substantial need for increased

investment in the HVD system, given its relatively low contribution to SAIDI as compared to the LVD system. He provides Table CTF-2 in his testimony as purported further proof of this, noting that none of the outages in Table CTF-2 occur on an HVD voltage, and he notes that "Transmission/Generation outages" accounted for only 0.4% of total customer minutes interrupted. Based on that, he argues that "almost the entirety of outages" on the Company's system from 2022 through 2024 were on the LVD system, meaning there is no need to invest in HVD reliability.

Q. Do you agree with this assessment?

A. No. First, Liberty's audit was published in September 2024, yet on March 21, 2025, the Commission issued its final Order in Case No. U-21585 which authorized a meaningful increase in HVD reliability. In other words, the Commission has supported increased investment in HVD reliability despite Liberty's recommendation. Besides that, specific justifications for each HVD capital sub-program and the spending levels in those sub-programs are provided throughout my direct testimony, with the most succinct summary being found on page 19, line 11, through page 20, line 2.

Mr. Fitzhenry's analysis of the Company's recent outage history also has some issues. Most critically, his Table CTF-2 is based on the Company's response to discovery response 21870-AB-CE-0700, as indicated by his footnote in the table itself. Although this is admittedly not clear in the discovery response, the data provided in the response is LVD-specific data to begin with, which is why there are no outages shown with a fault higher than 24.9 kV. Figures 42, 43, and 45 in Company witness Michael P. Kelly's direct testimony clearly show that outages on HVD lines and on substations are causing SAIDI over the last three years, so it is not accurate to claim that all outages are LVD-related.

Additionally, Mr. Fitzhenry's reference to transmission and generation outages is not relevant to this analysis, because HVD outages are not categorized by the Company as part of transmission or generation outages in the first place.

In short, Mr. Fitzhenry is greatly exaggerating when he suggests that there is no need to invest in HVD reliability.

Q. Does Mr. Fitzhenry propose any disallowances based on his above analysis?

A. Yes. On pages 25 and 26 of his direct testimony, he notes that the HVD Lines Reliability and HVD Substations Reliability sub-programs are intended to improve HVD reliability. Since he has argued that HVD reliability improvements are unnecessary, he proposes to hold investment levels for both sub-programs at 2024 actual levels.

Q. Do you agree with this recommendation?

A. No, except to the extent that I have already conceded some bridge period HVD Substations Reliability dollars in my response to Ms. Durfee. As discussed above, Mr. Fitzhenry's conclusion that there is no need to invest in HVD reliability is severely flawed, and this flawed analysis should not lead to a conclusion that huge amounts of capital investment should be summarily disallowed. My direct testimony provides extensive explanation of the benefits to customers that come from investments in HVD Lines Reliability and HVD Substations Reliability, all of which Mr. Fitzhenry seems to have ignored in favor of a brief appeal to Liberty and a look at LVD outage causes.

Furthermore, as already noted, the Commission already approved an increase in these sub-programs above 2024 actual levels in Case No. U-21585. The Company's bridge period is directly based on amounts approved by the Commission in that Order for the 2025 calendar year and early 2026, with significant work having already taken place.

Mr. Fitzhenry's proposal would disallow money already approved by the Commission when large amounts of work have already been done based on that approval. The Company's test year is based on a continuation of those approved levels of work, and in many instances bridge period projects continue over into the test year, and it would be unreasonable to suddenly disallow that work in such a way that would leave many half-finished projects on the Company's system.

Q. What is Mr. Fitzhenry's recommendation regarding the HVD Strategic Customers New Business sub-program?

A. On pages 26 and 27 of his direct testimony, Mr. Fitzhenry notes that the Company had $20,619,000 tied to a canceled 138 kV dedicated customer substation. He recommends that this amount be removed from the test year. He also states that the Company should recover costs already incurred for this project from the customer; he does not propose a disallowance for this, but it appears to be tied to Ms. York's recommendation about the same project.

Q. Do you agree with this recommendation?

A. I agree that the $20,619,000 for the canceled project should be removed from the test year. As I explained in my response to Ms. York, the Company is seeking to recover bridge period costs related to this project from the customer that it already incurred.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

MEGAN L. HAYWARD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

U21870-AG-CE-0466
Page **1** of **1**

Question:

147. Refer to lines 5-10 on page 48 of Ms. Hayward's direct testimony on ROW acquisitions. Please:

a. Provide a list of the projects and location where the bridge period and test year ROW purchases will be required with the ROW cost for each project.

b. Provide the amount of ROW costs incurred for each year 2020 to 2024.

Response:

a. See Attachment 1 for a list of the projects and locations with bridge and test year ROW spends by project.

b. All ROW purchases for the HVD Lines Reliability program prior to 2024 were included in the Lines & Subs Capacity – HVD program under the ROW Procurement Investment Category. Those expenditures can be viewed in Exhibit A-130 (MPK-20), page 2 line 9. In 2024, ROW procurement costs for HVD Lines Reliability were moved from Lines & Subs Capacity – HVD into the HVD Lines Reliability Program under the ROW Acquisition Investment Category. The HVD Lines Reliability portion of those expenditures in 2020-2023 along with the 2024 total can be viewed in the table below.

2020	2021	2022	2023	2024
$2,105,913	$1,846,719	$1,715,688	$1,300,330	$895,861

Witness: Megan L. Hayward
Date: September 12, 2025

21870-AG-CE-0466
Hayward Attachment 1
Page 1 of 1

Project Name	Location	Bridge Year Expenditures	Test Year Expenditures
Alden	Kewadin	$250,000	$1,206,000
Allendale	Allendale	$27,000	
Broadway	Muskegon	$100,000	
Casino	Weidman	$1,200,000	$500,000
Cement City South	Clarklake	$617,000	$500,000
Cement City Center	Clarklake	$617,000	$300,000
Cooper	Cooper Twp	$400,000	$350,000
Dietz - Gaylord East	Boyne City		$1,540,000
Dietz - Gaylord West	Boyne City	$101,000	$504,000
Dontz	Manistee		$300,000
Erie	Temperance	$225,000	
Getty	Muskegon	$1,259,000	
Golden	Midland	$15,000	
Goodale	Battle Creek	$347,000	
Grand Valley	Standale	$1,500,000	
Greenville North	Greenville	$155,000	
Greenville South	Greenville		$900,000
Hanover	Mosherville	$250,000	$750,000
Leslie	Rives Junction	$25,000	$320,000
Maple City	Glen Arbor	$25,000	
Merrill	Merrill	$120,000	
Morrice South	Perry	$109,000	$175,000
Morrice North	Owosso	$250,000	
Mt. Pleasant	Mt. Pleasant	$798,000	
Nashville	Barry County	$1,055,000	
Newaygo	Newaygo	$20,000	
Niagara South	Saginaw	$50,000	
Niagara North	Saginaw	$262,000	
Orleans	Orleans		$400,000
Plainwell	Plainwell	$10,000	
Quincy East	Quincy		$840,000
Quincy West	Coldwater	$200,000	$900,000
Remus	Remus	$200,000	
Rogers	White Cloud		$450,000
Salem	Salem Township	$210,000	
Saranac	Clarksville	$100,000	
Shelby	Rothbury	$1,239,000	$265,000
Stover	Mancelona Township	$10,000	
Union City	Union City	$556,000	
Virginia Park	Laketown Township	$350,000	$800,000
Wirtz	Gladwin	$15,000	
	Total	**$12,667,000**	**$11,000,000**

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

MEGAN L. JERORE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Megan L. Jerore (formerly Metz), and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same Megan L. Metz who previously submitted direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes. My initial testimony was filed under my former name Megan L. Metz. I have since gotten married and changed my legal name.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut or address positions in the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Laura Maio. In support of Staff witness Paul R. Ausum's proposed increase to Company witness Eugene M. Breuring's energy sales forecast, Staff witness Maio provided an updated calculation and proposed increase to power supply costs, based on the proposed sales increase. I am rebutting Staff witness Maio's increased power supply cost amount, should the Commission agree with proposed sales increase.

I will also rebut the direct testimony of Attorney General ("AG") witness Sebastian Coppola. I will address the argument that the Integrated Energy Management Platform Optimization project is too premature to include in this rate case.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

REBUTTAL OF STAFF WITNESS MAIO

Q. What was the power supply cost increase proposed by Staff witness Maio on Page 13, line 7 of her testimony?

A. The proposed power supply cost increase is$12,228,188, effectively increasing the present revenue to $13,663,096 and therefore decreasing the Company's revenue requirement.

Q. Do you agree with Staff witness Maio's calculation of the increase in power supply cost?

A. No. While Staff witness Maio's power supply cost calculation is a fair approximation of the increased Power Supply Cost Recovery ("PSCR") expense, for purposes of accuracy, it is overly simplified. The sales forecast provided by Company witness Breuring is just one of many inputs into Aurora, the Company's PSCR modeling software, that provides this forecast. Additional inputs are detailed in my direct testimony beginning on page 4, line 18.

Q. To the extent that the Commission agrees that the sales forecast shall be increased by 204,655 MWh, what do you propose the total amount of power supply costs adjustment should be?

A. The adjusted sales forecast was input to the original PSCR Aurora model, where all other inputs remained unchanged. The Aurora model redispatches supply to serve the revised load. Transmission costs related to the increased sales forecast was also calculated. The updated total power supply cost increases by $11,587,168 rather than $12,228,188 as proposed by Staff witness Maio.

REBUTTAL OF AG WITNESS COPPOLA

Q. Do you agree with AG witness Coppola's assessment on page 89, line 17 that including the Information Technology ("IT") project named Integrated Energy Management Platform Optimization in this rate case is premature because it is in the investment planning phase?

A. I do not. As supported by the rebuttal testimony of Company witness Stacy H. Baker, merely being in the investment planning phase does mean the project is uncertain. Once the funding is approved through the rate case, the project is expected to move forward as previously planned.

Q. Please restate the value this project offers in optimizing this platform.

A. The Integrated Energy Management Platform Optimization project will transition Payment Card Industry ("PCI") from on-premises infrastructure to cloud-based services. This migration will enhance vendor support, lower ongoing operational costs (such as upgrades and server maintenance), and enable the Company to take advantage of advanced cloud capabilities.

Currently, because PCI is hosted on-premises, the Company cannot utilize the full functionality offered by the vendor's cloud-hosted Software as a Service ("SaaS") solution. Maintaining the existing system requires internal resources for troubleshooting, maintenance, and upgrades, along with additional licensing costs tied to the infrastructure. These expenses are expected to be eliminated once the system is moved to the cloud.

- Leveraging the vendor's SaaS environment for more efficient and timely operational support—for example, eliminating the need to send database copies for replication.
- Freeing up internal resources for higher-value tasks.

- Reducing the footprint of Oracle servers maintained by the Company and retiring legacy infrastructure, thereby avoiding future maintenance and licensing complexities.
- Lowering IT labor support costs.
- Cutting expenses related to networking equipment upgrades and replacements.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

MICHAEL P. KELLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Michael P. Kelly, and my business address is 1945 West Parnall Road, Jackson, Michigan, 49201.

Q. Are you the same Michael P. Kelly who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission Staff ("Staff") witnesses Anna N. Schiller, Nicholas M. Evans, Jacob G. Martus, Hunter Hansen, and Ally Durfee; Attorney General witness Sebastian Coppola; Association of Businesses Advocating Tarff Equity ("ABATE") witnesses Colin T. Fitzhenry and Jessica A. York; Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar (collectively, the "Clean Energy Organizations" or "CEO") witnesses Boratha Tan, Lee Shaver, and William D. Kenworthy; Citizen Utility Board of Michigan ("CUB") witness Richard J. Bunch; Michigan Environmental Council, Natural Resources Defense Council ("NRDC"), Sierra Club, and CUB ("MNSC") witness Caroline Palmer; Great Lakes Renewable Energy Association ("GLREA") witness Richard Boehnke; Urban Core Collective ("UCC") witness Sergio Cira-Reyes; Michigan Electric Transmission Company ("METC") witness Michael Fleck; and Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United ("MEIU") witness John D. Albers.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-219 (MPK-29)	Actual and Forecasted 2025 Capital and O&M Spending;
Exhibit A-220 (MPK-30)	Audit Response 21870-SA-CE-248;
Exhibit A-221 (MPK-31)	Discovery Response 21870-AG-CE-0514; and
Exhibit A-222 (MPK-32)	Discovery Response 21870-AG-CE-0453.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please explain Exhibit A-219 (MPK-29).

A. Multiple parties to this case have analyzed the Company's projected capital and operating and maintenance ("O&M") spending based on the Company's actual year-to-date spending through June 2025, and a number of proposed disallowances are tied to this. Each individual disallowance is addressed by Company witness Jennifer M. Partlan, Company witness Megan L. Hayward, or myself. Exhibit A-219 (MPK-29) provides the Company's year-to-date spending for the contested programs through September 2025, with the forecast through the remainder of the year, in order to provide an updated picture of the Company's 2025 spending.

I. REBUTTAL OF STAFF WITNESS SCHILLER

Q. What is Ms. Schiller's position on alignment between the instant case and the Distribution System Plan ("DSP")?

A. Per the Commission's July 10, 2025 Order in Case No. U-20147 ("July 10 Order"), utility five-year distribution plans will use the standard descriptor Distribution System Plan ("DSP") going forward. To date, the Company has used the terms Electric Distribution Infrastructure Investment Plan ("EDIIP") and Reliability Roadmap. The Company plans

to use the DSP moniker on a go-forward basis, although the three terms – EDIIP, Reliability Roadmap, and DSP – can continue to be understood as interchangeable.

After reviewing the Company's DSP history since 2023, Ms. Schiller concludes on page 9 of her direct testimony that the revised version of the Company's current DSP, filed in the instant case as Exhibit A-129 (MPK-19), either was not necessary under the terms of the July 10 Order or should not have been filed at all. She allows that the Company filed the instant case before the July 10 Order was issued and was following the best guidance available at the time, but states that the Company should not file DSP revisions as part of future rate cases unless warranted by "significant" changes to strategy or misalignments between the rate case and the DSP.

Q. How do you respond to this position?

A. The Company fully intends to comply with all provisions of the July 10 Order, including when DSP revisions in rate cases are warranted. I will note that, contrary to the statement on page 10, line 2, of Ms. Schiller's testimony, the Company's next DSP will be filed in 2026.

Q. What else does Ms. Schiller say about DSP/rate case alignment?

A. On pages 10 and 11 of her direct testimony, Ms. Schiller notes that the Company has changed the names and contents of various programs and sub-programs across multiple rate cases, and between the Company's DSP and rate cases. She cites the movement of Automation Transfer Recloser ("ATR") Loops among different spending areas, and the changes related to breaking up the High Voltage Distribution ("HVD") Lines and Substations Rehabilitation sub-program. She acknowledges that some changes are necessary for the Company's business needs, but states on page 13 that "reasonable and

prudent costs should be categorized and similarly trackable between any DSP submitted by the Company and any rate case which uses such DSP to justify cost recovery."

Q. How do you respond to this argument?

A. Ms. Schiller's point is well-taken. In its 2026 DSP, the Company will endeavor to present planned investments in a format that allow for easier comparison between the DSP and how costs are presented in rate cases.

Q. What arguments does Ms. Schiller make about the outcomes of the audit by Liberty Consulting Group ("Liberty") in Case No. U-21305?

A. Beginning on page 14 of her direct testimony, Ms. Schiller begins discussing the Commission's July 12, 2025 Order in Case No. U-21305 related to the Liberty audit, and discusses the audit in general, especially regarding the Company's assessment of its reliability history relative to Liberty's assessment; the suitability of the Company's modeling that projects future System Average Interruption Duration Index ("SAIDI") based on levels of investment; and the Company's consideration of alternate glidepaths for improving SAIDI based on Liberty's recommendations.

Q. What is Ms. Schiller's position regarding whether the Company has been improving its reliability?

A. Beginning on page 16 of her direct testimony, Ms. Schiller argues that Figure 6 in my direct testimony is misleading. I explained in my direct testimony why Figure 6 illustrated recent improvement in reliability performance. Ms. Schiller avers that the Company's use of a five-year rolling average can obscure other trends, and notes that with a rolling average the line lags behind current data. She then presents her own Figure 1, which fits a linear regression to the Company's SAIDI excluding Major Event Days ("MEDs") from 2014

through 2024, and notes that it shows almost flat SAIDI over that time period. She contends that this illustrates that the Company's reliability has in fact not improved.

Q. Do you agree with this assessment?

A. No. Ms. Schiller's Figure 1 is essentially the same as Liberty's statement that if you use 2014 as a baseline, then reliability is flat over the course of a decade. I alluded to this on page 25, lines 13 through 16, of my direct testimony. One major issue with Liberty's, and with Ms. Schiller's, analysis is that 2014 is an arbitrary date to use for a baseline. Admittedly, some date much be chosen for the start of an analysis, but using 2015 or 2016, which had higher SAIDI results than 2014, would change the shape of the line in Ms. Schiller's Figure 1, as would using 2013 (when SAIDI excluding MEDs was 212) or 2011 (when it was 297). Ms. Schiller acknowledges on page 18, lines 8-9, that 2014 was a particularly good year for SAIDI when compared to adjacent years. I mention in my direct testimony that I used a rolling average to smooth out annual variability and to reduce the arbitrariness of which dates to use. Ms. Schiller suggests at page 17 of her direct testimony that using 10 years of data instead of five years mitigates this, but that is only partially true. Using a linear regression over 10 years may result in less variability than if a linear regression was done over just five years, but a linear regression such as that used by Ms. Schiller over any duration will not address annual variability in the same way that a rolling average does. A rolling average is better for identifying true trends over multiple years. I would further note that using a rolling average means that my Figure 6 actually incorporates 15 years of data, since it indirectly accounts for SAIDI going back to 2009.

Figure 6 in my direct testimony illustrates that reliability has improved since 2021, which was around the time that the Company's investments from its 2018 EDIIP were first

beginning to really impact the system. Notwithstanding any reliability trends from the 2010s, the Company's reliability in the current decade has clearly improved.

Q. What is Ms. Schiller's position on whether the Company effectively considered seven-year and 10-year glidepaths for SAIDI improvement in addition to a five-year glidepath?

A. On page 18 of her direct testimony, Ms. Schiller states that the Company did not "meaningfully examine" extended glidepaths, but simply adjusted its modeling to cover long timeframes. She explains several objections that she has to the Company's modeling, which I will address below. After describing these modeling objections, she returns to the alternate glidepaths themselves on page 20, stating that the Company's analysis did not consider cost effectiveness, affordability, or rate impacts, and that while the Company complied with the letter of Liberty's recommendations, it did not consider the Commission's Order related to approaching SAIDI in a cost effective manner.

Q. Aside from the modeling concerns, how do you respond to this?

A. It is not clear to me why it would be inappropriate to evaluate alternate glidepaths by adjusting the Company's modeling to target different dates. Indeed, it is not clear what other approach could be appropriate. The Company's model is designed to project a SAIDI performance at a given future date when considering spending inputs. If the Company is modeling a given SAIDI performance by 2029 (then five years into the future), then considering alternate glidepaths necessarily means running that model to show an equivalent performance in 2031 and 2034.

Additionally, as Ms. Schiller notes, the Commission's Order in Case No. U-21305 did not come out until June 12, 2025, which was after the instant case was filed. The

Company, at the time of filing, only had Liberty's report to rely on, and the Company therefore responded to Liberty's recommendation. The Company will certainly comply with the Commission's further direction from its Order in Case No. U-21305 in future filings.

Q. What else does Ms. Schiller say about the Company's comparison of alternate glidepaths?

A. On page 21 of her direct testimony, Ms. Schiller objects to my position (stated on page 40, line 9, through page 41, line 9, of my direct testimony) that the Company must pursue a five-year glidepath because the longer glidepaths would compel the Company to cut specific investment programs entirely or to low levels. Ms. Schiller states that neither Liberty nor the Commission has mandated that particular programs be cut to create the longer glidepaths, and that the Company could explain why certain programs should not be cut.

Q. How do you respond?

A. Ms. Schiller is correct that no such constraints were placed on the development of alternate glidepaths, but that does not mean that the Company would not be effectively constrained. As page 32, Figure 13 of my direct testimony illustrates, significant System Average Interruption Frequency Index ("SAIFI") improvements underpinning the Company's modeled glidepath come from a handful of investment categories (this does not mean other investments do not contribute to reliability – see page 31, lines 12 through 14, of my direct testimony). Given the clear direction from Liberty that Line Clearing should be increased, that cannot be reduced to create longer glidepaths. Security Assessment Repairs address actually failed components on the system and cannot be responsibly deferred. This leaves

Zonal Health Projects, Fractionalization, and ATR Loops as the remaining options for creating a model that delays the achievement of second quartile SAIDI excluding MEDs until later dates. If the Company delayed its glidepath, it would continue to invest in programs that hold SAIDI roughly steady by addressing deterioration, but would not invest as much or at all in certain programs that would improve SAIDI, since the entire purpose of an extended glidepath is to delay reliability improvements to achieve the tradeoff of making fewer capital investments.

Q. Does Ms. Schiller make any other comments about the Company's approach to alternate glidepaths?

A. Yes. On page 22 of her testimony, Ms. Schiller objects to my assertion that the Company should be entitled to invest at levels that would allow it to avoid penalties in the Commission's performance-based ratemaking ("PBR") framework.

Q. How do you respond?

A. The Company understands the Commission's PBR framework as at least a partial guide for targeted reliability improvements. Through its creation of the PBR framework, the Commission has established certain target reliability, backed by financial consequences for utilities. This framework establishes the target reliability levels that the Commission expects the Company at a minimum to pursue.

Q. What does Ms. Schiller say about the Company's modeling of future reliability performance?

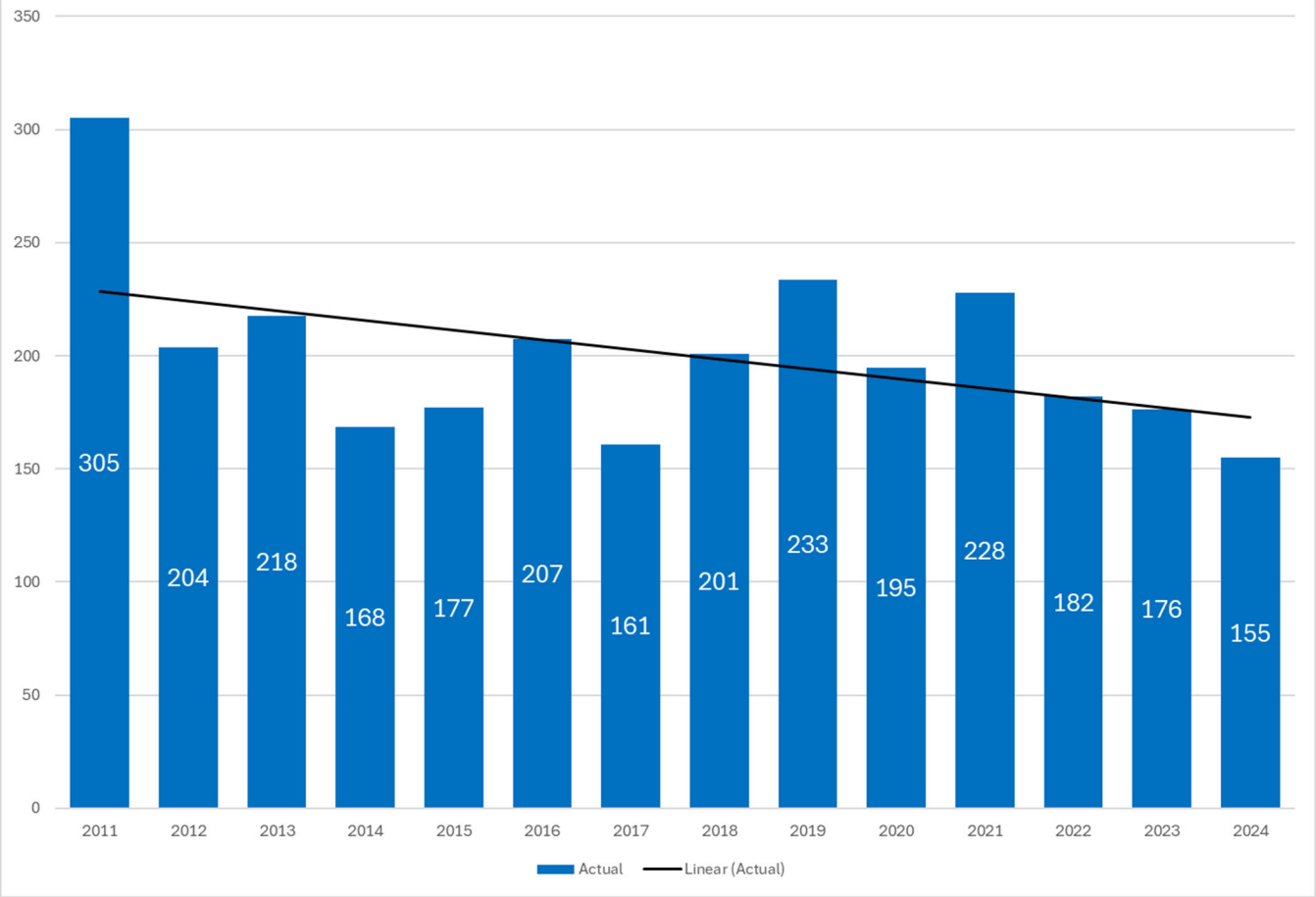
A. On page 19 of her direct testimony, Ms. Schiller criticizes the Company's modeling by saying that it has not been able to predict future reliability for two of the previous four years and that the Company cannot guarantee accuracy. She also states that the model is

flawed because it only considers five years of historical data (she recommends using 10 years) and because it is not weather-normalized in a period where increasingly severe weather is expected. Because of these concerns, she recommends that the Commission require a different modeling method to examine potential extended timelines for SAIDI improvements in the Company's next rate case.

Q. Do you agree with this?

A. No. The Company has been and will continue to make model improvements. While the model in its present form has undergone continued improvements from the version used for the last rate case, its fundamental origins date back to at least the 1990s. It is not realistically possible for the Company to guarantee the accuracy of a predictive model that is impacted by future weather patterns. Factoring in over a decade of system age related deterioration and ever increasingly severe weather, even a relatively flat 2014 to 2024 linear trend would indicate improved system performance, notwithstanding the flaws with only looking at a 2014 to 2024 linear trend as discussed above. The Company believes that the previous five years is more reflective for both present system and weather conditions. If additional years of data are desirable, the Company could look back at 14 years of data and show that annual SAIDI has nearly been cut in half since 2011, as shown in Figure 1 below.

FIGURE 1
SAIDI PERFORMANCE EXCLUDING MEDS, 2011-2024



Additionally, the Company has historically forecasted SAIDI excluding MEDs. By excluding MEDs, the Company is accounting for much of the volatility resulting from weather. Small storms do have an impact on the metric, but more importantly, to accurately normalize weather reporting for day-to-day operations, crisis-mode restoration in the days following catastrophic events needs to be appropriately accounted for when calculating the Company's performance for SAIDI excluding MEDs. Adjusting for such events in calculating SAIDI would likely improve the modeling by eliminating the volatility of these significantly large events and providing a better alignment to actual day-to-day system performance as measured by the SAIDI excluding MED standard.

Finally, in the Company's efforts to continuously improve its modeling capabilities for forecasting future reliability performance, it conducted a review of the regulatory filings of Midwestern peer utilities. In this review the Company found that only one utility, DTE, provided a forecast of future performance for All-weather SAIDI while the others simply discussed past performance. Compared to the Company's modeling of future SAIDI excluding MEDs, All-weather SAIDI, and CEMI performance, it appears that peer utilities share very little information. Therefore, if the Commission finds that the Company's current SAIDI performance model is inaccurate to the extent that it requires a new method to be developed, the Company asks that the MPSC Staff provide publicly available and benchmarkable models from electric utility industry peers that have guaranteed forecasted performance as Ms. Shiller deems is necessary for the Company. Furthermore, the Company asks that the Commission provide the Company with at least three years to test and validate an alternative methodology's precision and accuracy.

II. REBUTTAL OF STAFF WITNESS EVANS

Q. What is Mr. Evans' recommendation regarding the Company's Distribution Deferral Mechanism?

A. On page 8 of his direct testimony, Mr. Evans concludes that the Company's actual capital spending as part of the Distribution Deferral Mechanism between March 1, 2024 and February 28, 2025, was reasonable and prudent. Because of this, on page 9 of his direct testimony he recommends that the Company be permitted to continue using the deferral mechanism as requested in the instant case. Mr. Evans recommends four conditions to this approval, and notes in footnote 1 of his testimony that they are substantively identical to those approved by the Commission in Case No. U-21585.

Q. Do you agree with this recommendation?

A. Yes. The Company appreciates Staff's continued support of the deferral mechanism, and finds that the conditions continue to be reasonable.

Q. What is Mr. Evans' recommendation regarding the Company's Investment Recovery Mechanism ("IRM")?

A. On page 11 of his direct testimony, Mr. Evans indicates that Staff supports the Company's proposed two-year extension of its IRM, but with three changes. First, he recommends that the amount for the Repetitive Outages sub-program should be adjusted to reflect proposed disallowances made by Staff witness Ryan Boutet. Second, he recommends that investment related to the Vulnerable Communities Resiliency Plan ("VCRP") be removed from the IRM and placed into rate base. Third, he recommends that the rate of return associated with the IRM surcharge should be lower than the pretax rate of return, but no lower than the short-term debt rate.

Q. Do you agree with these recommendations?

A. No. Company witness Partlan explains in her direct testimony why Mr. Boutet's proposed disallowance for Repetitive Outages should not be adopted by the Commission. Company witness Heidi J. Myers addresses Mr. Evans' recommendation related to the rate of return.

As to the VCRP, Mr. Evans agrees, on page 12 of his direct testimony, that the Company should be investing in the VCRP, but states that recovery of these investments does not need to occur in the IRM. It is not clear why Mr. Evans reaches this conclusion. The Company proposed to include the VCRP in the IRM precisely because it is important to invest in Environmental Justice ("EJ") communities; the IRM provides a backstop to ensure that the investments are made, with the Company required to provide refunds if the

Company does not make the full investments. Furthermore, the Commission's Order in Case No. U-21389, approving the initial IRM, made clear that the Company should show how the IRM promotes system equity. The Company believes that including the VCRP in the IRM provides one clear mechanism for doing this.

III. REBUTTAL OF STAFF WITNESS MARTUS

Q. What is Mr. Martus' recommendation regarding the Company's proposed regulatory deferral mechanism for the Staking and Locating O&M sub-program?

A. As stated on pages 5 and 6 of his direct testimony, Mr. Martus states that Staff supports the Company's proposal, but he recommends that the mechanism only cover fluctuations stemming from the variability in staking volume. He recommends that the recovery and refund amounts for the mechanism be set by an equation that he provides and explains. He states that this recommendation is very similar to what Staff recommended for the Company's corresponding proposal in its most recent gas rate case, Case No. U-21806.

Q. Do you agree with this recommendation?

A. Partially. The Company does not oppose the principle that the deferral mechanism should be limited to fluctuations based on staking volume. Mr. Martus' "Equation 1" is a reasonable means of calculating what this fluctuation is in a future period. However, it is not appropriate to cap the recovery or refund amounts based on historical volume fluctuations, as Mr. Martus proposes. The purpose of the deferral mechanism is to address future uncertainty about staking volumes, and that uncertainty is due in large part to potential variability tied to new rural broadband programs. Because the future variability is tied to this new development, there should be no cap indexed to historical variability that may no longer apply. Furthermore, the Company's actual year-to-date staking volume through September 2025 is 411,518, and the Company is on track to have a 2025 staking

volume of over 520,000, an upward variation well in excess of 3.77%[1], further showing that Mr. Martus' proposed cap on deferral recovery is out of date. Therefore, Mr. Martus' "Equation 2" and "Equation 3" should not be used.

If the Commission decides that it wants some kind of cap on recovery and refund in the deferral mechanism, it should at least be symmetrical, such as +/- 10% in each direction. It is not reasonable to create an unbalanced mechanism with nearly three times as much risk as potential benefit to the Company, as Mr. Martus proposes.

IV. REBUTTAL OF STAFF WITNESS HANSEN

Q. What does Mr. Hansen recommend regarding the Company's proposed upfront charge for advanced metering infrastructure ("AMI") opt-outs?

A. On page 6 of his direct testimony, Mr. Hansen reviews information that the Company provided to Staff in audit, and calculates that the Company's proposed upfront charge of $216.22 should be reduced to $168.07 based on that audit information.

Q. Do you agree with this recommendation?

A. Yes. The information that the Company provided in audit supports Mr. Hansen's calculations.

Q. What does Mr. Hansen recommend regarding the Company's proposed monthly charge for AMI opt-outs?

A. On pages 6 and 7 of his direct testimony, Mr. Hansen states that the Company's breakdown of costs to support the proposed $3.09 monthly charge do not accurately reflect the Company's monthly cost of reading non-AMI electric meters. He argues that most of the costs seem to actually apply to reading Automated Meter Reading ("AMR") gas meters,

[1] To be specific, the Company's staking volume for January-September 2024 was 335,913, meaning the January-September 2025 actuals are a 22.5% year-over-year increase.

and therefore they do not support a cost-of-service basis for the Company's proposed charge. He recommends that the Commission reject the proposed charge, and that the Company should begin separately tracking the costs of reading non-AMI electric meters so it can propose a better cost-of-service based charge in the future.

Q. Do you agree with this recommendation?

A. No. For one thing, it is not clear whether Mr. Hansen is arguing that there should be no monthly charge at all until the Company performs this new analysis, or if the existing monthly charge should remain in effect until that time. If he intends the former, this is not reasonable. The existing charge is already in effect and should not be completely eliminated until a replacement is available. The monthly cost of reading non-AMI electric meters is clearly not $0.00, so it would be unreasonable for the Commission to effectively set the monthly charge at that level.

Beyond that, the Company provided an alternative analysis in alignment with the methodology used in prior cases, based on an allocation of labor and associated overhead for supervision, support, and vehicle costs for non-transmitting meters in Staff Audit response 21870-SA-CE-248, which is being provided as Exhibit A-220 (MPK-30). This analysis supported a charge of $12.61/meter/month. While the Company is not proposing a $12.61 monthly charge at this time, this illustrates that it would not be reasonable for there to be no monthly charge. As to separately tracking the costs of reading non-AMI electric meters, Consumers Energy can look into that possibility. I will note that there are challenges attempting to separately track these costs because the Company does not have a dedicated electric meter reader team that only reads non-AMI meters.

V. REBUTTAL OF STAFF WITNESS DURFEE

Q. What is Ms. Durfee's general approach to the Company's Electric Distribution O&M spending?

A. Ms. Durfee reviewed the Company's year-to-date spending through June 2025 and has interpreted that to represent the amount that the Company is likely to spending going forward. In each case, she assumes a linear monthly spending to project likely test year spending. I will address each sub-program individually, but it is important to note that many programs often do not follow a linear monthly spend, and it would be incorrect to base all projections only on a single six-month period.

Q. What is Ms. Durfee's recommendation regarding the Low Voltage Distribution ("LVD") Lines Reliability O&M sub-program?

A. On page 15 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $754,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a $7.222 million disallowance for the test year, based on the Company staying at these spending levels.

Q. Do you agree with this recommendation?

A. No. The Company constrained its O&M spending in the first half of 2025 following the catastrophic ice storm and subsequent severe weather experienced in March and April of 2025. The severe weather caused widespread damage to the Company's electric grid, resulting in the Company requesting Commission approval to defer O&M expenses associated with the storm even for recovery in a future case. The Commission granted the Company the accounting authority to defer these excess expenses on June 12, 2025 in Case No. U-21914, which has allowed the Company to once again focus on additional O&M-

related activities. Exhibit A-219 (MPK-29), line 1, shows how LVD Lines Reliability O&M was constrained in the first half of 2025, but how it has increased since then. The Company is fully planning to spend at the projected amounts in the test year.

Q. What is Ms. Durfee's recommendation regarding the HVD Lines Reliability O&M sub-program?

A. On page 16 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $68,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a disallowance of $821,000 for the test year, based on the Company staying at these spending levels.

Q. Do you agree with this recommendation?

A. No. Ms. Durfee is correct that the Company's filed test year position for HVD Lines Reliability O&M is too high. However, the Company's five-year history in this sub-program, as shown in Exhibit A-124 (MPK-14), line 5, shows that the Company has consistently spent at higher levels than Ms. Durfee is recommending here. The Company's test year spending level should be set at the five-year average of $214,000. See my rebuttal to Attorney General witness Coppola for further discussion of this topic.

Q. What is Ms. Durfee's recommendation regarding the LVD Substations Reliability O&M sub-program?

A. On page 17 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $3,821,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026,

and a $1.54 million disallowance for the test year, based on the Company staying at these spending levels.

Q. Do you agree with this recommendation?

A. No. The LVD Substations Reliability O&M sub-program is an example of an area where spending is not linear during the year. In a typical year, spending in this sub-program is lower in the winter and spring but ramps up in the summer and fall. The Company's current year-to-date spending is shown in Exhibit A-219 (MPK-29), line 2. As shown, the Company spent as much in the third quarter of the year as it did in the first half of the year combined, and the Company is on track to spend significantly closer to its projected amount. Accordingly, the projected test year is a reasonable projection the Company's expected spending.

Q. What is Ms. Durfee's recommendation regarding the HVD Lines Demand O&M sub-program?

A. On page 18 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $512,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a $2.451 million disallowance for the test year, based on the Company staying at these spending levels.

Q. Do you agree with this recommendation?

A. No. The workforce that completes HVD Lines Demand O&M work is also engaged in HVD Lines Reliability capital projects, meaning the Company must balance between the two categories of work. In the test year in the instant case, the Company is projecting a modest increase in HVD Lines Reliability capital work. This will allow for more balance

in the overall workplan for this workforce, which will enable the Company to complete more HVD Lines Demand O&M work in 2026 and 2027. The Company has already identified enough O&M work to account for the full test year projection.

Q. What is Ms. Durfee's recommendation regarding the Staking and Locating O&M sub-program?

A. On page 19 of her direct testimony, Ms. Durfee argues that it is inappropriate for the Company to use MISS DIG's projection of 7% statewide growth in staking volumes. She argues that the Company's own recent actual staking requests support an annual growth rate of 2.28%. She recommends recalculating the Company's projected staking volumes based on this revised rate, and calculates a $1.517 million disallowance based on the difference.

Q. Do you agree with this recommendation?

A. No. Simply looking at the Company's recent actual history does not paint a complete picture. As stated on page 150, line 15, through page 151, line 2, of my direct testimony, the Company anticipates greater than normal growth in staking requests due to expansion of rural broadband infrastructure (note that Company witness Partlan's direct testimony documents the scale of this activity, and the large impact that this will have on the Company's LVD system). On page 151, line 5, through page 152, line 16, of my direct testimony, I explain this rural broadband growth and its impact on staking volumes is what led the Company to propose a deferral mechanism for this O&M sub-program. The deferral mechanism provides a way to refund customers if staking volumes end up lower than projected for any reason. Since Staff supports this deferral mechanism, as outlined by

Mr. Martus, Staff should be confident that customers will be protected in the event that staking volumes are lower than projected.

Additionally, as noted above in my response to Mr. Martus, the Company's year-to-date staking volume through September is 411,538 and the Company is on track to have a staking volume in 2025 of over 520,000, indicating that staking growth is very robust. As noted on page 150 of my direct testimony, Figure 50, that amount would be higher than any of the annual amounts originally projected through 2027 in this case.

Q. What is Ms. Durfee's recommendation regarding the Alma Equipment Repair O&M sub-program?

A. On page 20 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $358,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a $201,000 disallowance for the test year, based on the Company staying at these spending levels.

Q. Do you agree with this recommendation?

A. No. As stated above, it is incorrect to only consider a single six-month period when assessing likely spending levels in the test year. The Company's five-year historical average is a better approximation of what the Company is capable of spending in a given year, since it accounts for some variation that can occur on an annual basis and because it is a longer track record of data. The Company's five-year average for Alma Equipment Repair O&M is $530,000, and the Company's test year projection in this case is effectively in line with that when accounting for inflation. The Commission should approve the Company's projected spending level.

Q. What is Ms. Durfee's recommendation regarding the Tools O&M sub-program?

A. On page 21 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $896,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a $1.057 million disallowance for the test year, based on the Company staying at these levels.

Q. Do you agree with this recommendation?

A. No. This is another sub-program where it is more appropriate to consider the Company's five-year average rather than just looking at one six-month period. The Company's five-year average for the Tools O&M sub-program is $1,634,000. The Company's projected test year spending is essentially in line with this level, and the Commission should approve the Company's projection.

Q. What is Ms. Durfee's recommendation regarding the Underground Workforce O&M sub-program?

A. On page 22 of her direct testimony, Ms. Durfee notes that, year-to-date through June 2025, the Company had only spent in this sub-program at a level commensurate with reaching $584,000 in 2025. She proposes adjustments for 2025 and the first four months of 2026, and a $1.633 million disallowance for the test year, based on the Company staying at these levels.

Q. Do you agree with this recommendation?

A. No. Underground Workforce O&M is a sub-program where it is particularly inappropriate to assume a linear monthly spending rate based on the first half of 2025. The Company was not performing a significant amount of undergrounding work during this time period.

However, in the test year the Company is planning to complete 50 miles of overhead to underground ("OHUG") conversions, a workplan that Staff is supporting in this case. This work in the test year will lead to higher O&M costs for the underground workforce than was incurred in the first half of 2025, and the Commission should approve the Company's projection.

VI. REBUTTAL OF ATTORNEY GENERAL WITNESS COPPOLA

Q. What is Mr. Coppola's recommendation regarding the Company's proposed OHUG conversion work?

A. Mr. Coppola begins his discussion of OHUG on page 31 of his direct testimony. He states that the Company's changing of selection criteria indicates that it is "still struggling to find an effective approach that adequately justifies undertaking" OHUG work. Company witness Partlan addresses this issue in her direct testimony. Mr. Coppola makes several other arguments that I will address.

Mr. Coppola states that my net present value analysis of OHUG shows that it is the most expensive option compared to other alternatives when using the utility cost test ("UCT"). He states that the Company's selection criteria set relatively low thresholds by which thousands of overhead line miles could be selected. He states that the Company has not conducted a separate benefit-cost analysis for each individual project to determine if it is economic compared to other potential solutions. He argues that the Company's OHUG pilot showed average costs of $443,079 per line mile, and notes that individual projects sometimes cost more than that, arguing that this further indicates a need for individual project benefit cost analyses. Finally, he states that my net present value analysis using the societal cost test ("SCT"), showing that OHUG is the most economic option, should be disregarded. He contends that the SCT analysis assumes an equal value for each minute

of an outage, when in reality some customers can sustain outages for many hours without incurring any costs, and that customers really only accrue costs to themselves when outages last a day or longer.

Q. How do you respond to these critiques?

A. As I also discuss later in my rebuttal to ABATE witness Fitzhenry, Figure 26 in my direct testimony does show that OHUG is more expensive than alternatives at scale. However, OHUG is only 2% more expensive, on average, and page 66, lines 9 through 13, of my direct testimony indicate that OHUG provides at least a 90% reliability improvement because the threat of trees is almost completely eliminated. This level of reliability improvement is much greater than that offered by alternatives. Combined with the fact that OHUG is only very marginally more expensive, this still represents good value for the money.

Although Mr. Coppola takes some issue with the potentially large number of overhead line miles that could theoretically be eligible for OHUG projects, it is important to emphasize that, in the instant case, the Company is only seeking approval for 50 miles of work. And on page 35 of his direct testimony, Mr. Coppola makes reference to the Commission's June 12, 2025 Order in Case No. U-21305, which called for "additional evidence, including *a* BCA"[2] following the completion of the pilot approved in Case No. U-21389 "to fully evaluate the proposed undergrounding and how it compares with other potential pathways to improved reliability performance." This language indicates that the Commission does not expect separate benefit cost analyses for each individual project, but only one analysis covering OHUG as a program, which I have provided in my net present value analyses in

[2] See page 27 of the June 12, 2025 Order.

the instant case. Indeed, the Company has complied with all relevant direction given by the Commission on this issue in Case No. U-21305.

As to Mr. Coppola's dismissal of the SCT, it may be the case that some customers can endure certain duration outages with comparatively little inconvenience. However, the Company's distribution strategy is not based on identifying the maximum outage duration that customers can endure and allowing customers to experience that. Many customers, particularly in vulnerable communities, cannot endure many hours of outages without facing material impacts. And the Company does not believe that any customers should be consigned to outages lasting a day or longer before those outages are worth preventing.

Q. What is Mr. Coppola's overall recommendation regarding OHUG work?

A. On page 35 of his direct testimony, Mr. Coppola recommends that the Commission should fully disallow all bridge period ($1.25 million) and test year ($20 million) costs for OHUG. For all of the reasons given above, Mr. Coppola's recommendation should be rejected. The Company has shown that OHUG is a competitive (using the UCT) or even superior (using the SCT) economic alternative for improving reliability and resiliency. Additionally, the $1,250,000 for OHUG in the bridge period is simply carry-over of pilot costs for work completed in the bridge period that was already approved in Case No. U-21389, and those dollars should not be disallowed in any case.

Q. What is Mr. Coppola's recommendation regarding the EGLE-MIEJ Undergrounding Secondary and Services projects?

A. On page 36 of his direct testimony, Mr. Coppola observes that these projects are still in the preliminary phases of development, and he recommends that the full $4,118,000 proposed for the bridge period and test year be disallowed.

Q. Do you agree with this recommendation?

A. The Company will not contest this proposed reduction in capital expenditures for these projects. However, if the $4,118,000 is removed from the bridge period and test year, then the corresponding grant amounts also need to be removed from the totals reflected in Exhibit A-12 (MPK-1), Schedule B-5.7, line 9. This would reduce those negative numbers by $1,349,000 for the bridge period and $2,698,000 for the test year as shown in Exhibit A-121 (MPK-11) line 1 - 2024 40101(d) Formula Grants to States and Indian Tribes - Investment in DACs for Reliability and Readiness for Electrification, in effect putting that amount back into the Company's rate base for those periods.

Q. What are Mr. Coppola's recommendations regarding the Staking and Locating O&M sub-program?

A. He makes two recommendations. On page 167 of his direct testimony, Mr. Coppola objects to the Company's use of a 7% growth rate. He makes a substantively similar argument to that made by Ms. Durfee on this issue, and recommends that a 2% rate be used instead, with a corresponding disallowance of $866,000 for the lower projected volumes.

Q. Do you agree with this recommendation?

A. No. As I already discussed in my rebuttal to Ms. Durfee, simply using historical actual levels does not paint a complete picture, the deferral mechanism provides protection for customers, and the Company's staking growth in 2025 supports the projected growth rate that the Company used in this case.

Q. What is Mr. Coppola's second recommendation?

A. On pages 167 and 168 of his direct testimony, Mr. Coppola objects to the Company's transition to a dedicated contractor model for staking and locating work, instead of a shared

contractor model. He argues that the Company did not demonstrate that performance issues existed across the Company's service territory. Based on this, he recommends a substantial disallowance of $5.872 million based on the incremental cost of the dedicated model.

Q. Do you agree with this recommendation?

A. No. It is important to note that the Company operates a single Staking and Locating program for both its electric and gas businesses, meaning the Company will generally have one set of practices for both. Especially in the Company's combination territory with both gas and electric customers, it would not be practical to use a dedicated contractor model for gas customers and a shared model for electric customers, particularly since the Company will only "roll one truck" to mark gas and electric infrastructure at a given site. With that in mind, the Company already proposed the dedicated contractor model in its most recent gas rate case, Case No. U-21806. In that case, Mr. Coppola raised various objections to the dedicated contractor model, and Company witness James P. Pnacek provided detailed rebuttal to Mr. Coppola's arguments.

In the instant case, Mr. Coppola argues that the Company has not supported going to a dedicated contractor model. But I provided substantial detail in support of the Company's strategy on page 146, line 18, through page 149, line 2, of my direct testimony. Mr. Coppola does not address or acknowledge this discussion in his direct testimony.

Perhaps the most crucial part of the Company's rebuttal to Mr. Coppola in Case No. U-21806 was the fact that the Company's former shared contractor model contract expired earlier in 2025. When the Company issued a request for proposals for a new contract, which was open to both dedicated and shared contractors, the Company only

received one bid for a shared contractor, and it had a higher unit cost than the dedicated contractor whom the Company selected. In other words, there was no option for the Company to continue using a shared contractor model to save money; going forward, the dedicated contractor model is the most cost effective. As indicated on page 148, line 1, of my direct testimony, the dedicated contractor model is $0.51 less costly on a unit cost basis than the shared contractor option that would have been available.

The Commission approved the Company's dedicated contractor model proposal in Case No. U-21806, and the Commission should reject Mr. Coppola's recommendation in the instant case just as it did in Case No. U-21806. The gas business has transitioned to a dedicated contractor model, with Commission approval, and the electric business should not be required to pursue an alternate approach.

Q. What is Mr. Coppola's recommendation regarding the HVD Lines Demand O&M sub-program?

A. On page 169 of his direct testimony, Mr. Coppola notes that the Company did not propose a large increase to this O&M sub-program's level in Case No. U-21585. He further notes that the Company is on track to underspend on this sub-program in 2025, and he recommends that the test year spending level should be set at the highest actual level incurred by the Company in the last five years.

Q. Do you agree with this recommendation?

A. No. First, Mr. Coppola is incorrect about Case No. U-21585. The Commission's March 21, 2025 Order in that docket, page 276, notes that the Company did in fact identify an increase in identified anomalies that warranted more spending in this sub-program, and on page 277, the Commission approved the Company's projected increase of $2.2 million

in this sub-program. Regarding the proposed disallowance based on spending in 2025, please refer to my rebuttal to Ms. Durfee.

Q. What is Mr. Coppola's recommendation regarding the Service Calls O&M sub-program?

A. On page 170 of his direct testimony, Mr. Coppola agrees with the Company's projected labor cost increase for this sub-program, but does not agree with the projected increase in hours worked. He proposes a disallowance based on tying costs to the five-year average, adjusted for the labor cost increase, resulting in a reduction of $798,000.

Q. Do you agree with this recommendation?

A. No. Although the Company does project a number of work hours for this sub-program, page 159, lines 17 through 22, of my direct testimony, indicates that projected spending is driven by work order volumes. As stated on page 159, line 9, the Company's recent history has involved approximately 33,000 discrete calls per year. Mr. Coppola makes reference to discovery response 21870-AG-CE-0514, which I am providing as Exhibit A-221 (MPK-31). As shown in that response, the Company is on track for 34,855 work orders in the test year, an increase from those historical levels. The response also indicates that work orders are multiplied by an hourly factor to produce a projected amount of work hours, but that different types of work orders can take different amounts of time, meaning work orders and hours may not always be correlated one-for-one.

Q. What is Mr. Coppola's recommendation regarding the LVD Lines Reliability O&M sub-program?

A. On page 172 of his direct testimony, Mr. Coppola notes that the Company is apparently not on track to meet its spending targets for this sub-program in 2025, and he recommends

a test year disallowance of $7.060 million to bring the Company's projection in line with its actual trajectory.

Q. Do you agree with this recommendation?

A. No. Mr. Coppola is making a substantially similar argument to that of Ms. Durfee. Please refer to my rebuttal to her.

Q. What is Mr. Coppola's recommendation regarding the HVD Lines Reliability O&M sub-program?

A. On page 172 of his direct testimony, Mr. Coppola notes that the Company admitted in discovery that its projected test year spending level should be reset to the five-year historic average, which would be a disallowance of $677,000 from the Company's filed position.

Q. Do you agree with this recommendation?

A. Yes. Mr. Coppola's recommendation aligns with the Company's stated revised position in discovery.

Q. What is Mr. Coppola's recommendation regarding the LVD Electric Distribution O&M sub-program?

A. On page 173 of his direct testimony, Mr. Coppola notes that the Company's 2025 spending in this sub-program is not on track to meet projected levels, and he proposes to limit the Company's test year spending to the 2024 actual level, resulting in a test year disallowance of $4.519 million. He further notes that the primary driver of the Company's proposed increase is tied to Grid Automation work, and he states that the "tasks performed in this area have been ongoing for some time" and therefore no increase is needed.

Q. Do you agree with this recommendation?

A. No. The projected increase tied to Grid Automation is not related to ongoing work, and Mr. Coppola does not state how he came to that conclusion or how he defines ongoing work. Because the Company's increase for this sub-program is driven by new Grid Automation work, it is not appropriate to index the spending level to a historical amount.

Q. What is Mr. Coppola's recommendation regarding the Electric Geographic Information System ("GIS") Utility Network Transformation project and the Electric GIS Design Platform Modernization project?

A. On page 90 of his direct testimony, Mr. Coppola argues that these projects are too early in their development for inclusion in rate base, and he recommends that they be disallowed.

Q. How do you respond to this?

A. Company witness Stacy H. Baker provides the primary rebuttal to Mr. Coppola regarding these projects. However, I want to also reemphasize the benefits of these projects for the Company's electric distribution system, as outlined on pages 118 through 122 of my direct testimony.

VII. REBUTTAL OF ABATE WITNESS FITZHENRY

Q. What is Mr. Fitzhenry's assessment of the Company's electric distribution reliability?

A. On pages 4 and 5 of his direct testimony, Mr. Fitzhenry suggests that the Company's 2024 SAIDI excluding MEDs of 155 minutes, compared to a projected 170 minutes, is the basis of the Company's claim that reliability investments are producing improvements.

Q. How do you respond to this characterization?

A. Mr. Fitzhenry references page 29 of my direct testimony to support his interpretation that the Company is claiming that reliability has improved based on 2024 actual results

compared to projections. While that is one piece that supports the Company's assertion, my position that the Company's reliability has been clearly improving is based on the data shown in Figure 6 in my direct testimony. This figure shows that SAIDI has been improving in absolute terms since 2021, that the rolling five-year average has been falling since 2022, and that each individual year beginning in 2022 has been substantially better than the five-year rolling average (see my earlier rebuttal to Ms. Schiller for the discussion as to why this analysis is appropriate). Page 25, lines 13 through 21, of my direct testimony further explains why the Company's analysis is more appropriate than Liberty's approach of simply looking at data from 2014 through 2023.

Q. What other arguments or analysis does Mr. Fitzhenry provide about the Company's reliability?

A. On pages 5 and 6 of his direct testimony, Mr. Fitzhenry states that he has conducted his own analysis to compare the Company's reliability to peer utilities. Using publicly available data, he has compared the Company's SAIDI with and without MEDs to investor-owned utilities in Michigan, Wisconsin, Indiana, and Ohio. Of the 17 utilities considered, Mr. Fitzhenry states that the Company always ranks 12th or worse, with an average rank of 15th. Based on this, he concludes that the Company is at or near the bottom for reliability when compared to peers.

Q. How do you respond?

A. The numbers cited by Mr. Fitzhenry do speak for themselves to some extent, but Mr. Fitzhenry's analysis supposes that other investor-owned utilities in states with land borders with Michigan (and in Michigan itself) are a good comparison group because those utilities face roughly similar weather challenges as the Company. But even if weather were

similar all the way from northern Wisconsin to southern Ohio, which is not necessarily the case, weather is only one part of what makes utilities similar or dissimilar for purposes of comparison. Utilities can have dramatically different systems in terms of square mileage, line mileage, customer density, percentage of system overhead versus underground, prevalence of heavily forested terrain, and various other factors that can have major implications for reliability. In his table CTF-1, Mr. Fitzhenry has included utilities in northern Wisconsin and the Upper Peninsula of Michigan with less than 1% of the Company's customer count and service territories that are exclusively rural areas and small towns. Additionally, Madison Gas & Electric has approximately 60% of its lines underground, making it a poor point of comparison to the Company. He has also included Dayton Power & Light, a utility that primarily serves a large metro area and surrounding areas of open farmland. A more nuanced discussion comparing the Company to peer utilities and accounting for system differences is given on pages 15 and 16 of Exhibit A-129 (MPK-19).

Notwithstanding that caveat, the Company's argument is not that its reliability is good relative to peers today. My direct testimony is very clear about the fact that the Company's SAIDI is even now in the third quartile, and the entire premise of the Reliability Roadmap is to improve the Company's reliability into the second quartile. However, the Company's reliability has improved in recent years relative to its peers, as I discuss on page 26, lines 1 through 9, of my direct testimony. The analysis supporting this was presented in Figures 7 and 8 in my direct testimony, based on the peer groups participating with the Institute of Electrical and Electronics Engineers ("IEEE").

Q. What is Mr. Fitzhenry's analysis regarding outage causes?

A. On pages 6 and 7 of his direct testimony, Mr. Fitzhenry cites information that the Company provided about LVD outage causes from 2022 through 2024, and observes that 52% of outages were due to trees either inside or outside the right of way, with a further 26% of outages caused by weather. Based on this, Mr. Fitzhenry argues that the Company should primarily focus on forestry work as opposed to asset replacement in order to improve reliability.

Q. Do you agree with this assessment?

A. No. I addressed the need for continued capital investments alongside increased line clearing at page 35, line 1, through page 37, line 9 of my direct testimony. Mr. Fitzhenry's direct testimony does not make any reference to this part of my direct testimony, so it is not clear that he has evaluated the Company's rationale for why forestry and capital investments are both important for improving reliability.

It is also important to note that it appears that Mr. Fitzhenry's analysis assumes that any weather-caused outage must have been tree-related, but this is not correct. Weather impacts on the system can cause direct damage to assets even if trees are not involved. For example, straight-line winds or a tornado in the middle of an open field can be strong enough to damage assets without tree contact. Furthermore, some tree-related outages are in part a result of failed assets that have not been hardened to withstand tree impacts; in other words, tree contact may have been the event that initiated an outage, but a hardened system is better able to withstand this initial strike and continue to serve customers.

Q. What else does Mr. Fitzhenry say about the impact of the Company's investments on reliability?

A. On pages 8 and 9 of his direct testimony, Mr. Fitzhenry compares the Company's additions to distribution plant over 2020 through 2024 to the Company's all-weather SAIDI over the same period. While distribution plant has increased, all-weather SAIDI has oscillated between about 500 minutes and 900 minutes. Mr. Fitzhenry accuses the Company of cherry-picking reliability by only focusing on SAIDI excluding MEDs when considering if reliability is improving.

Q. How do you respond to this?

A. The Company is certainly not cherry-picking its data by using SAIDI excluding MEDs. SAIDI excluding MEDs is an IEEE-defined industry standard metric, in widespread use by utilities. As stated on page 107 of my direct testimony, MPSC rules backed by Michigan law direct utilities to consider reliability metrics both including and excluding MEDs, so the use of SAIDI excluding MEDs has clear sanction from the State of Michigan. As stated on page 109 of my direct testimony, the benefit of SAIDI excluding MEDs is that it normalizes performance data for unusually severe weather. This is why the Company has used SAIDI excluding MEDs to evaluate recent improvements in reliability, to separate out fluctuations exclusively created by the severity of weather in a given year. This is also why the Company's distribution planning has been premised on making improvements to SAIDI excluding MEDs, since the metric is more reflective of conditions within the utility's control. (See also page 25, lines 9 through 12, of my direct testimony.) The Company's distribution strategy to date has been focused on improving SAIDI excluding MEDs, and the Company has had success in doing so.

Still, it is not accurate to suggest that the Company ignores SAIDI including MEDs, especially given the Commission's direction to consider both. Pages 110 and 111 of my direct testimony present the Company's 10-year history with that metric; the Company is not ignoring it. While the Company's strategy specifically targets SAIDI excluding MEDs, the Company has been introducing new efforts aimed at reducing SAIDI including MEDs for customers. The Resiliency sub-program is largely focused on this, and reducing major event days was the goal of the Company's IRM when it was proposed in Case No. U-21389. The VCRP is also designed to improve SAIDI including MEDs in EJ communities. The newness of these programs means that their impact on SAIDI including MEDs would not have shown up yet in the data.

Q. What is your overall response to Mr. Fitzhenry's discussion of reliability?

A. Mr. Fitzhenry argues on page 9 of his direct testimony that his analysis indicates that the Commission must view the Company's investment plan with "extreme skepticism." Later in his testimony, he uses his analysis to support proposing substantial disallowances, the specifics of which are rebutted by Company witnesses Partlan and Hayward. However, as I have shown, his analysis has multiple flaws and has not addressed much of the evidence on the record.

Q. What is Mr. Fitzhenry's assessment of the Company's plan for OHUG investments?

A. Mr. Fitzhenry begins assessing the Company's OHUG plan on page 16 of his direct testimony. On page 18, he states that he has concerns about the Company's use of the UCT and SCT to justify the OHUG as an economic option for improving reliability and resiliency. He then makes a number of criticisms about the outcomes of the Company's now-completed OHUG pilot.

Q. What does Mr. Fitzhenry say about the UCT and SCT?

A. While he states that he has concerns about the Company's methodology in these tests, he never clearly states what these concerns are. This makes it difficult to effectively rebut his position. He does indicate, on page 20, line 1, of his direct testimony that the UCT shows that OHUG is the most expensive option. As discussed in my rebuttal to Mr. Coppola, Figure 26 in my direct testimony does show that OHUG is more expensive than alternatives at scale. However, OHUG is only 2% more expensive, and page 66, lines 9 through 13, of my direct testimony indicate that OHUG is expected to provide at least a 90% reliability improvement because the threat of trees is almost completely eliminated. This level of reliability improvement is much greater than that offered by alternatives. Combined with the fact that OHUG is only marginally more expensive, this still represents good value for the money.

The SCT analysis presented in Figure 27 of my direct testimony makes this comparison even more favorable for OHUG. Mr. Fitzhenry's only apparent criticism of the SCT is that it is "speculative," because it values long-term benefits. Mr. Fitzhenry does not provide any support for why the SCT is inappropriate to use, nor why long-term benefits are "uncertain;" OHUG should logically provide near-perpetual resiliency benefits since the line will be permanently protected from trees and weather.

Q. What does Mr. Fitzhenry say about the Company's completed OHUG pilot?

A. On page 18 of his direct testimony, Mr. Fitzhenry states that the pilot "was not completed as planned" because some initial projects had to be replaced with others. He says that these issues indicate that the Company cannot scale its underground "from 8.8 miles completed

in the (p)ilot to 400 miles in this proceeding," and he states that substituting projects may lead to fewer benefits.

Q. How do you respond to these criticisms?

A. I disagree with Mr. Fitzhenry's contention that the pilot was not completed as planned. Any plan may require changes when it faces the reality of execution, but this does not mean the plan was unsuccessful. A hallmark of a successful organization is that it can make adjustments and adapt as challenges arise. In this case, the Company faced challenges with some initially proposed projects, but the Company was able to quickly find equivalent alternatives such that the same volume of work was still performed in the same timeframe. This agility indicates that the Company is capable of adapting to workplan challenges and continuing to get beneficial projects completed. It is also important to note that the Company is not proposing to immediately scale from 8.8 miles of OHUG work to 400 miles in this proceeding. The Company is only proposing to scale to 50 miles in this proceeding. The Company's long-term strategy is to scale to 400 miles, but not without first going through interim steps such as those proposed in the instant case.

Finally, because all undergrounding projects use the same selection criteria, each project should have generally similar benefits, even if a substitution is involved.

VIII. REBUTTAL OF ABATE WITNESS YORK

Q. How does Ms. York address the Company's distribution O&M?

A. On page 5 of her direct testimony, Ms. York notes the Company's recent distribution O&M has been between $640 million and $680 million per year, but in the instant case it proposes to increase it to $804 million. She opines that this is an excessive increase, and identifies several areas of proposed disallowances.

Q. Is there a common focus in how Ms. York proposes disallowances?

A. I note that several of her sub-program reviews focus on the "Other Adjustments" column in Exhibit A-128 (MPK-18), and multiple disallowances are based on the idea that these adjustments are not properly supported.

Q. Is there a problem with interpreting Exhibit A-128 (MPK-18) in this way?

A. Yes. Exhibit A-128 (MPK-18) should not be understood to suggest that the Company projected distribution O&M spending by starting with the most recent historical year, adding inflation, and then making adjustments from that level. In fact, the Company does not develop its projected distribution O&M spending in this manner; while each O&M sub-program is a little different, projected distribution O&M spending is usually based on a projected level of work, and the specific approach for each O&M sub-program is discussed throughout my direct testimony.

Please refer to page 124, line 5, through page 125, line 3, of my direct testimony for an explanation of how to properly understand Exhibit A-128 (MPK-18). The purpose of the exhibit is to illustrate what amount of the Company's projected O&M spending is tied to inflation, particularly so that interested intervenors can see the impact of different inflation rates. At no point is my direct testimony trying to specifically support the "Other Adjustments" column in and of itself; my testimony supports the total projected spending amount based on the total amount of work needed.

Q. What is Ms. York's recommendation regarding the Company's projections for the Non-Forestry Reliability O&M sub-programs?

A. On page 7 of her direct testimony, Ms. York states that the "Other Adjustments" for LVD Lines Reliability O&M, HVD Lines Reliability O&M, and LVD Substations Reliability

O&M are not supported. She goes on to state that the Company did not provide enough detail on how these sub-programs were projected. She recommends that the $10,003,000 in "Other Adjustments" for these sub-programs be disallowed.

Q. Do you agree with this recommendation?

A. No. First, as stated above, the Company supported the total sub-program expenditures, and not just the "Other Adjustments." Second, note that I have already discussed these sub-programs and the reasonableness of the Company's projections in my rebuttal to Ms. Durfee and Mr. Coppola. Finally, in discovery response 21870-AG-CE-0453, the Company provided detailed unitized information for these and other O&M sub-programs, illustrating the projected increasing workload that supports the projected increase in spending. I am providing this response as Exhibit A-222 (MPK-32).

Q. What is Ms. York's recommendation regarding sub-programs in the O&M and Metering without Service Restoration category?

A. On pages 10 through 12 of her direct testimony, Ms. York argues that the Company has not provided sufficient detail regarding how it projected its O&M costs for HVD Lines Demand O&M, LVD and HVD Substations Demand O&M, Staking, and Meter Services. She notes that my direct testimony did not provide detail about historical or projected work orders for some of these sub-programs. She recommends that the Commission disallow the $18,118,000 that are in "Other Adjustments" in Exhibit A-128 (MPK-18) for these sub-programs.

Q. Do you agree with this recommendation?

A. No. I will again note the issues with Ms. York's use of Exhibit A-128 (MPK-18), and I will also note that additional supporting work order details were provided in the discovery

response that is provided as Exhibit A-222 (MPK-32). Furthermore, I have supported the reasonableness of the Company's projections for HVD Lines Demand O&M and Staking O&M in my rebuttal to Ms. Durfee and Mr. Coppola, particularly the question about whether the Company's 7% growth rate for Staking O&M is appropriate.

Q. What is Ms. York's recommendation regarding the Training O&M sub-program?

A. On page 14 of her direct testimony, Ms. York states that, although Company witness Caitlin M. Tetrick has provided details about the Company's projected headcount that will drive increases in the Training O&M budget, the Company has not provided its assumptions related to the number of new employees who will require training during the test year. She also states that Company witnesses Sara E. Stewart and Richard T. Blumenstock have provided direct testimony related to challenges in obtaining necessary crews. As with the other O&M sub-programs, Ms. York recommends a disallowance based on the "Other Adjustments" amount in Exhibit A-128 (MPK-18).

Q. Do you agree with this recommendation?

A. No. For one thing, Company witness Stewart addresses forestry issues, and Company witness Blumenstock addresses generation. They are describing separate parts of the Company's workforce and/or contractors, so their testimony has no bearing on the distribution workforce that my direct testimony supports. Second, Ms. York is incorrect in focusing on the number of "new employees, apprentices, and external candidates that will actually require training during the projected test year." This implies that she believes that the Training O&M sub-program is only focused on on-boarding new employees. The Training O&M sub-program is actually used for training employees at various stages of employment. Page 167 of my direct testimony explains that the sub-program covers

expenses "whenever groups in the Electric Operations organization conduct official training courses." Page 168 states that the sub-program funds "union labor associated with additional hours of training, such as continuing education and required annual training courses." Company witness Tetrick has provided sufficient detail regarding the growth of the Company's Electric Operations workforce; since all employees require some amount of training, then the Training O&M sub-program budget will increase. Exhibit A-222 (MPK-32) shows that the number of total training hours is set to increase.

IX. REBUTTAL OF CEO WITNESS TAN

Q. What is Mr. Tan's assessment of the Company's regression analysis as presented in the instant case?

A. Mr. Tan has reviewed the regression analysis that the Company provided as Exhibit A-135 (MPK-25). On page 11 of his direct testimony, he concludes that the regression analysis as far as it regards reliability represents an "excellent job," and he finds value in it having been completed. I appreciate Mr. Tan's assessment in this area. Beginning on page 13 of his direct testimony, he discusses the part of the regression analysis that focused on customer disconnections and makes a number of recommendations in response to that, which will be addressed by Company witness Jessica R. Byrom.

Q. What recommendations does Mr. Tan make regarding future reliability regression analyses?

A. On pages 12 and 13 of his direct testimony, Mr. Tan recommends that the Company's next regression analysis (which will be required in its next rate case) should focus on a narrower set of reliability metrics using the same independent variables.

Q. Do you agree with this recommendation?

A. I do not have any concern with this recommendation. The Company hopes that future iterations of the reliability regression analysis will continue to focus on the most salient issues, and Mr. Tan's recommendation to narrow the focus will likely help with that.

X. REBUTTAL OF CEO WITNESS SHAVER

Q. What is Mr. Shaver's position on the Company's VCRP?

A. On page 4 of his direct testimony, Mr. Shaver states that he supports the VCRP, but that he recommends several "enhancements" to it. He goes into greater detail about this on pages 12 and 13 of his direct testimony, where he notes that the Company has presented the VCRP as a 10-year $600 million effort, yet has only proposed $30 million in investments in the test year in the instant case. He asks that the Company provide further detail about its total spending plan, as well as information regarding the six substations that are part of the VCRP that were already included in the Reliability Roadmap.

Q. How do you respond to this?

A. The Company is proposing to invest $30 million in the test year for two reasons. First, because it is a new initiative, the Company is seeking regulatory support from the Commission at an initial level before scaling up to a fuller annual spending level. Second, because the VCRP includes new types of work related to the development of high-reliability mainline three-phase circuits, the Company plans to do a smaller amount of work in the first year before scaling up, as opposed to trying to go "zero-to-60" in the first year. The Company's planned glidepath for the VCRP is based on investing $20 million in 2026, $40 million in 2027 (with the $30 million test year amount derived from the test year overlap between 2026 and 2027), and $67.5 million each year after that through 2035. Exact amounts may vary slightly from this based on specific projects selected in individual

future years; the Company has not yet identified specific projects beyond the test year in the instant case. It is not clear what information Mr. Shaver is seeking regarding the six new substations. He asks for details about "which substations these are," but these are new substations that will be built but which do not exist yet, so there is no current information about them. However, the $200 million dollars proposed for fractionalization in the VCRP does include those six new substations.

Q. What does Mr. Shaver say about the Company's reliability regression analysis?

A. On page 15 of his direct testimony, Mr. Shaver concludes, in conjunction with Mr. Tan, that the regression analysis has provided useful insight into reliability on the Company's system. Mr. Shaver also appears to agree that the regression analysis provides useful support for the VCRP. However, he also argues that the regression analysis should not be a stand-alone study, but that it should also "directly inform the Company's overall spending, including areas such as O&M and storm response." He recommends that the Company provide this kind of detail.

Q. How do you respond to this?

A. Mr. Shaver's recommendation here is unclear. The regression analysis supports the VCRP, which represents a significant investment in EJ communities. However, the regression analysis is not intended in the first place to serve as a comprehensive tool that governs all parts of the Company's electric operations or storm response. The reliability-related portions of the regression analysis were designed to[3]:

1. Quantify differences in the experiences of two groups of customers – those in EJ census tracts and those outside of them,

[3] Refer to Exhibit A-135 (MPK-25), pages 2 and 3 (the "Executive Summary" section).

2. Understand whether groups of customers may be disadvantaged or more exposed to disruptions in service than other customers, and

3. Assess how different characteristics of circuits relate to circuit reliability.

While the Company can always evaluate new ways to extract insights from this and future iterations of the regression analysis, it is not designed to provide direction on how the Company should allocate its O&M dollars in a comprehensive way.

Q. Does Mr. Shaver have any further recommendations?

A. On pages 17 and 18 of his direct testimony, Mr. Shaver recommends several ways in which the Company should track the impacts of the VCRP.

Q. Do you agree with this?

A. Mr. Shaver's recommendations for assessing the impacts of the VCRP seem generally reasonable. However, the first year of VCRP investments will not be complete until the spring of 2027, and there will likely be some lag after that time until the Company has sufficient "after" data to begin to draw conclusions, so little "before and after" analysis will be available in the immediate future.

XI. REBUTTAL OF CEO WITNESS KENWORTHY

Q. What is Mr. Kenworthy's position on virtual power plants ("VPPs")?

A. On page 3 of his direct testimony, Mr. Kenworthy recommends that the Commission move "from study to implementation [of VPPs] by requiring the Company to develop a near-term VPP program that delivers measurable value to customers and the grid." On subsequent pages, he provides details about what he believes this should entail; among the key points are that the Company should be able to create a full-fledged VPP program quickly, without needing a pilot (see page 5 of his direct testimony) and that it is possible to establish a

VPP within six months. Company witness Scott A. McPhail addresses the bulk of Mr. Kenworthy's recommendations on VPPs, but I also have concerns.

Q. What are your concerns?

A. I disagree with the suggestion that VPPs can be deployed in the Company's service territory starting immediately, reaching operational status within six months, without the need for any kind of pilot. Mr. Kenworthy suggests that VPPs are a mature concept that have been standardized in such a way that any utility can easily plug and play them onto its own system. Mr. Kenworthy's own evidence indicates that this is not the case. Page 13 of his direct testimony suggests that Exhibit CEO-4 provides evidence that VPPs reliably deliver benefits for the grid. But Exhibit CEO-4 seems to summarize a test event in California that just took place on July 29, 2025. This suggests the California parties involved have only just performed an initial demonstration of a new concept. This does not lead to a conclusion that VPPs are ready for deployment nationwide.

Each state has its own regulatory construct, and Michigan's is different from California's. There is no assurance that even a mature and well-established VPP in California could be transplanted wholesale to Michigan. Furthermore, the test event summarized in Exhibit CEO-4 was apparently coordinated with the California Independent System Operator ("CAISO"); there is no assurance that a VPP that works in CAISO could be transplanted wholesale to a utility operating in the Midcontinent Independent System Operator, Inc. region. Therefore, it is not correct to suggest that any conceptual VPP – especially one that appears to have just been tested two months ago – could be wholeheartedly adopted by the Company without first determining if it would work on the Company's system and in the Company's environment, which would necessitate some kind

of piloting by the Company. The workgroup described by Company witness McPhail could include discussion on the best approach to do this.

Q. What is Mr. Kenworthy's recommendation regarding non-wires solutions ("NWS")?

A. On page 20 of his direct testimony, Mr. Kenworthy recapitulates the Company's experiences with NWS since 2017 and his own arguments from Case No. U-21585 about how the Company could be deploying NWS now or in the immediate future rather than waiting for "off-the-shelf" solutions to be available. On page 21, he responds to the Company's intention to create a new NWS pilot by saying that "the time for pilots is over" and that the Company should now begin developing a formal program. On page 22, he seems to connect this argument to his argument about VPPs, saying that VPP program design should be informed by NWS analysis.

Q. How do you respond to this?

A. I continue to maintain that the Company must do another NWS pilot in order to demonstrate that an NWS will in fact deliver clear and consistent benefits for the Company's system, and that it can operate reliably on the Company's system. This is especially important since the Company's prior NWS pilots provided, at best, mixed results. Unless the Company is confident that a given NWS scheme will work, it would be irresponsible to begin implementing a program that may not be effective. This is particularly important as the Company would like to use a new pilot to explore using an NWS to provide reliability and resiliency benefits, whereas prior pilots have only looked at capacity deferral.

Q. How do you respond to Mr. Kenworthy's connection of VPPs to NWS?

A. In the Distributed Energy Resource Management System ("DERMS") workgroup discussed by Company witness McPhail, NWS could be an additional topic for discussion. Indeed, Mr. Kenworthy's discussion of the two topics in his testimony implies that there is overlap between the two concepts. But the synergy between VPPs and NWS also provides further evidence that neither concept is ready for immediate program-level deployment. Exhibit CEO-3 is the Department of Energy's "Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update" and is heavily cited by Mr. Kenworthy. Much of Mr. Kenworthy's discussion centers around "basic VPPs" – these are the schemes that can allegedly be deployed in six months. But the broader context of the report makes these basic VPPs sound closer to pilots in all but name. For example, Exhibit CEO-3, page 35, says that "many basic VPPs have been managed by customer programs teams with little to no impact to other functional groups within utilities; this limits the potential benefits of the VPP for the broader utility system. In contrast, leading utilities who operate more sophisticated VPPs have incorporated them into integrated planning processes and operations." In other words, delivering the grid-wide benefits contemplated by Mr. Kenworthy requires the development of sophisticated VPPs. The report indicates that such programs exist in places, but they are not easily or rapidly built. Notably, Exhibit CEO-3, page 28, states that sophisticated VPPs "may require the installation of additional hardware and software that provide (1) higher-resolution visibility into distribution grid conditions through sensors and improved data analytics and (2) more frequent and localized dispatch of DERs." In other words, the Company would not be in a position to deploy the kinds of VPPs or NWS that Mr. Kenworthy is seeking unless and until it has

made the appropriate foundational investments, particularly a DERMS. Since the Company does not have a DERMS, and the justification for one is an intended focus of the workgroup, it is not reasonable to suggest that the Company can immediately begin creating VPPs or NWS on its system.

XII. REBUTTAL OF CUB WITNESS BUNCH

Q. How does Mr. Bunch discuss the Company's reliability and its connection to planned investments?

A. On page 9 of his direct testimony, Mr. Bunch notes that in 2023 the "average Consumers customer went 913 minutes without power," an apparent reference to all-weather SAIDI, compared to a U.S. average of 342 minutes. He opines that this reliability performance should not be justified by an increase in rates (underpinned by increased investments in the system), suggesting that companies in competitive markets (presumably in other industries or perhaps in deregulated utility environments) would not be able to do this. Mr. Bunch concludes that the Company should be expected to deliver electricity to customers at rates similar to comparable utilities and with similar reliability, and that it would be unreasonable to grant rate increases to help the Company improve against reliability benchmarks.

Q. How do you respond to this argument?

A. I disagree with Mr. Bunch. For one thing, he has picked a single data point with which to assess the Company's reliability. All-weather SAIDI was considerably lower in 2022 and 2024, for example, and SAIDI excluding MEDs is also an industry-standard way of assessing reliability (indeed, the Company's Reliability Roadmap is based on improving SAIDI excluding MEDs – this is the reliability benchmark the Company is trying to improve against). Mr. Bunch's reference to hypothetical unnamed companies in other

industries is not relevant to this discussion because Consumers Energy does not exist in that environment; it provides electricity as a regulated utility under the regulatory construct established by Michigan law. Speculating about how the Company would fare in a competitive market, however Mr. Bunch would define that, is not relevant. Finally, it is unreasonable to argue that the Company has poor reliability while also contending that the Commission should not approve rate increases to fund reliability improvements.

Q. What is Mr. Bunch's position on which investments in distribution reliability should be approved?

A. On page 36 of his direct testimony, Mr. Bunch recommends that the Commission approve the Company's projected increases in line clearing and in LVD pole replacements. However, he classifies these increases as a "surge," and he and Douglas B. Jester (witness for NRDC, Sierra Club, and CUB) have developed a proposed deferral mechanism that classifies certain "surge" costs that would be kept out of rate base and only recovered later. Company witness Stewart addresses the Company's plans for line clearing, but I would note that it is not reasonable to remove the capital costs for pole replacements from rate base. Current customers do not cover the full capital investments in the first place, since the full revenue requirement is not recovered in a single year. See also the rebuttal testimony of Company witness Patrick D. Daly for additional discussion.

I am also concerned that, other than line clearing and LVD pole replacements, Mr. Bunch believes all other reliability investments should be held at "PAI-adjusted current levels," referring to a methodology that he has developed to index spending levels to inflation.

Q. Why are you concerned about this recommendation?

A. As I stated on page 41 of my direct testimony, it is important for the Company to have a diverse portfolio of investments to improve reliability, rather than going all-in on one or two types of activities; see also page 46, line 1, through page 47, line 2, of my direct testimony. Line clearing work is certainly an important part of the Company's reliability strategy, but pages 35 through 37 of my direct testimony have already provided a detailed explanation as to why it cannot be the only solution. LVD pole replacements are certainly an important part of the Company's plan as well, given their rate of deterioration, but as page 32, Figure 13 of my direct testimony illustrates, the Company's increased investment in LVD pole replacements will largely just allow the Company to hold the current line on SAIDI. As Figure 13 shows, multiple other investment categories in LVD and HVD play a role in the Company's holistic approach to improving reliability. Mr. Bunch's proposal would simply cause deterioration on the system to rapidly accelerate.

Mr. Bunch's recommendation is, in any case, vague. He recommends that the Commission "hold other reliability investments at PAI-adjusted current levels." It is not clear which investments he intends to include in this recommendation.

Finally, I disagree with Mr. Bunch's suggestion at page 36 of his direct testimony that the Company should invest in a very limited range of work in order to "make it easier to determine what additional reliability actions may be needed next, after the proverbial dust settles." I disagree with the implication that the Company cannot tell which reliability investments are beneficial. The Company has been documenting the specific reliability benefits of many types of investments over the years, particularly but not limited to Zonal

Health Improvements, and has provided evidence in this case (and in recent cases) about the percentage improvements that those projects make.

Q. What is Mr. Bunch's assessment of the Company's proposed OHUG plan?

A. On pages 48 and 49 of his direct testimony, Mr. Bunch states that the Company did not perform a benefit cost analysis ("BCA") for each proposed OHUG project. See my rebuttal to Mr. Coppola on this topic. Mr. Bunch also states that, based on his own analysis, half of the benefits of proposed OHUG work are attributable to a small minority of the work. He explains that he reviewed the customer-outage minutes avoided ("CMI") for the proposed projects in Exhibit A-167 (JMP-2), page 21, and calculated a present value of these CMI benefits for customers. In his Figure 3, he shows that half of the benefits are tied to just 11.3 of the Company's proposed 50 miles of projects. He recommends that the Company's OHUG work in the test year be limited to these 11.3 miles.

Q. Do you agree with this recommendation?

A. No. Mr. Bunch's model is incomplete because it is based solely upon the present value of avoided interruption costs to customers from an undergrounding project. This value is only one factor included within the SCT. In short, Mr. Bunch ignores many of the costs included in a BCA such as Return on Equity, interest, depreciation, taxes, O&M that customers will pay in return for the improved reliability benefits, and ignores the costs of alternatives to undergrounding the feeder like continued vegetation management. As a result, Mr. Bunch's alternative analysis is akin to a "do-nothing" scenario whereby the Company would not invest in the maintenance of equipment or vegetation on the feeder and would not invest in crew time or materials to restore customers when an outage occurs. Although Mr. Bunch leverages my own analysis to utilize the Interruption Cost Estimate ("ICE")

calculator in outlining the avoided interruption costs for customers, that analysis is misused. Because the ICE calculator has been limited to costs associated with outages that only last up to 24 hours, Mr. Bunch is likely understating the value of the project's impact on avoided interruption costs to customers given his analysis does not take into consideration the costs of alternatives.

XIII. REBUTTAL OF MNSC WITNESS PALMER

Q. What is Ms. Palmer's recommendation on the need to produce an AMI business case?

A. On page 9 of her direct testimony, Ms. Palmer recommends the Company continue to produce an AMI benefit analysis in subsequent rate cases.

Q. Do you agree with this recommendation?

A. No. In Case No. U-21389, the Commission has already clarified that the AMI business case was no longer needed because the value of the reporting was less about supporting a BCA for meters that had long been installed. The Company was directed to substitute the business case with AMI value-focused metrics that are discussed in my direct testimony. See my direct testimony, page 188 and Exhibit A-133 (MPK-23).

XIV. REBUTTAL OF GLREA WITNESS BOEHNKE

Q. What is Mr. Boehnke's thesis on VPPs?

A. On pages 7 and 8 of his direct testimony, Mr. Boehnke states that my direct testimony and discovery responses indicate that the Company does not believe that VPPs and other Distributed Energy Resource ("DER")-related applications can deliver reliability and resiliency benefits. Mr. Boehnke then extensively discusses the subject of VPPs, broadly agreeing with Mr. Kenworthy that VPPs are ready for immediate widespread deployment by the Company.

Q. Do you agree with his assessment?

A. No. For the reasons I discussed above in response to Mr. Kenworthy and discussed in the rebuttal testimony of Company witness McPhail.

XV. REBUTTAL OF UCC WITNESS CIRA-REYES

Q. What does Mr. Cira-Reyes say about the Company's reliability?

A. Beginning on page 47 of his direct testimony, Mr. Cira-Reyes expresses concern with the Company's reliability, and he makes the connection to the particular detrimental impacts that this has on disadvantaged communities. On pages 48 and 49, he reviews the actions that the Company has taken in recent years to review and address reliability issues in such communities (*i.e.,* in EJ communities), and he seems to acknowledge that progress has been made but ultimately concludes that the Company must act "more expeditiously" to address this issue. Specifically, he believes that the Company must do more to meet the investment targets for the VCRP, and that the Company must take more action to address inequities revealed in the regression analysis.

Q. How do you respond to these two recommendations?

A. As outlined on page 51 of his direct testimony, Mr. Cira-Reyes' concerns about whether the Company will meet its investment targets for the VCRP largely mirror the concerns that Mr. Shaver also expressed. Please refer to my rebuttal of Mr. Shaver for discussion on this.

On pages 52 and 53 of his direct testimony, Mr. Cira-Reyes states that the regression analysis in Exhibit A-135 (MPK-25) confirms that the distribution system has inequities based on race and socioeconomic status, and he believes the Company is not making a priority to address these inequities. Specifically, he takes issue with my statement in my direct testimony that the analysis concludes that, on average, EJ, urban, low-income,

and higher-percent-minority census tracts have better reliability. Similar to arguments made in Case Nos. U-21389 and U-21585, Mr. Cira-Reyes argues that average comparisons likely conceal inequities. I believe the full regression analysis has addressed this concern. Exhibit A-135 (MPK-25), pages 24 through 26,[4] lists several types of analyses that were used in the overall regression analysis project. One type, the binary difference-in-means t-test, was used to make binary overall comparisons between different sets of census tracts. This was an early phase of the project and was intended to (a) validate the comparisons made in Case Nos. U-21389 and U-21585 on a more formal statistical basis and to (b) conduct an initial first-pass analysis upon which later more detailed and nuanced analyses could be based. The detailed results on this binary difference-in-means t-test are shown on pages 28 through 40 of Exhibit A-135 (MPK-25), with the results discussed on pages 40 and 41. Those results reached the conclusion that, on average, EJ, urban, low-income, and higher-percent-minority census tracts have better reliability on average. Page 76, line 18, through page 77, line 2 of my direct testimony report this conclusion and notes that the analyses provide statistical validation for the Company's conclusions in Case Nos. U-21389 and U-21585.

My statement on page 78 of my direct testimony, with which Mr. Cira-Reyes takes issue, that "[t]here is nothing apparently systemic or unique about EJ census tracts (or other potential groupings of disadvantaged census tracts) as a whole that give them worse reliability, since they have better than average reliability than other census tracts," is tied to this conclusion from the binary difference-in-means t-test. When I say that there is nothing systemic or unique about EJ census tracts in this context, I mean that there is no

[4] My references to this exhibit cite the page numbers out of 143 at the top right of each page, not the original document page numbers at the bottom center.

across-the-system evidence that they experience worse reliability. If there were systemic issues, we would expect to see EJ census tracts facing worse reliability outright, but that is not the case.

Still, my direct testimony immediately goes on to acknowledge that the later more nuanced components of the regression analysis do indicate that there are some areas in which some EJ census tracts or circuits have worse reliability outcomes. The Company agrees with Mr. Cira-Reyes' concern that members of EJ communities are particularly vulnerable to power interruptions, which is why the Company has developed the VCRP. But this is not in response to a systemic issue, since there is no evidence of one; it is in response to the relatively isolated local issues that the regression analysis has helped the Company identify. The issues identified in the regression analysis warrant further study, as I said in my direct testimony, because further study can help the Company better understand those isolated issues and be better able to address them.

Q. What recommendations does Mr. Cira-Reyes have regarding the IRM?

A. On pages 56 and 57 of his direct testimony, Mr. Cira-Reyes notes that in Year 1 of the IRM authorized in Case No. U-21389, the Company overspent the authorized amount in some areas and underspent in others. He states that the Company should elaborate on these inaccuracies, and states that the Company must show through its reconciliation of Year 2 that it can do better.

Q. How do you respond to this?

A. The Company's reconciliation of Year 1 of the IRM is ongoing in a separate contested proceeding in Case No. U-21918. The Company provided details in that case on its Year 1 spending, and that case is a more appropriate venue to seek further details on Year 1

spending. Year 2 is currently in progress and will be reconciled as required in a separate contested proceeding beginning in 2026.

Q. What is Mr. Cira-Reyes' recommendation regarding equity in the IRM?

A. On pages 57 and 58 of his direct testimony, Mr. Cira-Reyes states that the Company's equity analysis should have been more thorough. He acknowledges the Company's evidence in Case No. U-21918 that it made a disproportionately high amount of Year 1 IRM investment in EJ communities, but he supposes that it is possible that EJ communities may have had even greater needs than that and the Company should have analyzed whether that is the case or not.

Q. Do you agree?

A. Again, the ongoing Case No. U-21918 is a better venue than the instant case to seek more detailed information about Year 1 IRM investment. That said, given the results of the regression analysis discussed above – that there are some nuanced reliability issues in some EJ communities, but that EJ communities do not have systemically poor reliability – I do not believe there is evidence that EJ communities should have had an even more disproportionately large share of Year 1 IRM investment. Ultimately, though, the Company is seeking to include the VCRP in its IRM proposal in the instant case precisely to ensure that the IRM has a positive impact on equity.

Q. What is Mr. Cira-Reyes' recommendation regarding the Company's public-facing GIS map regarding EJ reliability data?

A. On page 65 of his direct testimony, Mr. Cira-Reyes acknowledges the Company's map and expresses appreciation, but also lists ways that he believes it could be made more user-friendly.

Q. Do you agree with this recommendation?

A. The Company can certainly look for ways to make continuous improvements to this public-facing tool. However, saying that the map must be easily used by any member of the general public creates a very broad and vague target condition. The existing map was ultimately a creation of the proceedings of Case No. U-21389. In that case, the Company fielded numerous discovery requests from Staff seeking extensive amounts of GIS data, as Staff was conducting its own EJ analysis in that case. Those discovery requests were time-consuming and in some cases could not be completed in a timely fashion. In that case, Staff proposed that the Company create a public-accessible map with downloadable data on demand to reduce such a bottleneck in the future. As such, the current map was largely developed based on Staff feedback, particularly as Company representatives met with Staff on multiple occasions between the Order in Case No. U-21389 and the publication of the map.

Q. What is Mr. Cira-Reyes' recommendation regarding DERs and hosting capacity analysis ("HCA") in EJ communities?

A. On pages 66 and 67 of his direct testimony, Mr. Cira-Reyes indicates that EJ communities stand to benefit from DER adoption, but expresses concern that EJ communities may have low hosting capacity to accommodate them. If EJ communities do have low hosting capacity, then he states that the Company should upgrade them.

Q. How do you respond to this?

A. The Company published its more detailed Phase II HCA map on September 30, 2025, shortly after Mr. Cira-Reyes' testimony was filed. This provides considerably more detail, available to any member of the public, on how much hosting capacity is in each location,

and would enable any party to determine how much hosting capacity is in an EJ community (or any other community covered by the analysis). The map is published at: https://cms.maps.arcgis.com/apps/instant/lookup/index.html?appid=b90ff63b338043b7bcae43dd685a419d.

In addition to this publicly available information, the Company has done further analysis on its hosting capacity, and the average circuit-level hosting capacity on an EJ circuit is 8.9 MW, compared to the Company's systemwide average of 6.4 MW. This would suggest that EJ circuits are usually not hosting capacity-constrained. However, we have already discussed how systemwide averages can mask local peculiarities. To the extent that individual EJ circuits are found to be constrained, the Company would consider making capacity investments in those circuits.

XVI. REBUTTAL OF METC WITNESS FLECK

Q. What is Mr. Fleck's recommendation regarding coordination and alignment between the Company and METC on transmission and distribution planning?

A. Mr. Fleck's testimony generally indicates support for Company's distribution plan as defined in the Reliability Roadmap, and extols the benefits of coordination between METC and the Company. On page 11 of his direct testimony, he proposes the establishment of a stakeholder working group to align transmission and distribution planning with state electrification goals, which would represent formal coordination between the Company and METC.

Q. Do you agree with this recommendation?

A. Similar to the Company's position in recent rate cases, Consumers Energy is happy to have any discussions sought by METC at their request, and the Company will engage in informal

coordination (and indeed already does so in various ways). However, the Company does not believe that the Commission needs to order a formal coordination process.

XVII. REBUTTAL OF MEIU WITNESS ALBERS

Q. What is Mr. Albers' recommendation regarding the Company's inventory of equipment with long acquisition lead times?

A. In Case No. U-21585, Mr. Albers recommended that, in the instant case, the Company "identify hardware commonly associated with interconnecting advanced energy technologies, like DERs and EV charging facilities, that has long acquisition lead times." The Commission ordered this, and I provided an analysis in my direct testimony, which was supplemented during this case by discovery provided to MEIU (provided by Mr. Albers as Exhibit MEIU-3.2). Mr. Albers' testimony in the instant case is largely concerned with assessing this. On page 9, he concludes that the Company likely has sufficient inventory. However, he recommends that in order to "ensure greater certainty for developers," the Company should "make its inventory of equipment with long acquisition lead times available to DER and EV projects initiated by third parties on the same basis that such equipment is available to projects that it initiates."

Q. How do you respond to this?

A. Based on my understanding of Mr. Albers' request, the Company already does this. When it comes to projects that require long lead time equipment, the Company treats projects on a first-come, first-served basis in which inventory is made available for projects in order of project approval, without preferential treatment for internal projects. Regarding interconnection projects specifically, the Company creates and schedules work orders in the order that the interconnection approval process is completed. It is important to clarify that the Company does not sell inventory to third-party customers who would own and

maintain their own equipment. The Company is interpreting Mr. Albers' proposal to mean only projects initiated by third parties, not projects conducted by third parties.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

MICHAEL P. KELLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Actual and Forcasted 2025 Capital and O&M Spending

Case No.: U-21870
Exhibit No.: A-219 (MPK-29)
Page: 1 of 1
Witness: MPKelly
Date: October 2025

		2025 O&M Spending												
Line No.		Jan Actuals	Feb Actuals	Mar Actuals	Apr Actuals	May Actuals	Jun Actuals	Jul Actuals	Aug Actuals	Sep Actuals	Oct Fcst	Nov Fcst	Dec Fcst	**Total Current Fcst**
1	2.01 Lines Reliability - LVD	$16,739	$97,824	$40,047	$64,028	$49,558	$108,368	$127,375	$103,422	$137,118	$246,102	$700,119	$1,600,376	**$3,291,075**
2	2.04 Substations Reliability - LVD	$274,437	$235,570	$309,814	$217,835	$462,311	$406,201	$482,175	$538,353	$501,050	$500,244	$385,122	$332,232	**$4,645,345**

		2025 Capital Spending												
		Jan Actuals	Feb Actuals	Mar Actuals	Apr Actuals	May Actuals	Jun Actuals	Jul Actuals	Aug Actuals	Sep Actuals	Oct Fcst	Nov Fcst	Dec Fcst	**Total Current Fcst**
3	1.06 Distribution Transformer Purchases	$10,145,259	$16,921,075	$16,303,963	$21,384,981	$19,319,972	$18,155,495	$10,634,605	$12,137,417	$9,284,545	$12,585,616	$6,426,698	$3,848,475	**$157,148,102**
4	2.05 Substations Reliability - HVD	$1,683,961	$226,375	$1,732,374	$1,498,488	$967,652	$1,212,536	$622,492	$1,893,513	$1,322,687	$2,100,343	$3,908,535	$5,061,344	**$22,230,300**
5	2.12 Repetitive Outages - LVD	$320,943	$1,027,430	$1,173,196	$605,105	$645,065	$241,883	$253,984	$999,459	$1,100,815	$1,361,553	$1,795,002	$1,686,565	**$11,211,000**
6	2.14 Transformer Bank Replacements & Sub Rebuilds	$1,915,279	$2,914,937	$179,885	$1,236,824	$831,706	$389,688	$170,906	$1,822,818	$2,307,120	$3,377,107	$3,338,927	$8,820,881	**$27,306,079**
7	2.17 Metro Rehabilitation	$131,430	$286,330	$550,101	$318,413	$3,491	$140,193	$178,957	$1,485	$435,344	$1,141,722	$1,120,924	$880,409	**$5,188,800**
8	3.06 Lines New Business Capacity - LVD	$27	$2,332,105	$3,017,885	$1,756,211	$2,196,600	$1,573,146	$2,729,867	$2,662,565	$2,612,811	$2,929,454	$1,934,218	$884,756	**$26,962,200**

U21870-SA-CE-248
Requested By: Hunter Hansen (HH-6 - 1)
Respondent: Michael P. Kelly
Date of Response: 9/3/2025
Page **1** of **1**

Question:

1. In Case No. U-17990, on Exhibit A-65 (LDW-4), the Company proposed a cost-based update to its ongoing monthly cost to support AMI opt-out. The proposed cost for "Meter Reading @ 12 Reads Per Year" was proposed to be $19.26. In U21870-SA-CE-201_KELLY_ATT_1, it is proposed to be $0.29. Explain why the current cost has decreased so much since the proposal in U-17990.

Response:

The proposed cost for "Meter Reading @ 12 Reads Per Year" was based on non-AMI meters because non-transmitting electric meters cannot be separately tracked – see U21870-SA-CE-202. In U-17990, the cost was based on an allocation of labor and associated overhead for supervision, support, and vehicle costs for non-transmitting meters. A similar estimate has been provided in the attached spreadsheet as U21870-SA-CE-248_KELLY_ATT_1 whereby the "Meter Reading @ 12 Reads Per Year" would equal $12.61/meter/month.

(a)	(b)	(c)
Costs to Support Manual Reads	**Costs**	**Note**
Meter Counts		
Electric Manual Reads on Electric Meters	132,839	
Gas Manual Reads on Gas Meters	139,808	
Total Meter Count	**272,647**	
Yearly Salary Costs		
Supervision Salary and Benefit Cost	$ 439,548.00	4 Supervisors overseeing the Manual Reads
Schedulers Salary and Benefit Cost	$ 448,000.00	4 Schedulers overseeing the Manual Reads
Meter Reader Salary and Benefit Cost	$ 1,992,691.72	22 Meter Readers
Total Salary Cost	$ 2,880,239.72	
Yearly Vehicle Costs		
Meter Reading Vehicle Cost	$ 477,569.77	26 Vehicles - Fleet Overhead and Mileage
Yearly Technology/Equipment Costs		
Meter Reading Equipment Cost	$ 80,543.33	technology cost for maintenance and upkeep of 22 devices
Summary of Yearly Meter Reading Costs		
Yearly Salary Costs	$ 2,880,239.72	
Yearly Vehicle Costs	$ 477,569.77	
Yearly Technology/Equipment Costs	$ 80,543.33	
Total Yearly Manual Meter Reading Cost	**$ 3,438,352.82**	
Divide by the Number of Manual Reads	272,647	
Total Meter Reading Cost per Meter	**$12.61**	

Question:

191. Refer to Exhibit A-124 (MPK-14) and Mr. Kelly's testimony on pages 159 to 160 related to Service Calls and the O&M expense of $4.2 million in 2024 increasing to $5.7 million in the projected test year for a 36% increase.

Please:

a. Provide the expense increase related to the 17% increase in work hours and provide a schedule showing how the 17% increase in work was determined.

b. Mr. Kelly notes a 16% change in labor rates over the past five years for the union personnel involved. Provide the scheduled future increase in union labor rates and how they compare to forecasted CPI inflation rates.

Response:

a. The amount of test year expense related to the increase in work hours is $797,181. The Company's methodology for calculating work hours is described on page 159, line 17, through page 160, line 4, of my direct testimony. To further elaborate, the Company uses recent historical actual work volumes to project the number of monthly service call work orders at each Company service center. The Company then multiplies those service center work order totals by an hourly factor that indicates how long each type of service call job should take. The product of this multiplication gives a projected number of hours. These projections are as follows:

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Units	2,471	2,752	3,143	2,778	3,084	3,085	3,024	3,123	3,104	3,069	2,598	2,623	34,855
Hours	2,062	2,298	2,596	2,443	2,564	2,573	2,516	2,610	2,607	2,577	2,200	2,226	29,271

While the projected work hours were calculated in this way, the 17% increase cited in testimony simply reflects how much larger that is than the historical five-year average number of work hours, as shown below:

Type	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	5 Year Avg	Test Year	Variance
Hours	23,427	24,688	27,185	24,934	24,569	24,960	29,271	17%

b. Please refer to Exhibit A-128 (MPK-18), page 6, line 45, for the Company's projected inflation rates. The Company's current union contract, effective in June 2025, has the following union labor rate increases:

	2025	2026	2027	2028	2029
% Increase	3%	3.5%	3.5%	3.5%	3%

Witness: Michael P. Kelly
Date: September 16, 2025

U21870-AG-CE-0453
Page **1** of **1**

Question:

134. Refer to Exhibits A-125. Please:

a. Provide the quantities or work units supporting each of the expense items in each line for each year 2020 to 2027 and the projected test year in Excel.

b. For lines 4, 6, 9-11, 12, 17, 25, 29, and 33, provide the basis for the increase in expense from 2024 to 2025 and to the projected test year.

Response:

a. See Attachment 1 to this response.
b. The basis for the increase can be found in my testimony as follows:
    a. Line 4: page 131, lines 1 through 7
    b. Line 6: page 135 line 18 through page 136 line 2
    c. Line 9: page 140, lines 10 through 15
    d. Line 10: page 141 line 20 through page 142 line 8
    e. Line 11: page 143, lines 1 through 9
    f. Line 12: page 145, lines 8 through 13
    g. Line 17: page 160, lines 5 through 12
    h. Line 25: page 169, lines 1 through 5
    i. Line 29: page 172, lines 11 through 14
    j. Line 33: page 174, lines 15 through 19

Witness: Michael P. Kelly
Date: September 11, 2025

21870-AG-CE-0453
Attachment 1

Line No.	(a) Description (Boldface items indicate $000 and correspond to Exhibit A-125	(b) 2020 Actual	(c) 2021 Actual	(d) 2022 Actual	(e) 2023 Actual	(f) 2024 Actual	(g) 12 Mos Ended 12/31/2025	(h) Bridge Period 4 Mos Ending 4/30/2026	(i) 16 Mos Ending 4/30/2026	(j) Projected 12 Months Ending 4/30/2027
	Lines Reliability - LVD	**13**	**527**	**1,097**	**651**	**580**	**8,000**	**2,667**	**10,667**	**8,000**
	"Work Unit" Definition - Orders	Orders	Orders	Orders	Orders	Orders	Orders	Orders	Orders	Orders
1	*Work Units*	23	314	668	857	933	2,454	412	2,866	2,454
2	**Lines Reliability - HVD**	**226**	**188**	**287**	**261**	**109**	**784**	**284**	**1,068**	**891**
	HVD Lines Pole Inspections (O&M Portion of inspection)	340	963	709	1,082	1,117	805	268	1,073	805
	Test Operate Motor Operated Air Break Switches	270	319	332	342	384	386	39	425	386
	Motor Operated Air Break Switch Battery Replacements	21	95	45	12	82	52	13	65	52
	Substations Reliability - LVD	**2,393**	**2,771**	**2,992**	**3,100**	**3,525**	**5,458**	**1,672**	**7,130**	**5,475**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
3	*Work Units*	93	272	138	242	272	344	86	430	344
	Substations Reliability - HVD	**1,566**	**1,925**	**2,017**	**2,181**	**2,350**	**2,445**	**701**	**3,146**	**2,349**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
4	*Work Units*	125	145	155	148	156	209	52	261	209
	Lines Demand - HVD	**527**	**784**	**1,086**	**654**	**898**	**2,237**	**875**	**3,113**	**2,979**
	SAP Orders - Projects at specific structures / locations.	Projects	Projects	Projects	Projects	Projects	Projects	Projects	Projects	Projects
5	*Work Units*	119	146	196	174	149	160	50	210	170
	Substations Demand - LVD	**2,503**	**2,995**	**4,707**	**4,092**	**4,302**	**6,440**	**2,008**	**8,448**	**6,398**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
6	*Work Units*	237	384	268	226	337	313	78	391	313
	Substations Demand - HVD	**2,308**	**2,986**	**3,159**	**3,383**	**4,050**	**5,309**	**1,703**	**7,012**	**5,311**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
7	*Work Units*	348	392	278	382	578	295	73	368	295
	Corrective Maintenance	**4,064**	**4,535**	**4,131**	**4,130**	**4,615**	**4,970**	**1,631**	**6,601**	**5,236**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
8	*Work Units*	20,631	20,444	21,430	20,473	20,250	19,944	6,023	25,967	19,943
	Staking	**3,035**	**3,251**	**3,587**	**3,975**	**6,148**	**12,260**	**3,870**	**16,131**	**13,948**
9	*Please refer to discovery responses U21870-AG-CE-0441 through 0448 for supporting details regarding Staking O&M spending levels.*									
	Meter Services (and Credits)	**(1,120)**	**2,090**	**862**	**(3,934)**	**1,774**	**3,180**	**1,440**	**4,619**	**6,831**
	"Work Unit" Definition - Work Premise Hours (Expense)	Hours	Hours	Hours	Hours	Hours	Hours	Hours	Hours	Hours
		40,353	41,502	45,354	49,034	45,580	49,898	16,989	66,887	60,843
	Work Units									
	"Work Unit" Definition - Meter/Transformer Units (Credits)	Units	Units	Units	Units	Units	Units	Units	Units	Units
10	*Work Units*	97,961	129,972	211,163	440,405	90,586	77,789	19,207	96,996	57,623
	Streetlighting	**1,680**	**2,109**	**1,801**	**1,571**	**1,612**	**2,009**	**733**	**2,742**	**2,089**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
11	*Work Units*	8,422	9,203	10,732	10,616	7,884	10,748	3,551	14,300	10,750
	Service Calls	**3,871**	**4,518**	**4,110**	**4,434**	**4,194**	**4,632**	**1,805**	**6,438**	**5,699**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
12	*Work Units*	18,813	19,876	20,258	23,325	24,210	25,316	8,128	33,445	25,316
	Alma Equipment Repair	**699**	**787**	**430**	**379**	**357**	**563**	**188**	**752**	**571**
	Work Units defined as follows, with data provided by year:									
	Salvage Services/Oil Recycling (gals of junk transformer oil sold)	20,009	20,554	39,926	60,477	32,748	26,800	9,000	35,800	35,000
	Training (units = headcount (OM&C (variable), 1 NEX, 1 EX))	12	11	11	12	12	12	12	12	12
	Storeroom Tasks/Material Handling (pieces of equip handled)	12,231	11,996	8,609	8,515	7,553	7,800	2,400	10,200	8,000
	Mobile Substation Inspections/Repairs (unit = inspection or repair session)	39	82	64	77	51	58	21	79	65
13	*Supervisor Salary/Expenses (unit = HC of 1 EX & 1 NEX)*	2	2	2	2	2	2	2	2	2
	Meter Reading	**1,439**	**1,740**	**1,712**	**6,016**	**1,645**	**1,876**	**627**	**2,503**	**1,971**
	"Work Unit" Definition - Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount
14	*Work Units*	11	17	14	14	14	14	14	14	14
	Meter Tech & Mgmt Sys Support	**934**	**1,019**	**1,085**	**1,199**	**1,063**	**1,310**	**448**	**1,758**	**1,393**
	"Work Unit" Definition - Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount
15	*Work Units*	25	27	23	24	24	24	25	25	25
	Smart Energy MTC - Elec	**8,846**	**8,986**	**9,020**	**8,756**	**9,611**	**9,226**	**3,096**	**12,322**	**9,226**
	"Work Unit" Definition - Meters	Meters	Meters	Meters	Meters	Meters	Meters	Meters	Meters	Meters
16	*Work Units*	1,888,948	1,852,736	1,847,762	1,857,803	1,894,313	1,914,448	1,920,000	1,920,000	1,930,000
	Service Restoration - LVD	**71,262**	**159,659**	**113,271**	**188,041**	**156,098**	**159,737**	**54,606**	**214,344**	**165,215**
17	*Service Restoration O&M is discussed in significant detail by Company witness Snider.*									
	Training	**5,366**	**10,807**	**10,993**	**12,076**	**11,107**	**10,846**	**5,492**	**20,564**	**15,833**
	"Work Unit" Definition - Headcount (per training hr)	*Hours*	*Hours*	*Hours*	*Hours*	*Hours*	*Hours*	*Hours*	*Hours*	*Hours*
18	*Work Units*	*65,120*	*153,566*	*168,071*	*158,990*	*161,116*	*143,964*	*64,216*	*208,379*	*220,930*
	Tools	**1,422**	**2,358**	**1,753**	**1,384**	**1,256**	**1,497**	**997**	**2,494**	**1,982**
	"Work Unit" Definition - # of Tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools
	Work Units	9,571	26,956	17,534	11,351	17,307	17,530	5,785	23,368	17,850
	"Work Unit" Definition - # of FR Items	FR Items	FR Items	FR Items	FR Items	FR Items	FR Items	FR Items	FR Items	FR Items
	Work Units	9,450	5,575	12,362	11,965	11,714	13,450	6,031	24,125	18,500
	"Work Unit" Definition - # of tested/repaired tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools
19	*Work Units*	10,802	11,940	12,375	12,800	13,220	13,235	4,367	17,205	13,300
	Field Operations Expenses	**1,665**	**2,372**	**2,194**	**2,369**	**2,154**	**2,509**	**869**	**3,378**	**2,608**
20	*Field Operations Expenses represent costs outside of salaries incurred by field operations workforce, i.e. travel expenses, meals, telecommunications. Units are not applicable*									
21	**Supervision / Admin-Staff**	**5,047**	**4,994**	**6,366**	**3,710**	**3,672**	**4,820**	**1,734**	**6,555**	**5,312**
	"Work Unit" Definition = Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount
	Work Units	153	176	172	157	156	171	171	171	171
	Grid Management - Distr	**3,768**	**6,363**	**6,134**	**5,514**	**4,646**	**4,741**	**1,439**	**6,180**	**4,271**
	"Work Unit" Definition - Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount
22	*Work Units*	99	161	181	167	148	146	155	155	155
	Underground Workforce		**128**	**172**	**327**	**713**	**1,113**	**694**	**1,807**	**2,236**
23	*This reflects 100% of the training costs and 5% of the salaries, expenses, and tools for underground workforce employees. The other 95% of salaries, expenses, and tools are capitalized. Units are not applicable.*									
	Work Management & Customer Delivery	**1,315**	**4,027**	**6,799**	**3,910**	**2,518**	**1,883**	**635**	**2,518**	**1,917**
	"Work Unit" Definition - Headcount	*Headcount*	*Headcount*	*Headcount*	*Headcount*	*Headcount*	*Headcount*	*Headcount*	*Headcount*	*Headcount*
24	*Work Units*	72	270	235	382	247	*310*	*103*	*413*	*310*
	Operations Management	**2,381**	**2,911**	**2,891**	**2,360**	**2,591**	**2,022**	**569**	**2,591**	**1,955**
	"Work Unit" Definition - Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount
25	*Work Units*	8	8	6	6	5	4	4	4	4

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

SCOTT A. MCPHAIL II

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Scott A. McPhail II, and my business address is 3201 E. Court, Flint, MI 48506.

Q. Are you the same Scott A. McPhail II who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Attorney General witness Sebastian Coppola regarding Line Sensors, Voltage Regulator Controllers, Peer-to-Peer Automation, Metro Modernization, and Distribution Asset Management. I will rebut the direct testimony of Association of Businesses Advocating Tariff Equity ("ABATE") witness Colin. T. Fitzhenry on Voltage Regulator Controllers; Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Jing Shi, P.E. on Distribution Asset Management; Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar (collectively the "Clean Energy Organizations" or "CEO") witness William D. Kenworthy and Great Lakes Renewable Energy Association ("GLREA") witness Richard Boehnke regarding Virtual Power Plants ("VPPs"); and Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan ("MNSC") witness Caroline Palmer on cost of service.

Q. How is your rebuttal testimony organized?

A. My testimony is organized by topic, addressing each witness within those topics.

Q. Are you sponsoring any exhibits?

A. No.

RESPONSE ON LINE SENSORS

Q. Please summarize Attorney General witness Coppola's proposed capital spending adjustments for Line Sensors stated on page 67, lines 1 through 15, of his direct testimony.

A. Attorney General witness Coppola conducted a unit cost analysis on the proposed investment in the bridge period. The 2024 unit cost of $3,637 was adjusted for inflation resulting in a unit cost of $3,741. This was multiplied by the 1,000 units forecasted to be installed resulting in capital expenditures of $3,741,000. Mr. Coppola then recommends that the difference between the requested amount of $6,116,000 and the calculated amount above, equaling $2,345,000, be removed from the bridge period. Mr. Coppola argues that the Company did not support the increase in expenditures in the bridge period.

Q. Do you agree with Mr. Coppola's recommendation to use a 2024 inflation adjusted unit cost to determine the bridge period investment for Line Sensors?

A. No. On page 19, lines 16 through 21, of my direct testimony, I explain that in addition to the cost of the line sensor itself, the AMPLE and RAMP software are necessary and included in the bridge period amount. These two software costs were itemized in my testimony on page 19, lines 20 through 21, at $3,100,000 and $2,083,000, respectively. In Case No. U-21585, the MPSC Order supported the funding of the RAMP software (page 111) and the Company has completed this work. For the AMPLE software, in my direct testimony on page 20, lines 3 through 7, it is explained that all line sensors cannot function without this software renewal. Like with RAMP, this software renewal has been

completed. The use of a 2024 unit cost is inappropriate because these software renewals occur on a three- to five-year cycle, and in 2024 there was no software renewal. Lastly, as stated on page 18, line 19, of my direct testimony, the Company has completed the mass deployment of these line sensors and secured the necessary AMPLE and RAMP software, and these bridge year dollars have already been spent.

RESPONSE ON VOLTAGE REGUALTOR CONTROLLERS

Q. Please summarize Attorney General witness Coppola's proposed capital spending adjustments for Voltage Regulator Controllers stated on page 67, lines 16, through page 68, line 18, of his direct testimony.

A. Mr. Coppola conducted a unit cost analysis on the proposed investment in the bridge period. The 2024 unit cost of $22,442 was adjusted for inflation resulting in a unit cost of $23,093. This was multiplied by the 294 units forecasted to be installed resulting in capital expenditures of $6,789,000. Mr. Coppola then recommends that the difference between the requested amount of $10,526,000 and the calculated amount above equaling $3,737,000 be removed from the bridge period. For the test year, the inflation adjusted unit cost of $23,647 was calculated from the unit cost described above, $23,093 multiplied by inflation of 2.4%. The test year number of units of 143 was multiplied by $23,647 equating to $2,382,000, which is $1,738,000 less than the amount requested in the test year. In summary, Mr. Coppola is requesting $3,737,000 be disallowed in the bridge period and $1,738,000 be disallowed in the test year, suggesting that there is a lack of explanation for the change in unit cost.

Q. Do you agree with Mr. Coppola's recommendation to use a 2024 inflation adjusted unit cost to determine the bridge and test year investments on Voltage Regulator Controllers?

A. No. As discussed at page 28, lines 8 through 21, of my direct testimony, a conventional unit cost is not appropriate for estimating these program costs. For example, there were several instances where materials to be used for a subsequent deployment year were purchased in the year prior to the deployment, or delayed into another year, thus giving an inaccurate view of unit costs when just comparing annual costs to the number of units. In addition, as shown in my testimony on page 27, Figure 7, the historical spending in 2024 was relatively lower compared to 2020 through 2022 spending. The reason 2023 and 2024 were lower was the result of the Company having leftover controls from the previous years, mainly 2022. This pull ahead purchase of materials helped offset the costs in subsequent years. These additional controls have now been deployed, and the Company needs to purchase the necessary materials in the bridge period and test year to complete the program.

Q. Please summarize ABATE witness Fitzhenry's disagreement with the Benefit Cost Analysis ("BCA") provided in Exhibit A-146 (SAM-5) for Voltage Regulator Controllers stated on pages 20 through 23 of his direct testimony.

A. Mr. Fitzhenry disagrees with the BCA, contending that it does not include costs such as taxes, Return on Equity ("ROE"), interest, and stranded costs, thus underestimating the total costs.

Q. What other concerns does ABATE witness Fitzhenry raise with the provided BCA in Exhibit A-146 (SAM-5)?

A. On page 23, lines 7 through 14 of his direct testimony, Mr. Fitzhenry states that most of the benefits are based on the assumption that line regulators installed prior to the year 2000 will all fail over the next 10 years and the Company has not provided any analysis to support that assumption. Mr. Fitzhenry removes the monetized benefits of $12,880,000 from the BCA which results in a net present value ("NPV") of $10,726,493 and is lower than the cash value of the project.

Q. What does Mr. Fitzhenry recommend for the Voltage Regulator Controller program?

A. As explained on page 23, lines 17 through 20, of his direct, Mr. Fitzhenry recommends that the pace should be slowed to 25% of the proposed installation rate. This results in upgrading 55 locations in 2025 and 54 locations in 2026. The reduction in capital expenses would be $7,894,500 in the bridge period and $3,840,000 in the test year corresponding to the 25% reduction in installation pace.

Q. Do you agree with the assessment of Mr. Fitzhenry that the BCA at Exhibit A-146 (SAM-5) understates all the costs of the Voltage Regulator Controllers?

A. In part, yes. Mr. Fitzhenry is correct to state that a utility has other costs beyond the initial purchase and installation price such as taxes, ROE, and while no standard has been established on what should be included in the BCA when evaluating electric distribution investments, in this case, the Company offered a BCA estimate of the value of this replacement program. Mr. Fitzhenry suggests that the project would likely be less cost-effective if these additional costs were included. However, it is also important to remember that investment decisions on the electric grid are not solely based on a

cost-effectiveness test. On pages 23 through 25 of my direct testimony, I explain the other benefits customers see from this program, including improved power quality, as required by MPSC R 460.3702 (Rule 702); reduction of customer minute interruption ("CMI"), included in Exhibit A-146 (SAM-5) at 56,625 minutes; and reduced electrical and traffic exposure for Company electric line workers through the use of remote monitoring. A holistic evaluation of all the benefits should be considered.

Q. Please describe the Company's assumptions in the BCA regarding the average life of a controller.

A. Since the start of this project, the Company collected field data to better understand how these devices perform. Field data from over 3,000 regulators were analyzed and found that only five were manufactured in 1988 or earlier. This demonstrates that the typical operational lifespan of these regulators does not exceed 37 years. Furthermore, around 60% of the regulators that failed during the project were identified to be manufactured before the year 2000. This reinforces our confidence that the majority of field regulators, if not addressed by the Line Regulator Project, would fail between 2027 and 2037 as they approach their maximum lifespan. The BCA reflects that the average life of a control is 20–25 years, and it reasonably assumes that failures are more likely in the 10 years following that period. The Company's empirical field data supports this assumption. These failures lead to poor power quality, which negatively affects customers and risks non-compliance with MPSC R 460.3702 (Rule 702). Because of this project, those future adverse impacts are avoided.

Q. Do you agree with Mr. Fitzhenry's recommendation to slow the Voltage Regulator Controller program to 25% of its current rate of deployment?

A. No. It is unclear how Mr. Fitzhenry arrived at 25%. Slowing the installation rate will jeopardize the competitive contract described in my direct testimony on page 27, line 13, through page 28, line 4. The Company has dedicated Construction Labor to efficiently complete this project. The savings described on page 28, line 3, of my direct testimony amounting to $1.5 million has been built into this project and slowing the pace will erode the economies of scale that customers are benefiting from through a lower construction cost.

Q. What recommendation do you have related to voltage regulator controllers?

A. The voltage regulator controller replacement program has been underway since 2020 and has received support in all prior rate cases. The Company is nearing completion of this defined program, expected in 2026, within the test year. The Company has already made investments this year in 2025, purchasing the materials for the work to complete this year and in the bridge period 2026. Given the benefits described in my direct testimony and my explanations explained above, the amount requested in my direct testimony should be approved.

RESPONSE ON DISTRIBUTION ASSET MANAGEMENT

Q. Please summarize Attorney General witness Coppola's proposed capital spending adjustments for Distribution Asset Management ("DistAM") stated on page 72, lines 5 through 7, of his direct testimony.

A. Mr. Coppola recommends the removal of capital expenditures in the amounts of $1,740,000 for the bridge period and $4,050,000 in the test year.

Q. What are Mr. Coppola's concerns with the DistAM initiative?

A. Mr. Coppola argues that the BCA at Exhibit A-152 (SAM-11) is outdated and that current overall spending (beyond this rate case) is projected at $21 million since inception of the initiative. Mr. Coppola also takes issue with the benefits listed in the BCA, stating that they are vague concepts and would not provide realistic cost savings. Mr. Coppola goes on to state that the Asset Repository ("AR") cost is projected at $8.8 million, increased from the original estimate of $2.5 million, and argues that this indicates more upfront research should have been performed prior to proceeding with this initiative. Mr. Coppola contends that the BCA is now stale, and the higher projected costs make the NPV no longer favorable. Additionally, he argues that it would be premature to include the Asset Performance Management ("APM") costs in the rate case because the project is in the "planning phase."

Q. Please summarize Staff witness Shi's proposed capital adjustments and concerns with the DistAM initiative.

A. Staff witness Shi recommends a disallowance of $770,000 in the bridge period and $2,640,000 in the test year, contending that the Company did not explain why funds have not been spent on APM and how the projected funds in this current case will be used.

Q. Summarize Commission orders related to the DistAM Initiative.

A. The Commission originally approved the DistAM project in Case No. U-20697 and re-approved in the December 22, 2021 Order in Case No. U-20963. The concept approval at that time projected $12 million for the project. In Case No. U-21585, the Commission stated as follows in its March 21, 2025 Order, page 110: "The Commission finds that Consumers has not provided adequate data supporting recovery of the increased costs of

the DistAM program." Based on this Order, my direct testimony in this case provided additional justification along with a BCA in Exhibit A-152 (SAM-11) that shows future year expenses. As explained on page 51, lines 16 through 17, of my direct testimony, the total projected spend through the test year in this case is $13.6 million, which is only $1.6 million more than the previously approved amount of $12 million.

Q. Do you agree with Mr. Coppola's concerns and removal of the capital expenditure for the DistAM initiative?

A. No. The requested amounts in the bridge period and test year are necessary to continue the development and deployment of this initiative. The DistAM initiative works best as a whole, explained on page 49, line 19, through page 50, line 2, of my direct testimony. Each of the three primary components (AR, APM, Asset Investment Planning ("AIP")) all build on each other to improve capital efficiency. While the project costs are forecasted to increase since the initial concept approval, the Company continues to update and annually refine its estimate as more is learned. Page 52 of my direct testimony offers an explanation as to why this occurred. The Company continues to evolve based on new information, including avoiding $3.3 million in capital and $1 million in operating and maintenance ("O&M") expense based on building an internal APM solution instead of a vendor provided solution. The avoided $1 million per year in O&M expense was not included in the BCA, further supporting the investment. Lastly, it is incorrect to exclude the APM funding because it is in a planning phase. The APM is scalable, meaning as each health score is developed for each asset, that information becomes useful and will be used to guide investment decisions. The entire APM does not need to be complete for all in scope assets to begin to extract value out of it. Funding is being requested through April 2027, providing

a year after the end of the planning phase to add in assets and leverage their health scores as each asset is brought in.

Q. Do you agree with Staff witness Shi's reasoning to disallow capital investment on the APM portion of the DistAM initiative?

A. No. Staff witness Shi accurately described the purpose of the DistAM initiative and correctly summarizes the three key workstreams that make up the initiative as a whole. See pages 5 through 7 of Staff witness Shi's direct testimony. Each of the three workstreams (AR, APM, AIP) complement each other, providing greater value when used collectively. The APM is highly dependent upon the AR because the source data needed to calculate the asset health score will come from the AR. Funds have not yet been spent on the APM because the Company shifted focus to add more assets into the AR versus further development of the APM. The resources being used to build the AR are skilled in database structure and data design. To leverage this unique skillset, it was more efficient to streamline this workload and keep these resources focused on adding assets into the AR. While there has not been spending on the APM, it is more appropriate to consider DistAM as a whole given the interdependencies between the three workstreams. Given that perspective, the Company has invested and made progress on the overall DistAM program with the AIP complete and on track to have seven electric assets in the AR by the end of 2025.

Q. Considering the testimony of the Attorney General and Staff, what recommendation do you have related to DistAM?

A. The Commission should approve the Company's requested DistAM funding in this case. Pursuant to the Commission's order in Case No. U-21585, the Company has provided

updated data, including total costs, in this case. The Company intends to follow through on the recommendation provided on page 87 of the Liberty Consulting Group ("Liberty") report Part II by completing the holistic DistAM initiative including the AR and APM components discussed in this case. Lastly, in the Commission's July 10, 2025 Order in Case No. U-20147, in Exhibit A Section III, Part A, it is required for the Company to provide in its Distribution System Plan ("DSP") a data-based review on the general health and condition on its distribution system assets. This is precisely what the APM and the overall DistAM program aims to deliver. Failure to approve this investment risks the level of detail the Company will be able to provide in compliance with this order.

RESPONSE ON PEER-TO-PEER AUTOMATION AND METRO MODERNIZATION

Q. Please summarize Attorney General witness Coppola's proposed capital spending adjustments on Peer-to-Peer Automation and Metro Modernization.

A. At page 69 of his direct testimony, Mr. Coppola recommends the removal of capital expenditures for the combined Peer-to-Peer Automation and Metro Modernization initiatives in the amounts of $1,200,000 for the bridge period and $920,000 in the test year, arguing that there is a lack of support for these projects.

Q. Do you agree with Mr. Coppola's recommendation related to the Peer-to-Peer Automation investment?

A. While the Company does not agree with Mr. Coppola's reasons for removing these expenditures, the Company agrees to withdraw this projected investment of $895,000 in the bridge period and $270,000 in the test year for Peer-to-Peer Automation. The Company intends in a future case to seek funding for this project.

Q. Do you agree with Mr. Coppola's recommendation related to the Metro Modernization investment?

A. No. Exhibit A-151 (SAM-10) details the reliability benefits for customers of the Metro Modernization project using an avoided CMI calculation. Additionally, Exhibit A-151 (SAM-10) and my direct testimony at page 41, lines 5 through 7, provide an estimate on the safety benefit listed as a reduction of 185 hours of exposure in a confined space. The Metro Modernization project has two primary purposes: (1) improve reliability through remote operations and (2) improve safety for the public and the Company's electric line workers. This was described in my testimony on page 42, lines 10 through 20. While safety incidents in underground Metro electrical systems are rare, they can be extremely dangerous if they do happen[1]. The sensing and switching technology the Company plans to deploy is not new technology or experimental in the industry; the technology is only new to the Company. The direction of this project, like many of the projects within the Grid Automation department, is to engineer how these proven technologies will be used on the Company's system to benefit customers.

Q. Please describe ABATE witness Fitzhenry's discussion of the Metro Modernization project.

A. At page 27, footnote 44 of his direct testimony, Mr. Fitzhenry suggests that the proposed investments appear to be for research stating only a reduction in customer outages was considered.

[1] Boston Manhole Explosions Injure 1, Force Evacuations – NBC Boston - https://www.nbcboston.com/news/local/multiple-manhole-fires-reported-in-boston/2737181/

Q. Do you agree with Mr. Fitzhenry's characterization of the Metro Modernization project?

A. No. On page 41, lines 11 through 16, of my direct testimony, I describe the sites to be chosen and the specific use cases that will drive the benefits outlined. This includes environmental sensor detection and upgraded switching devices with Supervisory Control and Data Acquisition ("SCADA") capabilities for remote operations.

RESPONSE ON VPPs AND DISTRIBUTED ENERGY RESOURCES

Q. Please summarize CEO witness Kenworthy's recommendations to the Commission regarding the Distributed Energy Resource ("DER") Management System ("DERMS") Workgroup.

A. On page 4, lines 10 through 29, of his direct testimony, Mr. Kenworthy references the Commission's directive to the Company regarding DERMS in Case No. U-21585.

On page 5 of his direct testimony, Mr. Kenworthy states his understanding that the MPSC's Order in Case No. U-21585 requires that "the stakeholder-led DER optimization business case will evaluate VPP potential alongside DERMS capabilities." Mr. Kenworthy then acknowledges that the Company is not seeking DERMS funding in this case, yet recommends that the Commission order the Company to convene the workgroup.

In parallel with this recommendation to convene the workgroup, Mr. Kenworthy recommends in part, on page 17 of his direct testimony, that the Commission should require a VPP filing within six months that includes program tariffs, aggregator contracts, enrollment channels, capacity targets, and measurement and verification.

Q. Do you agree that a workgroup should be convened?

A. Yes. The Company agrees that a DERMS workgroup will be helpful in the development of a BCA, but that the development of a BCA would be premature at this time given the ongoing efforts to standardize a format to be used to evaluate these types of investment as part of Case No. U-20898. Based on Mr. Kenworthy's definition of VPPs on page 9, lines 6 through 11 of his direct testimony, the efforts underway within the Benefit-Cost Analysis Tool Collaborative apply (e.g. Demand Response, Distributed Generation, Electric Vehicles). Furthermore, in Case No. U-21585, the Commission asked the Company to conduct a workgroup and associated BCA prior to a request for cost recovery for DERMS, and the Company is not seeking cost recovery at this time.

Q. Do you agree with CEO witness Kenworthy's and GLREA witness Boehnke's definitions of VPPs?

A. The Company generally agrees with the conceptual definitions of VPPs provided by Mr. Boehnke and Mr. Kenworthy, but is unclear if VPPs in their present state of development are capable of delivering the full stack of benefits included in the definition. Mr. Boehnke cites the U.S. Department of Energy's ("DOE") definition (page 10, line 18, through page 11, line 2, of his direct testimony):

> VPPs are aggregations of distributed energy resources (DERs) such as rooftop solar with behind-the-meter batteries, electric vehicles (EVs) and chargers, electric water heaters, smart buildings and their controls, and flexible commercial and industrial loads that can balance electricity demand and supply and provide utility-scale and utility-grade grid services like a traditional power plant. VPPs enroll DER owners—including residential, commercial, and industrial electricity consumers—in a variety of participation models that offer rewards for contributing to efficient grid operations.

He also states on page 3, lines 5 through 10, of his direct testimony that VPPs are a "mature, essential, and cost-effective grid resource," and that they are "capable of providing utility-scale, utility-grade services, delivering affordable, reliable, and resilient power to ratepayers." The Company believes that these statements are premature and require demonstrated testing to determine these claims.

Mr. Kenworthy offers a similar definition for VPPs on page 9, lines 6 through 11, of his direct testimony:

> A Virtual Power Plant (VPP) is an aggregation of distributed energy resources—such as smart thermostats and water heaters, residential batteries paired with rooftop solar, EV managed charging, and flexible C&I loads—coordinated to balance supply and demand and deliver utility-grade grid services. It organizes customer flexibility into dispatchable capacity that reduces peaks, defers distribution infrastructure investment, and lowers system costs.

While these definitions align with common aspirations for VPPs and the benefits they may provide, questions remain as to how a VPP functions to provide "utility-scale and utility grade services." Without full integration of VPPs into utility operational systems and recovery for a utility owned and operated DERMS, it is not clear that VPPs are capable of delivering value streams outside of reducing system-level peak demand, and could potentially put the grid at risk if the VPP does not respond to dispatch signals that are mandatory to meet grid needs.

The DOE Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update report introduced in both Mr. Kenworthy's and Mr. Boehnke's direct testimony discusses this limitation in the key take-aways on page 23, as well as in the footnotes on page 29 and

30.[2] This point is also emphasized on page 55[3] of the Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment Report that the DOE references on pg. 21 and 64.

Mr. Kenworthy appears to acknowledge limitations of VPPs absent integration into utility operational systems such as DERMS/ADMS,[4] but Mr. Boehnke does not. While page 48, Figure 13 of Mr. Boehnke's direct testimony acknowledges the potential need for a DERMS in the Program Operator Role, Mr. Boehnke also states at page 49 of his direct testimony that "[e]ach of these primary roles can be operated by the utility, however, they need not be. Rather, it is critical to create a Market where the resources aggregated in VPPs can be bought and sold."[5] The Company disagrees with any position that seeks to minimize the operational needs of the Company that allow the Company to deliver safe and reliable power to all Consumers Energy customers in Michigan. As these operations become mission critical, such as in the case of a needed infrastructure upgrade deferral, the Company's grid operators must have the ability to monitor whether the VPP responds to third-party or utility dispatch signals and take appropriate actions based on grid needs if they do not.

Q. Do you agree that VPPs are ready for immediate implementation outside of a pilot process?

A. No. Mandating VPP implementation in their present state outside of a pilot raises utility operations concerns, particularly in the absence of established technical standards.

[2] Department of Energy, January 2025,"Pathways to Commercial Liftoff: VPPs 2025 Update" Accessed at https://virtual-peaker.com/wp-content/uploads/2025/09/2025-Jan-LIFTOFF_DOE_VirtualPowerPlantsUpdate.pdf
[3] "Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment" Accessed at https://emp.lbl.gov/publications/distributed-energy-utility-scale-30
[4] Direct Testimony of William D. Kenworthy: page 6, lines 1-2; page 10, lines 19-22; page 12, lines 1-7; page 17, lines 7-11.
[5] Direct Testimony of Richard Boehnke, page 49, lines 5-7.

Both Mr. Boehnke and Mr. Kenworthy suggest that VPPs are ready for immediate deployment, and that they've reached a maturity level that does not require pilots. On page 10, lines 2 through 4, of his direct testimony, Mr. Boehnke states that "A new pilot program will be insufficient to show the potential of VPPs and too limited to deliver the grid services and capacity as required to accommodate rapid load growth." He also states on page 3, lines 11 through 13, of his direct testimony that "VPPs are low-cost solutions, costing significantly less per kW-year than conventional resources, and that they can be deployed rapidly to address immediate challenges." Mr. Kenworthy states on page 5, line 19, through page 6, line 2, of his direct testimony that he does not believe a pilot is necessary.

The DOE's "Pathways To Commercial Liftoff: Virtual Power Plants 2025 Update" report that both Mr. Boehnke and Mr. Kenworthy reference highlights the present lack of standardization for VPPs and the complexities and limitations that result on page 23. On page 24 of the DOE report it states that "In the past year, DOE and other industry actors have launched or expanded efforts to standardize critical areas of VPP operations to reduce complexity and cost of implementation and increase reliability of performance." Page 24 through 27 of the report discuss eight critical VPP standardization initiatives that are taking place across the industry.[6]

It is important to note that based on the DOE's "Pathways To Commercial Liftoff: Virtual Power Plants 2025 Update" report, page 24, Section 3 part ii, very few of these initiatives are complete, and many have commenced within the last year or are yet to commence. The Company is particularly interested in participating in EPRI's FlexIT

[6] Department of Energy, January 2025,"Pathways to Commercial Liftoff: VPPs 2025 Update" Accessed at https://virtual-peaker.com/wp-content/uploads/2025/09/2025-Jan-LIFTOFF_DOE_VirtualPowerPlantsUpdate.pdf

initiative, that was announced in May 2025. Among other benefits, the initiative seeks to establish standards for the core utility-to-VPP/aggregator interactions.[7]

The Company is not aware of interoperability or integration standards governing VPPs. As a result, each third-party aggregator develops and operates proprietary platforms that require custom integration into utility operational systems. This creates a fragmented and inefficient landscape, where utilities must manage multiple tailored interfaces, data formats, and communication protocols. Such complexity increases the risk of operational inconsistencies, cybersecurity vulnerabilities, and higher implementation and maintenance costs in the long-term. These concerns put at risk the ability to safely and effectively incorporate VPPs/third-party aggregators at scale into core grid operations.

Currently, mandating widespread implementation of VPPs outside of an established pilot process poses unnecessary risks to system integrity, operational efficiency, and customer reliability. The Commission has already ordered that the Company is required to analyze the use of VPPs as part of developing a business case for DERMS prior to the Company requesting recovery for a DERMS in a future electric rate case. It would be premature to impose any additional requirements related to VPPs at this time.

RESPONSE ON COST OF SERVICE REGARDING BI-DIRECTION POWER FLOW

Q. On page 15 of her direct testimony, MNSC witness Palmer states that "One-way power flow is no longer the reality. Today, the power system is changing such that DERs are making bidirectional power flow more common on the distribution system, in turn providing generation and other services to higher voltage customers who

[7] EPRI FLEXIT: https://epri.co/flexit

previously only benefitted from centralized generation delivered at the transmission or primary level." What is your response?

A. The extent of bidirectional power flow occurring between the low voltage distribution ("LVD") and high voltage distribution ("HVD") system is de minimis. The distribution substation load data provided in the Company's response to discovery request U-21870-MNSC-CE-0207 reveals that only 0.39% of total MWh flowed in the reverse direction between LVD Primary (e.g. Voltage 3) and the HVD (46 kV and 138 kV) system.

While the Company is able to track the occurrence of bidirectional flow at certain substations using Distribution SCADA data, as explained in discovery response U-21870-MNSC-CE-0222 (Exhibit MEC-17), the Company does not currently have the capability to produce comprehensive datasets that capture the full extent of bidirectional flows across the entire distribution system. This limitation is especially pronounced between the LVD secondary (Voltage Level 4) and LVD primary (Voltage Level 3) systems, where downstream customer density is high and devices capable of sensing reverse flow to the LVD primary system are few. Advanced Metering Infrastructure ("AMI") can inform when DER interconnections are exporting to the LVD secondary system, but cannot provide visibility of where exports flow beyond the point of interconnect.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Heidi J. Myers and my business address is One Energy Plaza, Jackson Michigan 49201.

Q. Are you the same Heidi J. Myers who previously submitted direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Association of Businesses Advocating Tariff Equity ("ABATE") witness James R. Dauphinais related to the rate case test year. I will also address Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Nicholas M. Evans' return proposal related to the Investment Recovery Mechanism ("IRM"). In addition, I will also address Attorney General Dana Nessel ("AG") witness Sebastian Coppola's recommendation for the Commission to establish a contested proceeding to review the accounting and costs related to the continued operations of the J.H. Campbell Plant ("Campbell"). I will also address the testimony of Urban Core Collective ("UCC") witness Sergio Cira-Reyes regarding an affordability analysis. Finally, I will address the testimony of Citizens Utility Board of Michigan ("CUB") witness Richard J. Bunch promoting the use of productivity factor adjustments for operating and maintenance ("O&M") and capital expense.

Q. Are you sponsoring any exhibits?

A. No.

Test Year

Q. Has the Commission previously approved Consumers Energy's ability to utilize a Projected Test Year?

A. Yes, the Commission has, for many years, approved the use of projected test years. Most recently in Consumers Energy's gas rate case, Case No. U-21806, the MPSC's September 30, 2025 Order once again approved the use of a projected test year despite being presented with the same arguments from intervening parties that will be addressed in this rebuttal testimony.

Q. What specific guidance did the Commission provide in Case No. U-21806?

A. On page 9 of the Order, the Commission stated that it "finds that MCL 460.6a(1) permits a utility to use projected costs and revenue for a future consecutive 12-month period in developing its request rates and charges. The Commission is not persuaded that Consumers' use of a projected test year in the instant case should be rejected." The Commission noted that "the ALJ's recommendation is consistent with the Commission's enumerated approach and precedent with respect to the projected test year."

Q. What does ABATE witness Dauphinais propose related to the use of a projected test year?

A. On page 12 of his direct testimony, Mr. Dauphinais asserts that the Commission is not required to use a projected test year and suggests that the Commission has opined that if the utility cannot or will not provide sufficient support for a particular revenue or expense item, the Commission may choose an alternative method for determining the projection. He then indicates that the alternative method should be the historical test year adjusted for only known and measurable changes. However, Mr. Dauphinais does not assert that all of

the Company's projected costs were not sufficiently supported nor does he provide an explanation for what he believes constitutes a known and measurable change.

Q. Do you agree with ABATE witness Dauphinais' rationale for moving away from the Commission's approved use of projected test years?

A. No. The following testimony will individually address each of the points made by Mr. Dauphinais.

Q. Please comment on Mr. Dauphinais' assertion on page 10 of his direct testimony that customers experience rate increases sooner using a projected test year than they would under a historical test year.

A. The use of a projected test year provides the calculation of rates necessary during the period for which the rates will be in effect. This is the most accurate way to set rates and, as will be discussed further below, provides Intervenors with an opportunity to comment on the Company's plans for spending prior to the dollars being spent. Not only does Mr. Dauphinais' assertion ignore these points, it identifies a fact, that if acted upon by the Commission, would unfairly remove the fundamental ability of the Company to have an opportunity to earn a fair rate of return on its investments and knowingly provide customer rates that are below the cost to serve them. Mr. Dauphinais' proposal to use a historical test year is based upon the faulty and unreasonable premise that the utility should experience a lag between incurring costs to provide service and the opportunity to recover those costs. The Commission should reject the suggestion to adopt such regulatory lag.

Q. Do you agree with Mr. Dauphinais' assertion on page 10 of his direct testimony that a projected test year eliminates cost containment?

A. I do not. The Company has an incentive to hold spending levels at amounts approved in rates and to spend efficiently. Once rates are established, the Company is left to manage the business within those rates inclusive of risks that are outside the control of the Company such as weather impact on sales. This provides powerful incentive for cost containment.

Q. Do you agree with Mr. Dauphinais' assertion on page 10 of his direct testimony that the use of a projected test year handicaps Staff and Intervenors in reviewing Consumers Energy's rate filings to ensure the projected capital expenditures and expenses are reasonable because they have not yet been incurred?

A. I do not. Providing expected spending for a future test year provides a more transparent rate making process allowing Staff and Intervenors an opportunity to understand how dollars are intended to be spent and opine on the merits of the proposed spending. In comparison, setting rates based on historical spending is inferior as it only allows for review of spending after it has already occurred. This can have unfortunate consequences. If spending is only reviewed after the fact and only then determined to be an item that should be disallowed from rates, it can lead to write-offs for the Company and an inefficient use of a finite amount of dollars available to invest in the system. This is not good for the Company or customers. Customers are better served by the rate setting process provided by projected test years that allows parties to the rate case proceeding an opportunity to understand and opine on the merits of how dollars will be spent in advance of the spending.

Q. On page 9 of Mr. Dauphinais' direct testimony, he has included Table JRD-3 titled Historic Test Year and Projected Test Year Rate Sufficiency/(Deficiency). Do you agree with the conclusions that Mr. Dauphinais reached as a result of the data on this table?

A. I do not. Mr. Dauphinais' assertion based on the table is that the Company "…would not have been able to seek the large rate increases it has sought in its last eight general rate cases, and is seeking in this proceeding, until such time Consumers was actually experiencing the costs it was projecting, but for being permitted to use a projected test year." While it may be true that rate requests would be different if the Company were required to rely on a historical test year for rate relief, it would not remove the need for rate relief but would only unfairly delay it. In fact, the first time rates were established based on a historical test year, it would create a greater deficiency in the next historical year requiring a greater increase in that year. This does not create a regulatory environment conducive to customer interest. Relying on historical test years for setting rates would trade an environment where stakeholders and the Commission have an opportunity to weigh in on spending, projects, and programs before they are implemented for a short-term and inappropriate delay in rate relief. Establishing a built-in regulatory lag as proposed by Mr. Dauphinais would be detrimental to the Company and its customers, and is inconsistent with the Michigan Law providing for rates to be set using projected test years.

Investment Recovery Mechanism Return

Q. What does Staff witness Evans recommend regarding the rate of return for the IRM?

A. On page 11 of his direct testimony, Mr. Evans indicates that the rate of return associated with the IRM surcharge should be lower than the pretax rate of return as ordered in this

case but not lower than the ordered short-term debt rate. He further states that once the investments are found to be prudent and reasonable for inclusion in base rates in a future rate case, the pretax rate of return would apply.

Q. What reason does Mr. Evans give for this recommendation?

A. Beginning on page 12 of his direct testimony, Mr. Evans ties his recommendation for a lower IRM return to his assumption that the Company has under-invested in its distribution system for numerous years. Mr. Evans asserts that the Company has distribution capital projections for the late 2020s that are 4-6 times larger than the spending that occurred in most of the 2010s. He concludes that this points to earlier spending being insufficient and that the higher projected spending is closer in magnitude to what the system requires. He goes on to conclude that this indicates past under-investment in the distribution system.

Q. Please respond.

A. It would not be appropriate to apply a lower return to any portion of distribution capital spending included within the IRM for the reason provided by Mr. Evans.

Q. Why would the application of a lower return as recommended by Mr. Evans not be appropriate?

A. Applying anything less than the pretax rate of return to the IRM investments would be punitive. The cost of the capital investments included in the IRM are collected from customers over time through depreciation expense on those assets. Until the cost of the assets are fully collected from customers, the Company is required to finance the assets. Not allowing the Company to recover the full cost of financing these long-term assets based on reasoning that the Company underinvested in its distribution system in the past is a penalty and inappropriate rate making.

Q. Could this proposal have a negative consequence on customers?

A. Yes. Should a lower return be applied to the investments included in the IRM, the Company would be forced to reevaluate the inclusion of capital dollars in the IRM. The alternative would be to discontinue or reduce the scope of the IRM and include all or most of the projected capital in base rates to avoid being penalized with the lower rate of return. As described in my direct testimony, the IRM provides customer benefits that could be lost if Mr. Evans' recommendation is adopted. The IRM provides an assurance that the distribution capital spending targeted to reliability improvements are spent and provides a process that allows for more stakeholder engagement.

Q. Is Mr. Evans' argument that the Company has underinvested in its distribution system consistent with past Staff positions?

A. No, it is not. Staff did not support the Company's proposed distribution capital investments even when the Company's requested amounts were significantly less than in the last two cases. As shown in Table 1 below, Staff has proposed material distribution capital spending disallowances in prior cases. If you take Case Nos. U-18322 and U-20134 as examples, Staff proposed to disallow over 10% of the Company's ask of $450,305,000 and nearly 15% of the Company's ask of $568,723,000. This is another reason that Staff's proposal to apply a lower rate of return to IRM investments should be called into question. In the same periods where Staff is now saying there was under-investment, Staff proposed to reduce the spending to even lower levels than proposed by the Company.

Table 1: Distribution Capital Spending and Proposed Staff Disallowances

Case Number	Test Year Ending	Company Ask	Staff Proposed Disallowance
U-18322	9/30/18	$450,305,000	10.40%
U-20134	12/31/19	$568,723,000	14.87%
U-20697	12/31/21	$722,675,000	8.66%
U-20963	12/31/22	$766,266,000	4.62%
U-21224	12/31/23	$746,451,000	51.85%
U-21389	2/28/25	$770,680,000	9.33%
U-21585	2/28/26	$1,307,115,000	28.47%
U-21870	4/30/27	$1,529,914,000	6.88%

Q. Is Mr. Evans' suggestion that the Company has underinvested in its distribution system in past years a fair way to evaluate the return to be applied to an IRM in this case?

A. No it is not. Mr. Evans' proposal criticizes the level of the Company's investments made over a decade ago. Using current ratemaking to penalize the Company's investments made a decade prior would be unprecedented. It would be unfair and illogical to punish the Company in a 2026-2027 test year for investments Mr. Evans now says should have been made in the 2010s. Additionally, reducing the return on the investments needed now would not reflect the actual financing costs of the needed investments.

Q. How should the Commission respond to Mr. Evans' recommendation to apply a lower return to IRM investments?

A. The Commission should not adopt this recommendation. The investments included in the IRM should receive the same return applied to all similar long-term capital investments. Anything less than this would be punitive and would create a situation where the Company would not have the opportunity to recover all of its costs of making the needed investments.

Campbell Contested Proceeding

Q. Do you agree with Mr. Coppola's assessment of the Company's position related to the Campbell plant?

A. Yes. As a result of orders[1] the Company has received from the Department of Energy ("DOE"), the Campell Plant has continued to operate past its planned retirement date of May 31, 2025. The most recent order, Order No. 202-25-7, requires the Campell Plant to operate through November 19, 2025. The Company does not propose to adjust amounts included in this case related to the Campbell plant. The Company plans to request recovery of the costs associated with the DOE Orders through a Federal Energy Regulatory Commission ("FERC") process, as provided by the DOE Order, and will refund to MPSC jurisdictional customers any amounts collected through the FERC process that have been collected through MPSC jurisdictional rates. This is consistent with AG witness Coppola's assessment of the Company's position related to the Campbell Plant on pages 77 through 78 of his direct testimony.

[1] DOE Order No. 202-25-3 issued May 23, 2025 and DOE Order No. 202-25-7 issued August 21, 2025.

Q. Does Mr. Coppola agree with the Company's position related to the Campbell Plant?

A. Mr. Coppola agrees, in part, with the Company's position. On page 78 of his direct testimony, Mr. Coppola asserts that the Company's proposed solution to refund amounts collected through the FERC process that have been or will be collected through MPSC jurisdictional rates is the only workable solution at this time.

Q. Does Mr. Coppola make an additional recommendation related to the Campbell Plant?

A. Yes. On page 79 of his direct testimony, Mr. Coppola recommends that the Commission open a new docket for a contested proceeding to review all aspects, impacts, cost and revenue reconciliation, and refunding of net amounts to customers.

Q. Does Mr. Coppola provide a reason for this recommendation?

A. Yes. Mr. Coppola argues it is needed to ensure that a full and proper accounting of costs and revenue from the continued operation of the Campbell plant occurs, as well as the cost recovery in rates established in Case No. U-21585 and the current case.

Q. Do you agree that the Commission should establish a new docket for this purpose?

A. I do not. The establishment of a separate docket for this purpose is unnecessary and premature. The Company can provide for a full review of the costs and revenues related to the Cambell Plant and any associated refund to MPSC jurisdictional customers in the first electric rate case filed after the outcome of the FERC process is known. Any review of this nature should not take place until the outcome of the FERC process is known because it will provide information necessary to inform the analysis. Furthermore, Mr. Coppola has not provided any reason why this review cannot be completed as part of a

future rate case filing. Creating a new docket to review matters related to this issue is unnecessary.

Affordability Analysis

Q. At page 41 of his direct testimony, UCC witness Cira-Reyes suggests that the Commission should require the Company to perform a fulsome official affordability analysis incorporating the Commission's definition of energy affordability to ensure its programs are adequately addressing affordability among its customers before the Commission approves the rate increase. Has it been made clear what should be included in this analysis?

A. No. Mr. Cira-Reyes did not include any additional details regarding his proposed analysis and it is unclear to the Company how this would be done. The referenced Commission's definition of energy affordability is the extent to which a household has the resources to meet their home energy needs for heating, cooling, and other uses in a healthy, sustainable, and energy efficient manner without compromising a household's ability to meet other basic needs. The Company would not be able to incorporate information for all customers for each of the aspects included in the Commission's definition of energy affordability.

Q. Should the Commission, as recommended by Mr. Cira-Reyes, abstain from approving a rate increase in this case until the affordability analysis is completed?

A. No. As indicated, the Company is unsure of how the requested analysis would be completed or if it would even be possible to complete and it is unreasonable to expect that the Company could complete such an analysis in the time between the filing of Mr. Cira-Reyes' testimony and the filing of the Company's rebuttal. As such, the Commission should not wait to approve a rate increase in this case until this affordability

analysis is completed. See the rebuttal testimony of Company witness Jessica R. Byrom for discussion of the Company's customer payment assistance programs.

Productivity Factor

Q. Please summarize CUB witness Bunch's recommendation related to the use of productivity factors in this case.

A. On pages 12 through 35 of his direct testimony, CUB witness Bunch presents his recommendation that the Commission use productivity adjusted inflation to limit growth in O&M expense for all cost categories with the exception of forestry. Mr. Bunch also recommends that the Commission direct the Company to present both O&M and capital test-year cost baseline projections calculated as historical cost adjusted for productivity adjusted inflation in future rate cases with the ability to present other adjustments to the baseline with demonstration of why they are necessary owing to changes in sales, new statutory requirements, or new performance requirements.

Q. Do you agree with Mr. Bunch's recommendation?

A. I do not. The following testimony will address the rationale used by Mr. Bunch in drawing his conclusions and show that the Commission should not adopt his recommendations.

Q. At page 12 of his direct testimony, Mr. Bunch disagrees with the Company's assertion that a comprehensive and transparent method for incorporating productivity gains in its cost and expenditure projections is unnecessary. Please respond.

A. Mr. Bunch mischaracterizes my direct testimony in this case. My direct testimony, at page 29, did not characterize incorporating productivity gains in its cost and expenditure projections as unnecessary, but simply explained the complexities and hindrances of doing so.

Q. On page 19 of his direct testimony, CUB witness Bunch also argues that the Company is inconsistently applying inflation rates to arrive at test year cost projections in this case. Please respond.

A. Mr. Bunch is correct in stating that Company witnesses are not the same in the way they present inflation in their exhibits. However, the projected costs are fully supported by Company witnesses regardless of whether they applied inflation rates to historical costs to develop projected test year costs.

Q. On page 20, Mr. Bunch states the adjustments in Exhibit A-13 (PDD-42), Sch. C-5.1, do not always align with the actual inflation assumptions used by sponsoring witnesses. How do you respond?

A. Exhibit A-13 (PDD-42) is the Company's attempt to show on one page inflation impacts on the projected O&M expenses and is compiled from the detailed exhibits of each witness who sponsors O&M costs. I agree that the inflation data is not presented the same by each witness. However, Mr. Bunch's criticism illustrates that the testimony explains how the costs were developed and proves the point that the costs are fully supported in testimony, regardless of how they were developed.

Q. On page 23 of his direct testimony, Mr. Bunch states that the Company's projected costs are increasing much faster than inflation, and the bulk of the increase in costs is captured in the Other Adjustments columns of the Company's exhibits. How do you respond?

A. Costs above inflation should be included in the Other Adjustments columns; that is exactly what the column is supposed to represent. There are many reasons why costs increase other than inflation and the Company's witnesses fully support their projected costs.

Q. Does Mr. Bunch make a comparison of a regulated utility to unregulated companies for purposes of addressing the issue of inflation?

A. Yes. On pages 13 through 15 of his direct testimony, Mr. Bunch compares a regulated utility to unregulated companies and provides examples of ways unregulated companies can mitigate inflationary cost increases, ultimately concluding that a regulated utility has the same arsenal of managerial responses to inflationary cost increases as companies operating in a competitive market.

Q. What managerial responses to inflation does Mr. Bunch provide?

A. On pages 13 and 14 of his direct testimony, Mr. Bunch indicates a company can extract greater productivity from its existing assets, seek new suppliers or negotiate with existing ones, find an alternative production method, or increase labor productivity.

Q. Do you agree with Mr. Bunch's assessment of a regulated utility's ability to respond to inflationary pressures in these same ways as an unregulated company?

A. I do not. Unlike unregulated companies, a regulated utility has an obligation to serve their customers. Not only do they have an obligation to serve, but there are also expectations attached to safety, service quality, and reliability. For example, Mr. Bunch proposes that a company facing inflation can extract greater productivity from existing assets by running existing machines faster or longer, or it can keep older machines in service longer than it had intended by repairing and servicing them rather than replacing them, or it can run extra shifts to get round-the-clock production. The Company already operates around the clock to meet customer demand and cannot compromise safety or reliability by overextending equipment or deferring necessary investments. Unlike unregulated market participants,

regulated utilities must prioritize long-term system integrity and customer service over short-term cost reductions.

In short, while the Company actively manages costs, its ability to respond to inflationary pressures is constrained by its duty to provide safe, reliable service to all customers at all times.

Q. On page 28 of his direct testimony, Mr. Bunch argues that the Commission should constrain the Company to Productivity-adjusted Inflation ("PAI") increases in O&M and capital expenditures and require it to justify any excursions from these limits ("Other Adjustments") in terms of changes in sales, legal, or performance requirements to force it to become more productive. How do you respond?

A. The Company does not believe Mr. Bunch's PAI methodology should be applied to O&M or capital expenditures. For example, the Company's proposed capital investment in the distribution system enables productivity gains and improved reliability for customers. Aging infrastructure, increasing customer expectations, and evolving reliability standards demand proactive upgrades. These investments are designed to reduce outage frequency and duration, modernize grid operations, and ultimately lower operating expenses over time. For example, automation and grid modernization initiatives reduce manual labor and emergency response costs, directly impacting O&M. These are not short-term gains, but strategic investments that yield long-term value for customers and the system. Therefore, the Commission should not interpret increased capital and O&M spending as a failure to achieve productivity. Rather, it should recognize that these expenditures are foundational to delivering sustained improvements in reliability, safety, and operational efficiency. The Company fully supports its projected costs and the Commission should not apply a blanket

limitation on the Company's expenditures. The test should be whether the individual program expenditures have been supported by the Company as reasonable and prudent.

Q. On page 29 of his direct testimony, Mr. Bunch suggests that the Company should be expected to manage costs the same way an unregulated company would. How do you respond?

A. As a primary matter, Mr. Bunch's implication that the Company does not manage costs is false—as explained by the Company's witnesses in this case, the Company does work to control costs. However, regulated utilities are fundamentally different than unregulated companies and it is not appropriate to expect the Company to be able to mirror how prices may be constrained in unregulated sectors of the economy. While the Company strives to improve its efficiency and productivity in order to control costs, it is important to note that the Company has unique regulatory obligations, most importantly the obligation to serve that may cause it to respond to cost pressures differently than unregulated companies.

Q. Mr. Bunch recommends the Commission apply the PAI factor to all proposed O&M expenses and disallow excess costs unless they are driven by sales growth or specific performance or legal requirements. Would this be an appropriate way for the Commission to determine the appropriate allowable O&M expenses?

A. No. The Company strives to implement and incorporate productivity gains into its costs in order to keep customer rates affordable. The Company also continues to work to improve its processes for identifying and highlighting these productivity gains in its rate cases. However, the standard for cost recovery has been and should be whether the costs are reasonable and prudent, not solely dependent on whether productivity gains have been incorporated into costs or whether costs increase by more than inflation.

Q. How do you respond to the calculation of the proposed O&M disallowance provided on page 34 of Mr. Bunch's direct testimony?

A. Mr. Bunch recommends reducing O&M expense by $51.5 million to adjust all O&M expense, except for forestry, to historical expenses adjusted for productivity adjusted inflation. Mr. Bunch's Table 4 shows $47.7 million, or 93%, of this reduction is related to electric distribution O&M expense. Company witness Michael P. Kelly makes clear that the increase in O&M for this category of expense is directly tied to the Company's Reliability Roadmap. Mr. Kelly notes on page 123 of his direct testimony that "[t]he Company's O&M spending supports its capital investments through maintenance and operations of grid infrastructure, plus engineering and design work required to execute projects, and provides for restoration of service to customers following interruptions." Furthermore, Mr. Kelly detailed that increases in the Non-Forestry Reliability O&M program are driven by expanded inspection and monitoring of system equipment. This includes four sub-programs: Low Voltage Distribution ("LVD") Lines Reliability, High Voltage Distribution ("HVD") Lines Reliability, LVD Substations Reliability, and HVD Substations Reliability. Regarding the LVD Lines Reliability sub-program, Mr. Kelly noted on page 131, lines 3 through 7, of his direct testimony, "[h]istoric spending levels in this sub-program were insufficient to complete all of the IEEE-recommended work. The Company identified this issue when developing the Reliability Roadmap in 2023, and began developing a plan to increase needed maintenance work going forward." Similarly, on page 132, lines 12 through 13, of his direct testimony, Mr. Kelly explained, "[t]he increase in spending is being driven by increased inspections and testing to support projected investment increases in the HVD Lines Reliability capital program." He further

summarized on page 133, lines 4 through 7, of his direct testimony, that "the Company is increasing its total substation O&M spending across the four sub-programs to better align with the Electric Substation Reliability Guidelines ('ESR-1')," and that "[h]istorical levels of funding have not been adequate to complete sufficient inspections or to address maintenance backlogs." Additionally, Mr. Kelly testified on page 141, lines 3 through 5, of his direct testimony, that "the Company is projecting increased spending in these sub-programs to ensure the Company can complete the necessary substation maintenance under the ESR-1 guidelines, as given in the Reliability Roadmap." It is also important to note that increases in the Corrective Maintenance program are not merely inflationary. These increases represent incremental work intended to enhance public safety and support system reliability, which are core objectives of the Reliability Roadmap.

Q. What is the result of Mr. Bunch's proposed disallowance?

A. In order to continue the important distribution reliability work highlighted above, the remaining O&M categories would have to achieve more than a 13% reduction for the test year of this case. This is not a reasonable ask and would most likely leave the Company no choice but to pull back on some of the necessary distribution work.

Q. How should the Commission respond to Mr. Bunch's recommended reduction to O&M expense and his proposal to require the Company to present both capital and O&M expense based on historical amounts adjusted for productivity adjusted inflation in future rate cases?

A. The Commission should not adopt Mr. Bunch's proposed O&M expense disallowance. This testimony describes the numerous issues with Mr. Bunch's proposal. Most importantly, his testimony fails to account for the Company's obligation to provide safe

and reliable service to its customers. There should never be a standard set that simply caps expense levels at amounts below inflation. This would be a major and dangerous deviation from the Commission's review of expense levels through the lens of whether the expenses are reasonable and prudent and in support of safe and reliable delivery of electricity. For the same reason, the Commission should also deny the request to require future rate cases to present both O&M and capital as historical adjusted for a productivity adjusted inflation rate.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

JEFFREY A. MYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Jeffrey A. Myrom, and my business address is One Energy Plaza, Jackson Michigan 49201.

Q. Are you the same Jeffrey A. Myrom who previously submitted direct testimony in this proceeding on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. All intervenors who testified about the Company's proposed Transportation Electrification Plan ("TEP") enhancements (i.e., Michigan Energy Innovation Business, Institute for Energy Innovation, and Advanced Energy United (collectively referred to as "MEIU"); Michigan Electric Transmission Company ("METC"); Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (collectively referred to as "MNSC"); and Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff")) support the enhancements, albeit some with suggestions for additional enhancements and expenditures. Thus, the purpose of my rebuttal testimony is to address (i) Staff witness Allan D. Freeman's support of the proposal with additional suggestions by Staff witness Kevin Krause; (ii) MEIU witness Sophia Schuster's support of the proposal with suggestions for modification; and (iii) MNSC witness Douglas B. Jester's support of the proposal with suggestions for modification.

Q. Are you sponsoring any new exhibits in this rebuttal testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-223 (JAM-4) Discovery Response 21870-MEIU-CE-0042; and

Exhibit A-224 (JAM-5) Discovery Response 21870-MEIU-CE-0043.

RESPONSE TO STAFF

Q. At page 5, lines 17 through 21, of his direct testimony, Staff witness Freeman recommends that the Company consider impacts of the Electric Vehicle ("EV") tax credit ending to the EV adoption forecast for the upcoming TEP in 2026. How do you respond?

A. I agree. The Federal EV tax credit was intended to incentivize domestic EV and battery manufacturing and, indeed, many such developments are underway or nearing completion that will have a positive impact regarding economies of scale. That said, the price impact of losing the EV tax credit, as of September 30, 2025, in addition to other potential tax impacts from Federal initiatives, like tariffs (which are also intended to promote domestic manufacturing), will take time to develop and recalibrate customer adoption behavior. In the near term, the Company has seen a pull-forward of EV purchases to gain the tax credit before it expires. Consumers Energy anticipates that this pull-forward of purchasing behavior could result in a temporary reduction in EV adoption in Q4 of 2025, but by mid-2026 anticipate a trend toward normalization of customer behavior, barring further regulatory developments. The Company will continue to reforecast EV adoption in the annual reports and TEP filings going forward.

Q. At page 6, lines 3 through 16, of his direct testimony, Staff witness Freeman expresses support for the use of weatherized EV-rated outlets across all rebate categories as proposed. How do you respond?

A. I agree. The upfront cost of installing new charging infrastructure is a significant barrier to multifamily charging, community charging, workplace charging, and for smaller fleets, but presently only community charging has the Bring-Your-Own-Cord ("BYOC") option. The infrastructure cost challenge requires continued focus, especially in lower-income areas and multifamily locations that without financial assistance could not unlock the positive total energy-wallet impacts that transportation electrification can achieve.

Q. At page 7, lines 1 through 12, of his direct testimony, Staff witness Freeman expresses support for a temporary Direct Current Fast Charger ("DCFC") rebate program for underserved communities as proposed. How do you respond?

A. I agree. While the Federal tax credit for EV charging equipment under Section 30C of the Internal Revenue Code ("30C tax credit") is set to expire in June of 2026, which is a new development since the original proposal, the Company believes that the $50,000 rebate proposed is still a meaningful incentive to help create a skeleton network of fast chargers. The Company serves many smaller communities, especially in the northern half of the lower peninsula, that experience seasonal and weekend travel patterns related to Michigan's fantastic tourist destinations, which would benefit from fast charging infrastructure. Moreover, the Company anticipates that EV adoption will continue to expand in all areas of Michigan and the residents near fast charger developments will also benefit.

Q. At page 5, lines 2 through 6, of his direct testimony, Staff witness Krause recommends that Rate GP be closed to new and existing charging stations by June 1, 2028, and that a new Fast Charging Tariff be proposed in the next electric rate case. How do you respond?

A. Additional data and analysis are required. Fast charging infrastructure, especially in more rural areas and locations with seasonal travel, can benefit from rates with reduced demand charge components as Staff witness Krause recommends. However, the PowerMIDrive program is sharing fast charging load profile data with the Company's rates team, and Company witness Laura M. Connolly explains in her rebuttal testimony that this data set is not yet sufficient to propose a new rate structure in the next electric rate case. Additional time for fast charging load profile development is needed before Rate GP can be replaced with one or more alternatives.

RESPONSE TO MEIU

Q. At page 50, lines 12 through 16, of her direct testimony, MEIU witness Schuster recommends that rebate recipients utilizing the proposed outlet option provide proof of EV purchase or lease. What is your response?

A. I agree and disagree in part. A clarification regarding the scope of the BYOC proposal compared to current rebate options may lead us to alignment. In my direct testimony, pages 12–13, I proposed expanding the option to use a National Electrical Manufacturers Association ("NEMA") 14-50 or NEMA 5-20 outlets from community charging applicants to applicants for multifamily charging, workplace charging, and fleet charging. In the community charging scenario, for which BYOC is already approved, no proof of EV purchase or lease is required because the charging infrastructure is open to the public. In a

similar manner, the current Level 2 rebates for multifamily and workplace charging do not require proof of EV ownership or lease because that infrastructure is open to a wide variety of people who will live or work there, be it now or in the future. Thus, the Company is applying a similar logic with the BYOC option, to allow a lower cost solution for the multifamily and workplace host sites to serve their residents and employees, who like the public will change over time and include a wide variety of people. It would be impractical to verify or mandate EV adoption in these circumstances, but we know from the data provided in the Company's annual TEP reports that such charging infrastructure is actively used and largely off-peak. However, fleet charging is a use case where the Company has and will continue to require proof of EV adoption (purchase or lease) to qualify for a rebate, be it a Level 2 plug or a NEMA outlet, because fleet charging is specific to a particular private entity and not for the public at large. Thus, I agree that fleet charging requires proof of EV adoption but disagree that proof is needed for multifamily and workplace charging given the characteristics of those EV charging host sites.

Q. At page 50, lines 19 through 21, of her direct testimony, MEIU witness Schuster recommends that the fast-charging rebate be increased to $70,000 and the two-year application window be extended to six years. How do you respond?

A. If proven necessary with time and market development, such changes can and will be proposed in future rate cases. It is true that changes have occurred since the Company's original proposal that are material to fast-charging market development. For example, the Federal 30C tax credit is set to expire in June of 2026, which makes it nearly impossible that a rebate recipient would qualify for both the proposed rebate and the 30C tax credit. Alternatively, the uncertainty regarding the remaining National Electric Vehicle

Infrastructure ("NEVI") funding is now removed and the State of Michigan has additional flexibility in how it utilizes the NEVI funds. The intent of the Company's proposal is to fill in the final fast-charging infrastructure needs, creating what has been called a skeleton network, upon which the market can expand independent of Company rebates. The Company's long-term TEP strategy remains centered on lower-power, longer-duration, off-peak charging infrastructure to optimize the grid. Nonetheless, if the fast-charging proposal proves insufficient to achieve the skeleton network outcome, then the Company is very willing to consider higher rebate values and a longer application window duration in a future filing.

Q. At page 50, lines 22 through 23, and at page 51, lines 1 through 2, of her direct testimony, MEIU witness Schuster recommends that the Company provide an explicit definition of "community" and a clear rubric for fast-charger rebate applicant review. How do you respond?

A. The Company has provided such a response. Please see the discovery responses to discovery questions submitted by MEIU (21870-MEIU-CE-0042 and U21870-MEIU-CE-0043), included here as A-223 (JAM-4) and A-224 (JAM-5).

RESPONSE TO MNSC

Q. At page 27, lines 7 through 8, of his direct testimony, MNSC witness Jester recommends that the fast-charging rebate application window be extended to seven years given the Federal tax credit recission. How do you respond?

A. As discussed above in response to a similar proposal by MEIU witness Schuster, if proven necessary with time and market development, such changes can and will be proposed in future rate cases. The intent of the Company's proposal is to fill in the final fast-charging

infrastructure needs, creating a skeleton network, upon which the market can expand independent of Company rebates. If the fast-charging proposal proves insufficient to achieve the skeleton network outcome, then the Company is very willing to consider higher rebate values and a longer application window duration in a future filing.

Q. At page 27, lines 9 through 11, of his direct testimony, MNSC witness Jester recommends that the Company allocate specific funding for education and outreach to multifamily dwellings. How do you respond?

A. I agree that market challenges for multifamily charging remain and are significant. To help address this issue the Company has proposed the NEMA outlet alternative, supported by MNSC witness Jester, and continues to promote rebates for community and workplace charging that can also assist multifamily residents as alternative charging locations. Thus, targeted outreach and rebates to address multifamily charging will continue to be a focus in the Company's 2026 TEP. The Company remains open to stakeholder feedback between now and the 2026 TEP filing regarding additional enhancements to address the multifamily challenge, particularly for low-income and moderate-income residents. Given the large proportion of leased EVs, the Company believes that the used EV market will soon allow for even more widespread EV adoption and significant total energy-wallet savings for all customers.

Q. At page 27, lines 12 through 13, of his direct testimony, MNSC witness Jester recommends that the Company propose an active managed charging and telematics pilot in the next rate case. How do you respond?

A. I do not agree at this time, but acknowledge that telematics and active managed charging remain potential future elements of the Company's TEP. While third-party telematics

vendors are piloting with other utilities, the Company wants significant confidence in long-term solutions that have minimal risks and costs, and solutions which cover the majority of EVs in the Company's electric territory. The Enel X situation, for example, left multiple utilities that were dependent or largely dependent upon one company abandoned and starting over with their customer load management program. This is a risk the Company desires to mitigate if moving into a telematics pilot. For reference, Michigan Original Equipment Manufacturers ("OEMs") presently have the majority of EV market share in the Company's electric territory and are actively working on telematics solutions. Furthermore, the longevity of Michigan OEMs provides more confidence than a new company in this space and may be cut out at some point in the future given the proprietary nature of vehicle telematics for OEMs. Thus, the Company is still monitoring market developments regarding telematics and active managed charging, but at this time is unwilling to commit to a pilot in the next rate case.

Q. At page 27, lines 14 through 16, of his direct testimony, MNSC witness Jester recommends that the Company again propose a battery-integrated DCFC pilot in the next rate case. How do you respond?

A. I do not agree that this is necessary, but remain optimistic about battery-integrated fast-charging technology and economics. The Company made a battery-integrated DCFC proposal in the last electric rate case and it was rejected. Instead of reproposing that concept again, the Company utilized the guidance and feedback in Staff testimony and proposed the limited-time DCFC rebate program in the present case. Battery-integrated fast-charging will be eligible for the proposed $50,000 rebate if approved by the Commission.

Q. At page 27, lines 17 through 18, of his direct testimony, MNSC witness Jester recommends that the Company expand PowerMIFleet with a V2G-enabled electric school bus pilot in the next rate case. How do you respond?

A. I do not agree at this time, but acknowledge that bidirectional charging remains a potential future element of the Company's TEP. Several other utilities are already engaged with bidirectional school bus pilots, and the Company will continue to monitor these developments. The Company does not believe that there are unique aspects of bidirectional charging technology specific to its territory that needs to be explored through a pilot at this time.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

JEFFREY A. MYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Question:

9. Refer to the Direct Testimony of witness Jeffrey A. Myrom at p. 13. Witness Myrom states that "DCFC rebates will only be available for communities that do not have at least four 150 kW DCFC ports across two or more different host sites."

a. Please define "community."

b. Is "community" limited in physical space or defined by other traditional governmental boundaries?

Response:

a. A community is a governmental boundary.

b. Per "a" above, it is a traditional governmental boundary.

Witness: Jeffrey A. Myrom
Date: July 18, 2025

Question:

10. Refer to the Direct Testimony of Witness Jeffrey A. Myrom at pp. 14–15. The Company proposes to have the right to reject applications on a rolling basis that do not offer "quality customer experience" and cites several criteria to be used in evaluating future public DCFC site proposals.

a. Please detail the evaluation process that the company will use to assess each criterion and to compare applications to each other.

b. Please detail the methodology or rubric by which the Company will collectively assess the proposed criteria, including how the company will weight each metric for public DCFC projects to determine prioritization.

c. For each proposed criterion, will the Company use a sliding scale or a simple yes/no determinant?

d. Please indicate the minimum criteria that an application would need to meet to warrant the Company to reject an applicant's proposal.

e. Specifically, does a host site have to have security lighting?

f. Specifically, does a host site have to have a canopy?

g. Regarding the application closing dates:

   i. Will the Company have established application closing dates?

   ii. If there will not be an established application closing date, will applications simply have to meet the minimum criteria to be funded on a first-come, first-served basis?

   iii. If there will not be an established application closing date, how will applications be compared on a rolling basis?

Response:

a. The evaluation process will utilize the criteria detailed in my Direct Testimony on pages 14-15, paragraph "d", subparagraphs 1-6.

b. The evaluation criteria referenced in "a" above will be utilized on a "yes/no" basis per "c" below.

c. A yes/no determination will be made.

d. The minimum criteria are found on pages 14-15 of my Direct Testimony as follows:

   i. Per paragraph "d" subparagraph 1, lines 21-23: "In no case shall sites be allowed that do not offer 24-7 charging or that have no public amenities.".

   ii. Per paragraph "d", subparagraph 4, line 39: "The host site must have adequate security lighting".

iii. Per paragraph “d”, subparagraph 6, line 12: “all host sites must offer at least two 150 kW DCFC ports”.

e. Yes. Lighting is required.

f. No. A canopy is not required but could be a differentiating criterion regarding rebate selection.

g. The Company plans to review applications and designate rebates monthly. If an application does not meet the minimum criteria as noted in “d” above, then the applicant may re-apply with a revised site design. The goal of the temporary DCFC rebate program is to spur the growth of quality fast charging infrastructure and to do so as quickly as possible.

Witness: Jeffrey A. Myrom
Date: July 18, 2025

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

JENNIFER M. PARTLAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Jennifer M. Partlan, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. Are you the same Jennifer M. Partlan who previously submitted direct testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Ryan Boutet, Nicholas M. Evans, and Anna N.N. Schiller; Attorney General ("AG") witness Sebatian Coppola; and Association of Businesses Advocating Tariff Equity ("ABATE") witnesses Jessica A. York and Colin T. Fitzhenry.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-225 (JMP-5)	Discovery response 21870-ST-CE-0078;
Exhibit A-226 (JMP-6)	Example of LVD Concept Approval; and
Exhibit A-227 (JMP-7)	Discovery response 21870-AB-CE-0712.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

I. <u>REBUTTAL OF STAFF WITNESS BOUTET</u>

Q. Please summarize Mr. Boutet's direct testimony in this case.

A. Mr. Boutet's testimony is focused on the Company's low voltage distribution ("LVD") capital expenditures. He reviews several of the Company's LVD capital investment

sub-programs and recommends disallowances in six investment areas. I will respond to each of Mr. Boutet's recommendations.

Q. What is Mr. Boutet's recommendation regarding the Company's Conservation Voltage Reduction ("CVR") sub-program?

A. Mr. Boutet notes, on pages 10 and 11 of his direct testimony, that the Company appears to have underspent in the CVR sub-program in 2023 and 2024 when compared to the Company's prior rate case projections. Based on this, he recommends that the approved investment amount for CVR be set at the five-year historical average expenditures plus inflation, and recommends bridge period and test year disallowances to reflect that spending level. These proposed disallowances are equal to $1,158,514 for the bridge period ending December 31, 2025; $91,645 for the four-month bridge period ending April 30, 2026; and $733,454 for the test year ending April 30, 2027.

Q. Do you agree with Mr. Boutet's recommendation for CVR?

A. The Company will not oppose Mr. Boutet's recommendation regarding the CVR sub-program projected expenditures in this case.

Q. What is Mr. Boutet's recommendation regarding the LVD Lines Capacity sub-program?

A. On pages 12 and 13 of his direct testimony, Mr. Boutet expresses concern that the Company can effectively scale up LVD Lines Capacity investment as projected, and he contends that year-to-date spending through June 2025 shows that the Company is on track to underspend its 2025 projection. Mr. Boutet recommends that the Commission approve investment levels for the bridge period, as they are in line with what the Commission approved in Case No. U-21585, but recommends that the Commission not approve the full proposed test year

investment level. Instead, he proposes that test year investment be limited to a doubling of the pace of work approved in Case No. U-21585, with a corresponding disallowance of $18,720,000 in the test year.

Q. How do you respond to this recommendation?

A. The Company will not oppose Mr. Boutet's recommendation regarding the LVD Lines Capacity sub-program projected expenditures in this case.

Q. What is Mr. Boutet's recommendation regarding Zonal Health Improvements in the LVD Lines Reliability sub-program?

A. On pages 14 and 15 of his direct testimony, Mr. Boutet states that the Company has provided more information about Zonal Health Improvements in the instant case than in Case No. U-21585, but he believes the Company's presentation is still insufficient. Mr. Boutet states that there is little discussion or analysis of the most cost-effective approaches to improve reliability. He states that the Reliability Analytics Engine ("RAE") is used to identify projects, but that it appears the RAE only ranks Zonal Health Improvement projects against each other rather than considering other potential solutions. Ultimately, he supports the Company's proposed test year investments, since they are largely in line with 2024 actual spending, but he recommends reducing bridge period investments to the same level, so that the Company works at the same pace as in 2024 while awaiting further support regarding the impacts of Zonal Health Improvements.

Q. Do you agree with Mr. Boutet's recommendation regarding the bridge period?

A. No. The RAE does not rank Zonal Health Improvement projects against one another. As stated on page 42, lines 10 through 15, of my direct testimony, the RAE simply ranks the *zones* themselves against each other, to help the Company identify where *some kind* of

System Average Interruption Duration Index ("SAIDI") reduction work is needed. As stated on page 42, lines 17 through 19, once the RAE has been used to identify zones with recent reliability challenges and with the most opportunity for improvement, only then does the Company develop and prioritize projects themselves. Pages 43, line 1, through 44, line 2, provide further detail about how the RAE is just one tool used in identifying projects. When a zone has a reliability issue, the Company believes that the problem is worth fixing so that customers experience fewer interruptions. The least-cost-best-fit approach is then used to identify the most cost-effective way of doing so, regardless of the specific approach ultimately selected.

In short, the Company uses the RAE as an input to identify zones needing improvement, and then uses multiple tools to compare a variety of potential solutions against one another before pursuing a Zonal Health Improvement project.

Q. Can you provide a more detailed illustration of how the Company selects Zonal Health Improvement projects from among alternatives?

A. In Exhibit A-226 (JMP-6), I am providing an illustrative example of an LVD concept approval. In this example, the Company identified an initial problem using zonal analysis. The Company then considered three different alternatives to address the problem. As shown, the Company ultimately selected the median-cost alternative for reasons given in the document. In other words, the Company considered multiple approaches to solve an identified problem and chose the least cost option that would resolve the issue.

Q. Do you have any other concerns with Mr. Boutet's recommendation?

A. I do not agree with Mr. Boutet's suggestion that Zonal Health Improvement work must stay level until the impacts of the work are better substantiated. As stated on page 47 of

my direct testimony, the Company has been doing this work since 2013. Clear benefits from Zonal Health Improvement projects are shown in Figure 23 in my direct testimony and on page 52, line 13, through page 53, line 10.

Q. What is Mr. Boutet's recommendation regarding the Repetitive Outages sub-program?

A. On page 16 of his direct testimony, Mr. Boutet performs a similar analysis as he did with CVR, noting recent years of underspending as compared with Company projections. Mr. Boutet recommends a 20% disallowance in the bridge period and test year as a compromise between the recent underspending and the importance of the work in meeting the Commission's CEMI-4 standard.

Q. Do you agree with this recommendation?

A. No. Mr. Boutet's approach is flawed to the extent that it assumes that the amounts spent in 2023 and 2024 necessarily dictate what will be spent in the future. The Company is providing year-to-date spending for this sub-program through September 2025 in Exhibit A-219 (MPK-29). Exhibit A-219 MPK-29, line 5, shows that, through September 2025, the Company has spent well over $6.3 million year-to-date, with spending of approximately $1.0 million and $1.1 million in August and September, respectively, and the Company is on track to invest over $11.2 million in 2025 based on the rate of increase.

Q. What is Mr. Boutet's recommendation regarding the Make-Ready investment category in the LVD Asset Relocations sub-program?

A. On pages 17 through 19 of his direct testimony, Mr. Boutet calculates that the Company's unit costs for Make-Ready work are increasing by nearly 60% compared to approved spending levels in Case No. U-21585. Mr. Boutet contends that the Company has not given

an explanation for why unit costs increased when the types of work seem to be constant. He recommends a disallowance based on using unit cost levels implied in Case No. U-21585.

Q. Do you agree with this analysis?

A. No. In the Make-Ready investment category, the Company typically recovers a percentage of the cost from the attaching third party, and both the projected spending in Figure 16 in my direct testimony and the historical costs in Exhibit A-130 (MPK-20), page 2, line 40, reflect the Company's costs net of that recovery amount. However, the Company's net costs do not reflect the full cost of the work. The unit cost should be evaluated based on the total cost of the work, rather than the Company's responsibility alone for Joint Attachment requests. This is important because, although the recovery amount is usually consistent from year to year, there are outliers. Typically, the Company has recovered 46-48% of Make Ready costs from attaching parties, which the Company expects to continue in future years. However, in 2023, customer contributions unusually offset 65% of spend due to a temporary increase in reimbursement from attaching parties driven by extensive rural expansion. This made the Company's net 2023 unit cost appear artificially lower, and those 2023 net unit costs informed Case No. U-21585, which is what Mr. Boutet cites for his justification that 2023 unit costs should be used in the instant case.

However, all-in unit costs have been fairly steady since 2022, and that is what is projected to continue in the instant case. These costs increased in 2022 compared to earlier levels, driven largely by Covid-era rural digital expansion and supply constraints. This data is shown in Table 1 below.

TABLE 1
MAKE-READY WORK COST DATA

Year	Total Make Ready Spending	Customer Amount Recovered	CE Responsibility	Percent Recovery	Make Ready Orders Complete	Total Unit Cost	Unit Cost of CE Responsibility	
2020	$9,877,759	$4,514,790	$5,362,969	46%	752	$13,135	$7,132	Actual
2021	$12,377,903	$5,924,557	$6,453,346	48%	829	$14,931	$7,784	Actual
2022	$27,879,164	$13,305,056	$14,574,108	48%	1236	$22,556	$11,791	Actual
2023	$37,496,781	$24,474,069	$13,022,712	65%	1655	$22,657	$7,869	Actual
2024	$39,574,196	$19,151,261	$20,422,935	48%	1640	$24,131	$12,453	Actual
2025	$64,779,696	$31,349,035	$33,430,661	48%	2685	$ 24,131	$12,453	Forecasted
2026	$75,334,047	$36,456,634	$38,877,413	48%	3122	$24,131	$12,453	Forecasted
2027	$79,594,168	$38,518,248	$41,075,921	48%	3298	$24,131	$12,453	Forecasted

Q. What is Mr. Boutet's recommendation regarding right-of-way ("ROW") spending in the LVD Lines Reliability sub-program?

A. On page 20 of his direct testimony, Mr. Boutet contends that the Company has not supported its projected test year spending level for ROW. He notes that the Company did not provide details about specific ROW projects but only stated that ROW costs are projected based on a percentage of Targeted Circuit Improvement spending. Because of this, he recommends that ROW spending be held to the level approved by the Commission in Case No. U-21585.

Q. Do you agree with this recommendation?

A. No. The Company provided additional explanation in a discovery response that Mr. Boutet has sponsored at Exhibit S-13.9. As stated in that response, the Company has consistently projected ROW costs as a percentage of Targeted Circuit Improvement spending, as these are correlated over the years. Since 2020, ROW costs have averaged 14% of Targeted Circuit Improvement spending, with a range from 11% to 19%. In the test year, the Company is only projecting ROW costs at 12% of Targeted Circuit Improvement costs, less than the recent average actual amount. ROW expenditures includes items such as

research prior to designs to understand the rights that the Company already has, as well as the creation of easement documentation for any new easements and payments for easements. The extent to which these costs apply to particular projects are typically not known until closer to project completion. Thus, the Company's projection based on a historical spending percentage represents a reasonable method for projecting these ROW costs.

ROW spending is increasing due to increases in the overall LVD Lines Reliability sub-program. Since Staff is largely supporting the Company's test year projections for the sub-program, the associated ROW costs should also be approved.

II. REBUTTAL OF STAFF WITNESS SCHILLER

Q. What is Ms. Schiller's recommendation regarding the LVD Lines Demand Failures sub-program?

A. Based on several responses to discovery, included in Exhibit S-19.0, Ms. Schiller states concern that the Company is not appropriately categorizing the costs associated with inspections in the LVD Lines Demand Failures sub-program, particularly as it relates to Security Assessments. On page 6 of her direct testimony, she suggests that these inspection costs, currently capitalized, should more properly be treated as operating expenses. In the next rate case, she recommends that the Company (1) provide a breakdown of inspection costs across the capital programs/subprograms; (2) support the classification of costs that are capitalized instead of expenses with reference to accounting guidance; and (3) amend the classifications, as necessary.

Q. Do you agree with this recommendation?

A. While the Company does not believe its current categorization policies are improper, the Company will not contest this recommendation. In its next rate case, the Company will

review its capitalization policies around line inspections and security assessment work on the distribution system in line with Ms. Schiller's proposal, and propose any necessary changes.

III. REBUTTAL OF STAFF WITNESS EVANS

Q. What is Mr. Evans' recommendation regarding the Company's proposed tariff changes for new service connection fees?

A. On pages 15 and 16 of his direct testimony, Mr. Evans reviews the Company's proposed tariff changes related to new service connection fees and indicates that Staff agrees with the Company's overall plan to update fees, and to begin charging a fee for new overhead service connections. However, Staff does not agree with the Company's proposal to use flat fees of $1,300 for all new residential services and $2,200 for all new general services. Mr. Evans recommends that the Company continue to use a fee structure with a per-foot component, particularly so that customers with shorter-than-average new services are not subsidizing customers with longer-than-average new services.

Q. Do you agree with this recommendation?

A. No, for several reasons. First, a significant portion of installing a new service involves fixed costs associated with the crew being onsite to do the work, and those fixed costs are included in the Company's proposed fee structure.

Second, the Company already charges a flat fee of $350.00 for new residential underground services up to 150 feet, as stated in section C6.2B(3) of the Company's tariff.

Third, flat fees create billing efficiencies that benefit both the customer and the Company. With a flat fee, the customer can pay earlier in the process and be done after that payment, rather than needing to wait for a full design to be developed. It also prevents

the need for any rebilling if the actual footage differs from what is originally quoted. Overall, the customer experience is improved with a flat fee.

Finally, it is worth noting that the Company's tariff proposal in the instant case provides for a flat fee in most cases. However, the flat fee is predicated on the customer accepting the Company's proposed route, which will generally be the shortest reasonable route, and the most cost-effective one. If a customer opts for a different route, then the customer will be assessed any additional costs incurred by the Company in addition to the flat rate. This protects other customers from subsidizing routes for a given customer that are unnecessarily long or expensive.

IV. REBUTTAL OF AG WITNESS COPPOLA

Q. What is Mr. Coppola's recommendation regarding capital investment in the LVD Lines New Business sub-program?

A. On pages 16 and 17 of his direct testimony, Mr. Coppola states that the Company's forecasted number of new service connections is reasonable, but that the unit cost is high since unit costs declined from 2023 to 2024 and the Company is now using a higher unit cost for the bridge period and test year. He recommends that the decline from 2023 to 2024 ought to be sustained going forward, and proposes disallowances based on holding unit costs at 2024 levels, plus inflation.

Q. Do you agree with this recommendation?

A. No. Mr. Coppola's use of one year of historical data to calculate unit costs is not consistent with his proposed methodology in much of the rest of this case. For example, Mr. Coppola proposes to use three-year historic average unit costs for the vintage underground cable rejuvenation investment category and the Repetitive Outages sub-program. The three-year historical average unit cost in the LVD Lines New Business sub-program is $13,319.

Applying Mr. Coppola's 2.9% inflation rate for the bridge period would yield a unit cost of $13,705, and applying his 2.4% inflation rate for the test year would yield a unit cost of $14,033. These bridge period and test year unit costs based on a three-year average are higher than the unit costs Mr. Coppola applied based only on 2024 actual.

Regarding Mr. Coppola's assertion that the decline in costs from 2023 to 2024 should be sustained, that is not necessarily true. As described on page 12, line 19, through page 13, line 2, of my direct testimony, the Company is proposing a tariff change that will lead to an increase in the number of customers opting for underground services, which will have the impact of increasing unit costs.

Q. Does Mr. Coppola make any other recommendations regarding the LVD Lines New Business sub-program?

A. On pages 18 and 19 of his direct testimony, Mr. Coppola expresses concern that the Company's contractor costs for this sub-program are significantly higher than in-house costs. He recommends that, in the Company's next rate case, the Company should outline how this gap to contractor costs can be reduced, or else the Company should bring more work in-house.

Q. How do you respond to this?

A. The Company is not opposed to further study of this issue. It should be noted that the Company's in-house workforce is only so large, and in some cases, as with unplanned customer-driven work, the Company must rely on contractors to get new customers connected in a timely manner if Company employees are engaged in other critical projects, such as reliability work.

Q. What is Mr. Coppola's recommendation regarding the LVD Asset Relocations sub-program?

A. On page 20 of his direct testimony, Mr. Coppola takes issue with the Company's projection for the Customer-Requested and Other Internal Relocations investment category. He claims that the Company has not provided justification for increased investment above the recent historical levels of work in this category. He notes that Exhibit A-166 (JMP-1), page 1, and Exhibit A-167 (JMP-2), page 1, only show a fraction of the number of projects that the Company is projecting. He recommends a disallowance that keeps the number of projects in this investment category at the three-year average.

Q. Do you agree with this recommendation?

A. No. Mr. Coppola is incorrect to compare projected units in Customer-Requested and Other Internal Relocations to the project lists in Exhibit A-166 (JMP-1), page 1, and Exhibit A-167 (JMP-2), page 1. These exhibits are only related to the LVD Underbuild investment category, so there should be no expectation that they tie to the numbers of a different investment category.

The Company's rationale for its projected growth in this investment category is discussed on page 34 of my direct testimony. In particular, the growth rate was derived based on the actual 3.2% growth rate from 2020 through 2023.

Q. Does Mr. Coppola address any other parts of the LVD Asset Relocations sub-program?

A. On pages 21 and 22 of his direct testimony, Mr. Coppola expresses concern over the Company's projected growth of the Make-Ready investment category. He proposes bridge

period and test year disallowances based on a 37% growth rate from recent actuals, arguing that this is the only growth rate supported by data provided by the Company.

Q. Do you agree with this recommendation?

A. No. The Company provided additional support for its projections in a discovery response to Staff (discovery response 21870-ST-CE-0078), which I am providing as Exhibit A-225 (JMP-5). The first thing to note in this response is that the Company corrected its projected bridge period and test year units in the discovery response; on page 21, lines 4 through 7, of his direct testimony, Mr. Coppola is still using the original uncorrected numbers.

The table on the second page of this discovery response shows the Company's calculations for projected growth in Make-Ready work. The projected growth in federal broadband funding is based on information published by the federal government, and the Company has calculated the annual growth rates of this work. In order to provide additional assurance that these numbers are not over-projected for 2025 or 2026, particularly issues that can be created by timing issues with federal funding, the Company applied a 20% discount to the 2025 and 2026 growth rates, making the Company's numbers more conservative. Mr. Coppola is incorrect to assert that this response does not show the Company's calculations and he is incorrect to assert that the Company has not supported its projections.

Beyond the question of unit growth, Mr. Coppola's calculations on page 22 of his direct testimony are incorrect because he did not use the Company's updated Figure 16 as provided in Exhibit A-225 (JMP-5), and thus did not use the correct unit cost for his calculations. The Company's projected unit cost is not $5,955, but rather is approximately

$12,300. This is discussed in my rebuttal to Mr. Boutet. Mr. Coppola's proposed disallowances should not be adopted.

Q. What is Mr. Coppola's recommendation regarding the Zonal Health Improvements investments in the LVD Lines Reliability sub-program?

A. On pages 24 and 25 of his direct testimony, Mr. Coppola notes that unit costs may have been skewed in 2022 and 2023 by high amounts of fusing work, which was much reduced in 2024. Therefore, he argues that 2024 unit costs are a reasonable baseline to use, and he notes that apparent bridge period unit costs are approximately double and test year unit costs are nearly triple. He argues that this increase is not supported, and recommends disallowances based on remaining at 2024 unit costs plus inflation, amounting to reductions of $27.3 million in the bridge period and $22.6 million in the test year.

Q. Do you agree with this recommendation?

A. No. Zonal Health Improvements encompass a very diverse portfolio of projects, and indeed defining a number of units for the entire portfolio of Zonal Health Improvement projects is difficult to do. See the footnote to Figure 35, page 69, in my direct testimony, which notes that the 497 bridge period units and the 175 test year units just reflect the number of line items in Exhibit A-166 (JMP-1) and Exhibit A-167 (JMP-2).

A review of these two exhibits will show the diversity not only of projects, but of the types of actual underlying units as well. Exhibit A-167 (JMP-2), pages 3 through 5, shows that some line items simply indicate "1 project," while others are based on addressing a certain amount of line miles, and some are defined by addressing a certain number of poles, and still others continue to involve a certain number of fuses. It is not reasonable to try to reduce this to a single unit cost by dividing the total investment level

for Zonal Health Improvements by the number of line items in an Excel file. A similar issue is shown on Exhibit A-166 (JMP-1), pages 3 through 11.

Unit cost analyses can only possibly be valuable if the dividends and divisors are correctly set. Disregarding the actual units provided in Exhibits A-166 (JMP-1) and A-167 (JMP-2), and simply dividing by the number of Excel rows, does not provide a useful unit cost analysis, and the Commission should not adopt such an analysis as a basis for cost disallowances for these projects.

Q. What is Mr. Coppola's recommendation regarding voltage conversions?

A. On pages 25 through 27 of his direct testimony, Mr. Coppola states that the Company's response to discovery request 21870-AG-CE-0346 indicates that the Company's test year units are actually only 165, instead of the 283 that are shown in Figure 35 of my direct testimony. He then takes issue with the Company's unit costs compared to 2024 actuals, and recommends bridge period and test year disallowances based on this (and using 165 units as the multiplying factor for this test year calculation), amounting to reductions of $2.267 million in the bridge period and $9.462 million in the test year.

Q. Do you agree with this recommendation?

A. No. Mr. Coppola is incorrect to use 165 as the number of units for the test year. In discovery request 21870-AG-CE-0346, the Attorney General asked the Company to provide calendar year spending projections for voltage conversions even though the instant case is not based on a bridge period or test year that align with a calendar year. Providing calendar year projections can create misalignments with what is actually included in the test year, since work does not necessarily take place on a uniform basis month-to-month. Exhibit A-167 (JMP-2), page 2, provides the Company's actual workplan for the test year,

and it shows 283 miles of work, which is the correct unit to use for the test year. When 283 is used as the divisor, the Company's test year unit cost is $117,014 per mile, which is in fact lower than the actual unit cost for 2024. Therefore, Mr. Coppola's recommended test year disallowance is without merit.

Q. What is Mr. Coppola's recommendation regarding underground cable rejuvenation?

A. On pages 27 and 28 of his direct testimony, Mr. Coppola argues that the Company's unit costs for this work are excessive, and calculates a projected bridge period and test year spending level based on a three-year average of actual unit costs, recommending a disallowance of $16.616 million in the bridge period and $39.120 million in the test year.

Q. Do you agree with this recommendation?

A. No. Mr. Coppola appears to have obtained the Company's 2021 through 2024 unit costs from discovery response 21870-AG-CE-0346, Attachment 1, which included the following data.

TABLE 2

	2021		2022		2023		2024	
	Cost	**Units**	**Cost**	**Units**	**Cost**	**Units**	**Cost**	**Units**
Underground Cable Rejuvenation	$1,672,800	10	$1,123,300	5	$997,300	11	$3,545,900	21

Mr. Coppola's proposed disallowances rely on a comparison of this data to the data provided in Figure 35 in my direct testimony. However, this is not an apples-to-apples comparison. The data shown in Table 2 above is using projects as a unit, whereas Figure 35 in my direct testimony is using miles. Using miles for 2021 through 2024, the data would have shown as follows.

TABLE 3

	2021		2022		2023		2024	
	Cost	Miles	Cost	Miles	Cost	Miles	Cost	Miles
Underground Cable Rejuvenation	$1,672,800	2.67	$1,123,300	3.14	$997,300	2.01	$3,545,900	3.53

Using these numbers, the Company's four-year average unit cost has been $646,720, meaning the Company is actually proposing to do work in the bridge period and test year at a lower unit cost than recent actuals. Given the ramp-up in work (for which Mr. Coppola indicates support), the Company expects to realize some efficiencies.

Q. What is Mr. Coppola's recommendation regarding ROW costs for LVD?

A. On page 29 of his direct testimony, Mr. Coppola claims that the Company has not supported its increased ROW projection for the test year and recommends that it be set instead at 2024 levels, which he notes was the highest level of the past four years. This results in a test year reduction of $11.465 million.

Q. Do you agree with this recommendation?

A. No. The Commission should reject Mr. Coppola's recommendation for the same reasons given in my response to Mr. Boutet above.

Q. What is Mr. Coppola's recommendation regarding the Resiliency sub-program?

A. On pages 30 through 37 of his direct testimony, Mr. Coppola reviews the Company's proposed investment in overhead to underground conversions ("OHUG") and in the ELGE-MIEJ Undergrounding Secondary and Services work. Company witness Kelly is providing the rebuttal to Mr. Coppola for most of this, but I will address some of Mr. Coppola's assertions about OHUG selection criteria.

Q. What position does Mr. Coppola take regarding OHUG selection criteria?

A. On pages 31 and 32 of his direct testimony, Mr. Coppola notes that the Company changed its selection criteria between its proposal in Case No. U-21585 and its proposal in the instant case. Because of this, he claims that the Company "is still struggling to find an effective approach that adequately justifies undertaking the overhead to underground conversions."

Q. How do you respond to this?

A. I do not agree. By saying that the Company "is still struggling," Mr. Coppola is incorrectly implying that the Company is making dramatic changes as though this will result in the Company stumbling upon an effective solution. At no point has the Company been "struggling" in this area. The initial pilot proposed and approved in Case No. U-21389 had certain selection criteria for projects, which also informed the Company's proposal in Case No. U-21585 to continue undergrounding work through 2025 and into 2026. The Commission did not approve that request in Case No. U-21585 in order to allow the pilot to be completed so that lessons could be learned and applied. In the instant case, the Company has made modest revisions to its selection criteria precisely to account for those lessons learned. The changes are modest. For example, the Company increased the upper limit on an eligible zone from 100 to 200 customers because of concerns expressed in the pilot that too many customers would be excluded. The Company adjusted its criterion regarding tree cover to specifically focus on zones with recent tree- or weather-caused outages, in order to zero in on zones that are currently dealing with these issues that justify OHUG work.

Q. What is Mr. Coppola's recommendation regarding the LVD Lines Capacity sub-program?

A. On pages 37 through 39 of his direct testimony, Mr. Coppola analyzes this sub-program primarily through the lens of discovery response 21870-AG-CE-0357, which he has included in Exhibit AG-7. In that discovery request, the Attorney General asked if the Company's LVD Lines Capacity investments were exclusively directed at circuits with over 140% overload. In his direct testimony, Mr. Coppola seems to reason that circuits with over 140% overload are the only ones that should be addressed, and that any overload lower than that level is "less risky" and that apparently all investments directed at such overloads are unnecessary and can be deferred. Mr. Coppola recommends removing capital expenditures for projects with overload of less than 140%, resulting in removal of $5.375 million in the bridge period and $40.911 million in the test year.

Q. Do you agree with this recommendation?

A. No. As noted in my response to Mr. Boutet, the Company is not opposing Staff's proposed adjustment to the test year, but Mr. Coppola's disallowance goes far beyond that proposed by Staff. As Mr. Boutet noted in his direct testimony, the Company's bridge period investments are aligned with what the Commission approved in Case No. U-21585, and it would be unreasonable to impose a disallowance on that already-approved amount when much of the period in question has already taken place with spending that the Commission already found reasonable and prudent.

Mr. Coppola states that assets overloaded to 100% through 139% are "less risky," but his analysis seems premised upon them being "low risk." While the former is a relative term, the latter is a more absolute one. An asset loaded to 135% of the manufacturer's

rating may be in a less risky position than one loaded to 145%, but that does not mean it is low risk and can be safely ignored. Manufacturer ratings are established to ensure safe and reliable operation of assets. Prolonged operation beyond these ratings, even by a small margin, accelerates deterioration and significantly increases the risk of failure. Mr. Coppola's recommendation reflects an unacceptable tolerance for allowing assets to operate well beyond manufacturer specifications for extended durations.

Furthermore, Mr. Coppola's analysis treats all assets as though they have equal risk levels at a given overload percentage. The Company agrees that the general categories provided in Figure 52 in my direct testimony did not capture the nuance related to differing risk levels associated with different types of equipment at a given overload percentage, I explained this in discovery response 21870-AG-CE-0357 and provided examples. For example, the response stated that isolators and conductors loaded anywhere above 100% face acute risk of failure. The response shows that a considerable amount of the planned investment in the test year in the "119% or less" category is for conductor and isolators, and isolators also make up a component of the "between 120%-139%" category. Mr. Coppola's proposal that the Company should not address these overloaded assets would result in the Company being particularly irresponsible to reliability and public safety.

Mr. Coppola's proposed disallowances should not be accepted by the Commission, which should instead accept the proposal of Mr. Boutet.

Q. What is Mr. Coppola's recommendation regarding LVD Transformers?

A. On page 40 of his direct testimony, Mr. Coppola argues that the Company has not supported its projected need for more 1-phase and 3-phase padmount transformers. In

particular, he notes that the primary driver of increasing need for these transformers is the Company's OHUG work, which he asks the Commission to disallow in full, which would obviate the need for as many of the transformers. He recommends that the Company's increased purchases of padmount transformers be held to their respective growth rates between 2023 and 2024, and proposes reductions in capital expenditures of $9.791 million in the bridge period and $11.777 million in the test year.

Q. Do you agree with this recommendation?

A. No. Most importantly, the Company does not agree with Mr. Coppola's recommendation to completely eliminate the Company's OHUG work, as described above and in Company witness Kelly's testimony. If the Company's OHUG plan is approved, then the transformers will be needed.

As Mr. Coppola's own calculations show, padmount transformer purchases were already increasing from 2023 to 2024, predating the initiation of substantial OHUG work, and indicating that other factors like new business work are in fact driving growth in transformer needs. Expansion of OHUG work will drive further growth, and the Company's projection should be approved.

Q. What is Mr. Coppola's recommendation regarding the Repetitive Outages sub-program?

A. On page 45 of his direct testimony, Mr. Coppola indicates support for the Company's projected volume of work in the Repetitive Outages sub-program, but takes issue with the bridge period and test year unit costs, stating that the Company has not supported the increase. He calculates a much lower unit cost based on a three-year historical average,

and proposes capital expenditure reductions of $14.246 million in the bridge period and $20.745 million in the test year.

Q. Do you agree with this recommendation?

A. No. Unit costs from 2023 and 2024 should not be assumed to represent expected costs going forward, since those two years included reduced work volumes and therefore would not necessarily have included the full range of work types that the sub-program will include when scaled up. Furthermore, I addressed the issue of increasing unit costs on page 79, line 11, through page 80, line 2, of my direct testimony. As discussed there, the Company is shifting investment to more robust, and more costly, hardening projects such as line relocation, undergrounding, and replacing bare wire with tree resistant wire. Accordingly, projecting costs based on historical averages will not accurately reflect expected future costs,

The Repetitive Outages sub-program is critical for achieving the Commission's CEMI-4 targets, and the Commission should approve the Company projection. If it does not, it should at least adopt Mr. Boutet's position, which is significantly more reasonable.

Q. Does Mr. Coppola have any other comments about Repetitive Outages?

A. On page 46 of his direct testimony, Mr. Coppola suggests there are insufficiencies with the information provided in my direct testimony and in Exhibit A-169 (JMP-4). He recommends that the Company, in its next rate case, provide "more pertinent information" about completed Repetitive Outage projects.

Q. How do you respond?

A. The Company believes that it provided information in Exhibit A-169 (JMP-4) that was in line with the Commission's guidance in its Order in Case No. U-21585. If the Commission

provides updated guidance in the instant case, the Company will be happy to comply with that guidance to the extent that the requested information is available.

Part of Mr. Coppola's concern is with the fact that some identified historical projects took place on circuits that had no outages in 2023 or 2024. It should be noted that Exhibit A-169 (JMP-4) lists projects that were completed in those two years, and that many of those projects would have been identified based on outages from 2021 or 2022.

V. REBUTTAL OF ABATE WITNESS YORK

Q. What is Ms. York's recommendation regarding the LVD Lines Rehabilitation sub-program?

A. On page 26 of her direct testimony, Ms. York notes that two investment categories with LVD Lines Rehabilitation, namely modem replacements and meter voltage anomalies, do not have specific identified projects. Ms. York argues that, because of this, the entire LVD Lines Rehabilitation sub-program should be held at the five-year average level. This results in capital expenditure reductions of $2.975 million in the bridge period and $5.078 million in the test year.

Q. Do you agree with this recommendation?

A. No. The Company has not historically provided a list of all modem replacement projects, since they are individually small and since there are 800 of them each year. In Case No. U-21585, for example, Exhibit A-128 (DAL-2), page 38, line 25, also simply indicated that 800 modems would be replaced for $2,998,000. In Case No. U-21585, this proposed spending was approved with no objection from any party. Meter voltage anomalies, while a new investment category in the instant case, are similar. As shown in Figure 45 in Exhibit A-129 (MPK-19), the meter voltage anomalies investment category involves several hundred individual small work locations each year, and the Company has treated this

similarly to modem replacements by not endeavoring to list out each individual location. In addition, I supported the need for the modem replacement and meter voltage anomaly projects at pages 84-85 of my direct testimony, and the basis for the projections on page 87 of my direct testimony.

Aside from that, it would also not be reasonable to broadly disallow the entire LVD Lines Rehabilitation sub-program expenditures, which contains other investment categories not discussed in Ms. York's testimony. The Commission should not remove all funding for these important projects.

Q. What is Ms. York's recommendation regarding the LVD New Business Capacity sub-program?

A. On page 27 of her direct testimony, Ms. York states that projected spending in LVD New Business Capacity sub-program is largely uncertain since it is customer-driven, and she notes that the Company has only identified bridge year projects to cover a part of the projected spending, and no test year projects. Because of this, she argues that spending in the sub-program should be held to the five-year historical average, which results in capital expenditure reductions of $11.958 million in the bridge period and $3.908 million in the test year.

Q. Do you agree with this recommendation?

A. No, for several reasons. First, in Case No. U-21585, the Company provided a similar level of detail in its project lists. In that case, Exhibit A-127 (DAL-1), page 49, line 50, indicated that the Company had identified bridge year projects in the amount of $8,727,000, out of a total bridge year projection for the sub-program of $23,903,000. The Company also identified no specific test year projects for LVD New Business Capacity in Case No.

U-21585. However, the Commission approved full recovery of the Company's projected spending, following no objection from any parties.

Second, the Company's recent actual spending in LVD New Business Capacity shows that using a five-year historical average would set the approved spending levels far too low. As shown in Exhibit A-95 (MPK-3), line 25, spending in LVD New Business Capacity has been steadily increasing every year and exceeded the five-year average in 2022, 2023, and 2024. Setting spending at the five-year average would return the Company to roughly 2021 levels when the sub-program has been demonstrably growing. Furthermore, while the Company had only identified bridge period projects of about one-third of the total bridge period projection in Case No. U-21585, the Company actually ended up spending even more than the total projected amount, as summarized in Table 4 below.

TABLE 4
LVD NEW BUSINESS CAPACITY SPENDING

	1/1/24-12/31/24
U-21585 Projection[1]	$20,511,000
Actual[2]	$33,430,000

As this table shows, the Company has had to respond to customer demand and invest in excess of its recent projections, indicating that anticipated growth is not uncertain or speculative.

Finally, the Company's year-to-date spending through September has been $18,881,217, as shown in Exhibit A-219 (MPK-29), line 8. Even a simple continuation of

[1] Refer to Case No. U-21585, Exhibit A-98 (MPK-6), line 4, column c. In Case No. U-21585, the bridge period covered 1/1/24-2/28/25, but the Company included a projection for the 2024 calendar year.
[2] Refer to the instant case, Exhibit A-113 (MPK-3), line 25, column g.

the current spending rate through the remainder of the bridge period would result in spending in excess of Ms. York's proposal, which highlights the unreasonableness of her recommendation that is based on uncertainty of spending (Exhibit A-219 (MPK-29) shows that the Company is on track to spend over $26 million just in the 2025 calendar year).

Q. What is Ms. York's recommendation regarding the LVD Transformers sub-program?

A. On page 28 of her direct testimony, Ms. York argues that the Company's projected growth in transformer demand, especially tied to new business and electric vehicle adoption, faces significant uncertainty. Because of this, she argues that it would be more prudent to simply hold spending at 2024 actual levels, which she believes would capture some of the recent growth in demand while recognizing the uncertainty. This results in capital reductions of $105.077 million in the bridge period and $84.896 million in the test year.

Q. Do you agree with this recommendation?

A. No. First, as discussed on page 137 of my direct testimony, the growth in overall LVD Transformers spending is driven primarily by growth in purchases of 1-phase and 3-phase padmount transformers, driven in turn by undergrounding work, by general new business activity, and by projected electric vehicle ("EV") adoption. Undergrounding work is not uncertain; the Company has a clear plan for undergrounding backed by many specific projects. While ABATE witness Fitzhenry argues that the Company should not engage in undergrounding, the rebuttal testimony of Company witness Kelly explains why his analysis is incorrect. And as discussed above in response to Mr. Coppola, factors like new business work are in fact driving growth in transformer needs. The Company's basis for growth in LVD Transformers is well-substantiated.

Additionally, the Company is not purchasing transformers simply to build up its inventory. As alluded to on page 83 of Exhibit A-129 (MPK-19) and on pages 137 and 138 of my direct testimony, due to acute supply chain disruptions in the transformer industry during the early 2020s, utilities experienced significant backlogs in procuring essential equipment. In response, the Company has had to fundamentally alter its procurement strategy. Whereas the Company previously ordered materials incrementally — typically covering only a few months of anticipated demand — it is now compelled to place full-year orders upfront. This shift is driven by both historical procurement challenges and the increased variability in future forecasts, making it prudent to secure appropriate quantities as a hedge against ongoing supply risks and support the Company's Reliability Roadmap.

Finally, the Company's year-to-date spending of $134,287,313 in the LVD Transformers sub-program, as given in Exhibit A-219 (MPK-29), line 3, shows the Company is on pace to exceed the 2025 bridge period projection.

Q. What is Ms. York's recommendation regarding the LVD Asset Relocations sub-program?

A. On page 29 of her direct testimony, Ms. York states that the Company has only identified projects in the bridge period and test year that represent a small amount of total projected spending for the sub-program. She asserts that the remainder of the spending is highly uncertain, since it is driven by external parties, and she particularly notes that customer requests are sometimes tied to home remodeling work, which have slowed due to interest rates since 2023. Because of this, she recommends that LVD Asset Relocations spending

be held at 2024 actual levels. This reduces capital expenditures by $46.409 million in the bridge period and $27.587 million in the test year.

Q. Do you agree with this recommendation?

A. No. Please see my discussion of similar issues above in my response to Mr. Coppola. The Company has, for a number of years, provided project lists only for LVD Asset Relocation projects tied to the Company's own High Voltage Distribution ("HVD") projects, since these are known to the Company in advance. While home remodeling projects can impact requested relocations as noted on page 37 of my direct testimony, page 29, line 20, through page 30, line 13, of my direct testimony lists a large number of activities that can drive external requests.

Customer-requested work is only one part of the LVD Asset Relocations sub-program, and growth in customer-requested work only makes up a small part of projected growth in LVD Asset Relocations. See Exhibit A-130 (MPK-20), line 38, for recent history of customer-requested work specifically. The Company projected growth for customer-requested work using the methodology explained on page 34 of my direct testimony. However, much more of the projected growth in LVD Asset Relocations is tied to growth in make-ready work[3], which is explained on page 33, line 10, through page 34, line 5, of my direct testimony. Additional details on make-ready work growth were provided in discovery response 21870-ST-CE-0078, which is provided as Exhibit A-225 (JMP-5), and were described above in my response to Mr. Coppola.

[3] Refer to Exhibit A-130 (MPK-20), line 40, for recent history of make-ready work specifically, and compare to projected amounts in Figure 16 of my direct testimony.

VI. REBUTTAL OF ABATE WITNESS FITZHENRY

Q. What is Mr. Fitzhenry's recommendation regarding pole replacements in the LVD Lines Reliability sub-program?

A. Beginning on page 12 of his direct testimony, Mr. Fitzhenry discusses the Company's pole replacement plan. He says that, while the Company agreed with the Liberty's recommendation to place less emphasis on asset age when deciding to replace assets, it appears to him that the Company is relying solely on age when determining how many poles will be rejected and slated for replacement during inspections. He cites the Company's Reliability Roadmap, which shows a breakdown of LVD by poles with assumed rejection rates. He recommends that a 5% rejection rate be used instead of the Company's rejection rate assumptions, which would reduce the Company's investment in pole replacements by 50%, and cites the example of Midwest Energy, which saw such a rejection rate on its system. This results in capital reductions of $63.750 million in the test year.

Q. Do you agree with this recommendation?

A. No. First, the Company is not proposing to use age as the deciding factor in replacing LVD poles. Poles will only be replaced if they are rejected according to NESC criteria following inspection. But it is not the Company's understanding that Liberty advocated ignoring age in developing strategies or assumptions about the likely state of the system, with those assumptions to be validated by inspection. In developing a pole replacement plan, the Company needed to create a reasonable estimate of how many rejected poles were likely on the system. Age is a reasonable proxy in developing this kind of analysis, since age is correlated with deterioration of the wood.

The Company did not arrive at 10% arbitrarily. The Company's assessment of the likely average condition of poles of given vintages was based on research conducted by the Electric Power Research Institute ("EPRI"). The results of this research were provided to ABATE as discovery response 21870-AB-CE-0712, and I am sponsoring this as Exhibit A-227 (JMP-7). EPRI's research considered data from multiple utilities. It shows that the rejection rate of poles steadily increases with age. This informed the Company's assumptions about the likely rejection rates of different pole vintages on its own system.

EPRI's research is more robust than looking at a single utility in Kansas that has a much smaller system than that of the Company. Indeed, it is not clear why Mr. Fitzhenry chose Midwest Energy as his only point of comparison. However, he presents no other information about Midwest Energy that would allow us to determine if they are a reasonable proxy of the Company's system, and it would be imprudent to rely on a single data point in this analysis when more comprehensive resources are available.

Q. What is Mr. Fitzhenry's recommendation regarding underground cable rejuvenation?

A. Mr. Fitzhenry, on pages 15 and 16 of his direct testimony, recommends that the Commission disallow test year investments in underground cable rejuvenation above what is in the bridge period, and that the Commission should specifically strike it from the Investment Recovery Mechanism ("IRM"). Mr. Fitzhenry contends that underground cable rejuvenation does not provide immediate safety or reliability benefits, because the line is already underground. He argues that rejuvenation can "only provide future benefits in the event that an existing underground cable fails."

Q. Do you agree with this recommendation.

A. No. Mr. Fitzhenry's logic is not sound. Investments in the Demand Failures program address situations where an asset has already failed. Any investment in the Reliability program is, to some extent or another, proactive; the Company is making an investment today in order to prevent an outage in the future. Consider the aforementioned pole replacement plan: a rejected pole is still standing and supporting the conductor, and may continue to do so for some period of time. But the Company replaces it rather than waiting for it to completely fail. We would not say that the pole replacement provided no benefit, because a likely future outage is prevented. Similarly, underground cable rejuvenation targets cable that is starting to deteriorate even if it has not failed yet. The Company does not believe that assets should be run to failure, and does not believe that benefits only accrue to customers if the utility restores them from an active outage, when the work would be more expensive and when customers would have to deal with an interruption to service.

Additionally, as noted on page 60 of my direct testimony, Liberty concluded that underground cable rejuvenation is a sound means of addressing reliability issues, and that the Company has had success with it to date.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

JENNIFER M. PARTLAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Question:

5. Referring to Figure 15 of Company witness Partlan's testimony, please provide all calculations and data used to support the anticipated nearly 400% increase in Make-ready field work orders between 2024 and 2026.

Response:

The projected make-ready field work orders in Figures 15 and 16 of my direct testimony included an Excel formula error which inflated the work order numbers. This error did not affect the dollar amounts associated with make-ready work in the bridge period or test year. Corrected Figures 15 and 16 are as follows:

FIGURE 15
MAKE-READY FIELD COMPLETE WORK ORDERS BY YEAR

Year	Make-Ready Field Complete Orders
2019 actual	1,007
2020 actual	752
2021 actual	829
2022 actual	1,236
2023 actual	1,655
2024 actual	1,640
2025 Projected	2,689
2026 Projected	3,119
2027 Projected	3,307

FIGURE 16
LVD ASSET RELOCATIONS INVESTMENT CATEGORY EXPENDITURES

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units
Customer requested and other internal relocations	$45,018,000	4,163	$32,341,000	3,379
LVD underbuild relocations	$7,056,000	N/A	$7,484,000	N/A
Make-ready work	$45,837,000	3,728	$39,265,000	3,181
Total	**$97,911,000**		**$79,090,000**	

This still reflects an increase in make-ready work orders, albeit not an increase of 400%. As stated on page 33, line 9, through page 34, line 4, of my direct testimony, this increase is driven by an increase in broadband infrastructure work tied to certain federal programs, particularly the Broadband Equity Access

and Deployment ("BEAD") program. The BEAD program has earmarked approximately $1.6 billion in broadband funding for Michigan, and the Company expects that slightly more than 50% of this will be directed to the Company's service territory, leading to increased make-ready work.

The Company is projecting that federal broadband funding from all sources will impact its service territory as shown in column (a) below, with the associated annual percentage increase shown in column (b). Due to known timing modifications with the program, the Company adjusted 2025 and 2026 projections by 20 percentage points, as shown in columns (c) and (d). The adjusted percentage increase for each year was used to increase the number of projected work orders, as shown in column (e).

	(a) Federal broadband funding	(b) Increase in federal funding	(c) Adjustment	(d) Revised increase	(e) Work orders
2024 actual	$56M	-	-	-	1,640
2025 proj.	$103M	84%	-20%	64%	2,689
2026 proj.	$140M	36%	-20%	16%	3,119
2027 proj.	$148M	6%	-	6%	3,307

As noted above, the projected spending for make ready work, as shown in Figure 16, does not need to be revised. When accounting for the corrected number of work orders, the Company's unit cost for make-ready work in the bridge period and test year is commensurate with the actual unit costs in 2024, which are shown in Exhibit A-130 (MPK-20), page 2, line 40.

Witness: Jennifer M Partlan
Date: July 24, 2025

Consumers Energy
LVD Planning
CONCEPT APPROVAL

Notification Concept Number: 1034571392

Project Title: MARKEY/FOREST ESTATES LCP 452 **Work HQ:**

Date: 8/15/2024 **Proposed Year of System Changes:** 2026

Problem Description:

Zone analysis metrics identified this zone in the Bottom 3% with a 390 Index and Score of 17.

Additional project: A pending ATR proposal including this circuit would benefit from recommended solutions.

Alternative Solutions:

1. 1) Move 0.5 mile UG to OH and install 1 mile of HVD underbuilt to change the circuit source route.
   Estimated customer minutes saved = 174,000

   Estimated Design Hours = 590
   Estimated Loaded Cost = $227,266

2. Move 3680' 3 phase tangent from deep ROW to 1' east of Road ROW.
   Estimated customer minutes saved = 87,000

   Estimated Design Hours = 218
   Estimated Loaded Cost = $107,952

3. Reconductor 1.37 mile 3 phase tangent to Tree Wire construction
   Estimated customer minutes saved = 130,000

   Estimated Design Hours = 716
   Estimated Loaded Cost = $358,242

Recommended Alternative:

Alternative # 1 is recommended Relocate 0.5 miles of line and re-feed the source. This route is also HVD underbuilt ensuring greater protection from trees in the future due to larger easement for tree trimming along HVD corridors. The estimated customer minutes saved for alternative 1 is greater due to expanded tree trimming footprint around the lines and rerouting the source for these customers to avoid the trees that alternative 3 would mitigate.

Conceptual Estimate:

Program	Notification #	Loaded Cost	Plan Year	Description
LVD Reliability	1034571392	$227,266	2026	Relocate HVD underbuilt
Project Total		$227,266		

Consumers Energy
LVD Planning
CONCEPT APPROVAL

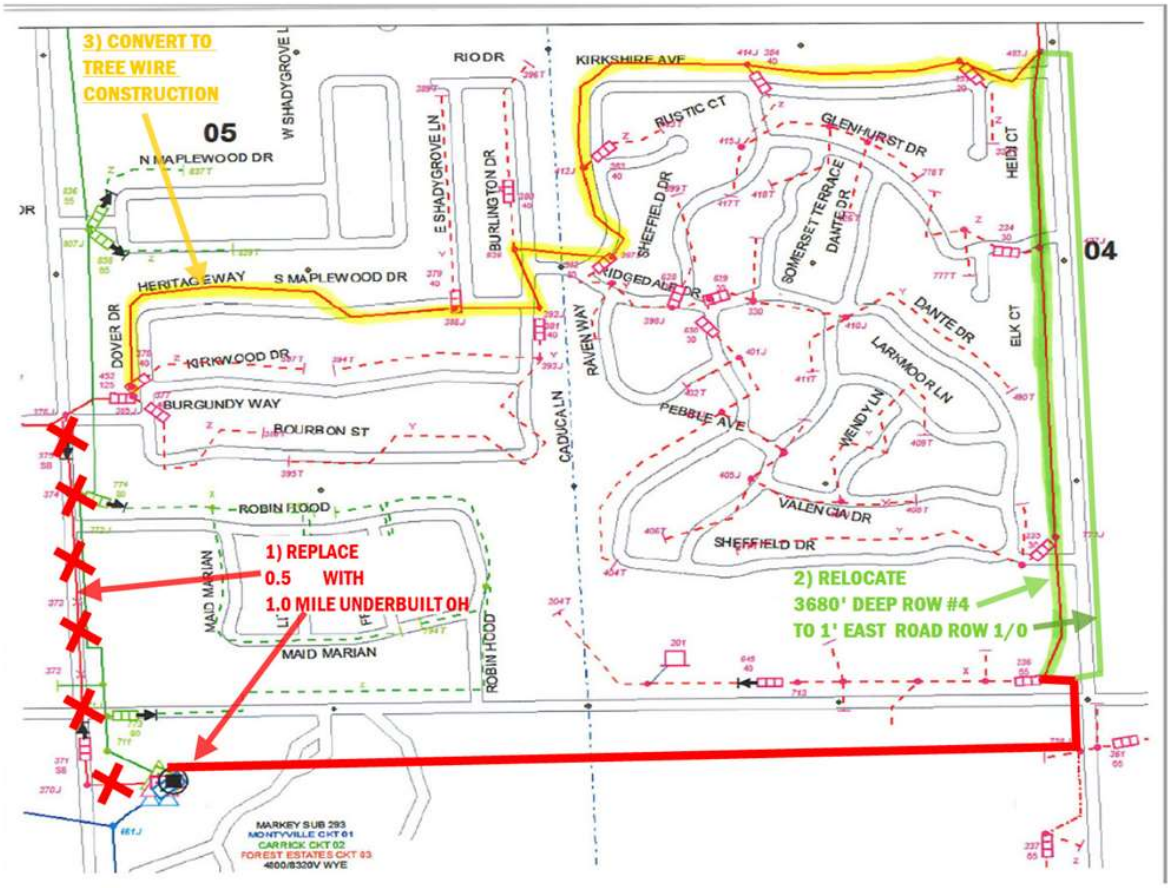
Present Need: On approval, this document authorizes the Low Voltage Distribution Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Circuit Owner: Richard Klender **System Engineer:** JLBirchmeier

Approvals:

Director, LVD Circuit Planning	Jennifer Partlan	Approved
Executive Director, Electric Planning	Gregory R. Griffin	Approved

Scope Map:



U21870-AB-CE-0712
Page **1** of **1**

Question:

Request 44:

Please refer to the Direct Testimony of Jennifer Partlan, pages 60-61, where Ms. Partlan discusses the replacement of rejected poles, and provide the following information with respect to this discussion:

a. Provide the total number of LVD poles identified as "rejected" from groundline and visual inspections in 2022, 2023, and 2024, and the number of those poles that have been replaced to date.

b. Provide the system data that supports the conclusion that approximately "10% of the poles on the LVD system will be classified as rejected." Please provide the data in its original format with all formulae and links intact.

Response:

a. The Company did not begin conducting groundline inspections until August 2025, so there were no rejected poles identified through this practice from 2022 through 2024.
b. The Company's expectation that 10% of LVD poles will be classified as rejected is based on a combination of a) the average LVD pole age on the Company's system, which is correlated with expected deterioration (refer to page 69 of Exhibit A-129 (MPK-19) for further details); and b) a 2019 Electric Power Research Institute study on wood pole asset health, the results of which are provided as Attachment 1 to this response.

Witness: Jennifer M Partlan
Date: September 22, 2025

Distribution Asset Analytics (P180.005)

Technical Presentation

Bhavin Desai
Senior Program Manager

Task Force Meeting
March, 2019

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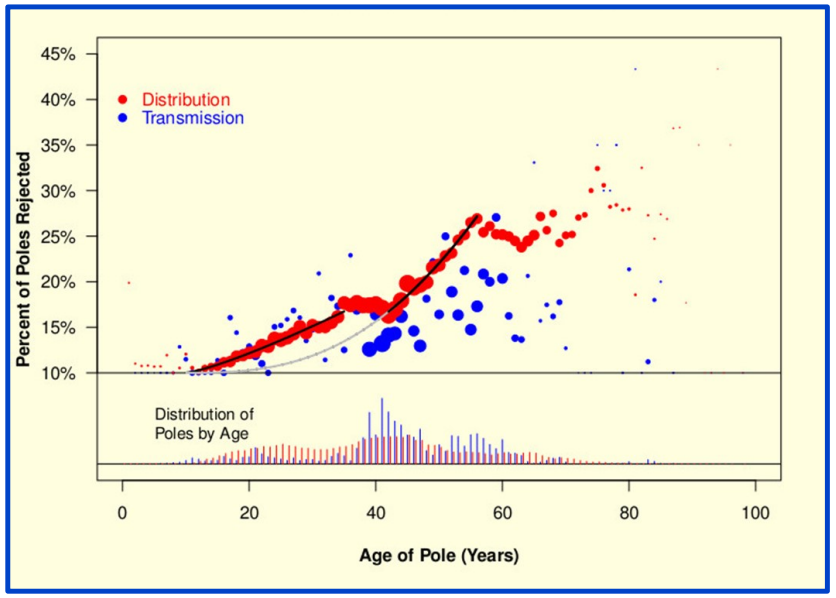
Wood Pole Inspection Data Analytics

Investigate Performance of Different Wood Species:

- Reject rate modeling as function of age at Inspection
  - Different climates/environments
  - Different treatment types
  - Impact of changes in inspection criteria –
    - Contractor to contractor variation
    - Contractor variations over time

Desired Data:

- Pole demographic data
  - E.g. age, wood species, in-service date
- Inspection results
  - E.g. date of inspection, reject status, other observations
- Replacement history
  - E.g. which, when and why



Modeling Reject Rate As Function of Wood Pole Age At Inspection

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Wood Pole Inspection Data Analytics

Data Model and Summary – approx. 3 million poles from 7 utilities

	Received During	# of poles	T/D	Species	Original Treatment Type	Original Ground Line Cir.	Effective Ground Line Cir.	Visual inspection – heart rot, shell rot	GIS	Reject Status	Status
A	November ‘16	33,382 (T) 709,833 (D)	T&D	Y	Y	Y	Y	Y	Y	Y	Analysis completed
B-1	April ‘18	111,723	D	N	N	Y	Y	N	N	Y	Analysis in-progress
B-2	October ’18	54,949	D	Y	Y	Y	Y	Y	Y	Y	Received new dataset
C	April ‘18	18,853	T	Y	Y	Y	Y	N	Y	Y	Received data – queued for further processing.
D	June ‘18	1,908,057	D	Y	Y	Y	Y	Y	Y	Y	Data curated; analysis in progress
E	May ‘18	274,368	D	Y	Y	Y	Y	N	N	Y	Data curation and analysis in progress
F	March ’18	19,986	T	Y	Y	Y	Y	N	Y	Y	Received data – queued for further processing.
G	July ‘18	36,401	T	Y	Y	Y	Y	Y	Y	Y	Initial review
H	February ‘19	52,331	T	Y	Y	Y	Y	N	Y	Y	Initial review

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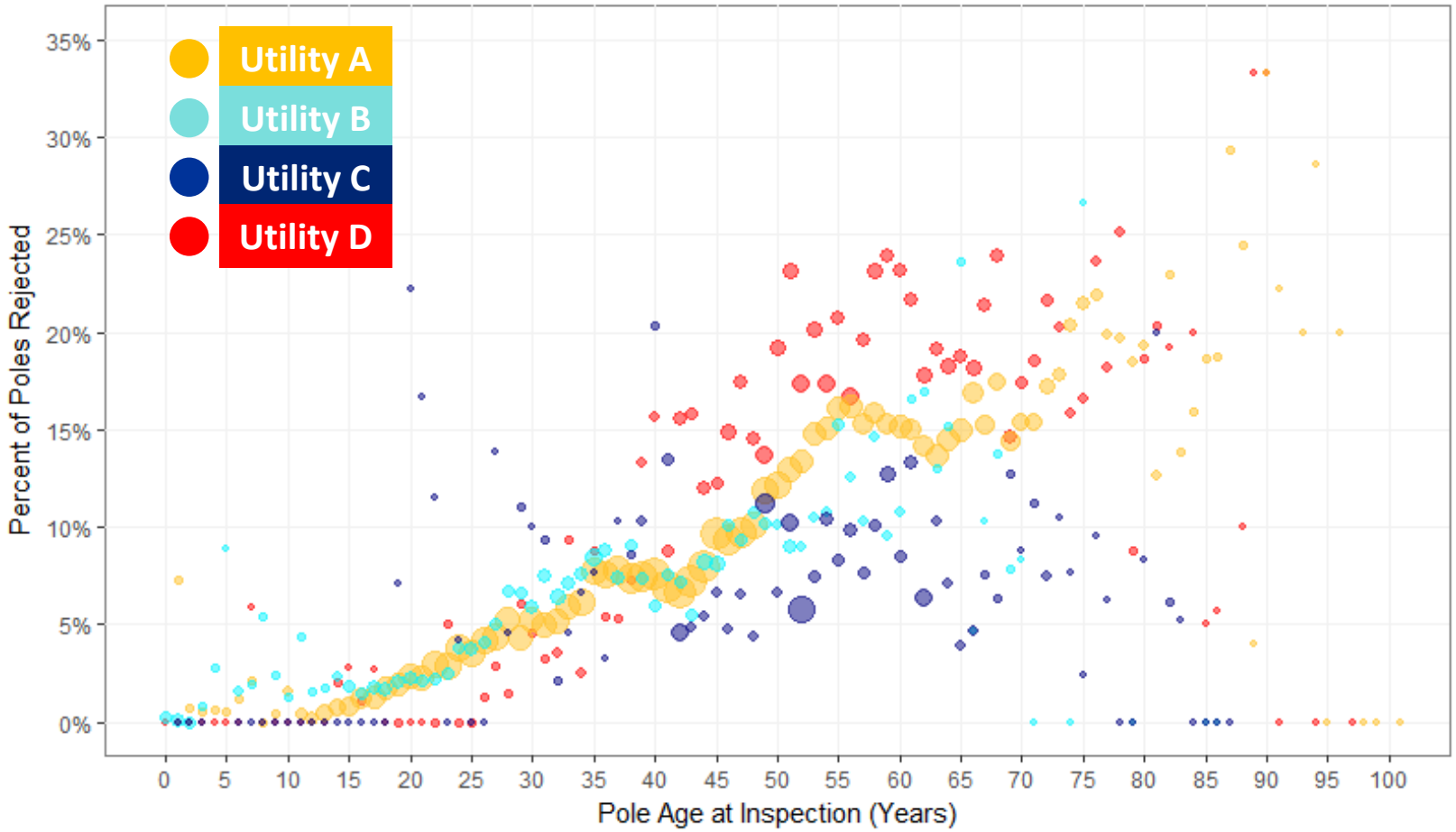
Reject Rates for Southern Pine Wood Poles Originally Treated with Creosote



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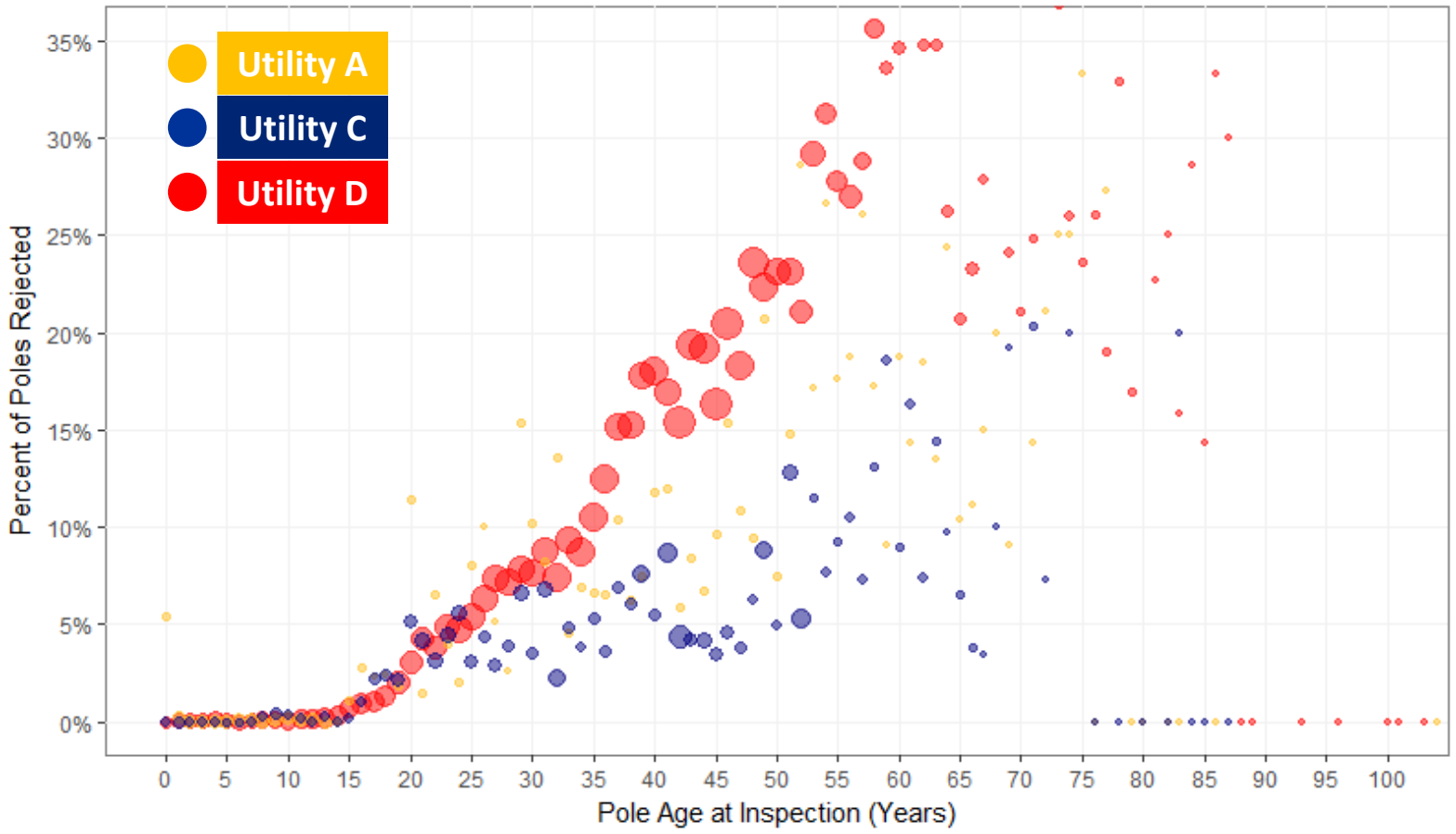
Reject Rates for Southern Pine Wood Poles Originally Treated with Penta



Note: Utility B does not have sufficient data on SPP poles and utility A has a much smaller data set on SPP than their SPC data

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Actionable Insights From Research To Date
Wood Pole Analysis

- Reject rate as function of age at time of inspection provides:
  - Projections of how many poles anticipated to be rejected in future years
  - Insights for resource planning and prioritizing inspections
  - Wood pole survivability (by wood species and original treatment type) in different regions
  - Impact of changes in inspection criteria –
    - Contractor to contractor variation
    - Contractor variations over time

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

DANIEL A. SCHMOEKEL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Daniel A. Schmoekel, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. Are you the same Daniel A. Schmoekel who previously submitted testimony in this case on behalf of Consumers Energy Company ("Consumers Energy" or the "Company")?

A. Yes. However, I have a new role. In September, I was promoted to Director of Engineering - LVD Statewide Programs. In this role I have responsibility for Streetlighting, low voltage distribution ("LVD") Resource Planning, Infrastructure Attachments, and Statewide Integration.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut a recommendation made by Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witness Jessica Duell. Specifically, I will provide rebuttal to Ms. Duell regarding her recommendation regarding the sufficiency of the Company's responses to discovery questions sent by Staff.

Q. Are you sponsoring any exhibits?

A. No.

Q. Have you reviewed the direct testimony of Ms. Duell?

A. Yes.

I. SUFFICIENCY OF THE COMPANY'S RESPONSES TO DISCOVERY QUESTIONS

Q. Beginning at page 15, line 15 of her direct testimony, Ms. Duell states "Staff recommends that the Company be more descriptive and detailed when replying to discovery questions sent by Staff." How do you respond to that recommendation?

A. I don't agree with the suggestion that Consumers Energy was insufficiently descriptive or detailed in its discovery responses to Staff, including the Company's response to discovery question U21870-ST-CE-0131 which Ms. Duell identified specifically. As stated by Ms. Duell starting on page 15, line 20, through page 16, line 3, in her direct testimony, the Company spent the remaining $1,056,000 of streetlighting budget on distribution capital investments.

Regarding Electric Distribution capital programs, the Company generally returns budgeted program funds that are unused to an Electric Distribution department level account. Funds are then reallocated to fund programs with additional capital needs in other parts of the electric distribution organization. However, specific dollars are not traced from one program to another. A reason for utilization of this method is that unused funds in one program and capital needs in other programs often occur at different times. As a result of this process, there were no more details the Company could have provided in response to Ms. Duell's question.

Q. Beginning at page 16, line 6, of her direct testimony, Ms. Duell states "In MPSC Case No. U-21585 the Commission ordered the Company to 'provide the Commission Staff with as much detail as possible regarding the application of excess funds for Streetlighting'. Unfortunately, the Company did not follow the order." Do you agree?

A. No. The Company is in compliance with the Commission's Order in Case No. U-21585. Again, specific dollars are not traced from one program to another. A reason for utilization of this method is that unused funds in one program and capital needs in other programs often occur at different times of the year.

The Company provided Staff with as much detail as possible regarding the application of excess funds for Streetlighting in all relevant discovery responses. The Company cannot provide detail that does not exist.

Q. What is your recommendation?

A. The Commission should reject Ms. Duell's claim that the Company failed to follow the Commission's Order in Case No. U-21585. That claim is untrue. Pertaining to the example referenced in Ms. Duell's testimony, discovery response U-21870-ST-CE-0131, unused funds in one program and funding of capital needs of other programs often do not occur at the same time.

As shown in Ms. Duell's direct testimony, page 15, line 20, through page 16, line 3, the Company demonstrated that unused streetlighting funds were allocated to distribution capital spending. There are no further details to share.

Q. Does this conclude your rebuttal testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

ANDREW R. SNIDER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Andrew R. Snider, and my business address is 4000 Clay Avenue, Grand Rapids, MI 49548.

Q. Are you the same Andrew R. Snider that offered direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to Service Restoration issues raised in the direct testimonies of Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") witnesses Jessica Duell and Theresa McMillan-Sepkoski, Attorney General ("AG") witness Sebastian Coppola, and Citizens Utility Board of Michigan ("CUB") witness Richard J. Bunch.

Q. How is your rebuttal testimony organized?

A. My rebuttal testimony is organized as follows:

I. Test Year O&M
II. Resiliency Fund
III. ESA
IV. Wire Down Process
V. Control/Dispatch Center Consolidation

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

I. Test Year O&M

Q. Please describe AG witness Coppola's proposal for the Service Restoration test year Operating and Maintenance ("O&M").

A. AG witness Coppola proposes a disallowance of $20.6 million for Service Restoration test year O&M because Consumers Energy Company's ("Consumers Energy" or the "Company") requested methodology veers from the practice of using a five-year average of restoration expenses to set the test year amount.

Q. Did any other witnesses in this case object to the Company's Service Restoration test year O&M request?

A. No. In fact, Staff witness Duell states on page 17, lines 24 through 27, of her direct testimony, that she approves of the Company's projected test year expense.

Q. Why is the Company proposing a change in the way service restoration costs are baselined?

A. As mentioned on page 21, lines 3 and 4, of my direct testimony, the historical process was insufficient resulting in a $351 million gap in funding over the past five years. Additionally, the historical method, using a five-year average, was challenged by The Liberty Consulting Group ("Liberty") in their independent audit.

Q. How did Liberty characterize the five-year historical average for calculating the Service Restoration test year O&M request?

A. As I detailed on page 17, lines 27 through 29, of my direct testimony, Liberty stated that, "It is not clear how a five-year average serves as a sound basis for setting budgets or a meaningful marker for sharing restoration costs that vary from five-year averages," and stated that reliance on the five-year average to fund service restoration should end.

Q. Did the Company's Service Restoration test year O&M request consider Liberty's recommendation from the Final Report in Case No. U-21305?

A. Yes. As I detailed on page 18, lines 7 through 17, the Company has stopped relying on a five-year historical average and bases the proposed bridge period and test year O&M amounts on the 2024 historic year expenses. The Company believes this approach provides the most accurate benchmark based on projected service restoration performance requirements. And, as explained below, when the Company's proposed approach to projecting its service restoration expense is paired with the proposed Service Restoration Resiliency Fund ("Resiliency Fund"), it alleviates the AG's concern that the Company's proposed approach does not "even out peaks and valleys in the annual expense."

II. Resiliency Fund

Q. Please describe Staff witness Duell's proposal for the Resiliency Fund.

A. Beginning on page 18, Staff witness Duell objects to approving the Company's proposed Resiliency Fund for several reasons including Staff's support of the full-service restoration expense for the test year, skepticism that customers will see a benefit from this proposal, and a preference to direct underspent Service Restoration expenses into other distribution programs.

Q. Do any other witnesses similarly object?

A. Yes. On pages 53 through 58 of his direct testimony, CUB witness Bunch recommends that the Commission reject the Resiliency Fund because, in his opinion, the proposal is like previously rejected proposals and is unlikely to benefit customers. On page 165 of his direct testimony, AG witness Coppola also recommends that the Commission reject the Resiliency Fund because it, along with the Extraordinary Storm Accounting ("ESA") proposal, are complex and require further study.

Q. Does the Company agree with these witnesses' recommendations for the Resiliency Fund?

A. No. The Company disagrees with the characterization that customers will not benefit from this proposal, as there is no extra cost to customers to implement the Resiliency Fund. Since the fund will either supplement existing service restoration resources or be refunded to customers, there is only customer benefit and upside from this proposal. Furthermore, the Resiliency Fund is not overly complex or similar to previous Company proposals such as the Service Restoration Cost Sharing Mechanism ("SRCSM"). Simply stated: the Resiliency Fund captures underspent service restoration dollars from prior years and saves them for future use if actual spending exceeds authorized amounts. The Company has also never proposed a mechanism in the style of a Resiliency Fund before. Previous recovery mechanisms dealt primarily with overspends, while the Resiliency Fund deals only with underspend and is clearly different from how the SRCSM would have addressed underspend costs.

Q. Does the Resiliency Fund also help address AG witness Coppola's concern, as described on page 165, lines 1 through 4, of his direct testimony, that the Company's proposed approach to projecting its service restoration expense does not "even out peaks and valleys in the annual expense"?

A. Yes. If the Company experiences a year when its service restoration expense is lower than its projected expense – what AG witness Coppola describes as a "valley" – then the difference would be deposited in the Resiliency Fund and would be available to offset expenses in the following year if it is what AG witness Coppola describes as a "peak" year when service restoration expenses are higher than projected.

III. Extraordinary Storm Accounting

Q. Please describe Staff witness McMillan-Sepkoski's proposal for ESA.

A. On page 8, line 14, through page 9, line 3, of her direct testimony, Staff witness McMillan-Sepkoski objected to approving the proposal citing the effectiveness and timeliness of the current ex-parte case process which the Company utilized following the March/April 2025 storm. Additionally, on page 9, lines 4 through 7, she expressed concern over the lack of a defined cost threshold, viewing the proposal as an open-ended mechanism that could lead to uncertainty in future cost recovery.

Q. Has the Company considered a defined cost threshold for the ESA as suggested by Staff witness McMillan-Sepkoski?

A. Yes. The Company considered a cost threshold when developing this proposal and ultimately decided it was impractical. The Company is committed to safe and efficient restorations no matter what acts of nature it's called to respond to. Consumers Energy will not stop restoration until every last customer is restored.

Q. How can customers be assured that the Company is prudent with extraordinary restorations without a specific cost threshold?

A. As shared in my discovery response U21870-ST-CE-0104, "The Company proposes to provide comprehensive storm data such as a breakdown of capital and O&M unit costs for internal and contractor crews, separated by category and demonstration of how its restoration performance during a given ESA event was conducted in a cost-effective manner." The Company also explained that "recovery of the deferred amounts will be included in any future electric rate case proceedings," which would include a prudency review.

Q. What are the benefits of ESA and how do they relate to Staff witness McMillan-Sepkoski's criticism of ESA?

A. ESA establishes a standardized process completely visible to all interested parties in the rate making process. It's transparent and will mandate consistency for future deferred recovery requests for restoration O&M expenses, unlike an ex-parte filing, which by nature does not have specific guidelines and can be filed at any time. In addition to bringing consistency, the ESA delivers important efficiencies. Creating a reasonable standard defining exactly what qualifies for (restoration) deferred accounting saves the Commission, and interested parties, significant time by establishing a rate case process that avoids the need for a separate ex-parte filing.

Q. Do any other witnesses similarly object?

A. Yes. Both CUB witness Bunch and AG witness Coppola appeared to conflate their criticism for the Resiliency Fund with ESA and recommended the Commission reject both proposals. On page 55 of his direct testimony, CUB witness Bunch opines that the ESA will be used frequently and shifts the risk to customers for the cost of restoration from damaging storms.

Q. On page 55, line 5, of his direct testimony, CUB witness Bunch characterizes ESA as not significantly different from past proposals. Does the Company agree?

A. No. CUB witness Bunch inaccurately asserts that ESA is similar to the SRCSM while glossing over key details and distinctions of the proposal. I cover the distinction between ESA and the SRCSM on page 32, lines 1 through 15, of my direct testimony. In the past, the Company has not differentiated extraordinary storms from other catastrophic categories of storms. ESA is therefore far more targeted than past proposals.

The context is different, as well. This case is the first electric rate case filed after the Commission issued its order in Case No. U-21305, which called for a change to service restoration budgeting and specifically endorsed deferral accounting as an effective means for permitting recovery of excess storm costs as I note in my direct testimony on page 18, line 27, through page 19, lines 1 through 3. Deferred accounting was specifically cited as an opportunity in Liberty's independent audit. This is also detailed in my direct testimony beginning on page 29, line 12.

Q. Does the Company agree with CUB witness Bunch's assertion on page 56, lines 12 through 14, of his direct testimony that ESA increases customers' exposure to restoration costs associated with large, extreme weather-related events?

A. No. Whether the Company is granted deferred accounting for extraordinary storm restoration costs through ESA or whether it obtains deferred accounting through an ex-parte proceeding, both approaches allow the Company to recover its reasonable restoration costs for extraordinary storms after a prudency review. Customer exposure remains equal whether the Company files in rates cases or separate cases.

Q. Does the Company agree with CUB witness Bunch's statement that by presenting two distinct mechanisms the Company has repackaged their approach from previous cases?

A. No, the Resiliency Fund and ESA are not interdependent. As I discussed on page 31, lines 10 through 13, of my direct testimony, the two proposals can function independently of one another. The Company has filed for approval of both proposals because they do operate best in tandem, but they can be approved separately.

Q. Does the Company agree with AG witness Coppola's statement on page 166, lines 11 through 14, of his direct testimony suggesting the Commission open a new docket to review the Resiliency Fund and ESA?

A. No. While the Company appreciates AG's willingness to discuss these proposals further, they are rate proposals that deserve to be reviewed, debated, and approved in rate cases. There is no more appropriate opportunity to debate these proposals.

IV. Wire Down

Q. Does the Company Agree with Staff witness Duell's recommendation to change the caution tape used for downed wires?

A. Yes. As referenced in discovery response U21870-ST-CE-0109, 16b, in Exhibit S-18, page 5, the Company historically uses caution tape specifying, "Caution Do Not Enter." The Company's policy for wire guards is to remain onsite until a downed wire is made safe. Therefore, once a location is barricaded with caution tape, a representative should be standing guard until the source is verified de-energized. However, the Company appreciates and will adopt the recommendation to utilize caution tape that indicates the potential of a live wire.

V. Control/Dispatch Center Consolidation

Q. Please describe AG witness Coppola's position on the Control/Dispatch Center consolidation project.

A. AG witness Coppola expresses concern regarding the Company's revised proposal to establish two fully staffed Control/Dispatch Centers. AG witness Coppola questions the justification for the increased capital investment, which has grown from the original $17.2 million to $30.7 million. He asserts that the operational benefits of the dual-center

model are not clearly demonstrated and that the projected cost savings—estimated by the Company at $10.2 million annually—are speculative in nature. AG witness Coppola refers to these savings as "purported" or "potential," suggesting they lack sufficient evidentiary support. Additionally, he characterizes the revised proposal as a "180-degree turn" from the Company's prior plan, which involved consolidating operations into a single facility. He implies that the dual-center approach may be redundant and questions whether the added investment delivers proportional value to customers.

Q. Does the Company agree with AG witness Coppola's characterization of the revised proposal as a "180-degree turn"?

A. No. AG witness Coppola's characterization oversimplifies the evolution of the Control/Dispatch Center initiative. The original plan, as discussed in Case Nos. U-21389 and U-21585, involved logistical consolidation, closing one facility and absorbing its workload into another. The current proposal represents a strategic transformation, including:

- Integration of System Control, Distribution Control, and Dispatch functions,
- Creation of new job classifications across the electric grid, and
- Workforce training and role alignment to support a modernized, resilient operations model.

These phases differ significantly in scope and purpose and should not be directly compared.

Q. Is staffing both Control/Dispatch Centers necessary?

A. Yes. Full staffing at both centers is essential for operational resilience and risk mitigation. In recent years the Company has had to stand down operations at the Jackson location multiple times due to tornado warnings or other weather-related threats, during which control was automatically transferred to Grand Rapids. This operational experience further

validated the need for geographically redundant, fully staffed centers. A second, fully staffed facility ensures continuity of operations and avoids delays in restoration. Additionally, the dual-center model:

- Reduces the risk of losing experienced employees by avoiding forced relocations,
- Supports recruitment and retention in key service areas, particularly Grand Rapids, and
- Aligns with industry best practices for geographic redundancy in critical infrastructure.

Q. Are the projected $10.2 million in annual savings based on actual cost reductions?

A. No. The Company has described these benefits as cost avoidance, which is a valid and recognized planning metric in utility operations. These avoided costs include:

- Reduced service restoration expenses,
- Lower overtime and Incident Command System ("ICS") activation costs, and
- Efficiency gains from improved coordination and situational awareness.

These benefits are detailed in my direct testimony (pages 41–46) and summarized on Figure 8.

Q. Is the revised Control/Dispatch Center plan proposal a reversal of its prior strategy?

A. No. The revised proposal is a strategic advancement informed by lessons learned and employee feedback. The dual-center model is designed to optimize system operations, enhance reliability, and protect workforce stability, while delivering measurable cost avoidance and reliability improvements.

Q. Should the Commission approve the proposed capital expenditures for the Control/Dispatch Center consolidation?

A. Yes. The Company respectfully recommends approval of the proposed investments, recognizing their long-term value to customers and grid operations.

Q. What is Staff witness Duell's general position on the Control/Dispatch Center consolidation project?

A. On page 18, line 26, through page 20, line 18, of her direct testimony, Staff witness Duell does not support full recovery of the capital expenditures requested by the Company for the Control/Dispatch Center consolidation project. Staff witness Duell recommends disallowing 50% of the requested capital for both the bridge period and the projected test year. Based on the Company's historical underspending, Staff witness Duell determined that the variance justifies a proportional reduction in the current funding requests. Additionally, Staff witness Duell questions whether the proposed investments are necessary and whether the operational benefits of the dual-center model are sufficiently demonstrated to warrant approval of the requested capital expenditures.

Q. Does Staff witness Duell support the Company's requested $4.871 million in capital expenditures for the Control/Dispatch Center during the bridge period (the four months ending April 30, 2026)?

A. No. On page 19, line 20, through page 20, line 4, of her direct testimony, Staff witness Duell recommends a disallowance of $2.4 million, representing 50% of the requested bridge period amount. This recommendation is based on the Company's prior performance, where actual 2024 spending was less than projected. Given the variance, Staff witness Duell determined that a proportional adjustment is appropriate.

Q. Is it reasonable to disallow funding for the Consolidated Control/Dispatch Center predicated on historical spend rates?

A. No, it is not. Staff's recommendation to disallow half of the Company's requested $4.871 million in bridge period capital expenditures is based solely on a comparison of projected versus actual 2024 spend. This overlooks the strategic evolution of the project and the timing of expenditures.

The Company's decision to transition from a single Unified Control Center to a dual-location model—Jackson and Grand Rapids—was made during execution to enhance resiliency and retain talent. As I stated in my direct testimony, this change did not cause any rework or redo of prior work. All previously completed engineering, design, and implementation activities remained valid and applicable. The transition was managed without duplicative effort or additional cost.

The lower-than-projected 2024 spend reflects the Company's decision to prolong the design phase to incorporate the expanded scope. The bridge period expenditures represent the natural ramp-up of capital investment following that design work.

Disallowing funding based on historical spend rates ignores the reality that capital projects—especially those involving complex operational infrastructure—do not follow linear spending patterns. The Company's bridge period capital request is reasonable, prudent, and aligned with the revised scope and timeline.

Q. On page 20, lines 10 through 18, Staff witness Duell recommends disallowing half of the Company's proposed $15.497 million capital expenditures for the Control/Dispatch Center consolidation project in the test year. Is the $15.497 million requested for the Control/Dispatch Center in the projected test year justified?

A. Yes. The funding supports the build-out of the dual Control/Dispatch Center model, which includes facilities in Jackson and Grand Rapids. This strategic investment enhances system resiliency, provides geographic redundancy, and ensures business continuity. The revised scope builds upon existing infrastructure in Jackson, preserving prior investments while expanding capabilities. The dual-center model aligns with industry best practices and supports further integration with advanced grid technologies such as Advanced Distribution Management System ("ADMS") and Distributed Energy Resource Management Solution ("DERMS"). These justifications are outlined in my direct testimony at pages 44 through 46.

Q. On page 19, line 20, through page 20, line 4, Staff witness Duell compares the Company's projected 2024 capital spending for the Control/Dispatch Center from Case No. U-21585 with its actual spending on the project in 2024. Does the Company's actual spend below the prior projection indicate overestimation or inefficiency?

A. No. The prior projected spend in Case No. U-21585 was not approved, and the Company should not be held to the amounts it had planned to spend that were not approved. The spending that did occur was prudent and targeted, as shown in Figure 9 on page 45 of my direct testimony and page 40, lines 8 through 28, of my direct testimony. The Company has executed the project in a way that reflects its commitment to fiscal discipline and

regulatory compliance. Using the difference between projected and actual spend as a rationale to deny future funding does not account for the Company's responsible approach to capital planning.

Q. Should the Commission approve the proposed expenditures for the bridge period and projected test year?

A. Yes. The Company maintains that both funding requests are prudent, necessary, and aligned with strategic operational goals. It is very difficult for the Company to complete a project that is only "half supported." These investments support reliability, resiliency, and best practices. The Company is respectfully seeking full support from the Commission to approve the proposed expenditures and recognize the long-term value of the Control/Dispatch Center transformation for our customers.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

SARA E. STEWART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Sara E. Stewart, and my business address is 1945 W. Parnall Road, Jackson, MI 49201.

Q. Are you the same Sara E. Stewart who previously presented direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will rebut the assertions and recommendations of the Association of Businesses Advocating Tarriff Equity ("ABATE") witness Jessica A. York, Michigan Public Service Commission ("MPSC") Staff ("Staff") witness Jessica Duell, and Attorney General ("AG") witness Sebastian Coppola regarding the Consumers Energy Company's ("Consumers Energy" or the "Company") line clearing program.

Q. Have you prepared any exhibits in conjunction with your rebuttal testimony?

A. No.

REBUTTAL OF ABATE WITNESS YORK

Q. Ms. York states her concern on page 15, line 11, of her direct testimony. Do you agree that the Company's High Voltage Distribution ("HVD") Line Clearing Program projected Operating and Maintenance ("O&M") spending is overstated?

A. No, I do not agree that the projected O&M spending for HVD Line Clearing is overstated. As the HVD system is on a four-year cycle, in 2026 the Company will need to clear line segments it cleared in 2022, *plus* additional line segments close in proximity that have been adjusted into 2026's workplan to support crew efficiency. Not only are there more miles to complete in 2026 than in 2022, but the Company also executed new line clearing contracts

in 2024 and experienced an increase in the base rates for line clearing contractors, which impacts HVD line clearing work.

Q. Should the Company be disallowed 10% of its projected test year HVD Line Clearing O&M, or $1.184 million?

A. No. The Company projects spending the full proposed amount on HVD Line Clearing in the test period. In the event the Company completes its HVD workplan spending less than the full proposed amount, it will reallocate any net decrease in HVD clearing costs for the test year to the Low Voltage Distribution ("LVD") system to support bringing the LVD system to its intended cycle, as it has historically done. The Company followed this historical practice (reallocating any net decrease) from 2020 to 2024 – the period that Ms. York discussed in her testimony. This historical practice, which the Company plans to continue, should alleviate any concern about a potential net decrease in HVD clearing costs.

REBUTTAL OF STAFF WITNESS DUELL

Q. Ms. Duell states Staff's opinion on page 9, lines 15 through 17, that the Company did not prioritize its line clearing program highly enough in the past. Does the Company agree with this statement?

A. No, the Company has demonstrated its commitment to its Line Clearing Program consistently since Case No. U-20697 where the Company first proposed the seven-year effective cycle for its LVD system. In that case and subsequent cases, the Company has been transparent with its current state of backlog circuits and its plan to eliminate the backlog, with a commitment to prioritize poorly performing circuits for line clearing. With the support of the Commission and Staff, the Company began working toward the seven-year effective cycle in the 2021 test period and continued with this strategy through

Case No. U-21585. As outlined in my direct testimony in Figure 20 on page 43, the Company has exceeded its authorized spending levels in all cases since Case No. U-20697. In the instant case, the Company is pursuing a path of continuous improvement in its proposal to ramp-up LVD line clearing to a five-year cycle, showing continued prioritization of this program.

Q. On page 12, lines 26 through 28, of her direct testimony, Ms. Duell states the Company underspent in line clearing in 2024 [calendar year] and cleared fewer miles than proposed and approved for line clearing expenses in Case No. U-21585. Do you agree?

A. No, I do not agree. The Company met and exceeded its authorized line clearing expense level for the 2024 test period (12 months ending 2/28/2025), which was authorized in the Order for Case No. U-21389. In comparison to the Case No. U-21389 test period (12 months ending 2/28/2025) authorized funding of $118,889,334, the Company spent $119,189,032 toward the Line Clearing Program.

While the Company forecasts calendar year spend, the authorized line clearing expense level is associated with the test period, and not to a calendar year. As discussed in my direct testimony on page 44, lines 14 through 20, it is operationally challenging to meet both a projected calendar year spending level and test year spending level that do not directly overlap in timeframe, especially when expense levels are increasing from one test period to the next test period.

Q. On page 13, lines 3 through 5 of her direct testimony, Ms. Duell states the Company did not answer where the $5,876,252 in remaining funding was allocated to. Do you agree?

A. No, the Company did answer this question in discovery response U21870-ST-CE-0116 as shown in Exhibit S-18, page 1. It is possible that Ms. Duell has unintentionally conflated the 2024 calendar year with the Case No. U-21389 test year. As mentioned, the Company is committed to meeting the authorized line clearing expense level associated with the test period as defined by Orders or Settlement Agreements.

Q. On page 13, lines 24 through 27, and page 14, lines 1 through 3, of her direct testimony, Ms. Duell shares a concern that the Company is experiencing contractor shortages. Is the Company experiencing contractor shortages?

A. No, the Company is not experiencing contractor shortages. In discovery response U21870-ST-CE-0117, as shown in Exhibit S-18, page 9, I stated the Company cleared fewer miles in 2024 than projected due to execution of new LVD contracts in May 2024, resulting in a higher unit cost per mile. This is not synonymous with a contractor shortage.

Q. On page 11, lines 15 through 22, Ms. Duell attributes the scope of the Company's canopy removal proposal to everything past the first zone. Is this accurate?

A. No, this is not accurate. As discussed in my direct testimony on page 23, lines 11 through 16, the Company is proposing that zone number alone not be the determining factor for canopy removal, but the consequence of failure of the section of line in question be the driving factor, which will include some second zones and may even extend past the second zone depending on the zone attributes. This scope also inherently includes many first zones as it targets the path of substation-to-substation connection to enable switching

opportunities during outage events (i.e. line crew enablement to isolate the fault location, restore some customers impacted by the outage, perform repairs, then fully restore all customers impacted by the outage), but it may not include 100% of first zones depending on individual zone attributes.

Q. On page 12, lines 16 through 19, Ms. Duell states that Staff initially interpreted my testimony as stating the Company removed all canopy in the first zone 100% of the time. Has the Company stated in testimony it removes all canopy in the first zone 100% of the time?

A. No. In my direct testimony on page 8, lines 20 through 23, I state that overhanging branches above conductors during first zone clearing are considered for removal, which is not indicative of 100% of the time. Later in my testimony on page 21, lines 10 through 15, I compare the Company's canopy removal proposal for targeted three-phase primary lines to the Company's general line clearing specification, which clearly states some canopy has been allowed to remain over LVD primary lines.

Q. On page 10, line 25, Ms. Duell states that Staff recommends the Company clear all canopy in the first zone. Do you agree that the Company should begin clearing all canopy in the first zone starting in the instant case test period?

A. No, I do not agree the Company should begin clearing all canopy in the first zone starting in the instant case test period. The scope of the Company's proposal for canopy removal is defined in my direct testimony on page 23, lines 1 through 16. While this proposed scope includes some three-phase mileage in first zones, it does not include 100% of first zones (e.g. it does not include single and two-phase unfused laterals off three-phase first zone). The funding level needed to execute canopy removal for both the Company's scope and

Ms. Duell's recommendation of all first zones is not reflected in the revenue requirement for the Line Clearing Program in the instant case.

Q. Would the Company consider clearing all canopy in the first zones of LVD circuits in a future electric rate case?

A. Yes, the Company is agreeable to considering clearing all canopy in the first zones of LVD circuits by performing an updated analysis on both the projected costs and benefits in a future electric rate case. As adding all first zones for canopy removal is an expansion upon the proposed scope of canopy removal in the instant case, the Company recommends that it be granted time to execute some canopy removal and allow these targeted three-phase lines time to begin collecting reliability data toward a statistically significant cost-benefit analysis.

Q. On page 9, lines 7 through 10, and page 14, lines 9 through 10, Ms. Duell states the Company did not provide a new analysis that considered the benefits of shifting to a fixed 4-year line clearing cycle. Did the Company conduct this analysis?

A. Yes, the Company conducted this analysis and its conclusion is in my direct testimony on page 32, lines 10 through 21, and page 33, lines 1 through 13. This analysis included projected costs, a timing assumption, and projected reliability improvement. Based on my analysis, I concluded that moving to a four-year cycle in the timeframe the Company proposed to move to a five-year cycle could increase expenses by 15% overall while adding only 3% to the total reliability benefits across multiple metric types.

Q. On page 14, line 30, and page 15, lines 1 through 3, Ms. Duell states the Company relies on the formal optimization analysis of line clearing cycles report to determine if a four-year effective line clearing cycle is efficient or not. Is this true?

A. No, the Company did not utilize the Formal Optimization Analysis of Line Clearing Cycles in the instant case when considering the benefits of shifting to a four-year fixed line clearing cycle. Rather, the Company utilized the same methodology to evaluate a four-year cycle that it used to evaluate the cost and benefit projections of shifting to a five-year line clearing cycle in the same ramp-up strategy period (i.e. the test period of the instant case through the 2030-2031 test period). In comparison, the Formal Optimization Analysis of Line Clearing Cycles assumed steady-state costs to maintain each cycle length analyzed (i.e. assumes the cycle has already been achieved for each cycle length), whereas the Company's analysis in the instant case assumed the current state of the LVD system and projected costs to move it to a four-year cycle.

Q. Should the Company file a new analysis of the costs and benefits of a four-year cycle with its next electric rate case, as Ms. Duell states on page 15, lines 5 through 11, of her testimony?

A. No. The prudent next step in the evolution of the Company's Line Clearing Program is the outlined five-year line clearing cycle. Once the five-year cycle is attained, the Company will re-evaluate other tactics for continuous improvement in risk management, including cycle considerations.

REBUTTAL OF AG WITNESS COPPOLA

Q. On page 174, line 7, through page 175, line 18, AG witness Coppola supports, in principle, the Company's proposal to defer line clearing expenses above a certain threshold but disagrees with the baseline the Company has chosen. How do you respond?

A. The Company appreciates the Attorney General's support for its proposal in principle, and the Company maintains that its recommended baseline for the test period is reasonable. Company witness Patrick D. Daly addresses Mr. Coppola's recommendation, but I would also like to clarify how the baseline would operate in practice in 2026 in further response to Mr. Coppola's recommendation that the Company defer all line clearing expenses above $110,225,000 beginning in 2026. The amounts in Figure 13 on page 36 of my direct testimony, which shows the Company's baseline expense requirements, were calculated using the Company's current projection for the annual expense required to maintain the five-year line clearing cycle once fully achieved after the 2030–2031 test period as further described in my direct testimony on page 35, lines 1 through 14. These projections were then set to present dollars to reflect each calendar year. This approach assumes that each year is operating under a full five-year cycle. The test period baseline was calculated as 8/12th of 2026 calendar year projected baseline to maintain the five-year clearing cycle (once attained) and 4/12th of 2027 calendar year projected baseline to maintain the five-year clearing cycle (once attained).

However, in practice, calendar year 2026 will be a transitional year in the ramp-up process. Specifically, the first four months of 2026 will still operate under the previous seven-year effective cycle approved in Case No. U-21585, while the remaining

eight months will reflect the ramp up to the new five-year cycle proposed in the present case. As a result, the Company wants to clarify that the baseline operational expense for calendar year 2026 is $150.6 million based on four months (January through April 2026) at the Company's currently approved Forestry spend from Case No. U-21585 plus eight months (May through December 2026) of the five-year line clearing cycle (once attained) projected for 2026. This amount reflects the transitional nature of the year and provides a more representative view than the $163.4 million shown in Figure 13. This includes $138.6 million in LVD expenses.

No clarifications are necessary to the test year baseline expense requirement of $164.5 million, which includes $152.6 million in LVD expenses, as this figure appropriately reflects the adjusted projection for the test period.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REBUTTAL TESTIMONY

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

Q. Please state your name and business address.

A. My name is Brian J. VanBlarcum, and my business address is One Energy Plaza, Jackson, MI 49201.

Q. Are you the same Brian J. VanBlarcum who previously submitted testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Attorney General witness Sebastian Coppola to increase the amount of accrued taxes included in working capital by $30 million, which reduces working capital by the same amount.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-228 (BJV-3) Workpaper WP-PDD-29; and

Exhibit A-229 (BJV-4) Workpaper WP-PDD-36.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. What amount of accrued taxes did Consumers Energy Company ("Consumers Energy" or the "Company") forecast to be included in working capital for the projected test year?

A. As shown in Company witness Patrick D. Daly's Exhibit A-12 (PDD-34), Schedule B-4, line 15, column (p), the Company projected accrued taxes of $256.080 million. The Company utilized the 13-month average from December 2024, which was $286.120 million as shown on Exhibit A-12 (PDD-34), Schedule B-4, line 15, column (d), and made

a downward accrued tax adjustment of $30.040 million, as shown on Exhibit A-12 (PDD-34), Schedule B-4, line 15, column h.

Q. Why is the Company's $30.040 million downward adjustment necessary?

A. The $286.120 million, 13-month average as of December 2024, includes Federal, State, and Local income taxes accrued for the 2023 and 2024 tax years. This balance is not reflective of accrued taxes related to the projected test period May 1, 2026 through April 30, 2027. Since accrued income taxes included in the December 2024, 13-month average will be settled prior to the projected test year, it is appropriate to remove the settled amount from the December 2024, 13-month average and replace that amount with a projection of Federal, State, and Local income taxes related to the projected test period.

Accrued taxes, which are included as a component of working capital in rate base, are calculated on taxable income derived from both pre-tax book income and timing differences that generate deferred income taxes. Deferred income taxes are a zero-cost component of the capital structure.

Sound ratemaking requires that there is synchronization between the capital structure and rate base. Since additional deferred income taxes, including those created by timing differences for projected book and tax depreciation, are included in the capital structure, and accrued taxes are included in rate base, the Company's adjustment to accrued taxes ensures that these two components are adjusted in unison. To the extent that the Company projects additional deferred taxes included in the capital structure for this case but fails to recognize the corresponding change in accrued taxes or rate base, this disconnection has the effect of immediately reducing rates and providing a tax benefit to customers. The failure to recognize this disconnection and providing such an unintended

tax benefit to customers has the effect of causing a normalization violation under the Internal Revenue Code. The consistency rules required by the Internal Revenue Code require four components to remain in synchronization: (1) depreciation expense; (2) tax expense; (3) reserve for deferred taxes; and (4) rate base. As outlined above, the Company's adjustment to accrued taxes as a component of working capital in rate base would ensure compliance with Section 168(i)(9)(B) of the Internal Revenue Code.

Q. On pages 105 and 106 of his direct testimony, Attorney General witness Coppola presented his adjustment to the Company's projection of accrued taxes. What specific adjustment did Mr. Coppola recommend?

A. In his direct testimony, Attorney General witness Coppola recommends that accrued taxes for the test year be set at $286.1 million, the Company's historical, 13-month average balance for the period ending December 2024, increasing the Company's projection of accrued taxes by $30.0 million and reducing working capital by the same $30.0 million.

Q. Please explain why Attorney General witness Coppola's accrued tax and working capital adjustment is incorrect.

A. Attorney General witness Coppola's recommendation to use the historical accrued tax balance of $286.1 million, the 13-month average balance as of December 2024, is incorrect as that balance includes accrued income taxes related to prior tax years which are not related to the projected test year. Further, Attorney General witness Coppola's recommendation to set accrued taxes at the actual 13-month average as of December 2024 fails to take into consideration any taxable income projection or timing differences related to the projected test year. Consideration of these items is imperative because book and tax timing differences, especially those related to book depreciation and tax depreciation,

require equal consideration when adjusting accrued income taxes derived from current tax expense and deferred income taxes derived from deferred income tax expense. As noted earlier, it is incorrect to adjust one side of this equation without equal consideration for both current and deferred income tax expense and the impact of accrued income taxes included as a component of rate base and deferred income taxes included in the capital structure.

Q. On page 105, line 11, of his direct testimony, Attorney General witness Coppola references the Company's discovery response U21870-AG-CE-0459, which acknowledged accrued taxes for the test year do not include additional income from rate relief requested in this case, claiming the Company's assumption of no new rate relief is unrealistic and its calculation of accrued taxes is seriously flawed. Did the Company calculate an appropriate amount of accrued taxes based on Federal, State, and Local taxable income projections relative to the projected test year?

A. Yes. The details supporting the Company's $30.0 million adjustment can be found on Exhibit A-228 (BJV-3), Company witness Daly's workpaper, WP-PDD-29, which removes the previously mentioned Federal, State, and Local accrued income taxes unrelated to the projected test period and adds back a 13-month average based on Federal, State, and Local income tax projections reflective of the projected test period. The Company's 13-month accrued income tax balance, based on assumptions from the test period, is shown on Exhibit A-229 (BJV-4), Company witness Daly's workpaper, WP-PDD-36.

Q. Do you agree that such an adjustment for rate relief should be made?

A. No. Attorney General witness Coppola's assertion that requested rate relief should be included in the calculation of accrued taxes included in rate base is contrary to the long standing and consistent methodology used in prior cases. In fact, no other working capital items are adjusted to reflect requested rate relief. If such an adjustment were made for income tax liabilities included in working capital, other assets included in working capital, such as accrued revenue or accounts receivable, would also need to be increased for rate relief offsetting the increase to income tax liabilities.

Q. Does this conclude your rebuttal testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No: A-228 (BJV-3)
Page: 1 of 1
Witness: BJVanBlarcum
Date: October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjustment to Accrued Taxes
For the Projected 12-Month Period Ending April 30, 2027

Case No.: U-21870
WP-PDD-29

Line No	(a) Description	(b) Source	(c) Amount
1	Accrued Taxes - December 2024 13-Month Average Balance	WP-PDD-10, Line 27, Col. (f.1)	$ 286,119,648
	Exclude Historical Accrued Income Taxes:		
2	Accrued Federal Income Tax Payable	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2300000	17,256,743
3	Accrued Income Tax Payable - APB 28	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2300500	8,772,541
4	Accrued State Income Tax	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2301000	3,706,496
5	Accrued SBT Tax	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2301200	-
6	Accrued State Income Tax Payable - APB 28	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2301500	3,106,617
7	Accrued Local Income Tax Payable	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2301600	78,985
8	Accrued Local Income Tax Payable - APB 28	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2301700	97,882
9	Total Historical Accrued Income Taxes Removed	Sum of Lines 2 - 8	33,019,264
10	Historical Accrued Taxes, Net of Income Taxes	Line 1 - Line 9	253,100,384
	Include Projected Accrued Income Taxes:		
11	Accrued Federal Income Tax - April 2027	WP-PDD-36	2,330,667
12	Accrued State Income Tax - April 2027	WP-PDD-36	618,539
13	Accrued Local Income Tax - April 2027	WP-PDD-36	29,998
14	Projected Accrued Income Taxes - April 2027 13-Month Average Balance	Sum of Lines 11 - 13	2,979,204
15	Projected Accrued Taxes - April 2027 13-Month Average Balance	Line 10 + Line 14	256,079,588
16	Accrued Tax Adjustment	Line 15 - Line 1	(30,040,060)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No: A-229 (BJV-4)

Witness: BJVanBlarcum
Date: October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjustment to Accured Income Taxes
For the Projected 12-Month Period Ending April 30, 2027
(DR) CR

Case No.: U-21870
WP-PDD-36

Line No.	(a) Description	(b) 2026 Apr	(c) 2026 May	(d) 2026 Jun	(e) 2027 Jul	(f) 2027 Aug	(g) 2027 Sep	(h) 2027 Oct	(i) 2027 Nov	(j) 2027 Dec	(k) 2027 Jan	(l) 2027 Feb	(m) 2027 Mar	(n) 2027 Apr	(o) 13 Mo Avg 4/30/2027
	Federal Income Taxes														
1	Accrual	-	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,058	2,058	2,058	2,058	
2	Accrual - Transfer to NOL C/F	-	-	(7,355)	-	-	(7,355)	-	-	(7,355)	-	-	(6,174)	-	
3	Payments	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Net Activity	-	2,452	(4,904)	2,452	2,452	(4,904)	2,452	2,452	(4,904)	2,058	2,058	(4,116)	2,058	
5	YTD Balance	2,452	4,904	-	2,452	4,904	-	2,452	4,904	-	2,058	4,116	-	2,058	2,331
	State Income Taxes														
6	Accrual	-	345	345	345	345	345	345	345	345	261	261	261	261	
7	Payments	-	-	-	(1,036)	-	-	(1,036)	-	-	(1,036)	-	-	(782)	
8	Net Activity	-	345	345	(691)	345	345	(691)	345	345	(775)	261	261	(521)	
9	YTD Balance	345	691	1,036	345	691	1,036	345	691	1,036	261	521	782	261	619
	Local Income Taxes														
10	Accrual		19	19	19	19	19	19	19	19	16	16	16	16	
11	Payments		-	-	(56)	-	-	(56)	-	(56)	-	-	-	(47)	
12	Net Activity		19	19	(37)	19	19	(37)	19	(37)	16	16	16	(31)	
13	YTD Balance	19	37	56	19	37	56	19	37	-	16	31	47	16	30
14	Total Federal & State Income Taxes	2,816	5,632	1,092	2,816	5,632	1,092	2,816	5,632	1,036	2,334	4,669	829	2,334	2,979

Consumers Energy Company

Electric Rate Case No. U-21870

Index of Exhibits - A# Order (Updated October 21, 2025)

Line No.	Exhibit #	Schedule #	Witness	Witness Exhibit #	Description
	(a)	(b)	(c)	(d)	(e)
	Historical Year Section				
1	A-1	A-1	Daly, Patrick D	PDD-1	Revenue Deficiency (Sufficiency) for the Historical Year Ended December 31, 2024
2	A-1	A-2	Daly, Patrick D	PDD-2	Historical Financial Metrics – Electric Results Only
3	A-2	B-1	Daly, Patrick D	PDD-3	Rate Base for the Historical Year Ended December 31, 2024
4	A-2	B-2	Daly, Patrick D	PDD-4	Total Utility Plant for the Historical Year Ended December 31, 2024
5	A-2	B-3	Daly, Patrick D	PDD-5	Depreciation Reserve and Other Deductions for the Historical Year Ended December 31, 2024
6	A-2	B-4	Daly, Patrick D	PDD-6	Working Capital for the Historical Year Ended December 31, 2024
7	A-2	B-5	Daly, Patrick D	PDD-7	13-Month Average Balance Sheet for the Historical Year Ended December 31, 2024
8	A-2	B-6	Daly, Patrick D	PDD-8	Point-In-Time Balance Sheet for the Historical Year Ended December 31, 2024
9	A-3	C-1	Daly, Patrick D	PDD-9	Adjusted Net Operating Income for the Historical Year Ended December 31, 2024
10	A-3	C-2	Daly, Patrick D	PDD-10	Calculation of the Revenue Conversion Factor for the Historical Year Ended December 31, 2024
11	A-3	C-3	Daly, Patrick D	PDD-11	Operating Revenue for the Historical Year Ended December 31, 2024
12	A-3	C-4	Daly, Patrick D	PDD-12	Cost of Fuel and Purchased Power for the Historical Year Ended December 31, 2024
13	A-3	C-5	Daly, Patrick D	PDD-13	Operation and Maintenance Expenses for the Historical Year Ended December 31, 2024
14	A-3	C-5.1	Daly, Patrick D	PDD-14	Operation and Maintenance Expenses by Witness for the Historical Year Ended December 31, 2024
15	A-3	C-6	Daly, Patrick D	PDD-15	Depreciation and Amortization Expenses for the Historical Year Ended December 31, 2024
16	A-3	C-7	Daly, Patrick D	PDD-16	General Taxes for the Historical Year Ended December 31, 2024
17	A-3	C-8	Daly, Patrick D	PDD-17	Federal Income Taxes for the Historical Year Ended December 31, 2024
18	A-3	C-9	Daly, Patrick D	PDD-18	State Income Taxes for the Historical Year Ended December 31, 202
19	A-3	C-10	Daly, Patrick D	PDD-19	Other (or Local) Taxes for the Historical Year Ended December 31, 2024
20	A-3	C-11	Daly, Patrick D	PDD-20	Allowance for Funds Used During Construction for the Historical Year Ended December 31, 2024
21	A-3	C-12	Daly, Patrick D	PDD-21	Income Tax Effect of Interest for the Historical Year Ended December 31, 2024
22	A-3	C-13	Daly, Patrick D	PDD-22	Interest Synchronization Adjustment for the Historical Year Ended December 31, 2024
23	A-4	D-1	Daly, Patrick D	PDD-23	Capital Structure and Rate of Return Summary for the Historical Year Ended December 31, 2024
24	A-4	D-2	Daly, Patrick D	PDD-24	Cost of Long-Term Debt (Excluding Securitization) for the Historical Year Ended December 31, 2024
25	A-4	D-3	Daly, Patrick D	PDD-25	Cost of Short-Term Debt for the Historical Year Ended December 31, 2024
26	A-4	D-4	Daly, Patrick D	PDD-26	Cost of Preferred Stock for the Historical Year Ended December 31, 2024
27	A-4	D-5	Daly, Patrick D	PDD-27	Cost of Common Shareholder's Equity for the Historical Year Ended December 31, 2024
28	A-5	E-1	Breuring, Eugene M	EMB-1	Annual Service Area Calendar Sales by Major Customer Classes and System Output – 5-Year Historical
	A-6	-	-	-	Intentionally Omitted
	A-7	-	-	-	Intentionally Omitted
	A-8	-	-	-	Intentionally Omitted
	A-9	-	-	-	Intentionally Omitted
	A-10	-	-	-	Intentionally Omitted

	Test Year Section				
29	A-11	A-1	Daly, Patrick D	PDD-28	Cost of Short-Term Debt for the Historical Year Ended December 31, 2024
30	A-11	A-2	Daly, Patrick D	PDD-29	Cost of Preferred Stock for the Historical Year Ended December 31, 2024
31	A-11	A-3	Daly, Patrick D	PDD-30	Cost of Common Shareholder's Equity for the Historical Year Ended December 31, 2024
32	A-12	B-1	Daly, Patrick D	PDD-31	Revenue Deficiency (Sufficiency) for the Projected 12-Month Period Ending April 30, 2027
33	A-12	B-2	Daly, Patrick D	PDD-32	Financial Metrics – Ratemaking Basis – For the Projected 12-Month Period Ending April 30, 2027
34	A-12	B-3	Daly, Patrick D	PDD-33	Comparison of the Historical and Projected Revenue Requirement for the Projected 12-Month Period Ending April 30, 2027
35	A-12	B-4	Daly, Patrick D	PDD-34	Rate Base for the Projected 12-Month Period Ending April 30, 2027
36	A-12	B-5	Daly, Patrick D	PDD-35	Total Utility Plant for the Projected 12-Month Period Ending April 30, 2027
37	A-12	B-5.1	Baker, Stacy H	SBH-4	Depreciation Reserve and Other Deductions for the Projected 12-Month Period Ending April 30, 2027
38	A-12	B-5.2	Blumenstock, Richard T	RTB-3	Working Capital Summary for the Projected 12-Month Period Ending April 30, 2027
39	A-12	B-5.3	Byrom, Jessica R	JRB-1	Capital Expenditures Summary for the Projected 12-Month Period Ending April 30, 2027
40	A-12	B-5.4	Foster, Matthew J	MJF-6	Electric Corporate Services Capital Expenditures for the Years 2024 through the 12 Months Ending April 30, 2027
41	A-12	B-5.5	Gast, Alex M	AMG-1	Actual and Projected Capital Expenditures – Demand Response
42	A-12	B-5.6	Guinn, Quentin A	QAG-1	Summary of Actual & Projected Capital Expenditures Facilities & Shared Services and Fleet Services
43	A-12	B-5.7	Kelly, Michael P	MPK-1	Electric Distribution Summary of Actual and Projected Capital Expenditures
44	A-12	B-5.8	Myrom, Jeffrey A	JAM-1	Transportation Electrification Plan Capital Expenditures
45	A-12	B-5.9	Schmoekel, Daniel A	DAS-1	Summary of Actual and Projected Electric Capital Expenditures for the Years 2020 through 2027
46	A-13	C-1	Daly, Patrick D	PDD-36	Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027
47	A-13	C-1.1	Daly, Patrick D	PDD-37	Development of Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027
48	A-13	C-2	Daly, Patrick D	PDD-38	Calculation of the Revenue Conversion Factor for the Projected 12-Month Period Ending April 30, 2027
49	A-13	C-3	Daly, Patrick D	PDD-39	Operating Revenues for the Projected 12-Month Period Ending April 30, 2027
50	A-13	C-4	Daly, Patrick D	PDD-40	Cost of Fuel and Purchased Power for the Projected 12-Month Period Ending April 30, 2027
51	A-13	C-5	Daly, Patrick D	PDD-41	Operating and Maintenance Expenses for the Projected 12-Month Period Ending April 30, 2027
52	A-13	C-5.1	Daly, Patrick D	PDD-42	Summary of Inflation and Merit Increases Included in Operation and Maintenance Expenses for the Projected 12-Month Period Ending April
53	A-13	C-6	Daly, Patrick D	PDD-43	Depreciation and Amortization Expenses for the Projected 12-Month Period Ending April 30, 2027
54	A-13	C-7	Daly, Patrick D	PDD-44	General Taxes for the Projected 12-Month Period Ending April 30, 2027
55	A-13	C-8	Daly, Patrick D	PDD-45	Federal Income Taxes for the Projected 12-Month Period Ending April 30, 2027
56	A-13	C-9	Daly, Patrick D	PDD-46	State Income Taxes for the Projected 12-Month Period Ending April 30, 2027
57	A-13	C-10	Daly, Patrick D	PDD-47	Other (or Local) Taxes for the Projected 12-Month Period Ending April 30, 2027
58	A-13	C-11	Daly, Patrick D	PDD-48	Allowance for Funds Used During Construction for the Projected 12-Month Period Ending April 30, 2027
59	A-13	C-12	Daly, Patrick D	PDD-49	Income Tax Effect of Interest for the Projected 12-Month Period Ending April 30, 2027
60	A-13	C-13	Daly, Patrick D	PDD-50	Interest Synchronization Adjustment for the Projected 12-Month Period Ending April 30, 2027
61	A-14	D-1	Bleckman, Marc R	MRB-1	Overall Rate of Return Summary
62	A-14	D-1a	Bleckman, Marc R	MRB-2	Capital Structure Development
63	A-14	D-1b	Bleckman, Marc R	MRB-3	Comparison of Development of Capital Structure
64	A-14	D-2	Bleckman, Marc R	MRB-4	Cost of Long-Term Debt
65	A-14	D-3	Bleckman, Marc R	MRB-5	Cost of Short-Term Debt
66	A-14	D-4	Bleckman, Marc R	MRB-6	Cost of Preferred Stock

67	A-14	D-5	Bulkley, Ann E	AEB-1	Cost of Common Shareholder's Equity
68	A-14	D-6	Bleckman, Marc R	MRB-7	Short-Term Debt Utilization
69	A-15	E-1	Breuring, Eugene M	EMB-2	Annual Service Area Calendar Sales by Major Customer Classes and System Output – 5-Year Projected
70	A-15	E-2	Breuring, Eugene M	EMB-3	Test Year Total Company Electric Revenues & Deliveries
71	A-15	E-3	Breuring, Eugene M	EMB-4	Electric Deliveries & Customer Counts by Rate Category
72	A-15	E-4	Breuring, Eugene M	EMB-5	Calculation of Annual System Load Factor
73	A-16	F-1	Davis, Emily A	EAD-1	Electric Cost-of-Service Study – Projected 12-Month Period Ending April 30, 2027 Version 1
74	A-16	F-1.1	Davis, Emily A	EAD-2	Electric Cost-of-Service Study – Projected 12-Month Period Ending April 30, 2027 Version 2
75	A-16	F-2	Connolly, Laura M	LMC-1	Summary of Present and Proposed Revenues by Rate Schedule
76	A-16	F-2.1	Connolly, Laura M	LMC-2	Calculation of Rate Design Targets
77	A-16	F-3	Connolly, Laura M	LMC-3	Present and Proposed Revenue Detail
78	A-16	F-4	Connolly, Laura M	LMC-4	Comparison of Present and Proposed Monthly Bills
79	A-16	F-5	Gray, Brittani A	BAG-2	Proposed Electric Tariff Sheets (M.P.S.C. No. 14 Redlined Version
80	A-17	-	Baker, Stacy H	SHB-1	Summary of Actual and Projected Information Technology Operations O&M Expense for the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027
81	A-18	-	Baker, Stacy H	SHB-2	Historical and Projected 13-Month Average of IT Cloud Computing Prepaid Balance for the historical years 2024 - 13-month balance ending December 31, 2024, and for the projected years 2026 – 13-month balance ending April 30, 2027
82	A-19	-	Baker, Stacy H	SHB-3	Summary of Actual and Projected Information Technology Investments O&M Expense for the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027
83	A-20	-	Baker, Stacy H	SHB-5	Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses for the Years 2024, 2025, 2026, and 2027 (CONFIDENTIAL)
84	A-21	-	Baker, Stacy H	SHB-6	Business Case Executive Summaries for Historical, Bridge Period, and Test Year Projects (CONFIDENTIAL)
85	A-22	-	Baker, Stacy H	SHB-7	Asset Refresh Programs Projected Electric and Common Capital Expenditures, For the Projected Year 2026 and Test Year Ending April 30, 2027, and For the Historical and Projected Years 2024 and 2025
86	A-23	-	Baker, Stacy H	SHB-8	Application Currency Programs Projected Electric and Common Capital and O&M Expenditures for the Years 2026, 2027, and Test Year 12 Months Ending April 30, 2027 (CONFIDENTIAL)
87	A-24	-	Baker, Stacy H	SHB-9	Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis
88	A-25	-	Baker, Stacy H	SHB-10	Enhancement Worklist Detail for Years 2016 through October 21, 2024
89	A-26	-	Baker, Stacy H	SHB-11	Projected 13-Month Average of IT S4/HANA Cloud Implementation Costs for the projected years 2026 – 13-month balance ending April 30, 2027 (CONFIDENTIAL)
90	A-27	-	Bleckman, Marc R	MRB-8	Current and Historical Credit Ratings
91	A-28	-	Bleckman, Marc R	MRB-9	Recent Utility Corporate Bond Issuances
92	A-29	-	Bleckman, Marc R	MRB-10	Peer Company Commission Authorized Equity Ratios
93	A-30	-	Bleckman, Marc R	MRB-11	State Regulatory Evaluations
94	A-31	-	Bleckman, Marc R	MRB-12	Wells Fargo December 8, 2023 Report – Figure of the Week: Approved Equity Ratios, 2005-2023
95	A-32	-	Bleckman, Marc R	MRB-13	Cumulative Annual Interest Savings
96	A-33	-	Bleckman, Marc R	MRB-14	S&P Global August 7, 2024 Report – RRA State Regulatory Evaluations – Energy
97	A-34	-	Bleckman, Marc R	MRB-15	UBS May 10, 2023 Report
98	A-35	-	Bleckman, Marc R	MRB-16	S&P February 14, 2024 Report
99	A-36	-	Bleckman, Marc R	MRB-17	S&P August 20, 2024 Credit Report

100	A-37	-	Bleckman, Marc R	MRB-18	Moody's May 31, 2024 Credit Report
101	A-38	-	Bleckman, Marc R	MRB-19	Fitch April 16, 2024 Credit Report
102	A-39	-	Bleckman, Marc R	MRB-20	Peer Company Revolver Capacity Analysis
103	A-40	-	Bleckman, Marc R	MRB-21	S&P January 14, 2025 Report
104	A-41	-	Blumenstock, Richard T	RTB-1	Generating Unit Periodic Outages
105	A-42	-	Blumenstock, Richard T	RTB-2	Generating Unit Availability Projections
106	A-43	-	Blumenstock, Richard T	RTB-4	Summary of the Generation O&M Expense for the Years 2024 through February 2027
107	A-44	-	Blumenstock, Richard T	RTB-5	Zeeland Phase I and II Gas Turbine Upgrade Concept Approvals
108	A-45	-	Blumenstock, Richard T	RTB-6	Jackson Site Spare GSU Transformer Concept Approval
109	A-46	-	Blumenstock, Richard T	RTB-7	Covert Load Commutated Inverter Static Frequency Converter Replacements Concept Approval
110	A-47	-	Blumenstock, Richard T	RTB-8	Covert Site Spare GSU Transformer Concept Approval
111	A-48	-	Blumenstock, Richard T	RTB-9	Covert Control System Project Concept Approval
112	A-49	-	Blumenstock, Richard T	RTB-10	Covert Units 1 through 3 Emerson DCS Evergreen Concept Approval
113	A-50	-	Blumenstock, Richard T	RTB-11	Karn Unit 4 ID Fan Inlet Damper Replacements Concept Approval
114	A-51	-	Blumenstock, Richard T	RTB-12	Karn Units 3 & 4 Combustion Air Heater Replacement Concept Approval
115	A-52	-	Breuring, Eugene M	EMB-6	Estimated Electric Rate Case PSCR Factor
116	A-53 Corrected	-	Byrom, Jessica R	JRB-2	Summary of Actual & Projected O&M Expenses – Customer Experience, Customer Operations: Customer Interactions (Corrected 9/17/2025)
117	A-54	-	Clark, Thomas P	TPC-1	Weadock BESS Project – Milestone Schedule
118	A-55	-	Clark, Thomas P	TPC-2	Weadock BESS Project – Substation Transformer Agreement by and between Virginia Transformer Company and Consumers Energy Company, dated March 1, 2024
119	A-56	-	Clark, Thomas P	TPC-3	Weadock BESS Project – Purchase Order by and between Virginia Transformer Company and Consumers Energy Company, dated March 7, 2024
120	A-57	-	Clark, Thomas P	TPC-4	Weadock BESS Project – EPC Contract between Rauhorn Electric, Inc. and Consumers Energy Company, dated August 2, 2024
121	A-58	-	Clark, Thomas P	TPC-5	Weadock BESS Project – Major Procurement Contract between Our Next Energy, Inc. and Consumers Energy, dated August 2, 2024
122	A-59	-	Clark, Thomas P	TPC-6	Weadock BESS Project – Contract Change Order #1 to the Major Procurement Contract by and between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated December 18, 2024
123	A-60	-	Clark, Thomas P	TPC-7	Iosco BESS Project – Milestone Schedule
124	A-61	-	Clark, Thomas P	TPC-8	Iosco BESS Project – Substation Transformer Agreement by and between Virginia Transformer Company and Consumers Energy Company, dated March 1, 2024;
125	A-62	-	Clark, Thomas P	TPC-9	Iosco BESS Project – Purchase Order by and between Virginia Transformer Company and Consumers Energy Company, dated March 7, 2024
126	A-63	-	Clark, Thomas P	TPC-10	Iosco BESS Project – EPC Contract between Rauhorn Electric, Inc. and Consumers Energy Company, dated August 2, 2024
127	A-64	-	Clark, Thomas P	TPC-11	Iosco BESS Project – Major Procurement Contract between Our Next Energy, Inc. and Consumers Energy Company dated August 2, 2024
128	A-65	-	Clark, Thomas P	TPC-12	Iosco BESS Project – Contract Change Order #1 to the Major Procurement Contract between Our Next Energy, Energy Vault, Inc. and Consumers Energy Company, dated December 18, 2024
129	A-66	-	Connolly, Laura M	LMC-5	Demand Response (DR) Surcharge
130	A-67	-	Connolly, Laura M	LMC-6	Electric Rate Case (ERC) Deferral Surcharge
131	A-68	-	Connolly, Laura M	LMC-7	Investment Recovery Mechanism (IRM) Surcharge

132	A-69	-	Connolly, Laura M	LMC-8	Long-Term Industrial Load Retention Rate (LTILRR) Revenues (CONFIDENTIAL)
133	A-70	-	Connolly, Laura M	LMC-9	Large Economic Development Rate (LEDR) Revenues (CONFIDENTIAL)
134	A-71	-	Conrad, Amy M	AMC-1	EICP Performance Measures
135	A-72	-	Conrad, Amy M	AMC-2	Target Pay Level Market Analysis
136	A-73	-	Conrad, Amy M	AMC-3	Summary of Actual and Projected – Annual Incentive O&M Expenses
137	A-74	-	Conrad, Amy M	AMC-4	Summary of Officer Compensation - Proxy Data
138	A-75	-	Daly, Patrick D	PDD-51	Regulatory Asset and Amortization Expense of the PowerMiDrive and PowerMiFleet for the Projected 12-Month Period Ending April 30, 2027
139	A-76	-	Daly, Patrick D	PDD-52	Regulatory Asset and Amortization of Karn and Campbell Plant Retention and Separation Costs for the Projected 12-Month Period Ending April 30, 2027
140	A-77	-	Daly, Patrick D	PDD-53	Regulatory Asset and Amortization Expense of the Net Book Value of Campbell Plant 1, 2 , and 3 for the Projected 12-Month Period Ending April 30, 2027
141	A-78	-	Daly, Patrick D	PDD-54	Regulatory Asset and Amortization Expense of Karn and Campbell Decommissioning Costs for the Projected 12-Month Period Ending April 30, 2027
142	A-79	-	Daly, Patrick D	PDD-55	Regulatory Asset and Amortization Expense of the Karn, Campbell, and Classic 7 Ash Disposal Costs for the Projected 12-Month Period Ending April 30, 2027
143	A-80	-	Daly, Patrick D	PDD-56	Regulatory Asset and Amortization Expense of the Pension and OPEB Volatility Mechanism, for the Projected 12-Month Period Ending April 30, 2027
144	A-81	-	Daly, Patrick D	PDD-57	Campbell Regulatory Asset – Return On for the Projected 12-Month Period Ending April 30, 2027
145	A-82	-	Daly, Patrick D	PDD-58	LVD Forestry Ramp-up – Revenue Deficiency Impact of O&M Deferral
146	A-83	-	Daly, Patrick D	PDD-59	Demand Response Revenue Requirement
147	A-84	-	Daly, Patrick D	PDD-60	Distribution Deferral for the projected test year ending February 28, 2025
148	A-85	-	Daly, Patrick D	PDD-61	Distribution Deferral for the projected test year ending February 28, 2026
149	A-86	-	Daly, Patrick D	PDD-62	SAP S/4HANA Implementation Project – Revenue Deficiency Impact of O&M Deferral (CONFIDENTIAL)
150	A-87	-	Davis, Emily A	EAD-3	Capacity Related Cost and Charge Calculation (SRM)
151	A-88	-	Davis, Emily A	EAD-4	Substation Ownership Credit
152	A-89	-	Davis, Emily A	EAD-5	Allocation of Surcharges
153	A-90	-	Foster, Matthew J	MJF-1	Summary of Projected Electric & Common O&M Expense for the Years 2024, 2025, 2026 and the 12 Months Ending April 30, 2027
154	A-91	-	Foster, Matthew J	MJF-2	Electric Projected Corporate Services O&M Expense for the Years 2024, 2025, 2026 and the 12 Months Ending April 30, 2027
155	A-92	-	Foster, Matthew J	MJF-3	S&P Global Market Intelligence Ranking of Consumers Energy Electric A&G Costs for 2023
156	A-93	-	Foster, Matthew J	MJF-4	Electric Uncollectible Accounts Expense for the Years 2020 through 12 Months Ending April 30, 2027
157	A-94	-	Foster, Matthew J	MJF-5	Electric Injuries & Damages Expense for the Years 2020 through the 12 Months Ending April 30, 2027
158	A-95	-	Gast, Alex M	AMG-2	Summary of Actual & Projected O&M Expenses – Demand Response
159	A-96	-	Gray, Brittani A	BAG-1	Summary of Tariff Changes
160	A-97	-	Grob, Kendra K	KKG-1	Summary of Actual and Projected Benefits O&M Expenses for the Year 2024 and Test Year Twelve Months Ending April 30, 2027
161	A-98	-	Grob, Kendra K	KKG-2	CMS Energy – Pension Plans A and B - ASC 715 Pension Expense Estimates ($ millions)
162	A-99	-	Grob, Kendra K	KKG-3	CMS Energy - ASC 715 OPEB Expense Estimates ($ millions)
163	A-100	-	Grob, Kendra K	KKG-4	CMS Energy – Actuarial Letter of Support for 2025 Year Projections
164	A-101	-	Guinn, Quentin A	QAG-2	Summary of Actual and Projected O&M Expenses Facilities & Shared Services
165	A-102	-	Guinn, Quentin A	QAG-3	Detailed List of Projected Electric Capital Expenditures Facilities & Shared Services
166	A-103	-	Guinn, Quentin A	QAG-4	Fleet Responsibility Costs

167	A-104	-	Guinn, Quentin A	QAG-5	Detailed List of Projected Electric Capital Expenditures Fleet Services for the Years 2024, 2025, 2026 and test year 12 months ending April 30, 2027
168	A-105	-	Guinn, Quentin A	QAG-6	Summary of Fleet Tooling Actual & Projected Capital Expenditures
169	A-106	-	Guinn, Quentin A	QAG-7	New Construction & Renovations Plan Summaries
170	A-107	-	Hayward, Megan L	MLH-1	Consumers Energy Electric Asset Management High Voltage Distribution (HVD) Pole Inspection Specifications
171	A-108	-	Hayward, Megan L	MLH-2	Pole Inspection Plan by HVD Line
172	A-109	-	Hayward, Megan L	MLH-3	Summary Projected Electric Capital Expenditures for the Bridge Period 16 Month Ending April 30th, 2026
173	A-110	-	Hayward, Megan L	MLH-4	Summary Projected Electric Capital Expenditures for the Test Year 12 Months Ending April 30th, 2027
174	A-111	-	Hayward, Megan L	MLH-5	Electric Asset Categorization Mapping Document
175	A-112	-	Kelly, Michael P	MPK-2	Electric Distribution Actual and Projected Capital Expenditures Master
176	A-113	-	Kelly, Michael P	MPK-3	Electric Distribution Summary of 5yr Historical Electric Capital Expenditures
177	A-114	-	Kelly, Michael P	MPK-4	New Business Program Summary of Actual and Projected Electric Capital Expenditures
178	A-115	-	Kelly, Michael P	MPK-5	Reliability Program Summary of Actual and Projected Capital Expenditures
179	A-116	-	Kelly, Michael P	MPK-6	Capacity Program Summary of Actual and Projected Capital Expenditures
180	A-117	-	Kelly, Michael P	MPK-7	Demand Failures Program Summary of Actual and Projected Capital Expenditures
181	A-118	-	Kelly, Michael P	MPK-8	Asset Relocation Program Summary of Actual and Projected Capital Expenditures
182	A-119	-	Kelly, Michael P	MPK-9	Electric Other Program Summary of Actual and Projected Capital Expenditures
183	A-120	-	Kelly, Michael P	MPK-10	Wildfire Risk Mitigation Program Summary of Actual and Projected Capital Expenditures
184	A-121	-	Kelly, Michael P	MPK-11	IIJA Grant Funds Summary of Actual and Projected Capital Expenditures
185	A-122	-	Kelly, Michael P	MPK-12	Summary of Actual & Projected Electric & Common O&M Expenses Master
186	A-123	-	Kelly, Michael P	MPK-13	Summary of Actual & Projected Electric & Common O&M Expenses – Operations and Engineering
187	A-124	-	Kelly, Michael P	MPK-14	Summary of 5yr Historical O&M Expenses
188	A-125	-	Kelly, Michael P	MPK-15	Summary of Actual & Projected Electric & Common O&M Expenses – O&M Programs, part 1
189	A-126	-	Kelly, Michael P	MPK-16	Summary of Actual & Projected O&M Programs, part
190	A-127	-	Kelly, Michael P	MPK-17	Summary of Actual & Projected O&M Expenses Cost Splits
191	A-128	-	Kelly, Michael P	MPK-18	Summary of O&M Expenses Projected Using Inflation
192	A-129	-	Kelly, Michael P	MPK-19	Amended Reliability Roadmap
193	A-130	-	Kelly, Michael P	MPK-20	2020-2024 Distribution Unit Costs
194	A-131	-	Kelly, Michael P	MPK-21	2023 Electric System Loss Study Report
195	A-132	-	Kelly, Michael P	MPK-22	Mitigating Wildfire Risk in Consumers Energy's Service Territory (2025-2029)
196	A-133	-	Kelly, Michael P	MPK-23	Advanced Metering Infrastructure Metrics and Elements
197	A-134	-	Kelly, Michael P	MPK-24	Electric Distribution Summary of Actual & Projected Capital Expenditures per Rate Case Filing Requirements Attachment 11
198	A-135	-	Kelly, Michael P	MPK-25	Reliability Regression Analysis for Environmental Justice Communities
199	A-136	-	Kelly, Michael P	MPK-26	AMI Opt Out Charges
200	A-137	-	Kelly, Michael P	MPK-27	Environmental Justice Hosting Capacity Maps
201	A-138	-	Kelly, Michael P	MPK-28	Reliability and Disconnections Regression Analysis Overview and Observations
202	A-139	-	Koetje, Jon J	JJK-1	Karn Units 1&2 Decommissioning Plan Expenditures
203	A-140	-	Koetje, Jon J	JJK-2	Actual Coal Ash Disposal Plan Expenditures
204	A-141	-	Koetje, Jon J	JJK-3	JHC Decommissioning Plan Expenditures

205	A-142	-	McPhail, Scott A	SAM-1	Bridge Period Grid Automation Projects
206	A-143	-	McPhail, Scott A	SAM-2	Test Year Grid Automation Projects
207	A-144	-	McPhail, Scott A	SAM-3	Line Sensor Reliability Benefits
208	A-145	-	McPhail, Scott A	SAM-4	RAMP Reliability Benefits
209	A-146	-	McPhail, Scott A	SAM-5	Line Regulator Controller Upgrades BCA
210	A-147	-	McPhail, Scott A	SAM-6	NOVA TS Comms Reliability Benefits
211	A-148	-	McPhail, Scott A	SAM-7	Peer-Peer Schemes Reliability Benefits
212	A-149	-	McPhail, Scott A	SAM-8	Recloser Modernization Reliability Benefits
213	A-150	-	McPhail, Scott A	SAM-9	Supplemental Line Sensors Reliability Benefits
214	A-151	-	McPhail, Scott A	SAM-10	Metro Modernization Reliability Benefits
215	A-152	-	McPhail, Scott A	SAM-11	Distribution Asset Management BCA
216	A-153	-	McPhail, Scott A	SAM-12	FLISR EPRI Report
217	A-154	-	McPhail, Scott A	SAM-13	FLISR BCA
218	A-155	-	McPhail, Scott A	SAM-14	Weather Stations Reliability Benefits
219	A-156	-	Meschke, Ashley E	AEM-1	2024-2025 EICP Operational Goals
220	A-157	-	Meschke, Ashley E	AEM-2	2024 Customer Benefits: Employee Safety
221	A-158	-	Meschke, Ashley E	AEM-3	2024 Customer Benefits: Reliability
222	A-159	-	Meschke, Ashley E	AEM-4	2024 Customer Benefits: Culture Index – Reduced Employee Turnover
223	A-160	-	Metz, Megan L	MLM-1	Power Supply Cost Recovery Forecast for May 1, 2026 – April 30, 2027
224	A-161	-	Metz, Megan L	MLM-2	Consumers Energy Forecast – Energy Market Sales Revenue and Total Variable Expense
225	A-162	-	Metz, Megan L	MLM-3	Summary of PPA Changes from September 30, 2024 – February 1, 2025
226	A-163	-	Myers, Heidi J	HJM-1	Distribution Investment Recovery Mechanism - Annual Revenue Requirement
227	A-164	-	Myrom, Jeffrey A	JAM-2	Transportation Electrification Plan Deferred Asset Costs
228	A-165	-	Myrom, Jeffrey A	JAM-3	Transportation Electrification Plan Cost Benefit Analysis
229	A-166	-	Partlan, Jennifer M	JMP-1	Bridge Period LVD Project List
230	A-167	-	Partlan, Jennifer M	JMP-2	Test Year LVD Project List
231	A-168	-	Partlan, Jennifer M	JMP-3	Conservation Voltage Reduction Measurement and Verification Independent Assessment
232	A-169	-	Partlan, Jennifer M	JMP-4	Summary of 2023 and 2024 LVD Repetitive Outages Investment
233	A-170	-	Stewart, Sara E	SES-1	Line Clearing O&M Expense
234	A-171	-	Stewart, Sara E	SES-2	Projected LVD Tree-Caused Reliability Impacts of the Line Clearing Ramp-Up Plan
235	A-172	-	Stewart, Sara E	SES-3	2025 HVD Line Clearing Work Plan
236	A-173	-	Stewart, Sara E	SES-4	2025 LVD Line Clearing Work Plan
237	A-174	-	Stewart, Sara E	SES-5	Post-Work Review Supporting Documentation Examples (CONFIDENTIAL)
238	A-175	-	Stewart, Sara E	SES-6	Summary of O&M Expenses Projected Using Inflation
239	A-176	-	Stewart, Sara E	SES-7	Formal Optimization Analysis of Line Clearing Cycles
240	A-177	-	Stewart, Sara E	SES-8	Utility Vegetation Management in North America: Results from a 2019 Utility Forestry Census of Tree Activities and Operations
241	A-178	-	Tetrick, Caitlin M	CMT-1	Summary of Historical Year, Bridge Period, and Projected Test Year for Operations Resources – Electric LVD Workplan
242	A-179	-	Tetrick, Caitlin M	CMT-2	Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources – Electric HVD Workplan

243	A-180	-	VanBlarcum, Brian J	BJV-1	Development of the Property Tax Rate for the Test Year
244	A-181	-	VanBlarcum, Brian J	BJV-2	Amortization of Excess Deferred Federal Income Taxes for the Test Year and Tax Reform Regulatory Liability & Amortization
245	A-182	-	Gast, Alex M	AMG-3	Whole Home Optimization Demand Response pilot
246	A-183	-	Baker, Stacy H	SHB-12	Asset Refresh Program ("ARP")-Field Device Asset Management ("FDAM") and ARP-Workstation Asset Management ("WAM") New Purchases Four-Year Historical Average
247	A-184	-	Baker, Stacy H	SHB-13	Staff Audit Responses U21870-SA-CE-024 and U21870-SA-CE-090
248	A-185	-	Baker, Stacy H	SHB-14	Asset Refresh Program-Field Device Asset Management number of units/devices in place at the end of each year 2021, 2022, 2023, and 2024 including new purchases
249	A-186	-	Baker, Stacy H	SHB-15	Staff Audit Response U21870-SA-CE-080
250	A-187	-	Bleckman, Marc R	MRB-22	Company Revision to Staff's Exhibit S-4, Schedule D-1 Alternative
251	A-188	-	Bleckman, Marc R	MRB-23	Company Revision to Staff's Exhibit S-4, Schedule D-2 Alternative
252	A-189	-	Bleckman, Marc R	MRB-24	MPSC Staff's Answer to Consumers Energy's Fourth Discovery Request
253	A-190	-	Bleckman, Marc R	MRB-25	Attorney General's Answer to Consumers Energy's Third Discovery Request
254	A-191	-	Blumenstock, Richard T	RTB-13	Covert Generating Station Units 1 & 3 LTSA Extra Work
255	A-192	-	Blumenstock, Richard T	RTB-14	Ludington Pumped Storage Dike Load Center Replacement
256	A-193	-	Blumenstock, Richard T	RTB-15	Ludington Pumped Storage Oil Water Separator
257	A-194	-	Blumenstock, Richard T	RTB-16	Ludington Pumped Storage Pony Motor Rotor Cracking and Fretting
258	A-195	-	Blumenstock, Richard T	RTB-17	Ludington Pumped Storage Distributed Control System Control Relay Replacement
259	A-196	-	Blumenstock, Richard T	RTB-18	Ludington Pumped Storage Unit Governors
260	A-197	-	Blumenstock, Richard T	RTB-19	Ludington Pumped Storage Lower Penstock Expansion Joint Chamber Waterstop
261	A-198	-	Blumenstock, Richard T	RTB-20	Covert Generating Station spare Generator Step-Up ("GSU") transformer
262	A-199	-	Blumenstock, Richard T	RTB-21	Zeeland Generating Station Phase II Gas Turbine Advanced gas path replacement and axial fuel staging project
263	A-200	-	Blumenstock, Richard T	RTB-22	Zeeland Generating Station Phase I performance report
264	A-201	-	Blumenstock, Richard T	RTB-23	Emergent Reliability Investment for the years 2022 through 2025
265	A-202	-	Blumenstock, Richard T	RTB-24	Jackson Generating Station spare GSU transformer
266	A-203	-	Blumenstock, Richard T	RTB-25	Jackson Generating Station LM1-6 variable inlet guide vane
267	A-204	-	Blumenstock, Richard T	RTB-26	Year over Year Generation O&M Expense
268	A-205	-	Blumenstock, Richard T	RTB-27	Copperleaf Value Model Methodology
269	A-206	-	Bulkley, Ann E	AEB-2	Cost of Common Shareholder's Equity
270	A-207	-	Bulkley, Ann E	AEB-3	Work Papers AG-37B, AG-39A, and AG-39B
271	A-208	-	Daly, Patrick D	PDD-63	Adjusted Revenue Deficiency for the Projected 12-Month Period Ending April 30, 2027
272	A-209	-	Daly, Patrick D	PDD-64	Adjusted Rate Base for the Projected 12-Month Period Ending April 30, 2027
273	A-210	-	Daly, Patrick D	PDD-65	Adjusted Utility Plant for the Projected 12-Month Period Ending April 30, 2027
274	A-211	-	Daly, Patrick D	PDD-66	Capital Spending Reconciliation for the Projected 12-Month Period Ending April 30, 2027

275	A-212	-	Daly, Patrick D	PDD-67	Adjusted Working Capital for the Projected 12-Month Period Ending April 30, 2027
276	A-213	-	Daly, Patrick D	PDD-68	Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027
277	A-214	-	Daly, Patrick D	PDD-69	Reconciliation of Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027
278	A-215	-	Daly, Patrick D	PDD-70	Adjusted Operations & Maintenance Expenses for the Projected 12-Month Period Ending April 30, 2027
279	A-216	-	Daly, Patrick D	PDD-71	Income Tax Effect of Interest for the Projected 12-Month Period Ending April 30, 2027
280	A-217	-	Daly, Patrick D	PDD-72	Interest Synchronization Adjustment for the Projected 12-Month Period Ending April 30, 2027
281	A-218	-	Hayward, Megan L	MLH-6	Discovery Response 21870-AG-CE-0466
282	A-219	-	Kelly, Michael P	MPK-29	Actual and Forecasted 2025 Capital and O&M Spending
283	A-220	-	Kelly, Michael P	MPK-30	Audit Response 21870-SA-CE-248
284	A-221	-	Kelly, Michael P	MPK-31	Discovery Response 21870-AG-CE-0514
285	A-222	-	Kelly, Michael P	MPK-32	Discovery Response 21870-AG-CE-0453
286	A-223	-	Myrom, Jeffrey A	JAM-4	Discovery Response 21870-MEIU-CE-0042
287	A-224	-	Myrom, Jeffrey A	JAM-5	Discovery Response 21870-MEIU-CE-0043
288	A-225	-	Partlan, Jennifer M	JMP-5	Discovery response 21870-ST-CE-0078
289	A-226	-	Partlan, Jennifer M	JMP-6	Example of LVD Concept Approval
290	A-227	-	Partlan, Jennifer M	JMP-7	Discovery response 21870-AB-CE-0712
291	A-228	-	VanBlarcum, Brian J	BJV-3	Workpaper WP-PDD-29
292	A-229	-	VanBlarcum, Brian J	BJV-4	Workpaper WP-PDD-36

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Crystal L. Chacon, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on October 21, 2025, she served an electronic copy of **Consumers Energy Company's Rebuttal Testimony and Exhibits** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 21st day of October 2025.

Melissa K. Harris

Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 06/11/2027
Acting in the County of Hillsdale

ATTACHMENT 1 TO CASE NO. U-21870

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